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DEVONIAN SHALE PRODUCTION AND POTENTIAL

Proceeding of the Seventh Appalachian Petroleum Geology Symposium held at Morgantown, W.Va. March l-4 1976

Sponsored by West Virginia Geological Survey, West Virginia University, Morgantown Energy Research Center, ERDA

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

Morgantown Energy Research Center

Available from the National Technical information Service, U. S. Department of Commerce, Springfield, Virginia 22 161

Price: Paper Copy $9.25 (domestic)
$11.75 (foreign)
Microfiche $2.25 (domestic)
$3.75 (foreign)

Printed in the United States of America
USERDA Technical Information Center, Oak Ridge, Tennessee

MERC/SP-76/2
Distribution Category UC-92

PROCEEDINGS

OF THE

SEVENTH ANNUAL

APPALACHIAN PETROLEUM GEOLOGY SYMPOSIUM

DEVONIAN SHALE--PRODUCTION AND *POTENTIAL*

sponsored by

THE WEST VIRGINLA GEOLOGLCAL & ECONOMIC SURYEY

THE WEST VIRGINIA UNIVERSITY DEPARTMENT OF GEOLOGY & GEOGRAPHY

AND THE UNITED STATES ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION,

MORGANTOWN ENERGY RESEARCH CENTER

March l-4, 1976

Lakeview Inn & Country Club

Morgantown, West Virginia

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INTRODUCTION

The Devonian Shale Symposium sponsored by the West Virginia Geological and Economic Survey, the West Virginia University Department of Geology and Geography, and the United States Energy Research and Development Administration was held at the Lakeview Country Club and Inn outside of Morgantown, West Virginia, from the 1st through the 4th of March, 1976.

The subject of "*Devonian Shale--Production* and *Potential*" was selected for the annual symposium this year because of widespread interest within industrial, academic and governmental organizations concerning the hydrocarbon potential of the Devonian shales in the Appalachian Basin.

The shales, often called the black and/or brown shales, have produced gas since the early 1900's along the western margin of the basin; and, individual wells within the southern portion of the basin have been producing for over thirty years. However, throughout most of the deeper portions of the basin, wells only encounter non-commercial shows of gas from the shale. Yet, the enormous amount of gas contained within the shale (estimated at 460 quadrillion cubic feet of gas resource) suggests that it has great resource potential. Indeed, the amount is so large, and our projected needs are so great, that the eastern shales offer great hope for the future, if only the technology can be found which will locate and unlock the gas in commercial amounts. We designed the symposium in an attempt to make an authoritative assessment of the current geological, geochemical and engineering aspects of these rocks, and to discuss further research and developmental needs for enhanced production.

As usual, the symposium consisted of three days of lectures by foremost authorities on the various aspects of the petroleum geology and engineering of shales.

Evenings were devoted to panel discussions concerning specific geologic and engineering problems, and were aimed at encouraging the interchange of ideas among speakers and attendees.

The first day of the program was designed to cover the stratigraphy, distribution and present production of the shale. The second day covered structural parameters of the geology which control production, and techniques to discover and produce commercial amounts of gas. The third day continued with the technology for logging and stimulating wells within the shale, The meeting concluded with a brief outline and discussion of E.R.D.A.'s eastern shale project which is designed to enhance discovery and production of gas from the shale.

Discussions throughout the meeting pointed out the variability of production characteristics and potentials between adjacent wells even within the same field. The uncertainties and complexities of geologic parameters that control production make exploration very much a "hit or miss" proposition in an attempt to find commercial wells. Based on the low permeability of shale and variable yields of adjacent wells, it is generally conceived that fracturing within the shale controls the production potential of each well. Even though this well-to-well variability is common, it was noted that there clearly are certain areas within the basin and, therefore, certain areas that have produced far more gas than other areas. At the present time, the only area of active exploration within the Appalachian Basin is in eastern Kentucky and southwestern West Virginia. Very little geological information is available to indicate why these areas form the center of the production. It was suggested during the meeting that other areas may be prospective, but that these are simply not being investigated because of marginal economics of shale gas development, even in the active areas of the southern basin. Given these marginal economics of production and the high-risk value of exploration, it is unlikely that industry would spend the large sums of money needed to evaluate exploration and production parameters to expand production.

E.R.D.A. has embarked upon an extensive resource evaluation and research into the controls that affect the accumulation of hydrocarbon within the shale section. E.R.D.A.'s program is also designed to increase the production of gas from proven reserves in these shales by development and implementation of new drilling and production techniques.

The chief goals of the symposium--to clarify and define those engineering and geologic parameters that control production--were attained. Unfortunately, it was clear that little is known about the geologic and geochemical parameters that control production, and that the current technology and engineering for producing these shale gases is mostly an offshoot of normal production and engineering techniques found in other types of reservoirs. Many of the participants felt that an accelerated program of research is necessary for the development of new techniques to enhance the recovery of gas from the shales; and, to that end, a rise in the price of gas, along with governmental research, should stimulate exploration and development of gas reserves in the shale.

R. C. Shumaker

UPPER DEVONIAN BLACK SHALE--WORLDWIDE DISTRIBUTION AND WHAT IT MEANS

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University of Cincinnati

ABSTRACT

Radioactive, organic-rich black shales of Late Devonian-Early Mississippian age are distributed widely over North America. These black shales are known from twenty-six states of the United States and from six provinces and territories of Canada. In addition, black shale may have limited distribution in northern Mexico near the United States-Mexican boundary. Over twenty-five different stratigraphic names have been assigned to Devonian-Mississippian black shales. Perhaps the most familiar of these names are the Chattanooga and Ohio shales of the Appalachian Basin. Other basins which lie far to the west and to the north of the Appalachian Basin, however, also contain black shales of Devonian-Mississippian age. The Exshaw Formation, for example, is present over much of southern Alberta; and, the Long Rapids Formation is a black shale found in the Moose River Basin just south of Hudson Bay.

Thickness of Devonian-Mississippian black shales ranges from less than twenty feet in central Texas (Doublehorn Shale) and south-central Kentucky (New Albany Shale) to well over 2000 feet in the subsurface of West Virginia. In the Appalachian Basin, natural gas has been produced commercially from these shales for about one hundred years, although gas from black shale was first used in 1821 in New York State. Oil has been produced from some of the western equivalents of Appalachian black shales, such as the Bakken Formation of the North Dakota portion of the Williston Basin. Generally, oil occurs in siltstones between thin black shale beds.

Sedimentation during Late Devonian and Early Mississippian time in North America occurred over approximately one-quarter of the continent, in a pattern which resembles the Cretaceous seaway of western Canada and the United States. Areas of Devonian-Mississippian sedimentation extended from northern Alaska and the Canadian Arctic southward through western Canada and the United States. Devonian-Mississippian sedimentary rocks are also found in Michigan, southern Ontario, and Hudson Bay. Three orogenic belts fringed North America, parallel to the present eastern, western, and Arctic coastlines.

Two tectonic settings characterize black shale of North America. Black shale may occur as distal facies of turbidities associated with the Catskill Delta. Or, it may occur on the craton, far from marginal geosynclines.

Devonian-Mississippian black shales are typical not only of North America, but also occur on three other continents: South America, Africa, and Europe. Black shales of South America and Africa are similar to those of North America in that they are associated with sandstones and siltstones. In central Europe and the western Soviet Union, on the other hand, black shales are found as basinal facies near growing carbonate reefs which stood high above the floor of the basin. The association of reefs and black shale is a third tectonic setting of black shale and is not known from North America.

To have produced these distinctive shales, black, organic-rich mud had to accumulate during the Late Devonian and Early Mississippian. The accumulation of this type of sediment is independent of water depth or position of shoreline, as black muds are known from very shallow areas like the Baltic Sea to deep oceanic environments such as the Argentine Basin of the South Atlantic Ocean. Moreover, black mud deposition is also independent of time, for examples of black shales occur in Precambrian, Paleozoic, Mesozoic, and Tertiary sections. Two controls probably influence the accumulation of black mud. First, there must be an abundant supply of organic matter. And, second, density stratification of the water mass in the basin must exist so that vertical circulation is poor, a condition which favors preservation of organic matter. The implication of these two controls is this: They suggest that former arguments over water depth of black shales are not the critical arguments, as depth does not control the accumulation of black, organic-rich muds.

STRATIGRAPHY AND PETROLOGY OF THE DEVONIAN "BROWN" SHALE IN WEST VIRGINIA

Douglas G. Patchen and Richard E. Larese

West Virginia Geological and Economic Survey

SUMMARY

The term "Devonian shales" includes all of the clastic rocks between the base of the Lower Mississippian Berea Sandstone and the top of the lower Middle Devonian Onondaga Limestone (fig. 1). The name is used only in the western and southern one-third of the State where the Catskill redbeds, various Hampshire and Chemung sandstones, and the Tully Limestone are not present to subdivide the thick shale sequence. The term "Brown shale" is more restrictive, referring to only the finer, darker, more radioactive shales in the lower half to two-thirds of the Devonian shales. The thickness of the Middle and Upper Devonian clastics increases from 1000 to 7000 feet from Kentucky to the Maryland border (fig. 2). The portion of this interval that is occupied by black or dark gray "Brown" shales, however, is much less, ranging from 10 to 60 percent in the counties with Brown shale gas production, and 15 to 20 percent in counties farther north and east where gas is produced from 17 named Hampshire and Chemung sandstones. Tentative subsurface correlations, based on sample descriptions, have enabled us to subdivide the 2200-2400 feet of Devonian shales in Jackson and Putnam County fields (fig. 3) into four zones: an upper gray and greenish-gray, sandy, silty interval which occupies the upper half; a dark gray to black interval, 400 feet thick, of "Brown shales" characterized by finer grain size, darker colors, and the presence of spores; a greenish-gray zone, also 400 feet thick, which lacks silt and spores; and a lower black shale, probably equivalent to the Harrell and Marcellus (fig. 4).

Attempts to extend these four zones farther to the east have resulted in the tentative correlations of the brown shale interval with the Riley-Benson zone, the main gas-producer in north-central West Virginia. This brown shale zone is the main gas-producer in 26 named fields in wouthwestern West Virginia, and one, Cottageville, farther to the north in Jackson County (fig. 5).

A preliminary petrographic analysis was performed on selected oriented core samples from the L. A. Baler well in the Cottageville Field (fig. 6, Permit Number Jac. 1369) which were made available to the writers by Consolidated Gas Supply Corporation and USERDA. Mineralogical and textural aspects of the core were analyzed employing X-ray diffraction, light microscopy and low-temperature ashing techniques.

Lithologically, the samples analyzed in this study fell into four rock-type categories: shaly-siltstones, silty-shales, dolomitic shales, and shales (fig. 7). Generally, however, the samples consisted of silty-shales and shales. The argillaceous fraction of the core specimens consisted principally of illite with lesser amounts of kaolinite, chlorite and mica (muscovite, biotite). These minerals comprised the bulk of the clay size (< .0039 mm) material of the core, and by thin section modal analyses were noted to collectively account for as much as 92 percent by volume in the true shale facies to as little as 33 percent by volume in the silty facies of the unit. The non-clay fraction of the core consisted principally of angular to rounded monocrystalline quartz in addition to minor amounts of orthoclase and plagioclase feldspar. Taken together, quartz and feldspar (> .0039 mm in diameter; the clay-silt boundary) accounted for as little as 5.2 percent by volume in organic-rich shale samples to as much as 43 percent by volume in the more silty facies of the unit. Undoubtedly, these values of quartz and feldspar do not represent the total amount present in the analyzed samples, as some of these constituents were most likely clay-size and, subsequently, not resolved under the light microscope. Almost every sample analyzed contained at least trace amounts of carbonate, principally in the form of dolomite. The dolomite was authigenic in origin, occurring as both discrete euhedral crystals and as irregular patchy masses constituting as much as 16.5 percent by volume of some specimens. Much of this carbonate apparently formed by replacement of argillaceous material. Calcite was also noted in minor amounts, never exceeding 2.4 percent by volume. For the most part the calcite was of clastic origin representing fragmentary remnants of fossil shells. The dominant heavy mineral within the unit was pyrite. Ranging from 0.5-18.0 percent by volume of selected samples, this heavy mineral was noted to occur as: discrete euhedral and irregular-shaped crystals; lenses parallel to bedding, and as framboidal masses. Most commonly, pyrite appeared to have replaced organic and argillaceous material. Other heavy minerals identified in the shale included angular to rounded grains of zircon and tourmaline. In addition, concretionary masses of sulfate surrounded by pyrite were noted in one sample.

Within the pay zone of the L. A. Baler well, the most common rock type consisted of dark gray to brown organic-rich shale. In the analyses of samples from this interval several interesting diagenetic and textural characteristics were noted. These included: nature of the organic material; orientation and mineral filling of fractures; and occurrence of quartz-rich lenses.

Organic material comprised as much as 3.9 percent by weight of selected shale specimens and occurred in at least three forms. Commonly it was present as finely-divided material which imparted a reddish-brown to chocolate-brown color to the matrix. It appears that some of this material may have occurred as coatings on argillaceous constituents making up the matrix. Secondly, organic material was noted to occur as reddish-brown irregular shreds which may have represented woody material. These shreds commonly exceeded 1.0 mm in length and generally accentuated bedding. The third way in which organic matter was found in the shale was as discrete organic bodies (fig. 8) constituting spore material. In thin section the spores took on a lemon-yellow color and were commonly elongated in a direction parallel to bedding. Generally, the centers of the spores contained pyrite. In some specimens, the amount of spore material exceeded 7.0 percent.

In an analysis of fracture orientations in the Baler core, Mr. Royal Watts-of USERDA noted that in the portion of the core above the pay zone (fig. 9, A-D), 80 percent of the measured fractures possessed orientations of N 40°-50° E. However, in the lower portion of the core in areas where gas shows were noted, he found a greater variation in fracture orientation (fig. 10, A-B). In these areas, 21 percent of the fractures were oriented N 40°-50° E; whereas, 14 percent were oriented N 10°-15° W. Ten (10) percent of the measured fractures in these areas had N 15°-20° E orientations. In the extreme basal portions of the core 13 percent of the measured fractures had orientations of N 85°-89° W. It was also noted that fractures in the pay zone were commonly filled with dolomite (figs. 11, 12) a situation not commonly noted in other non-productive portions of this particular core. The dolomite-filled fractures varied from 0.15 mm- 0.51 mm in width and averaged 0.30 mm in width. One impregnated sample served to illustrate that the dolomite filling could be both porous and permeable. In essence, the dolomite mineral filling served to hold the fractures open.

In an analysis of organic-rich shales in the pay zone, it was noted that clastic quartz and feldspar were commonly segregated in lenses parallel to bedding (fig. 13). Although not readily apparent in hand specimen, these lenses were actually quite common, with the quartz and feldspar grains being sand size in some instances. Possibly, gas geing generated within the organic-rich matrix of the shale is able to permeate into these lenses and, subsequently, migrate laterally to areaswhere the lenses intersect the vertical fractures which ultimately appear to control most of the gas production in the "Brown shale" fields.

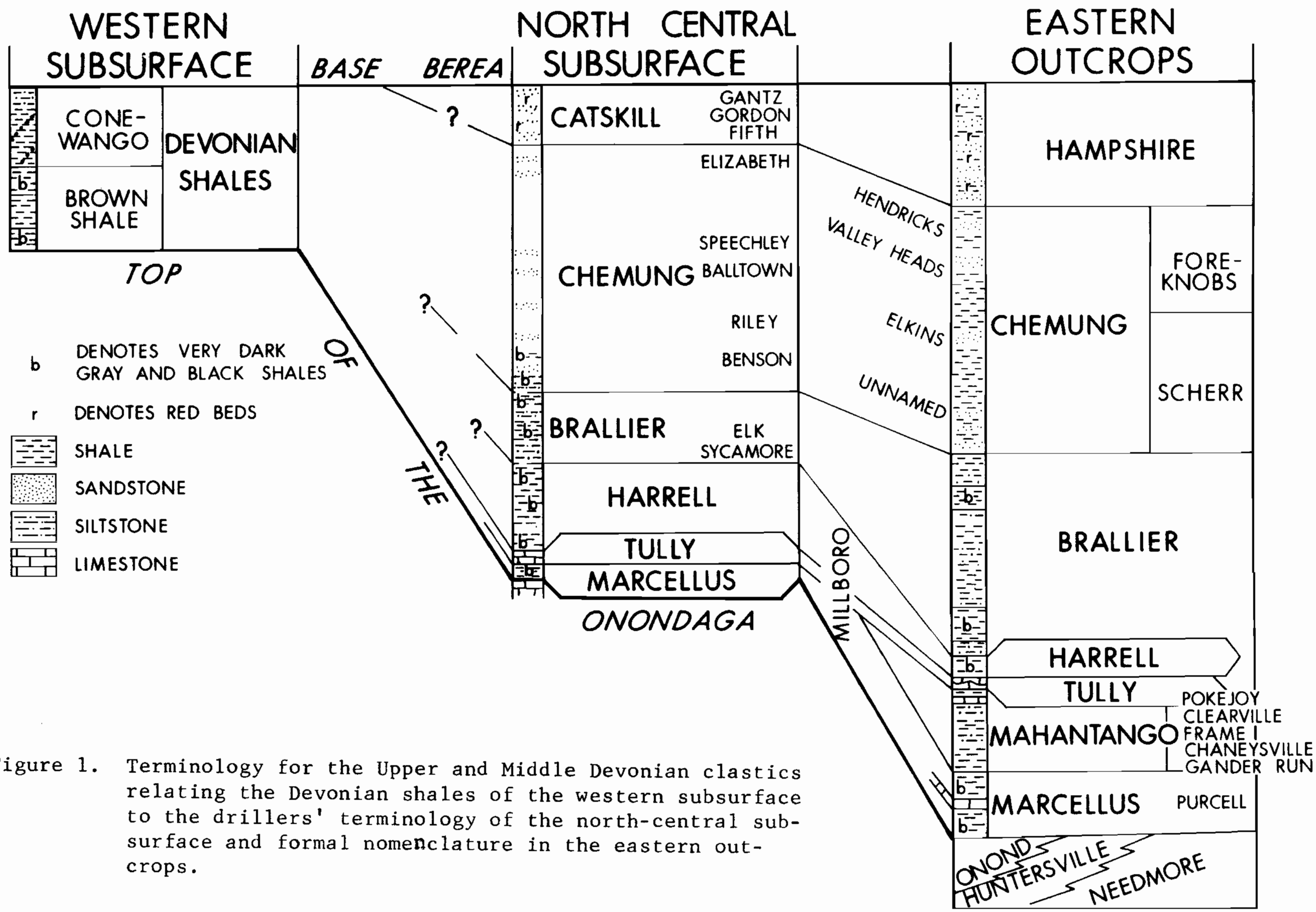


Figure 1. Terminology for the Upper and Middle Devonian clastics relating the Devonian shales of the western subsurface to the drillers' terminology of the north-central subsurface and formal nomenclature in the eastern outcrops.

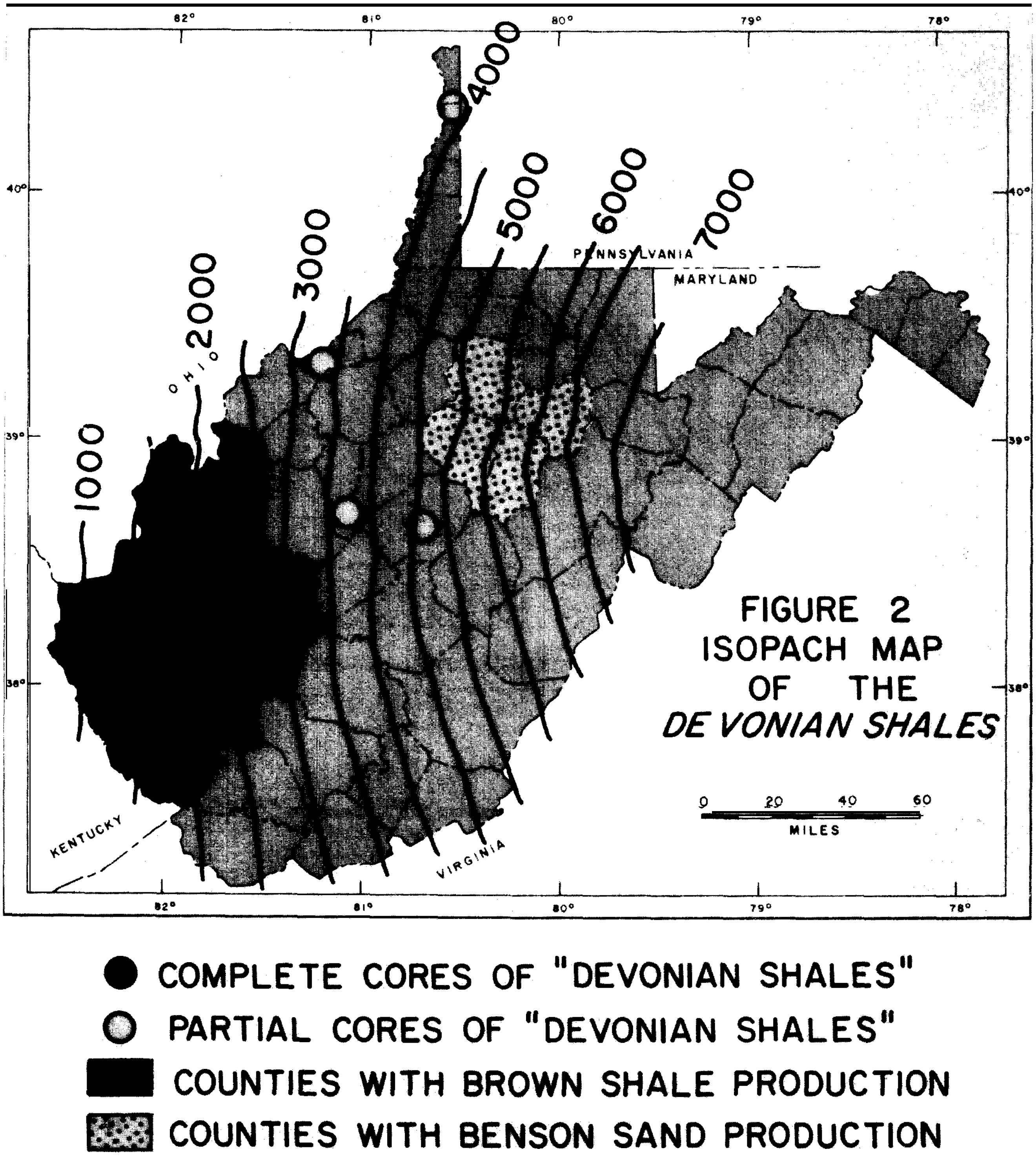


Figure 2. Isopach map of the Devonian shales and their equivalents to the east.

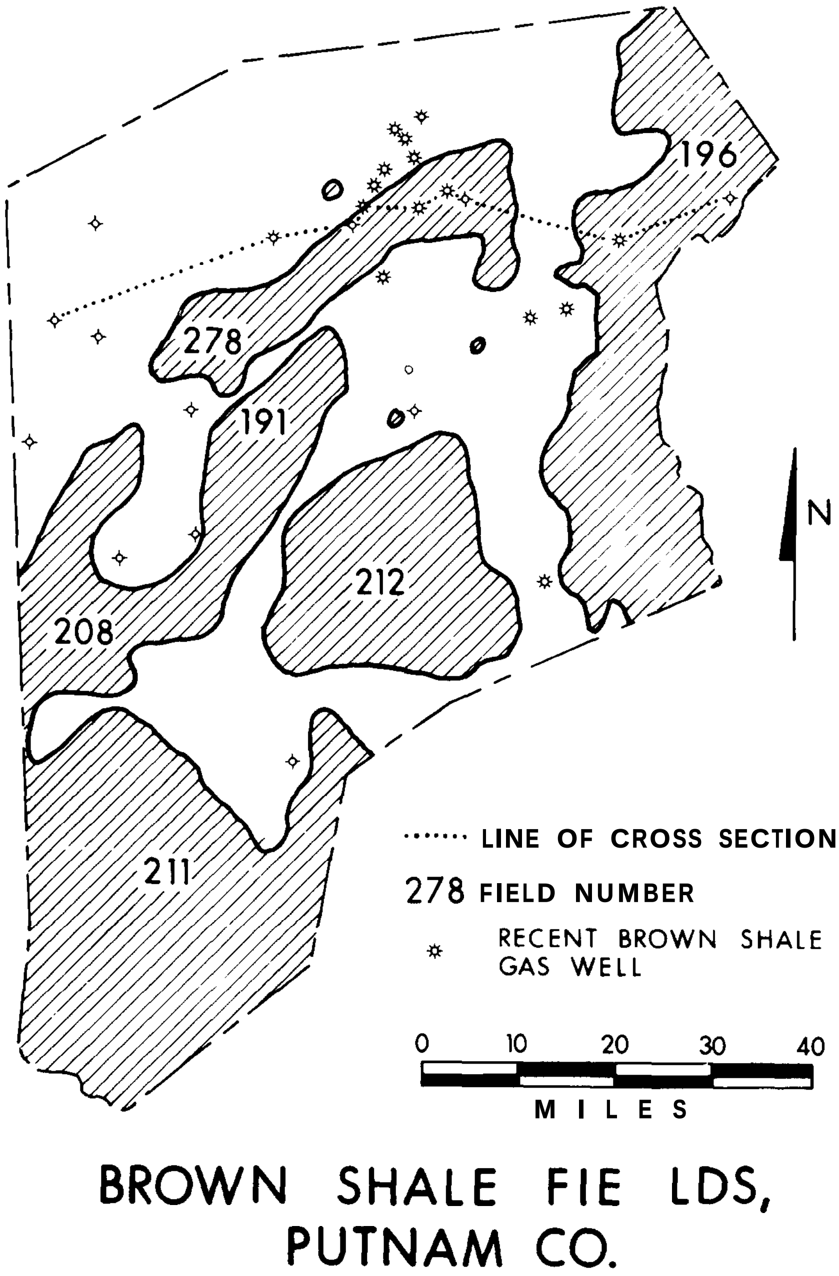
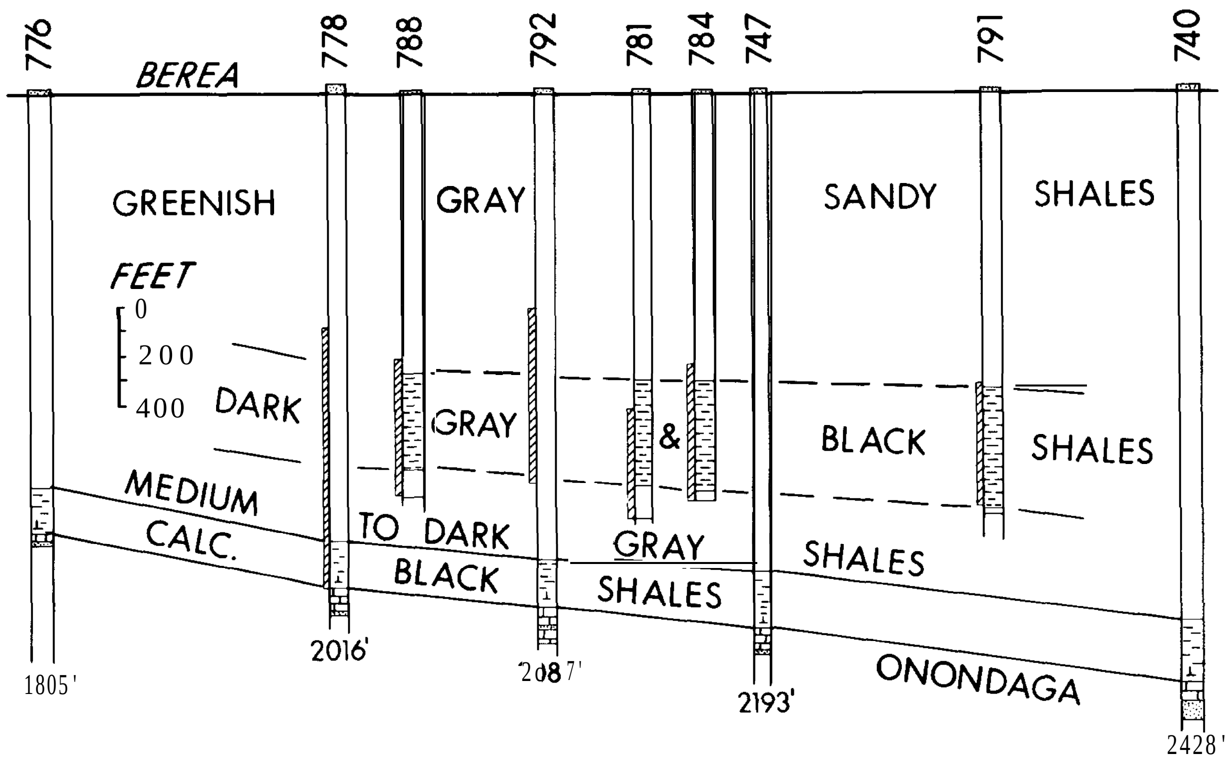


Figure 3. Brown shale fields in Putnam County, WV. Field numbers are from the 1970 Oil and Gas Fields Map (WVGS) and include: Midway-Extra (278), Red House (191), and Scott Depot (212).



BROWN SHALE ZONE, PUTNAM CO.

Figure 4. Cross section of the Devonian shales in northern Putnam County illustrating the four-fold subdivision of the shales. Well numbers are state permit numbers; total shale thickness shown at bottom of each well. Shot intervals shown by hachured column at left of well.

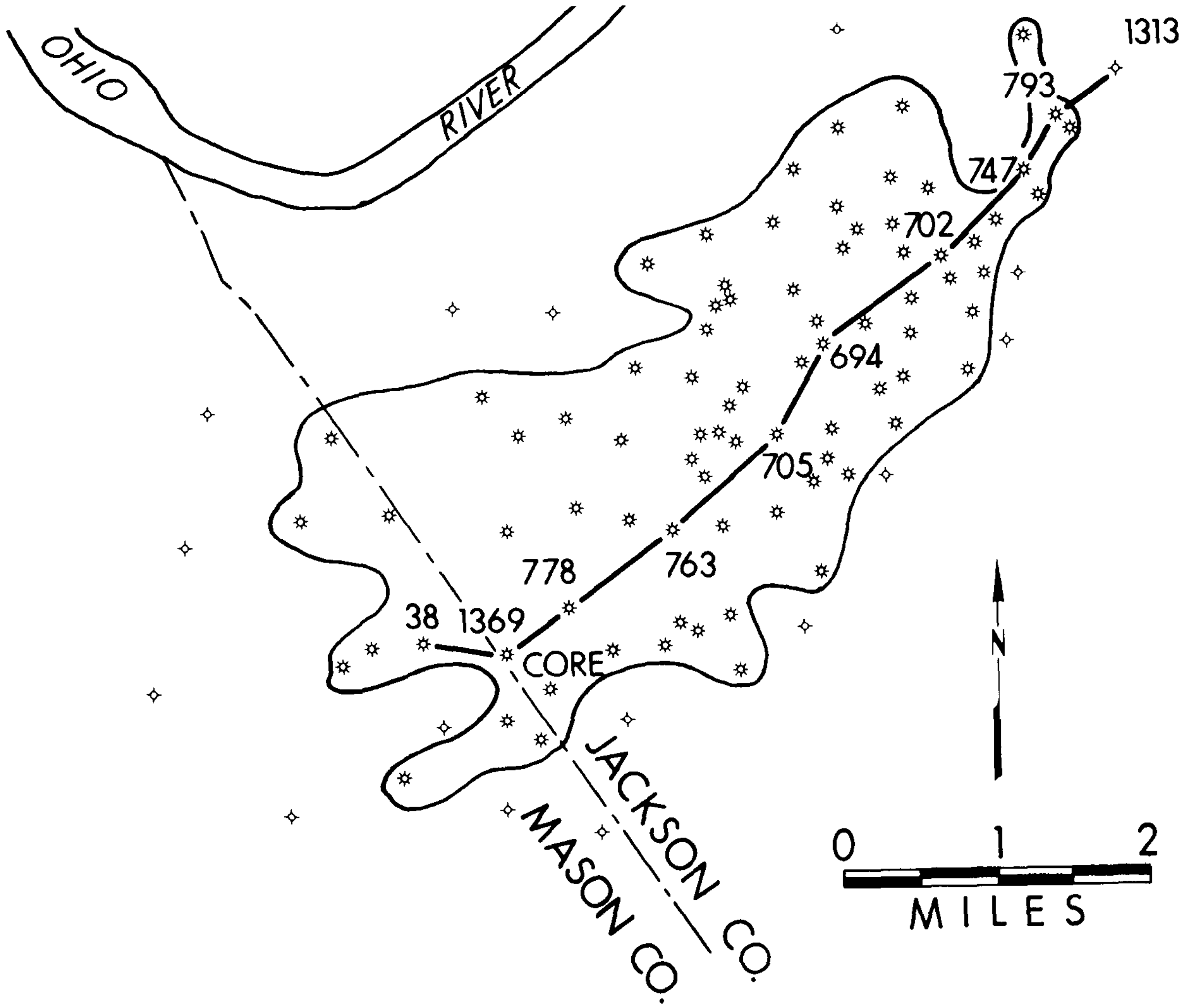


Figure 5. The Mt. Alto (Cottageville) Field in Mason and Jackson Counties, WV with line of cross section (Figure 6) and core location (# 1369).

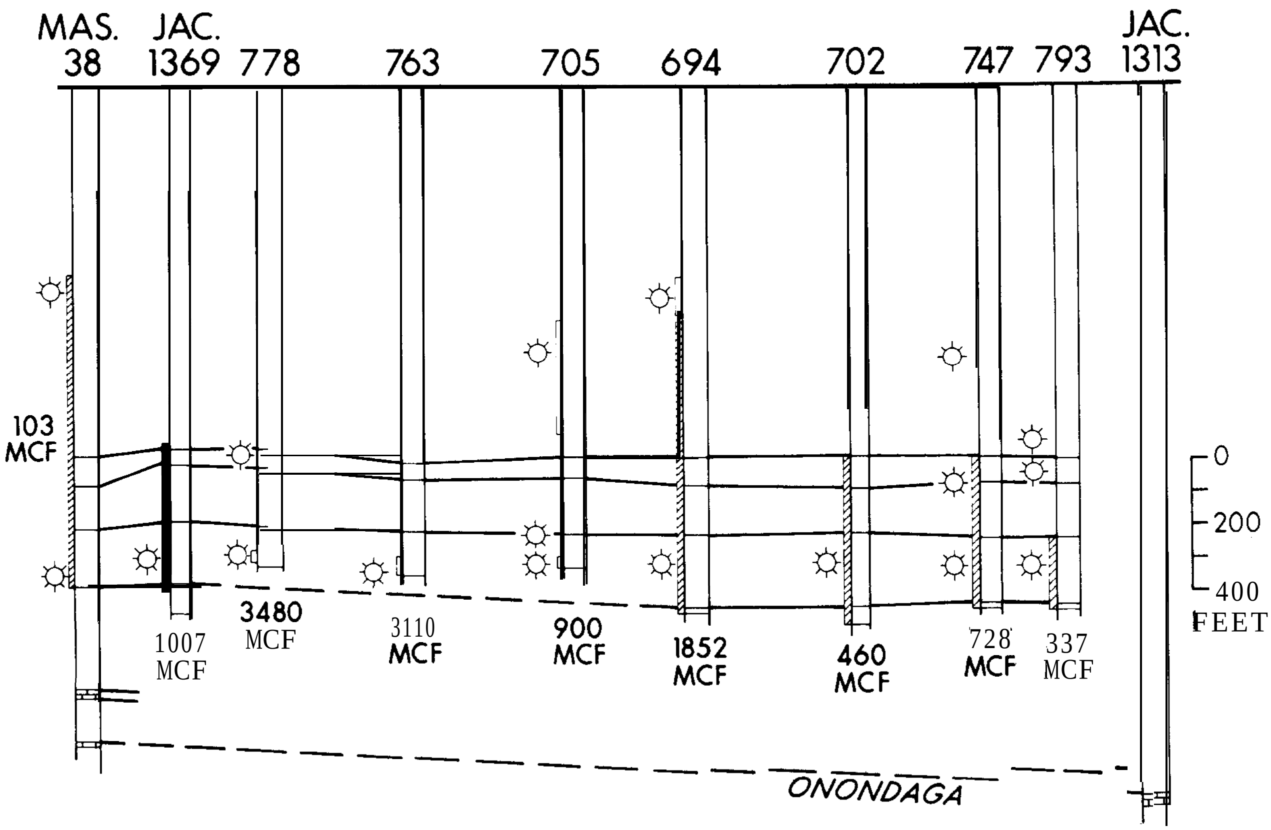
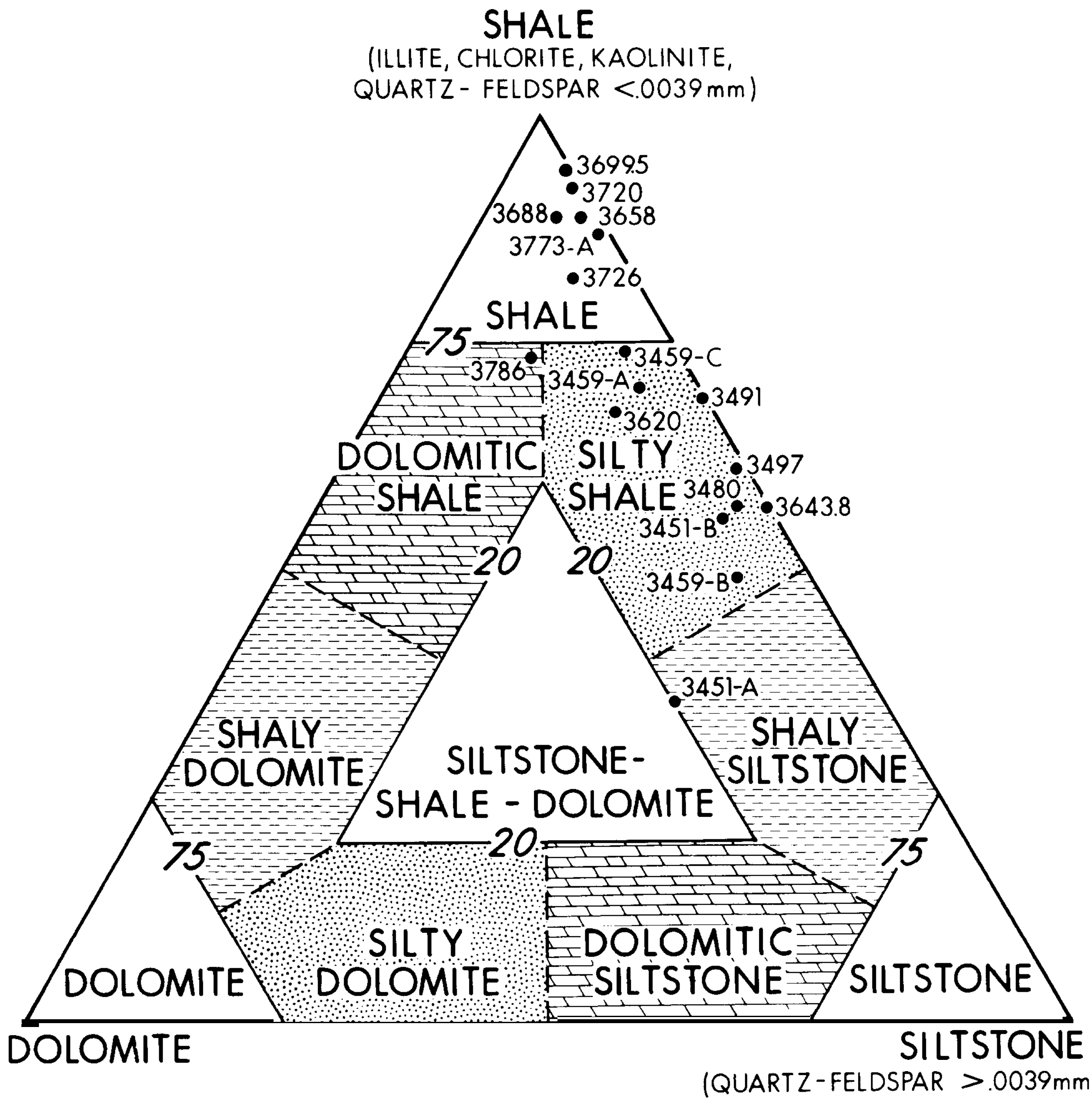


Figure 6. Cross section through the Mt. Alto (Cottageville) Field illustrating the upper two Brown shale zones with gas pays and shows, and shot intervals (hachured). Cored portions of Jackson-1369 shown in solid blocks; final gas flows below each well.



TEXTURAL CLASSIFICATION OF SELECTED
DEVONIAN SHALE SAMPLES
L. A. BALER WELL (JAC. 1369) JACKSON CO., WEST VIRGINIA

Figure 7. Textural classification of selected Devonian Shale samples from the L. A. Baler Well (Jackson 1369) Jackson County, West Virginia.

Figure 8. Organic-rich shale containing spores (S). Note spores with pyrite (arrows) in centers. The two compacted spores are aligned parallel to bedding. Magnification 130x, plain light. L. A. Baler Well, Jackson County, West Virginia, specimen 3726.

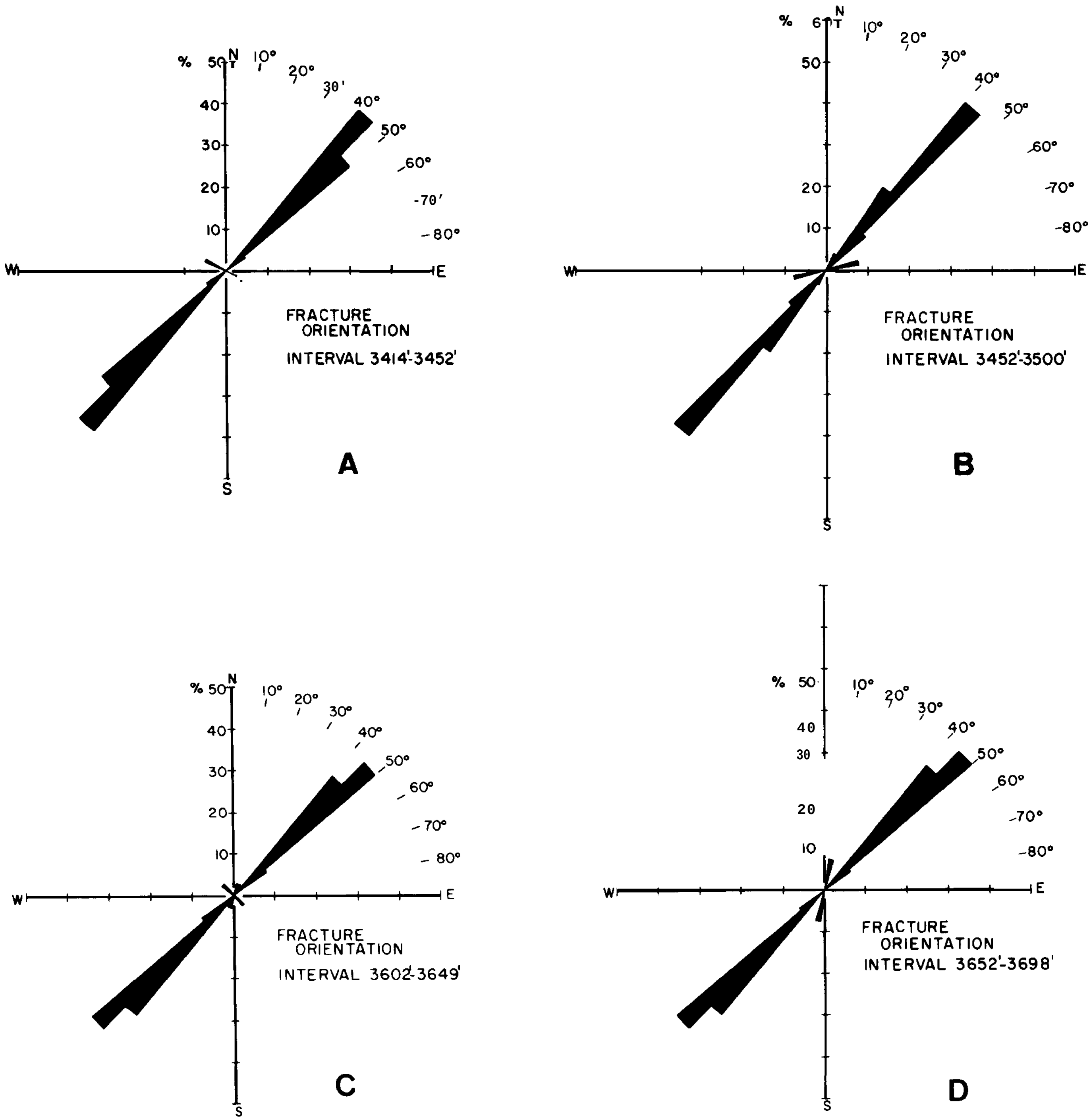


Figure 9. Orientation of fractures in core samples from the L. A. Baler Well (Jackson County, WV) measured in that portion of the core above the pay zone. Diagrams A and B from upper cored interval 3414'-3500'. Diagrams C and D from lower cored interval 3600'-3797'. Source of data-Royal Watts, USERDA.

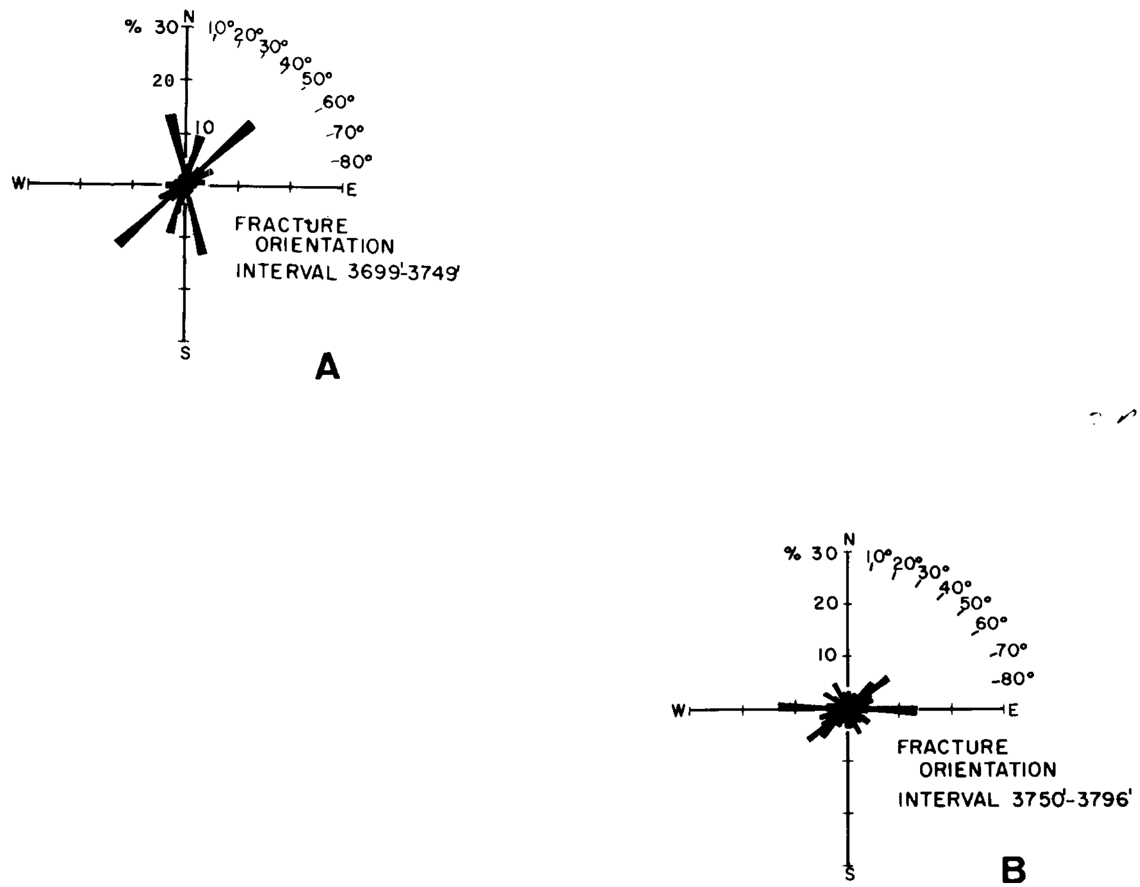


Figure 10. Orientation of fracture in core samples from the L. A. Baler Well (Jackson County, WV) measured in that portion of the core within the pay zone. Diagrams A and B are both from the lower cored interval 3600'-3797'. Source of data-Royal Watts, USERDA.

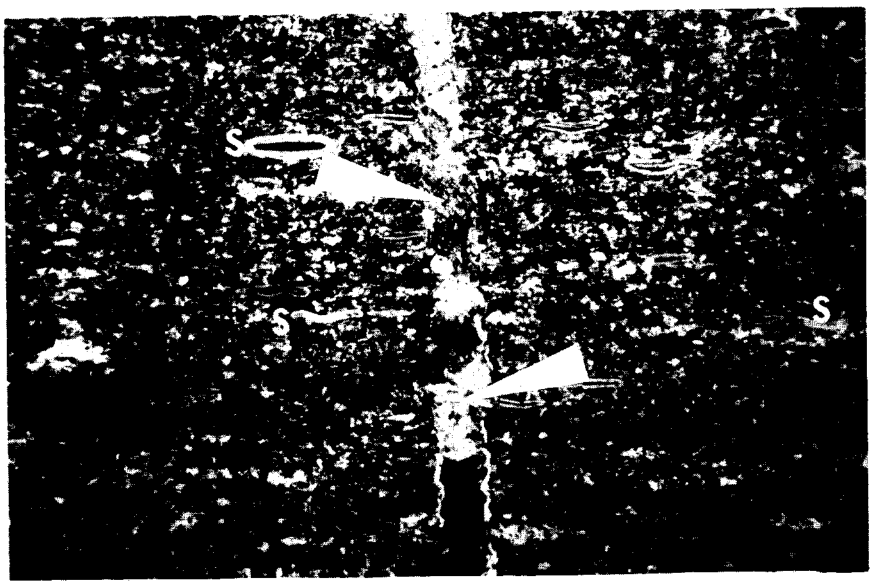


Figure 11. Vertical fracture (width 0.17mm) which has been filled with dolomite (arrows). Note spores (S). Magnification 43x, plain light. L. A. Baler Well, Jackson Co., WV, specimen 3726.

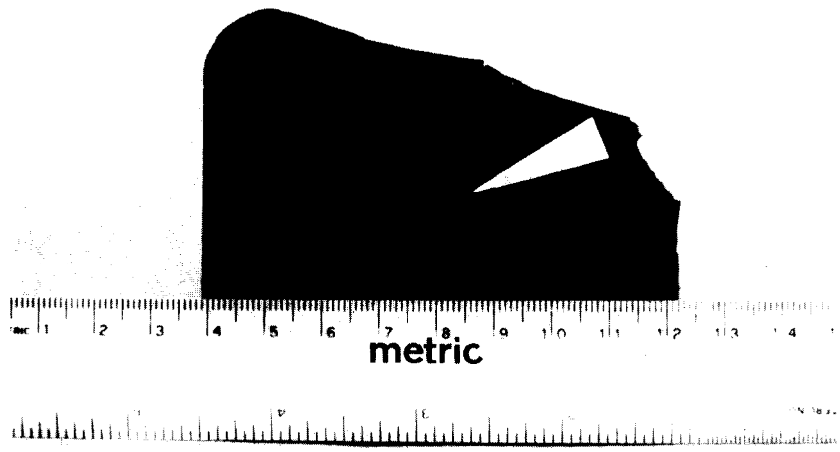


Figure 12. Typical core sample from gas producing zone in the L. A. Baler Well, Jackson County, WV. Note vertical fracture (width 0.37mm) filled with dolomite (arrow). Specimen 3722.

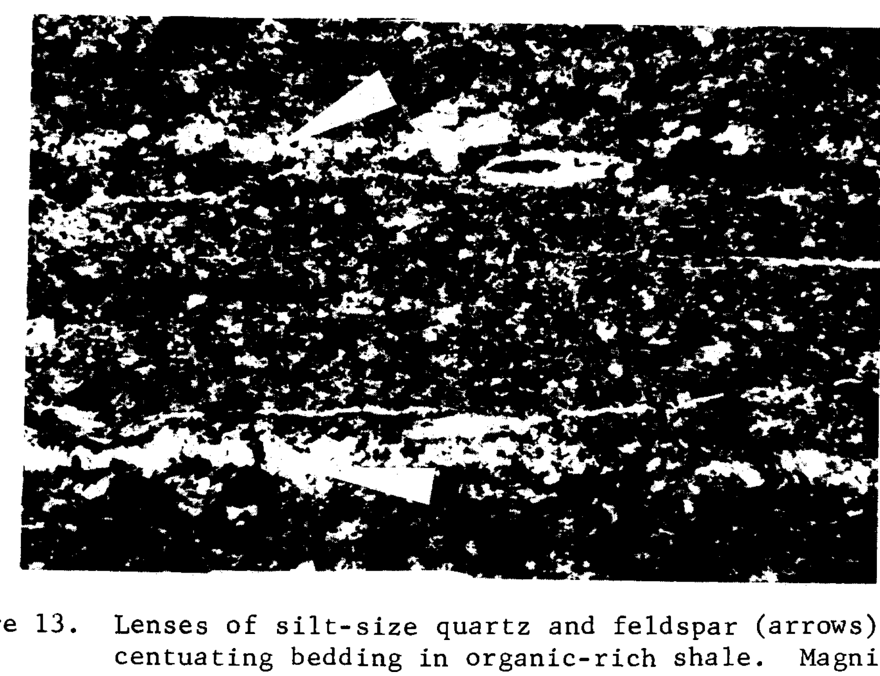


Figure 13. Lenses of silt-size quartz and feldspar (arrows) accentuating bedding in organic-rich shale. Magnification 130x, plain light. L. A. Baler Well, Jackson County, WV, specimen 3720.

GEOLOGY AND OIL AND GAS OCCURRENCE IN THE DEVONIAN SHALES: NORTHERN WEST VIRGINIA

P. Martin and E. B. Nuckols III - Consolidated Gas Supply Corp.

INTRODUCTION

Several years ago Consolidated Gas Supply Corporation undertook a reevaluation of the Devonian Shales. The present report is a summary of that investigation. One of the first facts to come to light in beginning research is the almost total lack of literature relating the geology of the shales to oil and gas production. Data is especially sparse in northern West Virginia, where well control is spotty, and many of the wells present were logged only through the deeper and shallower formations, while the shales were skipped over. In fact, at the present, data is still being collected so that this report should be regarded as only preliminary in nature.

AREA OF INTEREST

Figure 1 shows the Geologic Map of West Virginia, published by the State Geological Survey. This report deals with the shales in that part of West Virginia generally north of the line superimposed on this map. In the eastern part of the state, the Devonian Shales outcrop along the Deer Park Anticline, around Browns Mountain Anticline, and east of the Allegheny Front in the Ridge and Valley.

Figure 2 shows that portion of the shales being dealt with here. This includes most of what is generally called the Chemung Group and everthing below that to the top of the Onondaga. In the east these shales reach a thickness of over 5,000 feet, while in the western part of the state, they are only about 2,000 feet thick and include everything between the Berea Sandstone above and the Onondaga or Corniferous limestone below.

ZONES OF INTEREST

The shale section in the west contains a number of zones of brown, highly radioactive and highly kerogenitic shale which are of major interest here. These zones are easily identified on Gamma Ray logs in this area and, for lack of a better term, have been identified here as Zones I, II and III. These are shown in Figure 3, which illustrates a typical log from the Cottageville Field, with Zone I at the bottom, Zone II in the -middle, and Zone III at the top.

In trying to correlate and map these zones, certain problems were encountered in moving eastward. Instead of being easily mapped, discreet units, it was found that the brown zones appear to be western facies of gray shale zones which thicken eastward into the basin. The brown radioactive zones break up into many thin units which individually feather out eastward. This is illustrated rather well on the cross-section in Figure 4 which extends eastward from the Cottageville Field to Randolf County.

Zone I, which is the lower-most zone, extends farthest east and fingers out in eastern Calhoun County. It is 100 feet thick in the west and 500 feet thick in Calhoun County where it disappears. Zone II Brown Shales begin to break up in western Roane County, with some individual beds extending eastward into western Calhoun County. This zone is about 100 feet thick west of Cottageville and over 200 feet thick where it breaks up. Zone III also disappears in Roane County.

As a matter of interest, the cross-section in Figure 4 also illustrates the westward pinchout of the Tully Limestone and the occurrence and extent of two sandy silt zones far up in the shale section, which are called here the Lower and Upper Sycamore Grit. The Sycamore Grits are interesting since they do carry some gas.

PRESENT PRODUCTION

The primary producing zone at Cottageville is Zone II Brown Shale. An isopach map of Zone II is illustrated in Figure 5. The stratigraphic unit, of which the Brown Shale is a western facies, thickens

PRESENT PRODUCTION (con't)

eastward into the basin being about 100 feet thick at the Ohio River and over 500 feet at the eastern limit of mapping. The Brown Shale facies occupies the entire 100 feet of the unit at the Ohio River and it attains a thickness of some 200 feet before it starts fingering eastward as thin individual beds. Optimum conditions in Brown Shale Zone II would probably be found in the solid-colored area in Figure 5. An isopach of Zone I is being prepared at present, and may reflect the same general character, while being thicker and individually more extensive than Zone II.

Existing shale production in northern West Virignia is shown in Figure 6. The largest field in this area is Cottageville located in Jackson and Mason Counties. Production from this field is almost exclusively from Brown Shale Zone II. In Roane and Calhoun Counties, a number of wells have been producing from what is called shale at a depth of around 3,000 feet. It is more likely, however, that the production in these wells is from sandy silts, possibly equivalents of the Gordon or 4th or 5th sands than from true shales. During the past two years, Consolidated has drilled 5 wells in this area in an attempt to evaluate this old production and possibly establish true shale production. The first two wells were drilled to the top of the Onondaga. The hole was lost in the first when the shot dislodged the 8 inch casing and the hole filled with water and caved in. The lower-most 741 feet of the second hole were successfully shot with a resulting open flow of 60,000 cubic feet per day. Although not a large open flow, the well has produced continuously at approximately the same rate for around a year and had made 5,690,000 cubic feet of gas at the end of November, 1975. Fourteen day rock pressure (surface) was 500 pounds. The section completed here is probably equivalent to Brown Shale Zone I, but also includes the Marcellus. The natural flow was 2,000 cubic feet of gas per day.

Farther to the south, Consolidated drilled

PRESENT PRODUCTION (con't)

a well in the summer of 1975 intended to go the top of the Onondaga to test the shales; but, at approximately 2,900 feet, or in the same silts and shaly silts mentioned above, a natural flow of about 16,000,000 cubic feet of gas per day was encountered. The well was killed in order to remove the tools. When cleaned up again, it was finaled for 2,200,000 cubic feet per day at 630 pounds. Needless to say, drilling did not continue to the Onondaga. Consolidated drilled two offsets to this well, neither of which found the high volume of gas that the original well did. Both holes went past 5,900. One could not be completed because of mechical problems, but the other was successfully shot over the lower-most 1,300 feet of section including the Sycamore Grits. Final open flow was 221,000 cubic feet per day at 460 pounds. The well had no natural flow.

A number of wells have been drilled over the years in the Parkersburg area and to the east and north east which have reported gas and oil from such zones as the Berea and Shale or Gordon and Shale. Unfortunately, detailed information is not available, so it is not possible to tell just where the production is coming from. Gas shows from various parts of the shale section have been recorded from many wells in northwestern West Virginia but none of these have led to development drilling. Thus far, Cottageville remains the only field developed exclusively in the Brown Shale in the northern part of the state.

Figure 7 shows a more detailed view of the Cottageville Field. The field is located primarily in Jackson County, with some wells being in Mason County. The town of Cottageville lies within the field and Ripley is about 7 miles to the east. About 90 wells were drilled in 1948-1949 and 1950. Consolidated, then under the name of Hope Natural Gas, drilled 37 of these wells, 35 of which were producers. Eighteen wells are still producing. The production data presented in Figure 8 is based on the 37 Consolidated wells.

PRESENT PRODUCTION (con't)

Natural open flows generally ranged from 0 to 815,000 cubic feet per day, while one well flowed 3,5000,000 cubic feet per day. The average natural open flow, excluding the 3.5 million well, was 133,000 cubic feet. Most of these wells were shot and after-shot open flows ranged from 71,000 to 1,981,000 cubic feet, with the average being 523,000 cubic feet. The highest rock pressure was 800 pounds, and the average qas 595 pounds. Wells drilled within the past year in this field had rock pressures of from 190 to 350 pounds. The average first year's production from the original wells was 27.3 million cubic feet of gas; and, the second year's production was 22.432 million. The third and fourth year averages were 17.263 million cubic feet of gas and 15.652 million cubic feet of gas, respectively. During the first 11 months of 1975, the average production per well from the remaining 18 wells was 5,731,000 cubic feet, which translates to 521,000 cubic feet per month or 17,000 cubic feet per day. 1975 was the twenty-seventh year these wells have been producing.

Cumulative production from the 18 wells ranges from 106 million cubic feet to 909 million cubic feet with an average of 313 million cubic feet per well. When all 37 wells are considered, the average cumulative production per well is 185 million cubic feet. Total production to date from Consolidated's wells on the Cottageville Field is about 6.5 billiom cubic feet of gas. Assuming similar success ratios and production histories for other wells in the field, these other wells will have made about 9.3 billion cubic feet for a field total of 15.8 billion cubic feet.

All of Consolidated's recent wells in the field have been drilled with air rotary. Eleven inch casing is set at around 350 feet. Water is encountered in the Salt Sands at around 1700 feet and in the Berea at around 2400 feet, making it necessary to go to foam or fluid. Eight inch casing is set below the Berea at around 2500 feet. The hole will dust on to a total depth of about 4000 feet of below Shale Zone II. The lower 500 feet of hole are then shot

PRESENT PRODUCTION (con't)

with jelled ammonium nitrate with the rig on the hole and cleaned out immediately after shot. A well drilled in this fashion in 1975 cost around $65,000. Therefore, given the first few year's production figures as shown here, and a price of $1.00/Mcf the average well will pay out in about four years.

EFFECT OF FRACTURES

The primary reservoir in the Cottageville Field is Brown Shale Zone II. Figure 9 is a Typical Gamma Ray-Density log of a Cottageville well showing Zone II. On the right, and adjusted to the same depth below the Berea as the Gamma Ray log, are plotted the depths at which natural shows were recorded in 37 wells in the field. The correlation can easily be seen.

In order to obtain a better look at this reservoir, Consolidated cored Zones II and III in two wells in the field, one located at the southern end and one at the northern end. This work was done in 1975 in cooperation with ERDA. ERDA is now conducting extensive analysis on both cores in their labs in Morgantown, W. Va. and has almost finished with the first, while recently starting on the second. ERDA's analysis will include measurement of porosity and permeability, grain density, oil and gas saturation, mineral content, hardness, and studies of rock mechanics, thin sections, and chemistry. Both cores were oriented so that studies of fracture orientation can also be made.

These cores support the premise that porosity and permeability in the shale in the Cottageville Field are due to natural fracturing. Many sections of the core from the first well were completely shattered and this well had over 1 million cubic natural flow. Very few fractures were observed in the second core and the well had 0 open flow. Figure 10 shows a top view of one piece of core from the first well. Note the several different directions of fractures of joints. Figure 11 shows a side view of the same piece of core. The left side is the side of the bore hole. On the right side the almost vertical orientation of the fractures can be observed..

EFFECT OF FRACTURES (con't)

Of special interest is the small open fracture about 1/32" wide shown in Figure 11. This is a direct view of the type of fracture porosity present in the shale. Many fractures are filled with a brown, medium to coarse crystalline, porous, dolomite, and some are plugged with non-porous, calcite. The shale itself is composed generally of about 50% illite, about 30% quartz, about 10% kaolinite, less than 5% plagioclase and about 5% unidentified, with traces of pyrite, dolomite, and orthoclase.

As was mentioned above, both cores were oriented so that the fracture trends could be mapped by ERDA. The fracture orientation down through Zones II and III in the southern core is displayed in Figure 13. The primary fracture trend is North 40^{o} to 50^{o} East. However, it may be noted that in part of Zone II,, the primary trend is about North 80^{o} to 90^{o} West, with many other trends present also. The tectonic significance of this is uncertain but it is probably more than coincidence that it was in this zone that the largest natural flow of gas was detected in this well. This particular well was finaled for a natural open flow of 1.1 million cubic feet.

When the fracture pattern just described is related to the production trend in the Cottageville Field, a definite corollary appears. As is illustrated by Figure 14, the general trend of the field is about North 40^{o} East and when those wells that had open flows of a million or better are emphasized, the northeast trend is emphasized even more. This is, of course, the regional Appalachian trend. But, what structure could cause fracturing in the Devonian Shale so far over in the area of flat-lying plateau rocks? The logical, but as yet unproven, answer is basement faulting, possibly associated with the west side of the Rome Trough, which dissipates upward in the shales. Unfortunately, it will take seismic evidence to verify this; and, the present economics of shale drilling tend to discourage an extensive program of this type aimed specifically at Shale.

CONCLUSION

In summary, then, natural gas production in the Cottageville Field is primarily from fracture porosity and permeability in Brown Shale Zone II. This fracturing may be related to basement faulting, possibly along the west side of the Rome Trough. About 90 wells were drilled in the field and possibly over 15 billion cubic feet of gas have been produced over the last 25 years. About half the wells are still producing at an average rate of over 5 million cubic feet per year.

Undoubtedly, there is more gas to be found in the Cottageville area but further development, especially by independents, will depend to a large extent on what happens in the gas price situation.

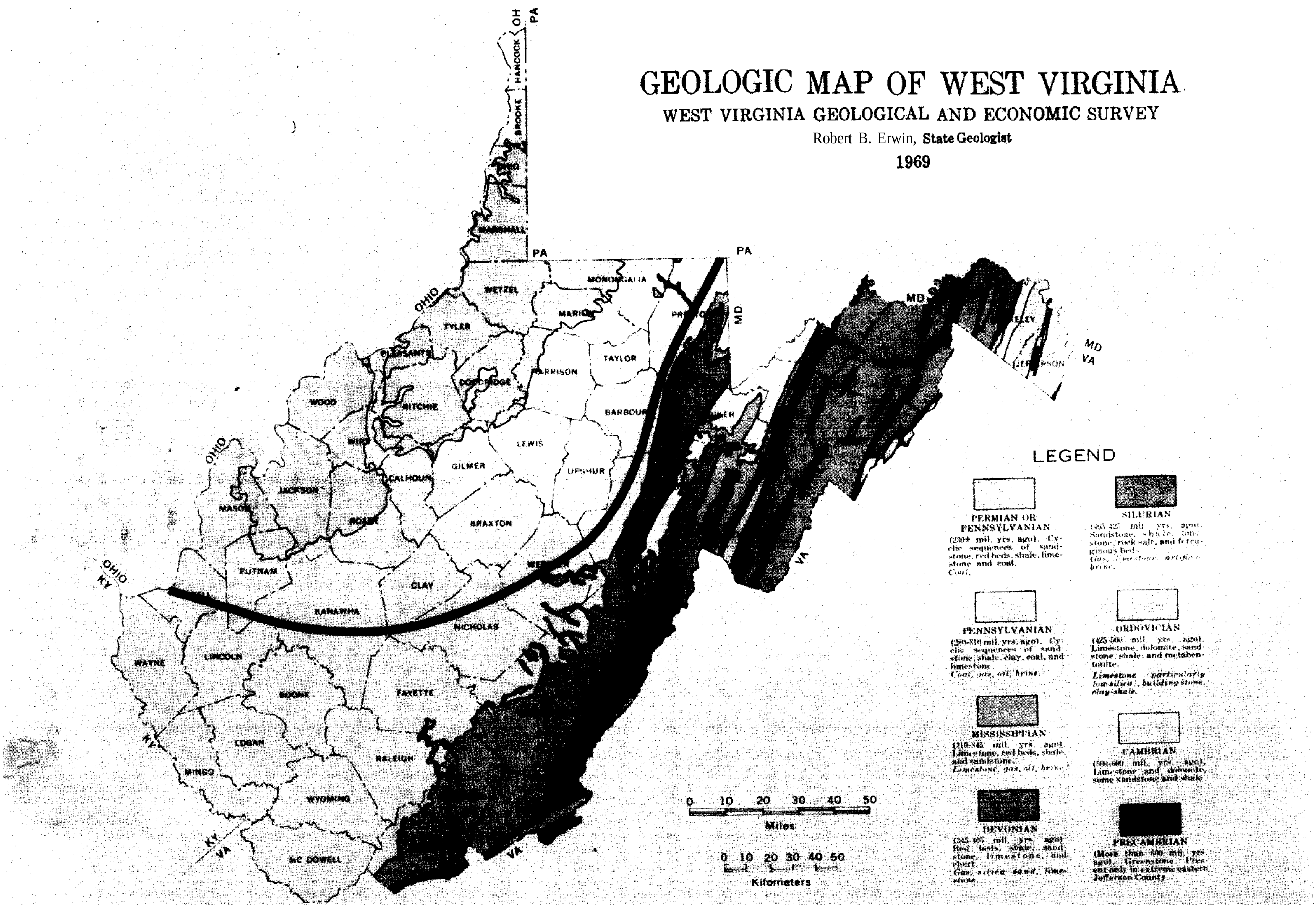

GEOLOGIC MAP OF WEST VIRGINIA
WEST VIRGINIA GEOLOGICAL AND ECONOMIC SURVEY
Robert B. Erwin, State Geologist
1969
LEGEND
PERMIAN OR PENNSYLVANIAN
(230+ mil. yrs. ago). Cyclic sequences of sandstone, red beds, shale, limestone and coal.
Coal.
SILURIAN
(405-425 mil. yrs. ago). Sandstone, shale, limestone, rock salt, and ferruginous beds.
Gas, limestone, artesian brine.
PENNSYLVANIAN
(280-310 mil. yrs. ago). Cyclic sequences of sandstone, shale, clay, coal, and limestone.
Coal, gas, oil, brine.
ORDOVICIAN
(425-500 mil. yrs. ago). Limestone, dolomite, sandstone, shale, and metabentonite.
Limestone (particularly low silica), building stone, clay-shale.
MISSISSIPPIAN
(310-345 mil. yrs. ago). Limestone, red beds, shale, and sandstone.
Limestone, gas, oil, brine.
CAMBRIAN
(500-600 mil. yrs. ago). Limestone and dolomite, some sandstone and shale.
DEVONIAN
(345-405 mil. yrs. ago) Red beds, shale, sandstone, limestone, and chert.
Gas, silica sand, limestone.
PRECAMBRIAN
(More than 600 mil. yrs. ago). Greenstone. Present only in extreme eastern Jefferson County.
0 10 20 30 40 50
Miles
0 10 20 30 40 50
Kilometers
HANCOCK
BROOKE
MARSHALL
WETZEL
TYLER
MONONGALIA
MARION
TAYLOR
HARRISON
BARBOUR
LEWIS
UPSHUR
GILMER
CALHOUN
RITCHIE
WOOD
JACKSON
MASON
ROANE
BRAXTON
CLAY
PUTNAM
KANAWHA
NICHOLAS
WAYNE
LINCOLN
BOONE
FAYETTE
LOGAN
RALEIGH
MINGO
WYOMING
MC DOWELL
OHIO
PA
MD
VA
KY
OH

FIG. I

GENERALIZED GEOLOGIC COLUMN

OF THE UPPER & MIDDLE DEVONIAN

IN

WEST VIRGINIA

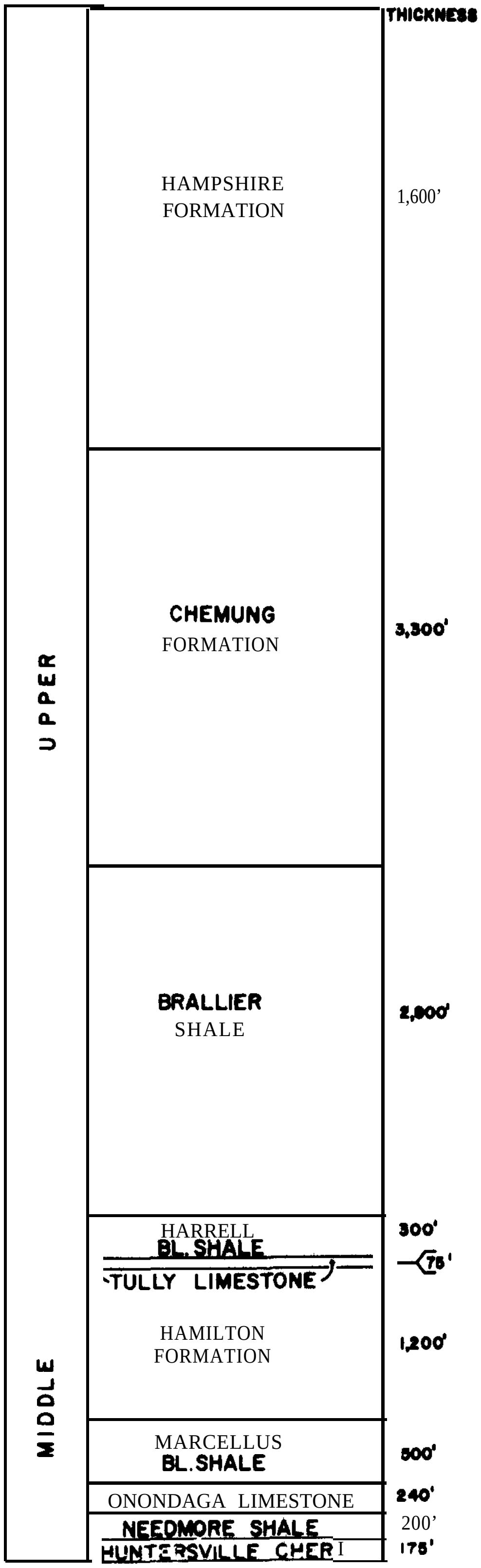


FIG. 2

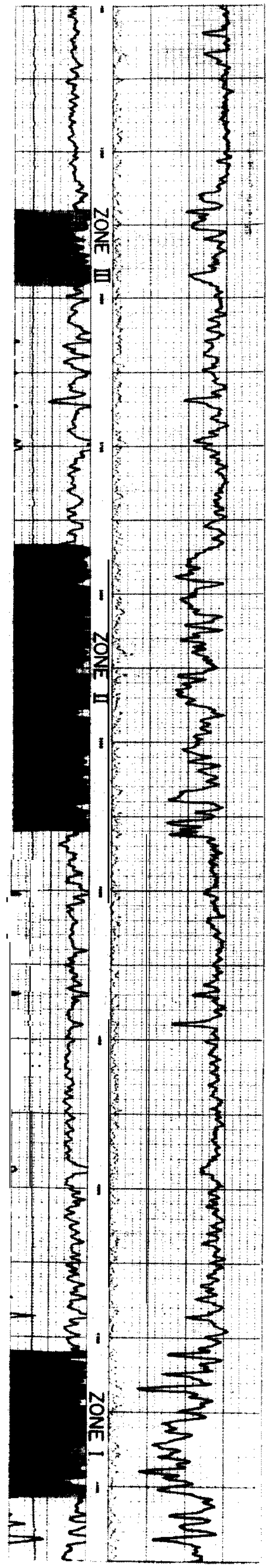


FIG. 3

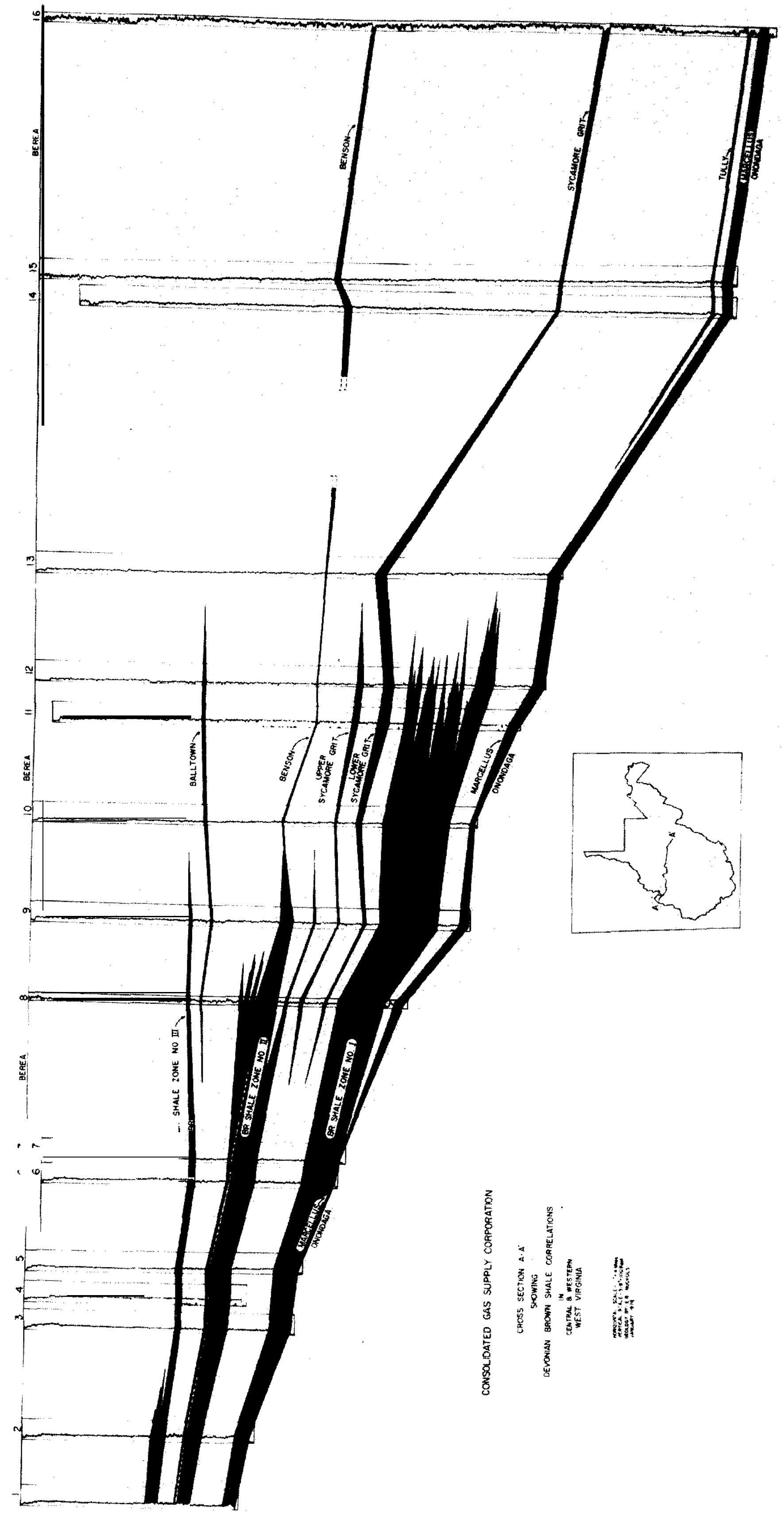
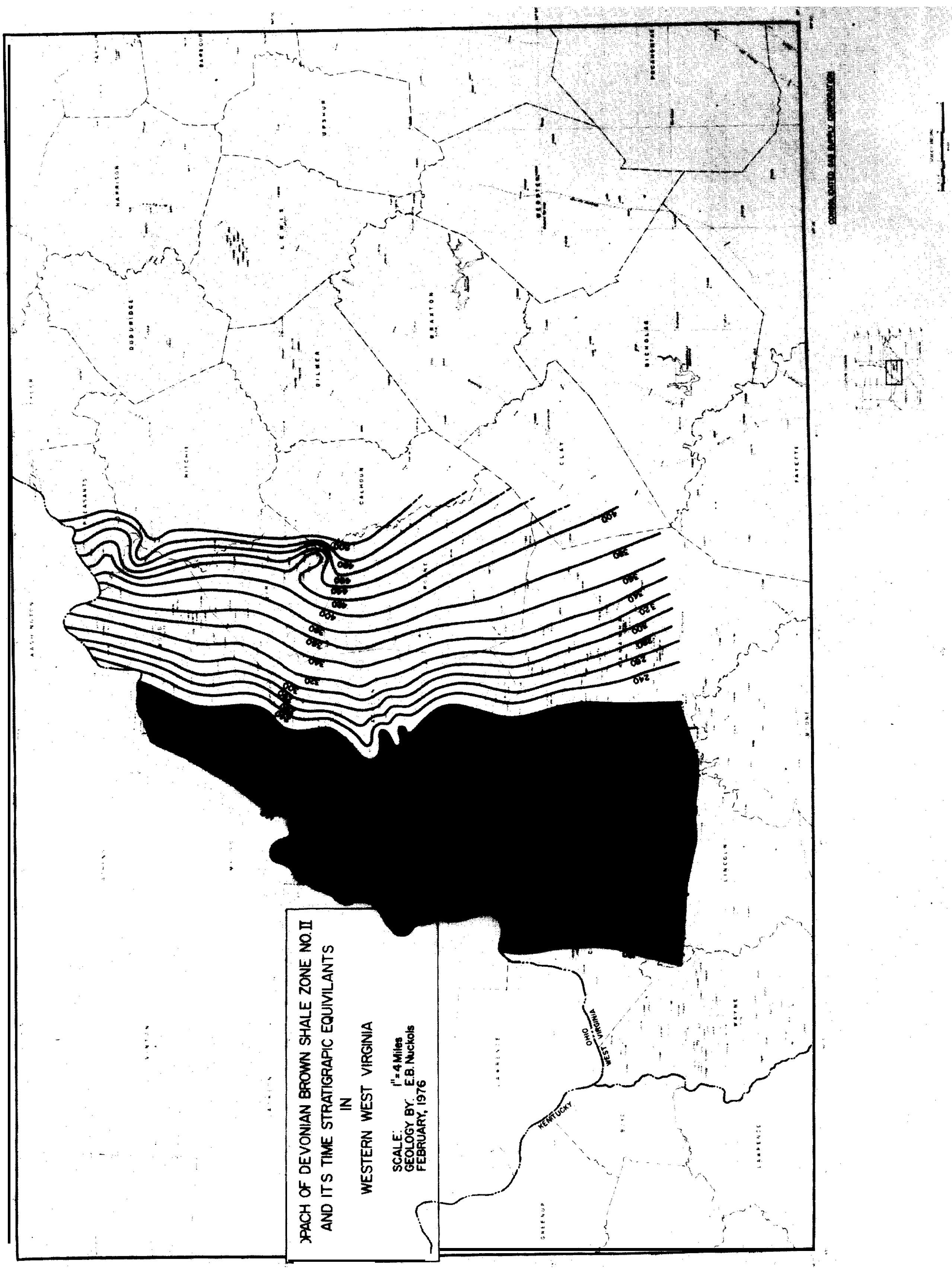

BEREA
BENSON
SYCAMORE GRIT
TULLY
MARCELLUS
ONONDAGA
BALLTOWN
UPPER SYCAMORE GRIT
LOWER SYCAMORE GRIT
SHALE ZONE NO III
GR SHALE ZONE NO II
GR SHALE ZONE NO I
CONSOLIDATED GAS SUPPLY CORPORATION
CROSS SECTION A-A'
SHOWING
DEVONIAN BROWN SHALE CORRELATIONS
IN
CENTRAL & WESTERN
WEST VIRGINIA

FIG. 4



PACH OF DEVONIAN BROWN SHALE ZONE NO. II
AND IT'S TIME STRATIGRAPIC EQUIVILANTS
IN
WESTERN WEST VIRGINIA
SCALE: 1"=4 Miles
GEOLOGY BY: E.B. Nuckols
FEBRUARY, 1976
OHIO
WEST VIRGINIA
KENTUCKY
PLATE 3-E

FIG. 5

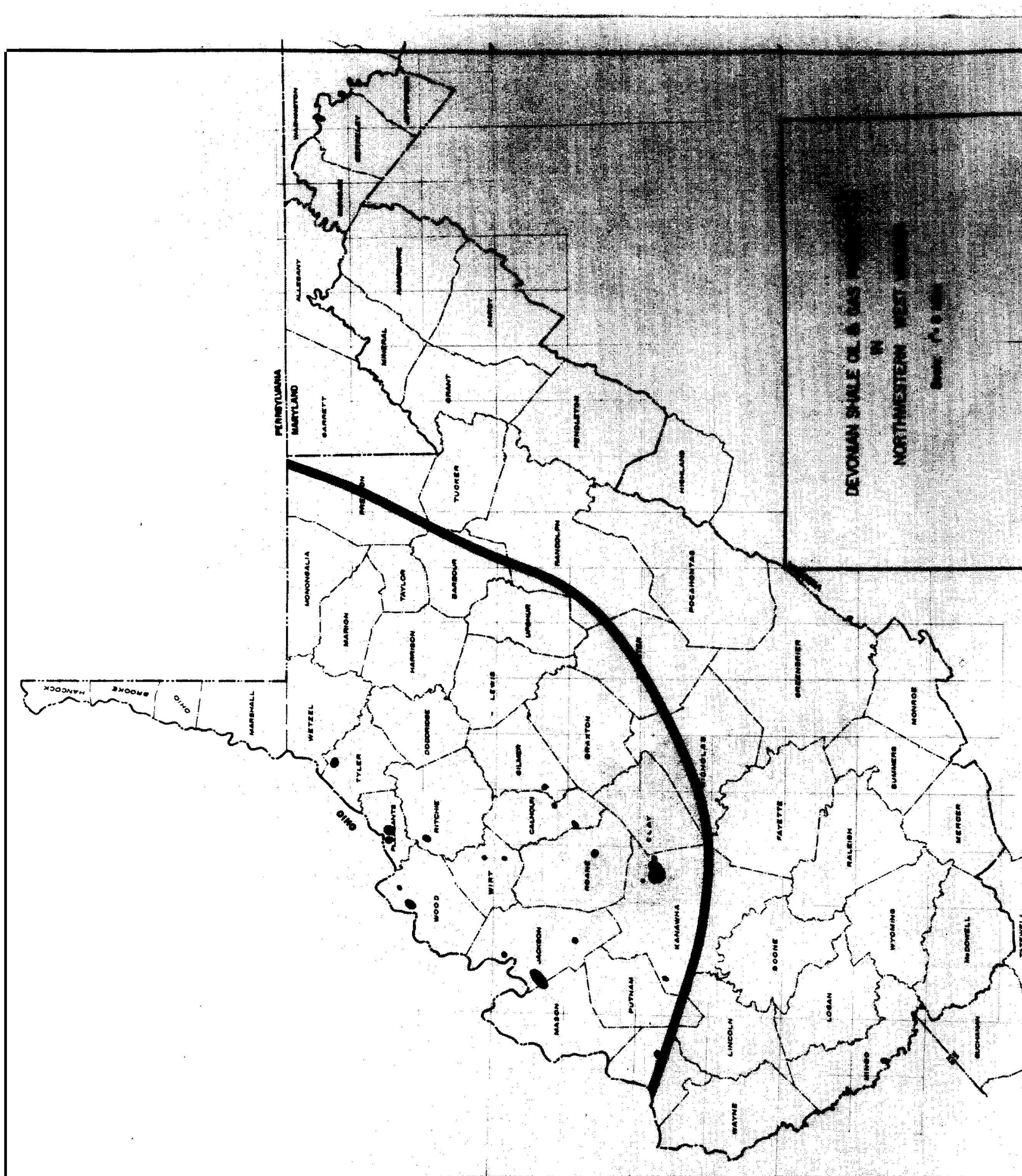

DEVONIAN SHALE OIL & GAS
IN
NORTHWESTERN WEST
PENNSYLVANIA
MARYLAND
OHIO
HANCOCK
BROOKE
OHIO
MARSHALL
WETZEL
TYLER
PLEASANTS
WOOD
RITCHIE
DODDRIDGE
HARRISON
MARION
MONONGALIA
PRESTON
TAYLOR
BARBOUR
TUCKER
RANDOLPH
UPSHUR
LEWIS
GILMER
CALHOUN
WIRT
ROANE
JACKSON
MASON
PUTNAM
KANAWHA
CLAY
BRAXTON
NICHOLAS
FAYETTE
RALEIGH
WYOMING
McDOWELL
MERCER
SUMMERS
MONROE
GREENBRIER
POCAHONTAS
PENDLETON
HIGHLAND
GRANT
MINERAL
HARDY
HAMPSHIRE
GARRETT
ALLEGANY
WASHINGTON
BOONE
LOGAN
MINGO
LINCOLN
WAYNE
BUCHANAN
TAZEWELL

FIG. 6


THE COTTAGEVILLE FIELD
JACKSON & MASON COUNTIES
WEST VIRGINIA

FIG. 7 & FIG. 14

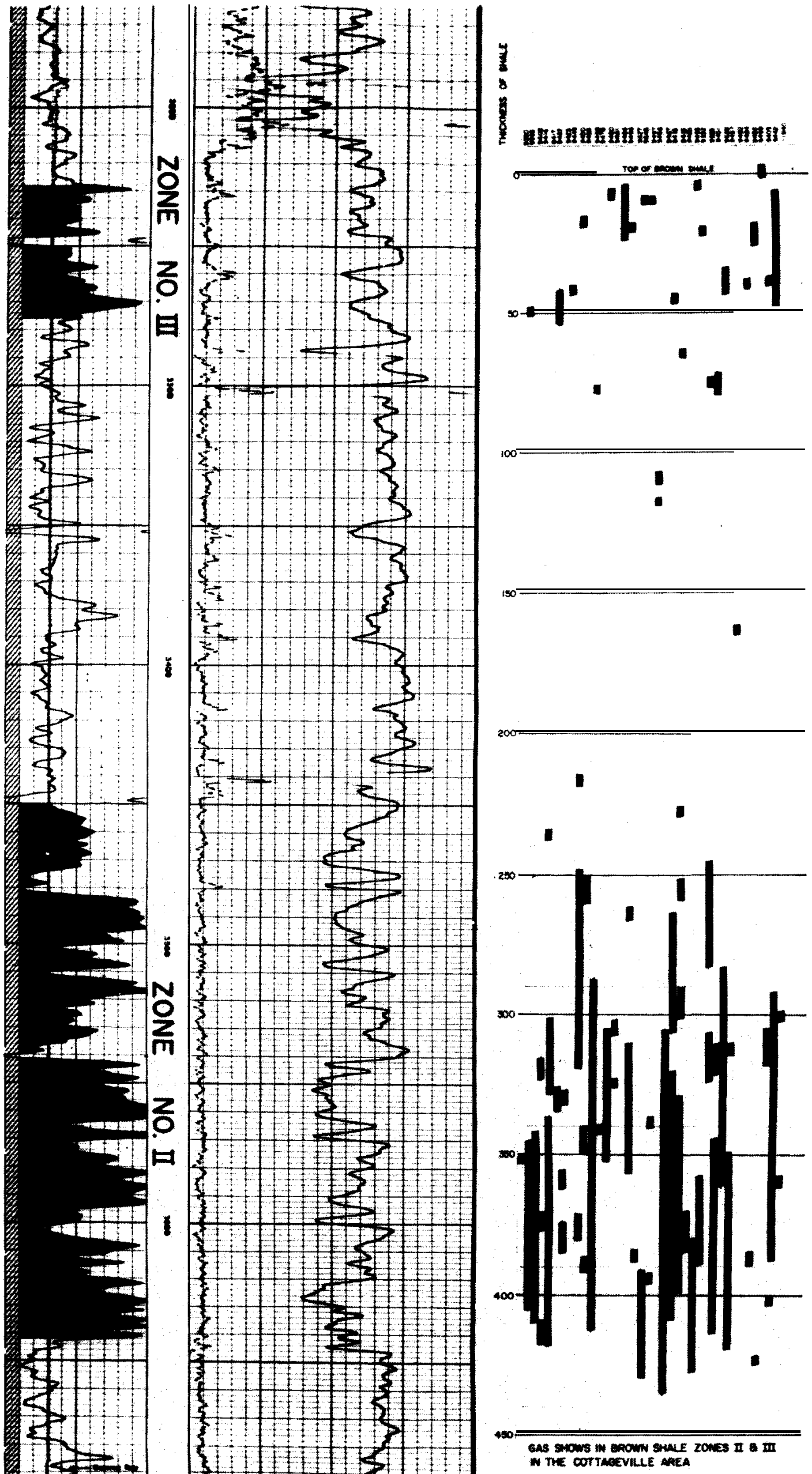

ZONE NO. III
ZONE NO. II
THICKNESS OF SHALE
TOP OF BROWN SHALE
0
50
100
150
200
250
300
350
400
450
GAS SHOWS IN BROWN SHALE ZONES II & III
IN THE COTTAGEVILLE AREA

FIG. 9

PRODUCTION STATISTICS
COTTAGEVILLE FIELD
JACKSON & MASON COUNTIES, WEST VIRGINIA
CONSOLIDATED GAS SUPPLY CORP. WELLS ONLY
ALL FIGURES ARE AVERAGE

Natural Open Flow	133 Mcf
After-Shot Open Flow	523 Mcf
Initial Rock Pressure	595 lbs.
First Year's Production	27,300 Mcf
Second Year's Production	22,432 Mcf
Prod. per Well, 11 Months-1975, 18 Wells	5,731 Mcf
Cumulative Prod. per Well, 18 Prod. Wells	313,000 Mcf
Cumulative Prod. per Well, All Wells	185,000 Mcf
Total Prod., Nov. 1975, CGSC Wells	6.5 Bcf

FIG. 8

INTERSECTING VERTICAL FRACTURES IN BROWN SHALE CORE

FIG. 10

PARALLEL AND INTERSECTING VERTICAL FRACTURES IN BROWN SHALE CORE

FIG. 11

SLICKENSIDES IN BROWN SHALE CORE

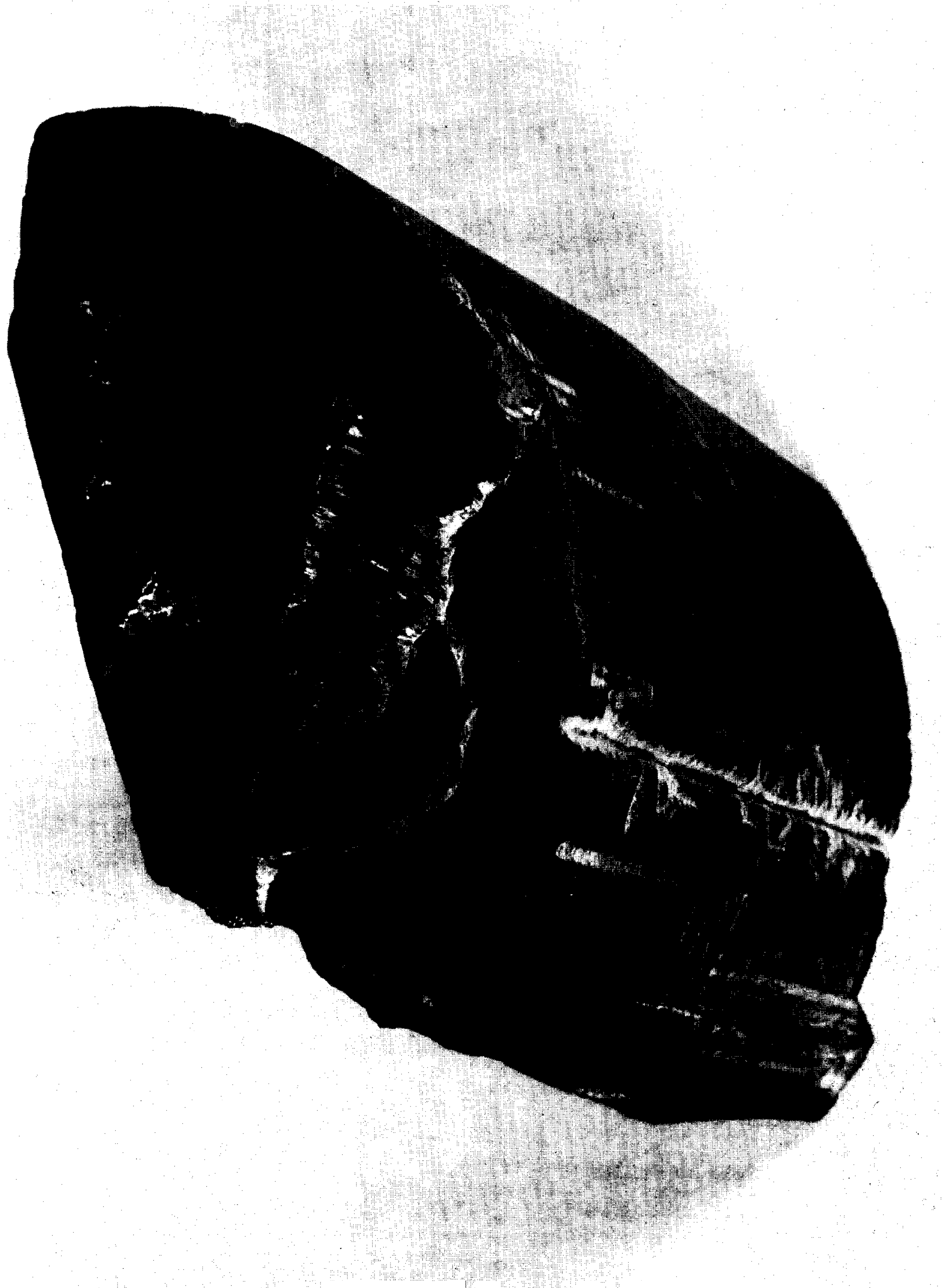


FIG. 12

BROWN SHALE FRACTURE ORIENTATION

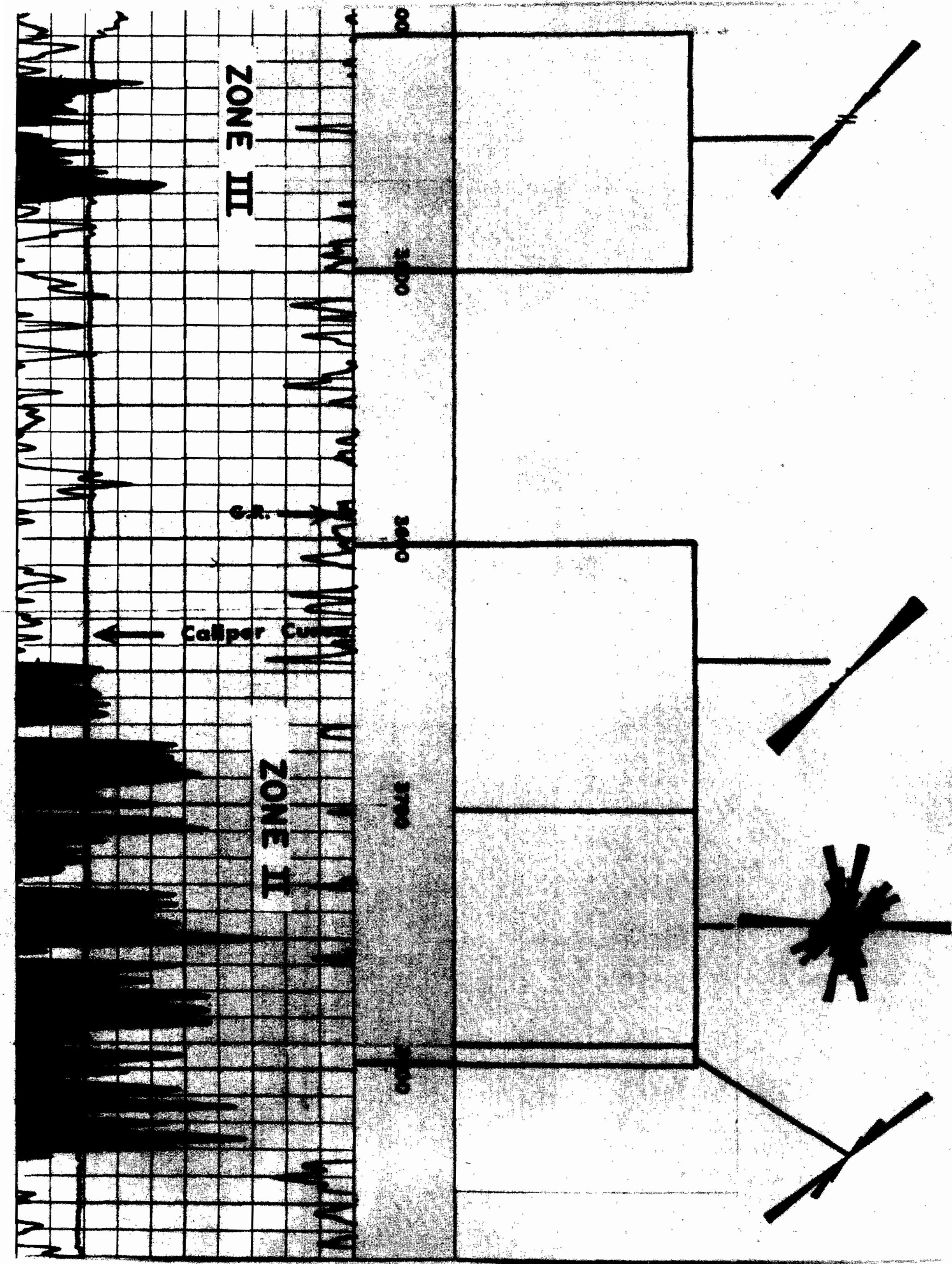


FIG. 13

THE GEOLOGY, RESERVES, AND PRODUCTION CHARACTERISTCS OF THE DEVONIAN SHALE IN SOUTHWESTERN WEST VIRGINIA

William D. Bagnall and William M. Ryan - Columbia Gas Transmission Corp.

ABSTRACT

The Devonian shale in southwestern West Virginia includes all strata between the base of the Berea Sandstone (Mississippian) and the top of the Onondaga Limestone (Lower Middle Devonian). Within this area, some 3000 productive shale wells have been drilled. Estimated ultimate recoverable reserves for these wells exceed one (1) TCF.

Gas production from the Devonian shale is controlled largely by natural fractures with the production rate dependent on the density and openness of these fractures. In general, the better shale wells occur when natural fractures are encountered in the brown, kerogen-rich shales that comprise between 10 and 60 percent of the total shale interval. These brown horizons interfinger eastward with lighter colored shales and siltstones. In western Clay and Fayette Counties, the brown shale horizon from which most of the shale gas in southwestern West Virginia is produced is barely recognizable on logs and in samples.

As a result of standard completion practices that left several potentially productive horizons exposed to the borehole, some gas attributed to the Devonian Shale has actually been produced from shallower Mississippian horizons.

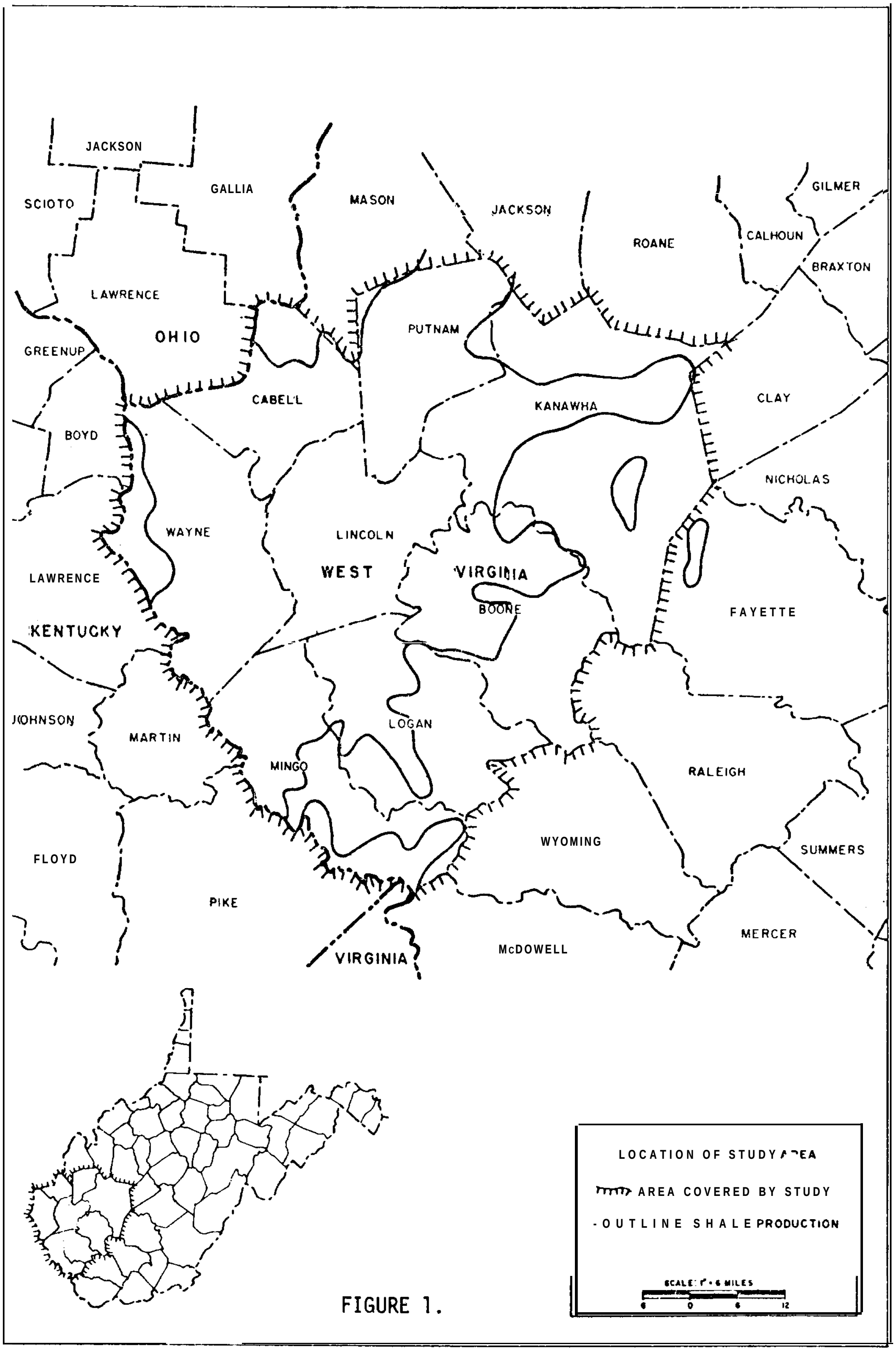
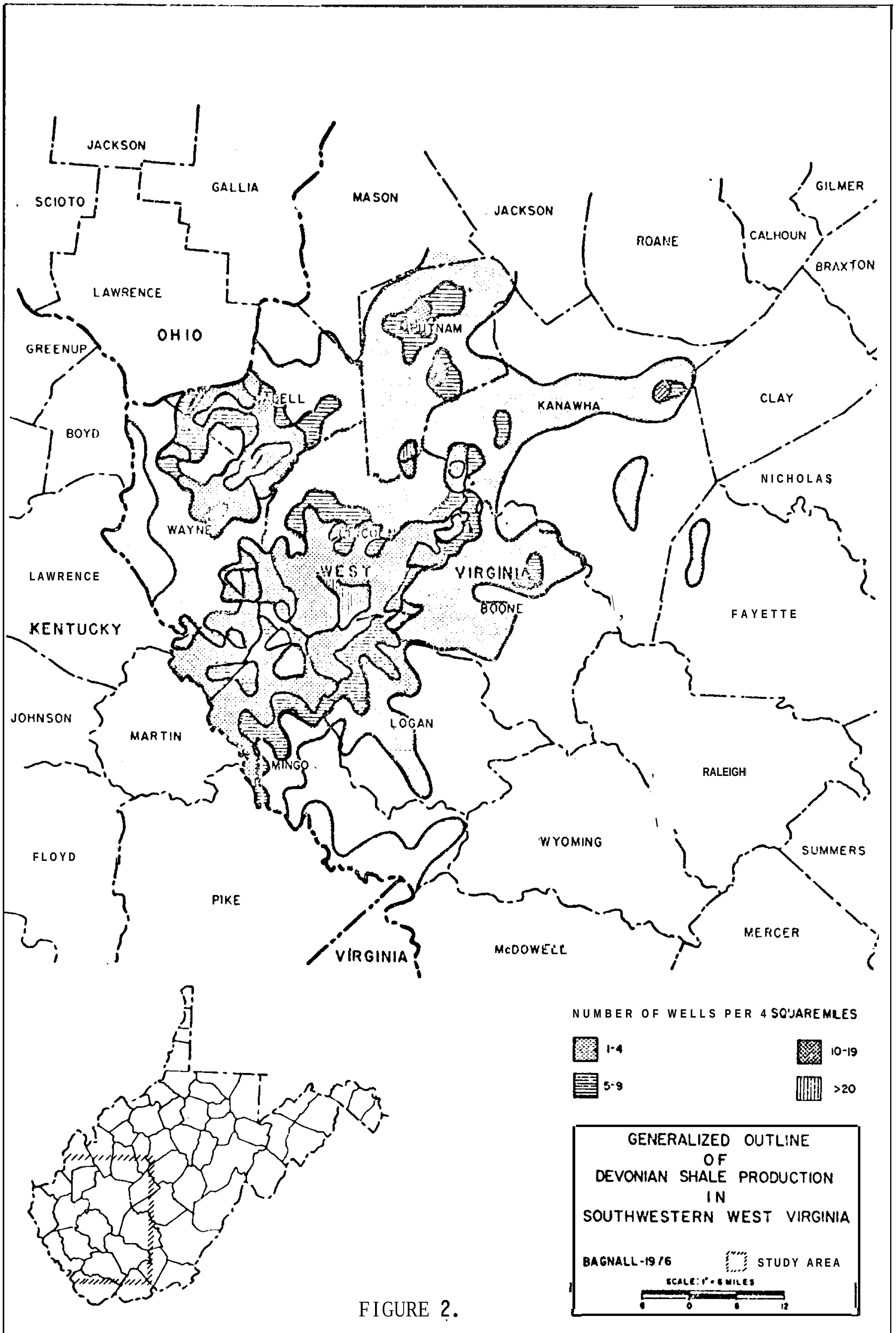

JACKSON
SCIOTO
GALLIA
MASON
JACKSON
ROANE
GILMER
CALHOUN
BRAXTON
LAWRENCE
OHIO
GREENUP
PUTNAM
CABELL
KANAWHA
CLAY
BOYD
NICHOLAS
WAYNE
LINCOLN
LAWRENCE
WEST
VIRGINIA
BOONE
FAYETTE
KENTUCKY
JOHNSON
MARTIN
LOGAN
MINGO
RALEIGH
FLOYD
WYOMING
SUMMERS
PIKE
MERCER
VIRGINIA
McDOWELL
LOCATION OF STUDY AREA
AREA COVERED BY STUDY
OUTLINE SHALE PRODUCTION
0
0
6
12

FIGURE 1.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JACKSON
ROANE
CALHOUN
GILMER
BRAXTON
LAWRENCE
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GREENUP
PUTNAM
KANAWHA
CLAY
BOYD
NICHOLAS
WAYNE
LINCOLN
WEST
VIRGINIA
BOONE
LAWRENCE
FAYETTE
KENTUCKY
JOHNSON
MARTIN
LOGAN
MINGO
RALEIGH
WYOMING
SUMMERS
FLOYD
PIKE
MERCER
VIRGINIA
McDOWELL
NUMBER OF WELLS PER 4 SQUARE MILES
1-4
10-19
5-9
>20
GENERALIZED OUTLINE
OF
DEVONIAN SHALE PRODUCTION
IN
SOUTHWESTERN WEST VIRGINIA
BAGNALL-1976
STUDY AREA
SCALE: 1" = 6 MILES
6
0
6
12

FIGURE 2.

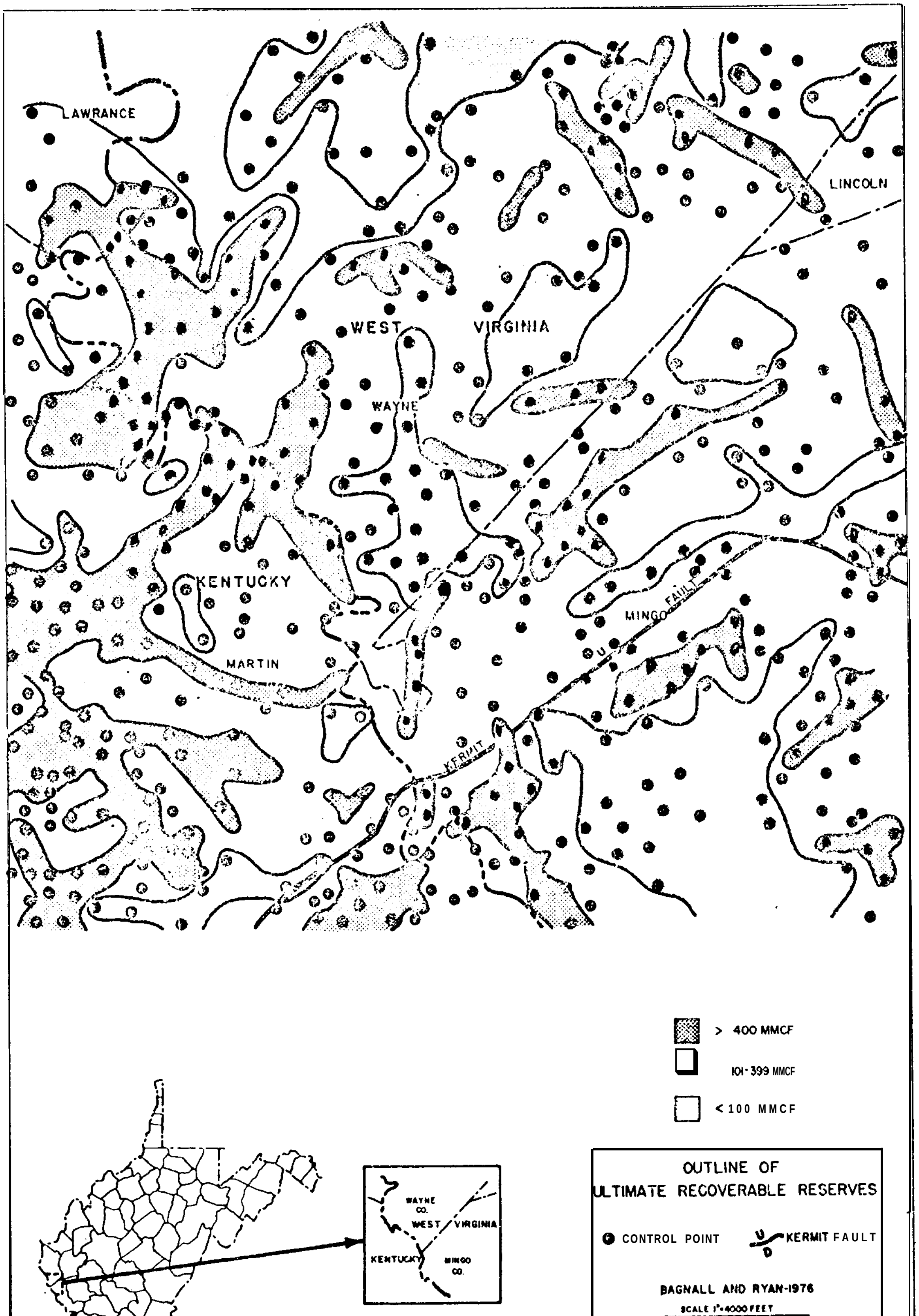
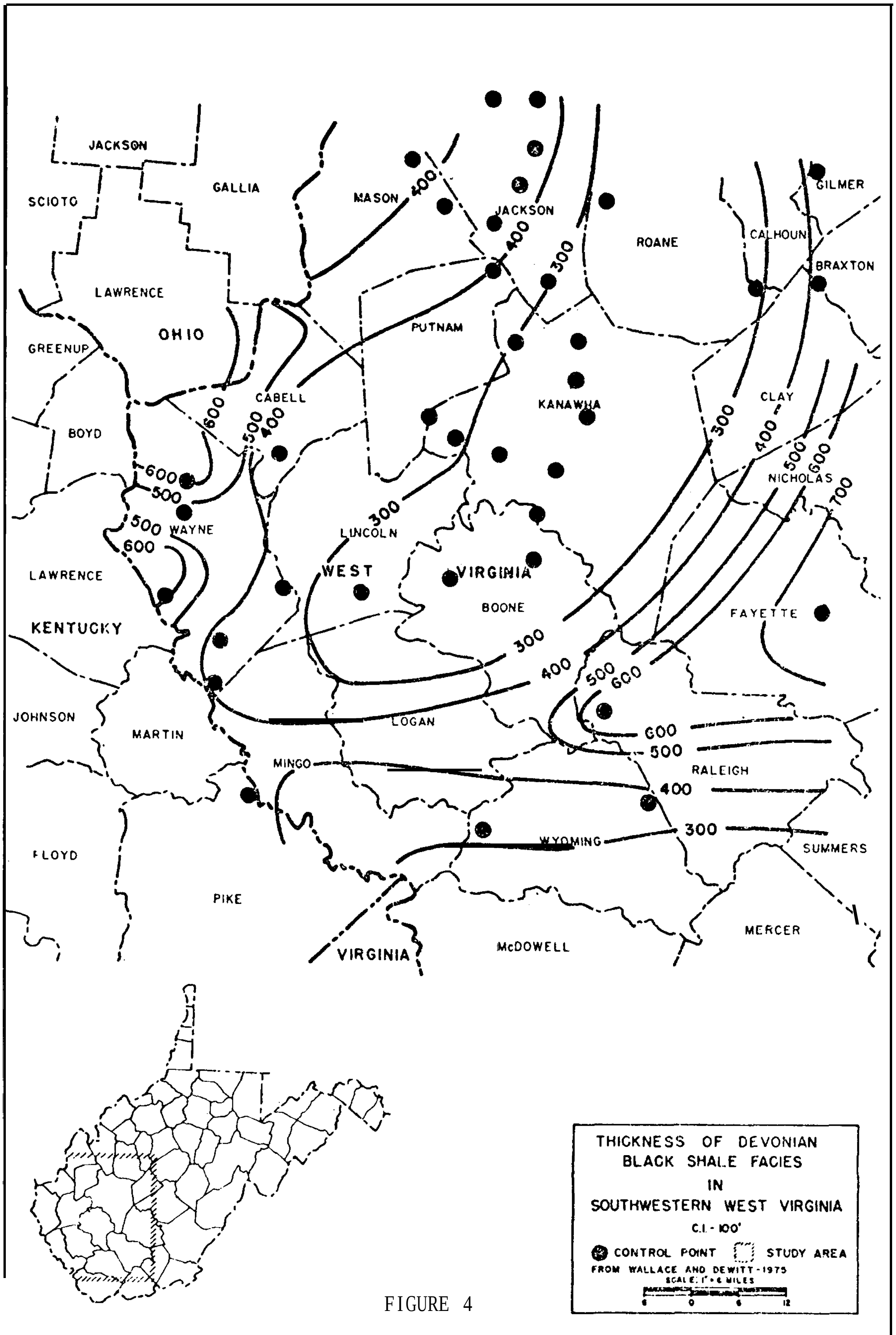

LAWRANCE
LINCOLN
WEST VIRGINIA
WAYNE
KENTUCKY
MARTIN
MINGO
FAULT
KERMIT
> 400 MMCF
101-399 MMCF
< 100 MMCF
WAYNE CO.
WEST VIRGINIA
KENTUCKY
MINGO CO.
OUTLINE OF
ULTIMATE RECOVERABLE RESERVES
CONTROL POINT
KERMIT FAULT
BAGNALL AND RYAN-1976
SCALE 1"=4000 FEET
4000'
0
4000'
8000'

FIGURE 3



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CALHOUN
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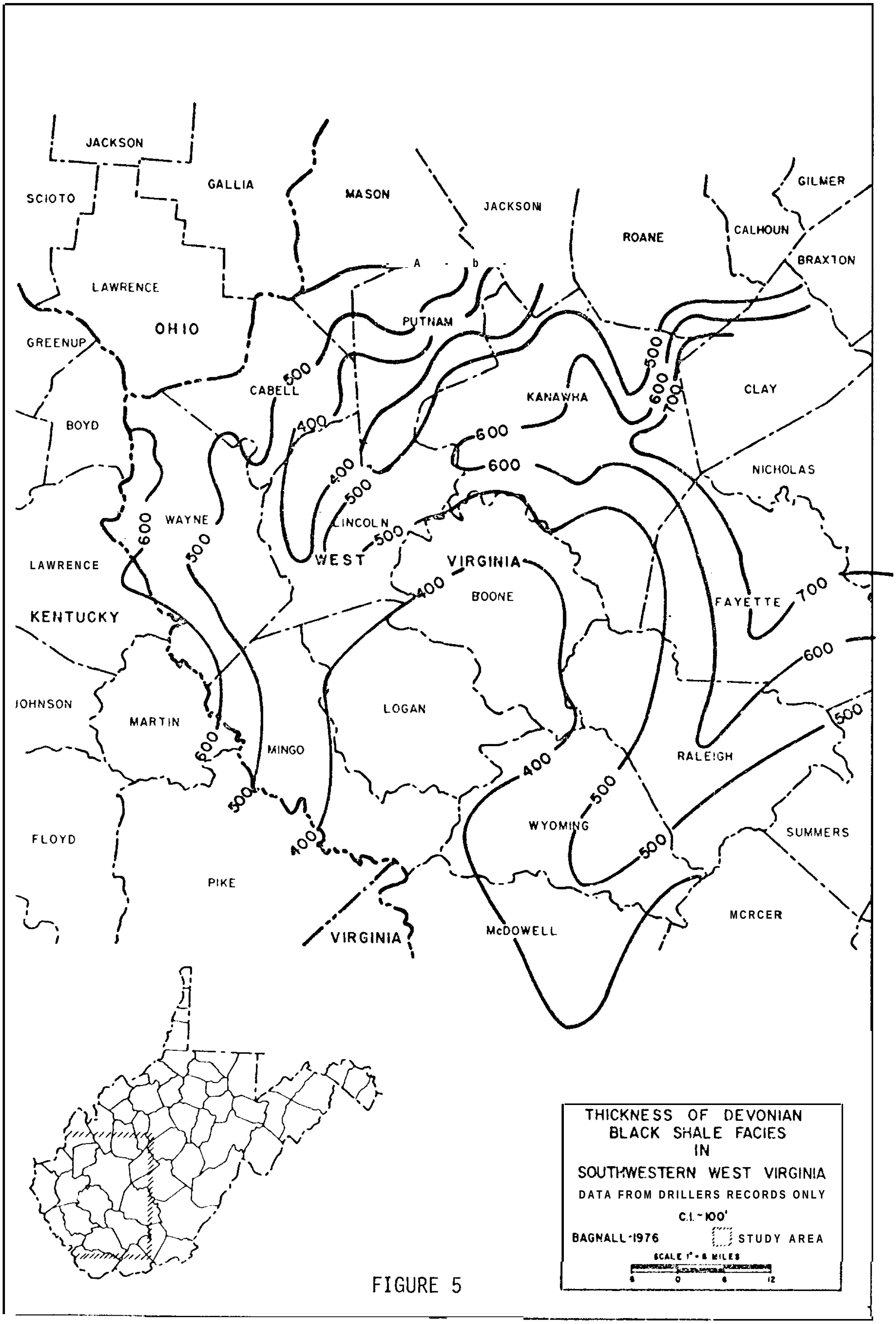
LAWRENCE
OHIO
PUTNAM
GREENUP
CABELL
KANAWHA
CLAY
BOYD
NICHOLAS
WAYNE
LINCOLN
LAWRENCE
WEST
VIRGINIA
BOONE
FAYETTE
KENTUCKY
JOHNSON
MARTIN
LOGAN
MINGO
RALEIGH
WYOMING
SUMMERS
FLOYD
PIKE
MERCER
VIRGINIA
McDOWELL
300
400
500
600
700
THICKNESS OF DEVONIAN
BLACK SHALE FACIES
IN
SOUTHWESTERN WEST VIRGINIA
C.I. - 100'
CONTROL POINT
STUDY AREA
FROM WALLACE AND DEWITT - 1975

FIGURE 4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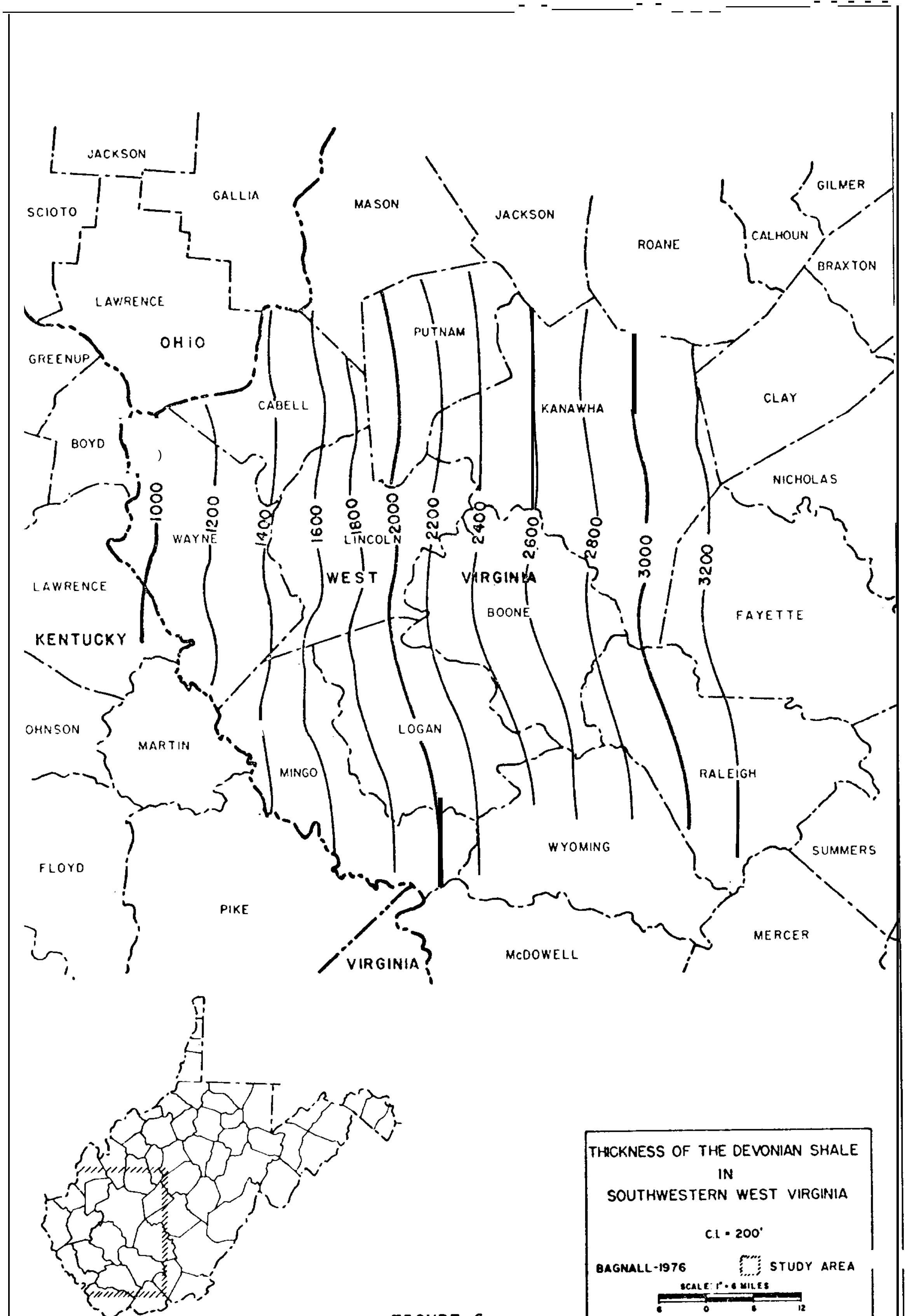
JOHNSON
MARTIN
LOGAN
MINGO
RALEIGH
WYOMING
FLOYD
SUMMERS
PIKE
MERCER
VIRGINIA
McDOWELL
THICKNESS OF DEVONIAN
BLACK SHALE FACIES
IN
SOUTHWESTERN WEST VIRGINIA
DATA FROM DRILLERS RECORDS ONLY
C.I. - 100'
BAGNALL - 1976
STUDY AREA

FIGURE 5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CALHOUN
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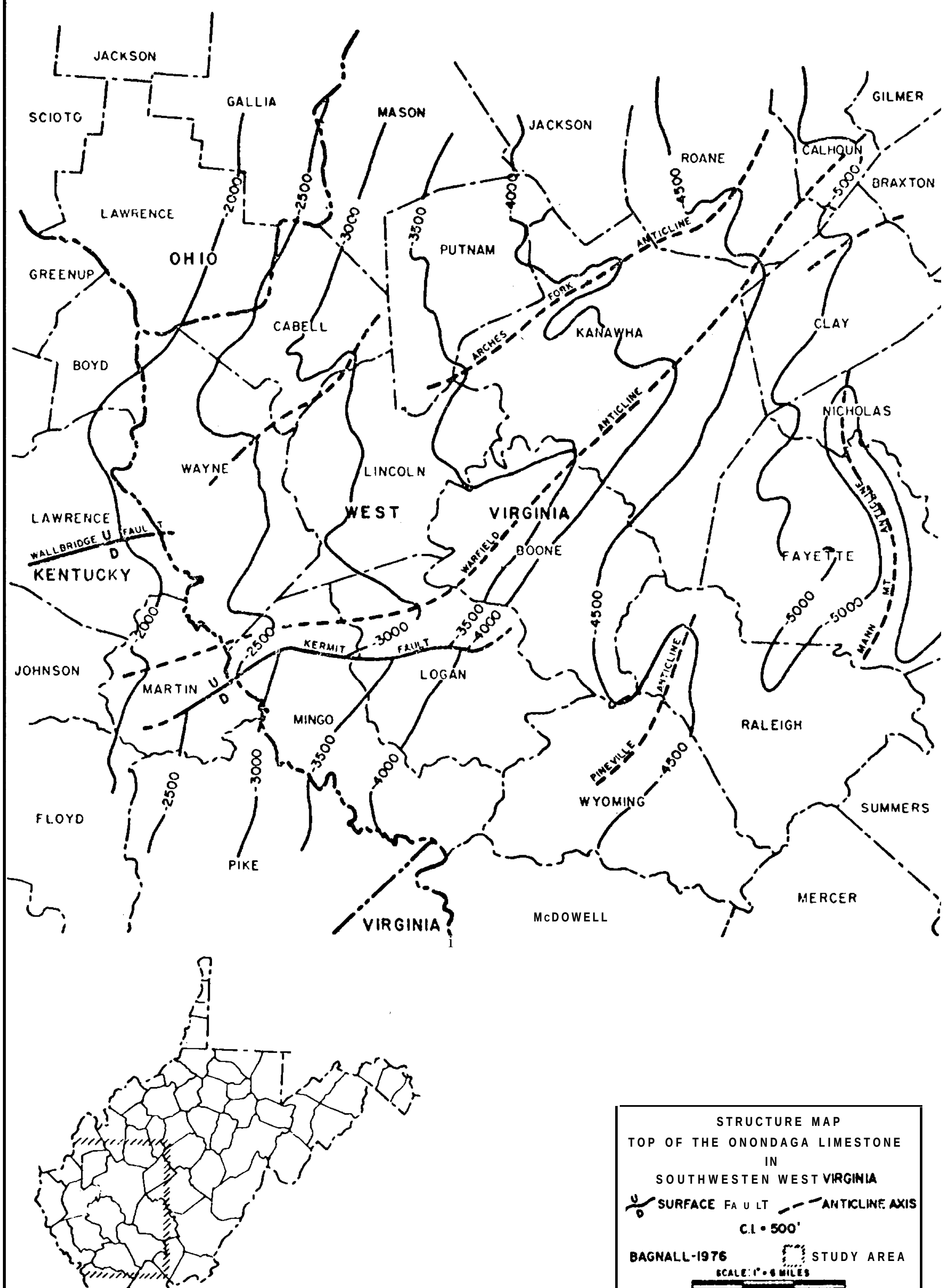
LAWRENCE
OHIO
GREENUP
PUTNAM
CABELL
KANAWHA
CLAY
BOYD
NICHOLAS
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
WAYNE
LINCOLN
WEST
VIRGINIA
LAWRENCE
BOONE
FAYETTE
KENTUCKY
OHNSON
MARTIN
LOGAN
MINGO
RALEIGH
FLOYD
WYOMING
SUMMERS
PIKE
MERCER
VIRGINIA
McDOWELL
THICKNESS OF THE DEVONIAN SHALE
IN
SOUTHWESTERN WEST VIRGINIA
C.I. = 200'
BAGNALL-1976
STUDY AREA

FIGURE 6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CABELL
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CLAY
BOYD
NICHOLAS
WAYNE
LINCOLN
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LAWRENCE
KENTUCKY
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JOHNSON
MARTIN
LOGAN
MINGO
RALEIGH
FLOYD
WYOMING
SUMMERS
PIKE
MERCER
VIRGINIA
McDOWELL
ARCHES FORK ANTICLINE
WARFIELD ANTICLINE
KERMIT FAULT
WALLBRIDGE FAULT
PINEVILLE ANTICLINE
MANN MT. ANTICLINE
STRUCTURE MAP
TOP OF THE ONONDAGA LIMESTONE
IN
SOUTHWESTEN WEST VIRGINIA
SURFACE FAULT
ANTICLINE AXIS
C.I. = 500'
BAGNALL-1976
STUDY AREA
SCALE: 1" = 6 MILES

FIGURE 7

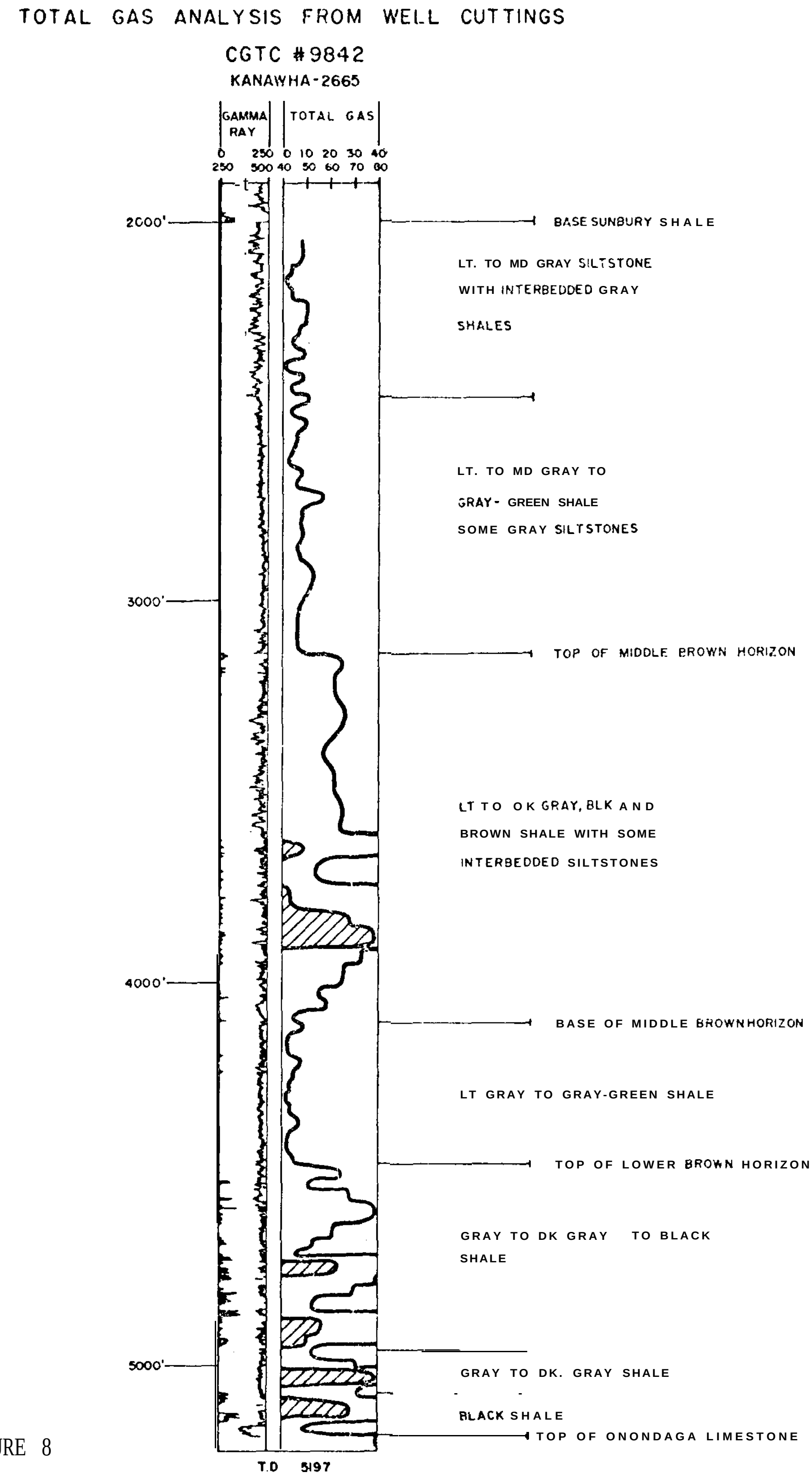
TOTAL GAS ANALYSIS FROM WELL CUTTINGS
CGTC #9842
KANAWHA-2665
GAMMA RAY
TOTAL GAS
0 250
250 500
0 10 20 30 40
40 50 60 70 80
2000'
3000'
4000'
5000'
BASE SUNBURY SHALE
LT. TO MD GRAY SILTSTONE WITH INTERBEDDED GRAY SHALES
LT. TO MD GRAY TO GRAY- GREEN SHALE SOME GRAY SILTSTONES
TOP OF MIDDLE BROWN HORIZON
LT TO DK GRAY, BLK AND BROWN SHALE WITH SOME INTERBEDDED SILTSTONES
BASE OF MIDDLE BROWNHORIZON
LT GRAY TO GRAY-GREEN SHALE
TOP OF LOWER BROWN HORIZON
GRAY TO DK GRAY TO BLACK SHALE
GRAY TO DK. GRAY SHALE
BLACK SHALE
TOP OF ONONDAGA LIMESTONE
T.D 5197

FIGURE 8

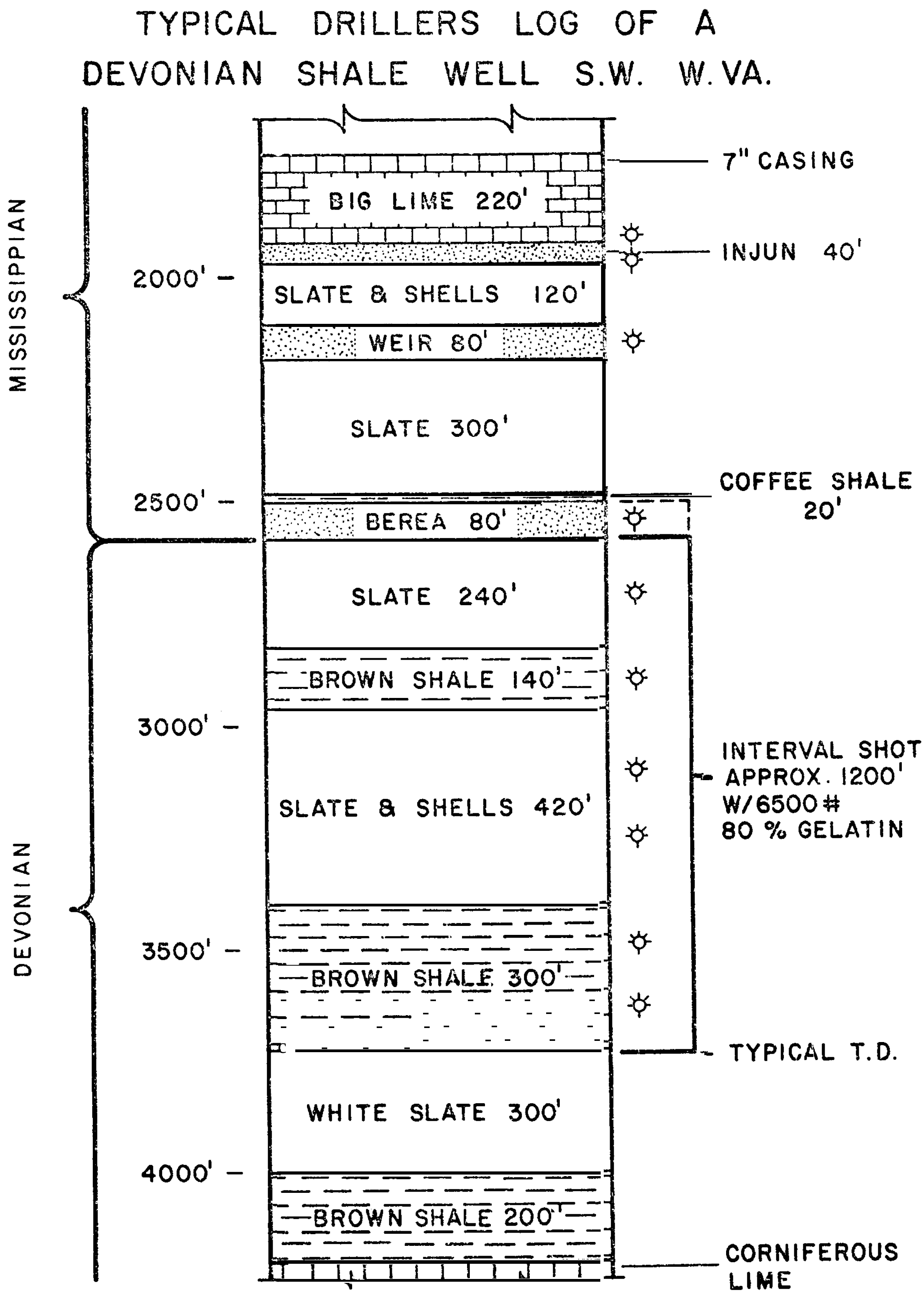
TYPICAL DRILLERS LOG OF A
DEVONIAN SHALE WELL S.W. W.VA.
MISSISSIPPIAN
DEVONIAN
2000' –
2500' –
3000' –
3500' –
4000' –
BIG LIME 220'
SLATE & SHELLS 120'
WEIR 80'
SLATE 300'
BEREA 80'
SLATE 240'
BROWN SHALE 140'
SLATE & SHELLS 420'
BROWN SHALE 300'
WHITE SLATE 300'
BROWN SHALE 200'
7" CASING
INJUN 40'
COFFEE SHALE
20'
INTERVAL SHOT
APPROX. 1200'
W/6500#
80 % GELATIN
TYPICAL T.D.
CORNIFEROUS
LIME

FIGURE 9

SUMMARY OF AVERAGE RESERVES PER WELL
FOR VARIOUS PRODUCING HORIZONS
IN SOUTHERN AND WESTERN WEST VIRGINIA
AS OF 10-72

FORMATION	RECOVERABLE RESERVES (MCF)	NO. OF WELLS	AVERAGE RESERVES PER WELL (MCF)	AVERAGE ACREAGE PER WELL
SALT SAND	7,638,410	38	201,011	140
RAVENCLIFF	5,675,000	10	567,500	100
MAXON	15,798,000	33	478,727	100
BIG LIME	66,198,949	175	378,280	125
INJUN	456,275,799	748	609,994	120
SQUAW	12,230,000	14	873,571	120
WEIR	162,324,500	189	858,859	115
BEREA	136,975,410	325	421,453	140
DEVONIAN SHALE*	377,966,057	1104	342,360	150
ORISKANY	51,833,072	47	1,102,831	65
NEWBURG	198,750,000	195	1,019,231	175

*RESERVES FOR THE DEVONIAN SHALE INCLUDE BOTH ACTIVE AND ABANDONED WELLS AS OF 12-31-74

FIGURE 10

AVERAGED PRODUCTION DECLINE CURVES FOR DEVONION SHALE WELLS IN LINCOLN, MINGO, AND WAYNE COUNTIES, W. VA.

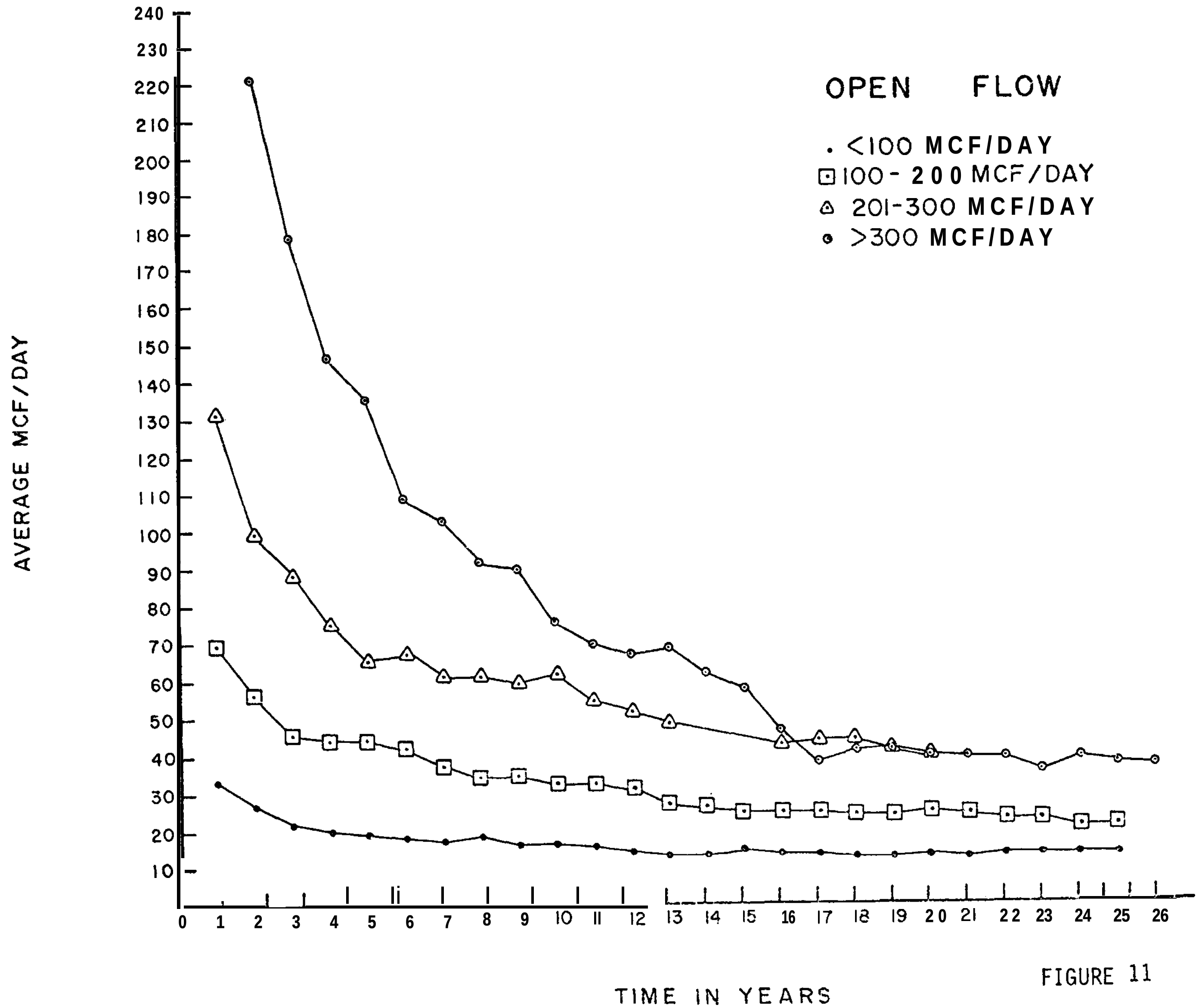

FIGURE 11

PRODUCTION AND RESERVES FROM ACTIVE SHALE WELLS
AS OF 12-31-74

COUNTY	NO. OF WELLS	ANNUAL PRODUCTION (MCF)	CUMMULATIVE PRODUCTION (MCF)	ESTIMATED ULTIMATE RESERVES (MCF)	COUNTY AVERAGE PER WELL (MCF)
BOONE	16	129,012	5,399,868	6,348,000	396,750
CABELL	9	79,053	4,573,494	5,115,000	568,333
JACKSON	6	36,279	1,784,993	2,095,052	349,052
KANAWHA	20	240,426	2,683,996	8,293,000	414,630
LINCOLN	317	3,148,652	105,658,238	133,296,541	420,494
LOGAN	118	1,195,582	26,084,112	36,669,000	310,754
MINGO	206	2,265,115	58,001,188	77,416,000	375,805
PUTNAM	3	18,705	985,834	1,171,000	390,333
WAYNE	259	2,535,719	68,276,008	86,563,000	334,220
TOTALS	955	9,648,557	273,447,731	356,996,593	
AVERAGE PER WELL		10,103	286,333	373,818	

FIGURE 12

FRACTURE SYSTEMS: CHARACTERISTICS AND ORIGIN

Robert A. Hodgson - Gulf Research and Development Co.

INTRODUCTION

Studies of the nature of geologic structures suggest that they fall into one or the other of two fundamentally different types which can be classified as Continuous or Discontinuous, and distinguished on the basis of their distribution in time and space. The types of structures which fall into each category and the main characteristics which distinguish them are outlined in Figure 1. All systematic fractures fall into the category of Continuous structures on the basis of the criteria used. The universal and remarkably uniform distribution of these features, as well as the persistence of their azimuthal distribution over very large areas, suggests some constant level of continuous or intermittent structural activity.

Joints, in particular, can be divided into two categories based on their spatial relations. The distinction between these two groups is shown in Figures 2a and 2b. As shown in the diagrams, systematic joints occur as groups of regularly-spaced parallel or sub-parallel (in plan) planar fractures called joint sets or systems. Non-systematic joints, whether irregular or planar, cross the interval between systematic joints of a set, and terminate against the systematic joints and prominent bedding surfaces. Whether a similar distinction can be applied to the larger orders of linear features is a question that has not been investigated.

There appear to be several distinct orders of linear structural features which have in common a systematic distribution in plan, although they differ in the level of their structural complexity depending on their magnitude. The

INTRODUCTION (con't)

following table gives a tentative classification in decreasing orders of magnitude.

ORDERS OF SYSTEMATIC LINEAR FEATURES		
1.	Planetary	DISTINCTION MAY BE BASED ON LINEAR EXTENT, AS WELL AS CHARACTER
2.	Regional	
3.	Local	
	Fracture Zones	
	Master Joints	
	Systematic Joints	

SYSTEMATIC JOINTS

The various aspects of what is called a joint are shown in Figure 3. In plan, joints of a set commonly have a roughly uniform unit spacing; and the joints of a given set are distributed in narrow zones en echelon, as shown in Figures 4a and 4b.

Generally speaking, joint sets are defined by their parallelism in plan. Joints of the same set can intersect in section as shown in Figure 5.

The unit spacing of joints within a set will vary within a given rock unit, from one rock unit to another and, in-the same manner, from one set to another. These variables are shown graphically in Figure 6.

The structures on the surfaces of systematic joints give a very important clue as to the mechanism of their formation. The plumose and conchoidal structure of the face of a systematic joint is shown schematically in Figure 7. Inspection of joint surfaces exhibiting a plumose pattern shows that the surfaces tend to be elongate in direction of the axis of the pattern. The plumose pattern originates at a point or small area near the center of the surface; and, the ridges of'the pattern radiate outward toward the edge of the joint surface until they terminate in the fringe joints of the edge of the surface. The concentric ridges appear at intervals on the surfaces of some joints and may indicate pauses in the development of the joint fracture. Joints may be similar to fatigue or static fractures which begin as some inhomogeniety in the

SYSTEMATIC JOINTS (con't)

rock (Griffith crack?) and propagate outward from that point, forming a planar fracture.

The point of origin of the plumose pattern may lie at the intersection between the joint surface and an identifiable bedding surface; but, in many examples, this relation is not found, as in massive, fine-grained sandstones. The point of origin of the plume may lie at some point above or below the bed in which it is observed, and the pattern will give a clue whether the edge or the center of the joint is being observed. A detailed classification of joint surface structure is shown in Figure 8.

The occurrence of systematic joints as sets of closely and evenly spaced fractures indicates that the forces responsible for their formation must have been relatively homogeneous in both intensity and direction.

REGIONAL JOINT PATTERNS

The angular relations between joint sets commonly are maintained with a remarkable constancy over large areas. The number of sets can range from one to as many as eight, and the angles of intersection from less than 15° to 90°. Orthogonal relations are not uncommon. A sample of a typical regional joint pattern in the Colorado Plateau is shown in Figure 9.

The most impressive feature of many regional joint patterns is that elements (sets) of the pattern do not appear to be affected materially by the presence of folds. Each element of the pattern can cross folds without swinging to maintain a given angular relation to a fold axis as the axis changes direction. The only obvious correlation between fold aces and joint sets is that the fold axes tend to lie more or less parallel along their length to some one element or another of the regional joint pattern.

Regional joint patterns persist across period boundaries and into "basement" rocks, and details of the pattern, such as the presence or absence of certain trends, appear to be consistent throughout the section and into the basement. The joint pattern in Figure 9 persists through several thousand feet of stratigraphic section, for example.

ORIGIN OF JOINTS

Though numerous fundamentally different hypotheses have been advanced to account for systematic and non-systematic joints, no hypothesis is universally accepted at the present time. The main theories are summarized in Figure 10. The present author has favored the Tidal-Fatigue hypothesis although it appears from the new regional data from the Landsat experiment that, even though this may be a primary mechanism in producing joints in new rocks, the primary imposition of the pattern is genetically related to the systematic and non-systematic changes in the shape of the earth through time, as required by changes in the rate of rotation of the earth. Such a mechanism may be reflected in the pattern of all orders of systematic fracture phenomena, suggesting a genetic relationship among all orders.

SMALLER ORDERS OF FRACTURES

In addition to joints there are two other smaller orders of systematic fractures which appear as elements of the regional fracture pattern. These are Master Joints and Fracture Zones and are shown in Figure 11.

Periodically, what is effectively a single systematic joint within a joint set will attain unusually large dimensions, extending for several hundreds of feet in both plan and section. Such a joint is called a Master Joint.

Features comparable or larger than master joints in dimensions, and roughly comparable in spatial relations with systematic joints are the Fracture Zones. In contrast to master joints, fracture zones are composed of a zone or band of very closely spaced joints, the zone usually being at least a meter or two in width. These zones frequently have the outward aspect of a fault but differ from faults in having no recognizable displacement of one side relative to the other. Fracture

SMALLER ORDERS OF FRACTURES (con't)

zones may reach several tens of meters in width and several kilometers in length. The larger fracture zones may grade into lineaments as described below.

LINEAMENTS

Figures 12a and 12b show the physiographic and structural aspects of the Florence Pass Lineament, a typical structural lineament of the Central Rocky Mountain Region. The total mapped length of this lineament is about 65 miles. It is of particular interest in that it is clearly expressed in both the sedimentary and basement rocks of the Bighorn Range.

In the sedimentary rocks along the west flank of the range, the lineament is represented by a monocline having an average structural relief of about 200 feet. Eastward this structure is replaced en echelon on the south by another similar monocline. In the Precambrian terrane the lineament is again offset to the south and is represented by a deep, narrow valley incised along a set of east-west joints. At the crest of the range, the lineament is marked by a normal fault of some 500 feet displacement. From this point the lineament continues east across the range and is marked by a deep valley.

The Florence Pass Lineament shows little relation to either local structural trends or lithologic units within the Precambrian basement. It does, however, follow a regional joint direction in the Precambrian in which joints of Precambrian age are found.

Clearly lineaments of this type are composite structures and display a variety of geomorphic and geologic aspects. In this sense they fit the original definitions of Hobbs which are shown in Figure 13.

SPACE PICTURES AND FRACTURE SYSTEMS

Recently, space pictures from Skylab and Landsat (ERTS) have added a new dimension to the mapping of regional fracture networks and the recognition of many new lineaments of the largest size. In addition, the multi-spectral imagery of Landsat allows enhancement of the data

SPACE PICTURES AND FRACTURE SYSTEMS (con't)

content to an extent not available before on a regional basis. Figure 14 shows graphically the types and orders of fracture elements which can be identified from Landsat data.

Figure 15 depicts a series of the largest (Planetary) lineaments which can be mapped from readily available Landsat mosaics of the United States. The importance of such new information to the understanding of the fracture systems of the crust can hardly be overestimated.

In detail most of the largest features recognized are composed of a connected series of structural phenomena along their length such as fault zones, fracture zones, linear folds and fold belts, and edges of regional features such as downwarps and upwarps, all constituting narrow, linear zones of deformation when considered at the viewing scale. A few lineaments are marked by what appears to be a single well-defined suture along their length. There is a generally systematic distribution for all orders of linear features recognized on the imagery; and, as a generalization, one can say they are distributed azimuthally in sets following approximately NE, NW, E-W and N-S directions over very large regions.

ORIGIN

The areal fracture patterns of all orders of fractures appear to be consistent with each other to a remarkable degree for large regions. This would suggest a genetic relationship between the orders of fractures from the smallest to the largest, and that the smaller orders are a reflection of the largest lineamental features with respect to azimuth in particular. If true, the understanding of the genesis of the largest elements of the fracture network might aid in explaining that of systematic joints.

The observed systematic areal pattern of the major lineaments is reasonably compatible with that predicted by theories which postulate global deformation caused by systematic and non-systematic changes in the rate of rotation of the

ORIGIN (con't)

earth or, the position of its axis of rotation relative to the lithosphere.

The several theories that postulate crustal fracture patterns similar to those observed on Landsat imagery have been reviewed in detail in the literature by Sonder, Vening-Meinesz, Belousov, Stovas, Bondarchuk and others.

From both observation and theory, it can be concluded that the tectonic forces which first produced the great earth lineaments are global in nature and have to do with changes in the rate of rotation of the earth. Once established, a constant level of structural activity would be maintained along the lineaments through the earth tides. These forces can be considered to act today at essentially the same level they did in the beginning, and the major lineaments have existed since that time. The lower order of fracture elements appears to represent the details of the global fracture network and, if so, would have been generated and maintained by the same forces responsible for the largest elements of the network.

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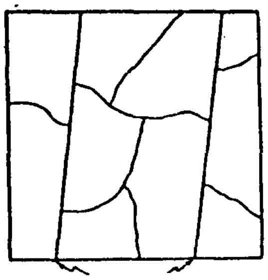
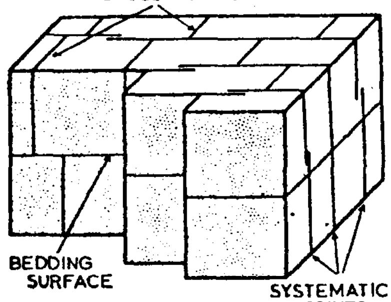
BASIC TYPES OF STRUCTURES	
CONTINUOUS	DISCONTINUOUS
SYSTEMATIC JOINTS MASTER JOINTS JOINT ZONES LINEAMENTS BELTS OF LINEAMENTS	FAULTS FOLDS CLEAVAGE VOLCANIC CRYPT0 VOLCANIC IMPACT
MAIN CHARACTERISTICS	MAIN CHARACTERISTICS
1. UBIQUITOUS OCCURENCE IN ROCKS OF ALL TYPES AND AGES – NON-REVERSIBLE 2. MAINTAIN UNIFORM AREAL PATTERNS OVER VAST AREAS 3. UNIFORM SPACING MAINTAINED BETWEEN ELEMENTS OF EACH ORDER 4. REGIONAL AND PLANETARY ORDERS CROSS ALL OTHER STRUCTURAL FEATURES WITHOUT DEVIATION OR OFFSET 5. ALL SYSTEMATIC LINEAR FEATURES CROSS EACH OTHER WITHOUT DISCERNIBLE OFFSET 6. LARGER ORDERS – COMPLEX STRUCTURES	1. ISOLATED STRUCTURAL EVENTS IN TIME AND SPACE 2. NON-UNIFORM AREAL DISTRIBUTION 3. CLEAVAGE AND FLEXURES – NON-REVERSIBLE – EPISODIC 4. FAULTS – REVERSIBLE (?) – EPISODIC 5. VOLCANIC – EPISODIC 6. CRYPTOVOLCANIC AND IMPACT – UNIQUE – NON-REPEATED

Fig. 1: Basic types of geologic structures.



-Diagrammatic plan view showing typical pattern of non-systematic joints and their characteristic termination against systematic joints.

Fig. 2a



—Schematic block diagram showing relations between cross-joints and systematic joints and between cross-joints and prominent bedding surfaces.

Fig. 2b

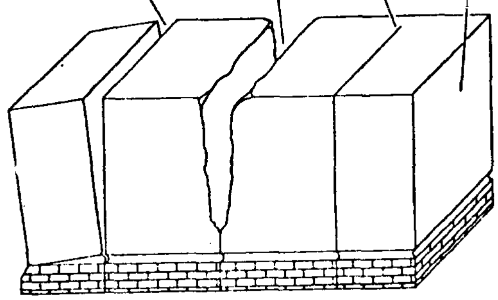


Fig 3:- Aspects of a systematic joint.

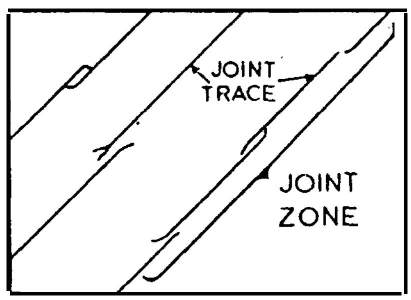
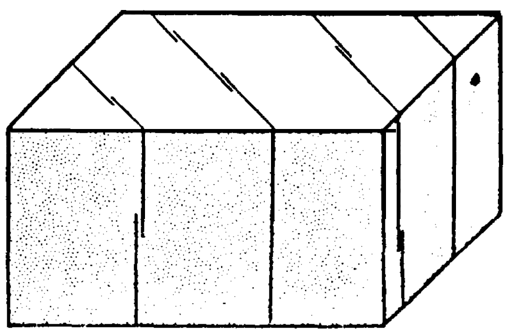


Fig. 4a



(Upper). Diagrammatic plan view showing arrangement of systematic joints in narrow zones of *en échelon* fractures (joint zones).
(Lower). Schematic block diagram showing joint zones.

Fig. 4b

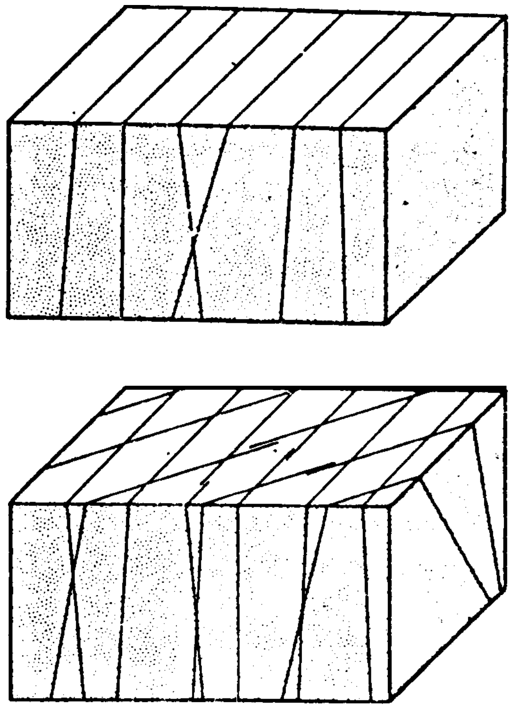
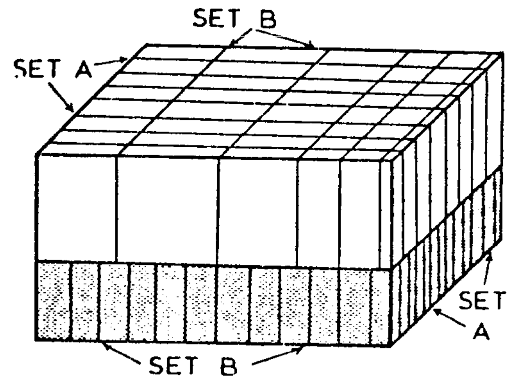


Fig. 5- (Upper).—Schematic block diagram showing manner in which joints of snmc set intersect in section.
14h (Lower).—Schematic block diagram showing manner in which joints of different sets intersect in section. Regular pattern otmervcd in plan is not found in section.



-Schematic Mock diagram showing observed variables in joint spacing.

Fig. 6

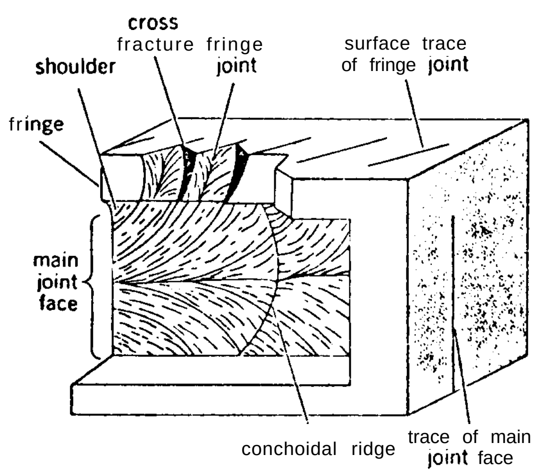


Fig. 7- Schematic block diagram showing primary surface structures of a systematic joint.

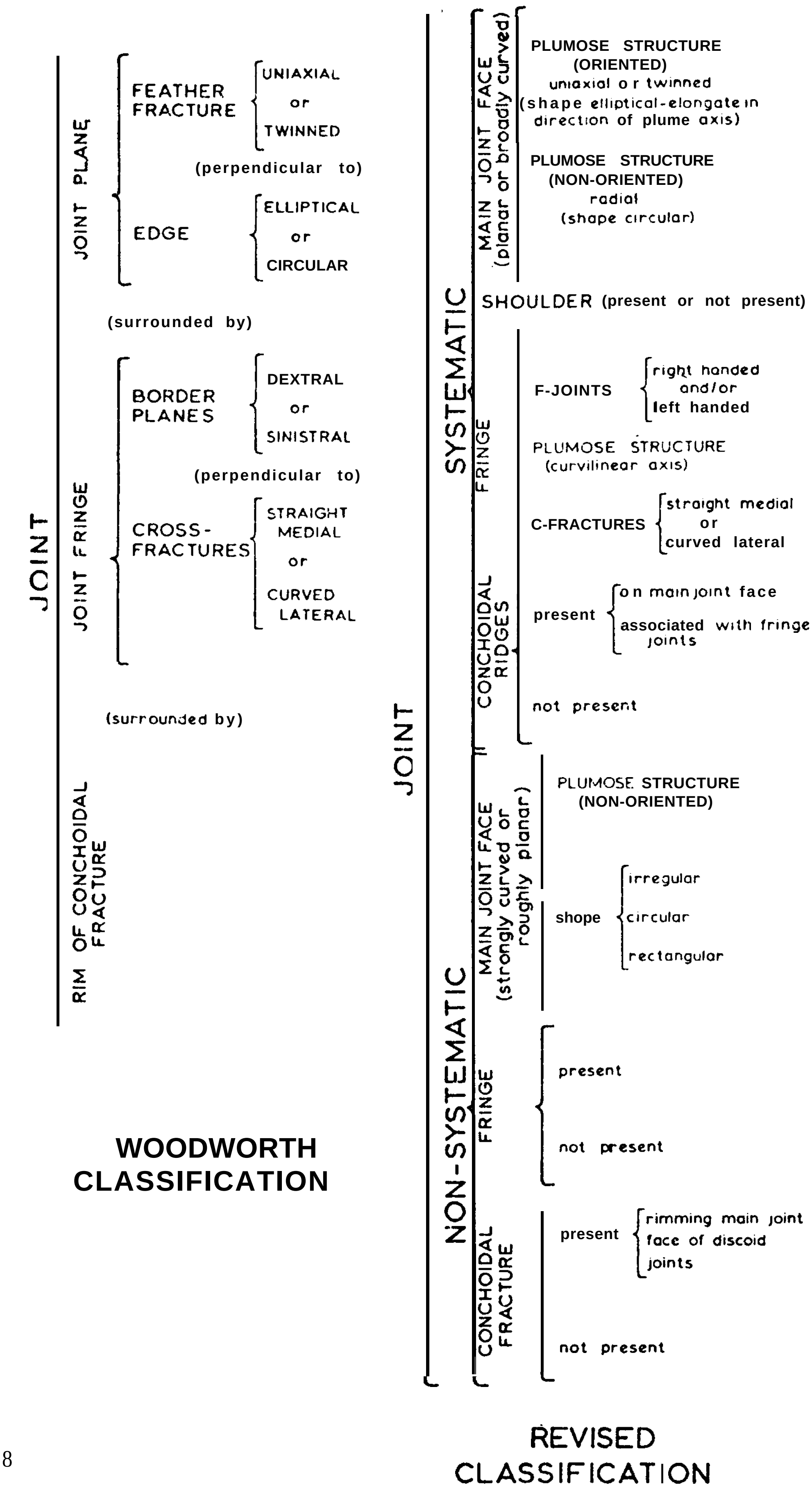
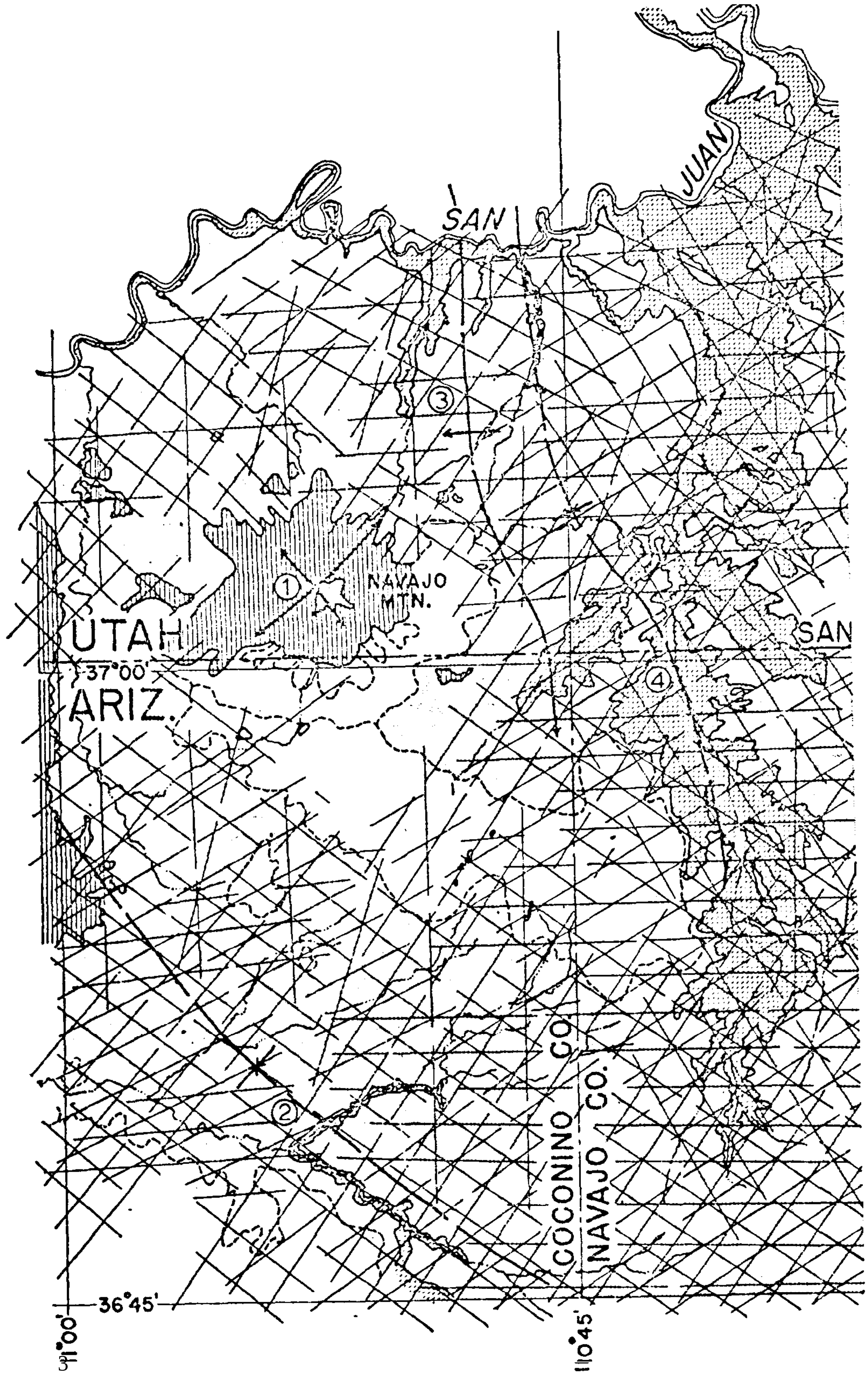

JOINT
JOINT PLANE
FEATHER FRACTURE
UNIAXIAL
or
TWINNED
(perpendicular to)
EDGE
ELLIPTICAL
or
CIRCULAR
(surrounded by)
JOINT FRINGE
BORDER PLANES
DEXTRAL
or
SINISTRAL
(perpendicular to)
CROSS-FRACTURES
STRAIGHT MEDIAL
or
CURVED LATERAL
(surrounded by)
RIM OF CONCHOIDAL FRACTURE
WOODWORTH CLASSIFICATION
JOINT
SYSTEMATIC
MAIN JOINT FACE (planar or broadly curved)
PLUMOSE STRUCTURE (ORIENTED)
uniaxial or twinned
(shape elliptical-elongate in direction of plume axis)
PLUMOSE STRUCTURE (NON-ORIENTED)
radial
(shape circular)
SHOULDER (present or not present)
FRINGE
F-JOINTS
right handed
and/or
left handed
PLUMOSE STRUCTURE (curvilinear axis)
C-FRACTURES
straight medial
or
curved lateral
CONCHOIDAL RIDGES
present
on main joint face
associated with fringe joints
not present
NON-SYSTEMATIC
MAIN JOINT FACE (strongly curved or roughly planar)
PLUMOSE STRUCTURE (NON-ORIENTED)
shape
irregular
circular
rectangular
FRINGE
present
not present
CONCHOIDAL FRACTURE
present
rimming main joint face of discoid joints
not present
REVISED CLASSIFICATION

FIGURE 8



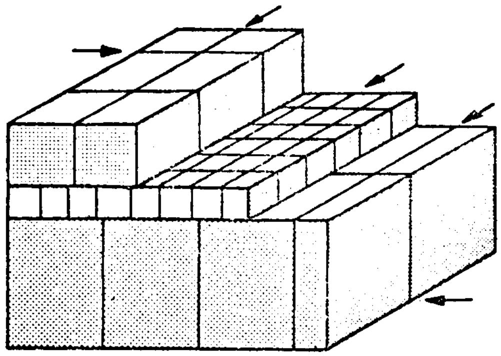
.—Comb Ridge-Navajo Mountain region.

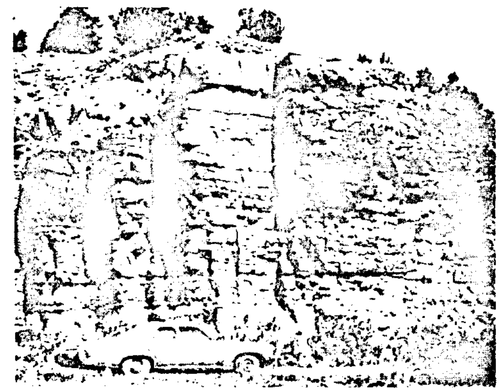
Fig. 9

Various theories of jointing

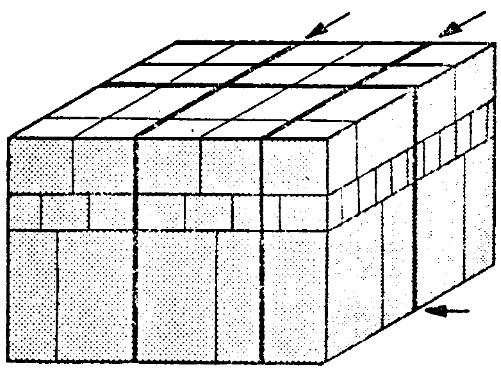
Theory	Origin
	Systematic joints
Cleavage	Genetically similar to cleavage in minerals (theory no longer maintained)
Magnetic forces	Genetically related to and controlled by Earth's magnetic field (theory no longer maintained)
Torsion	Result of local and regional warping of Earth's crust
Earthquake	Seismic shock produces and controls direction of jointing
Torsion-earthquake	Rock warped to breaking point; fracturing triggered by earthquakes
Tension	Result of contraction of sediments due to compaction or loss of water or both
Tension	Result of local or regional (or both) vertical forces involved in uplift or folding of Earth's crust
Tension and shear	Result of local or regional (or both) tangential forces involved in uplift or folding of Earth's crust
Tidal	Result of cyclic tidal forces acting tangential to Earth's crust; forces control direction of jointing
Tidal fatigue	Result of rock fatigue engendered by cyclic semidiurnal tidal forces; direction of jointing inherited from preexisting fracture pattern
Residual stresses	Residual rock stresses modified during uplift in such a manner as to produce shear and tension joints
	Nonsystematicjoints
Tension	Resulting from contraction of sediments due to compaction or loss of water or both
Tension	Resulting from contraction of igneous rock upon cooling
Compression-tension	Resulting directly or indirectly from removal of overburden or from surface weathering of rock

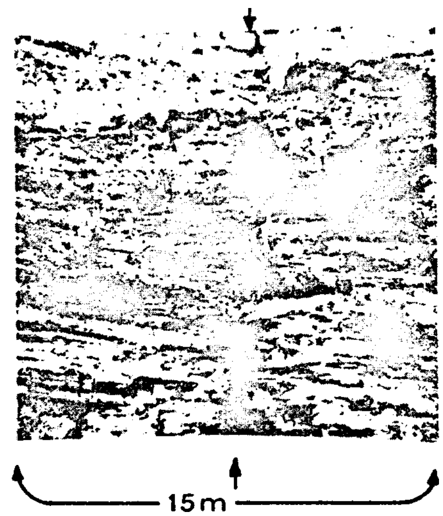
Fig. 10



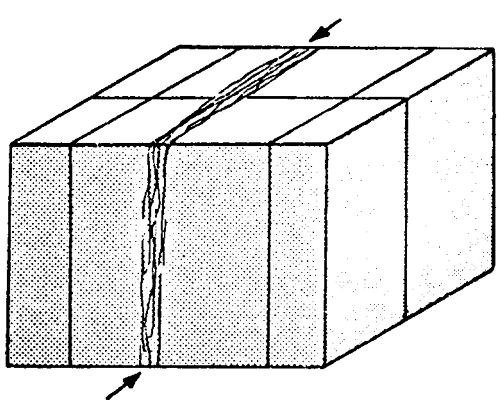


SYSTEM&TIC JOINTS





MASTER JOINTS



Joint zone deforming graywakes ot the Lower Carboniferous strata dips about 25°- a quarry NE of Olomouc, Czechoslovakia. (Photo by Miroslav Plička)

FRACTURE ZONES

Fig. 11 – Smaller orders of linear geologic structures.

Fig. 12a – Aerial view west along Florence Pass lineament showing physiographic expression of the structure. (Sketch after photo by R. A. Heimlich).

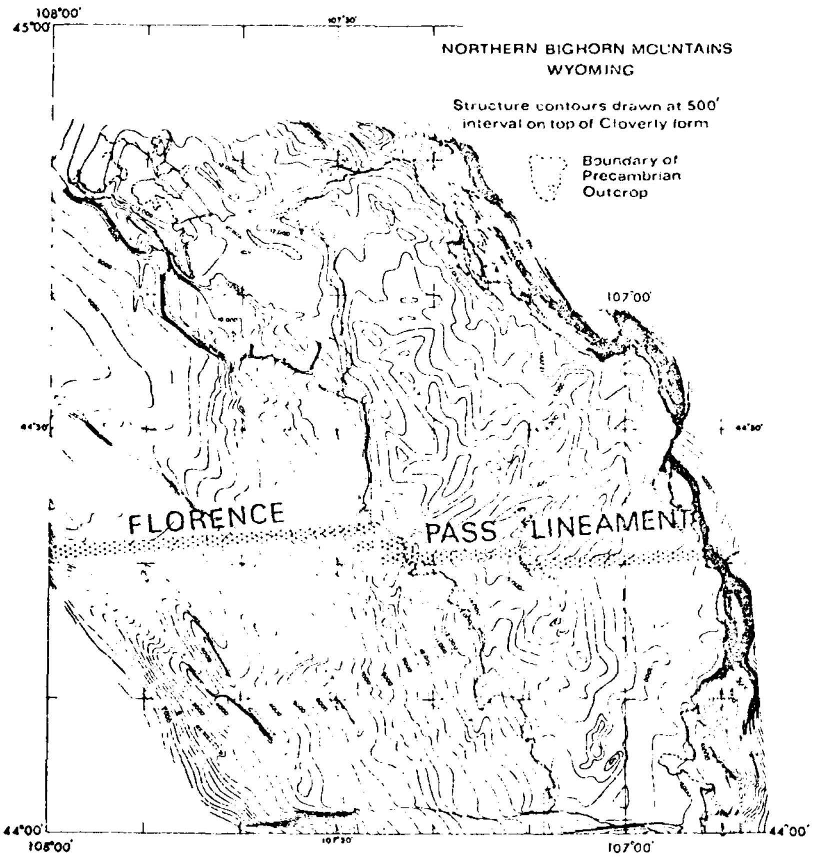
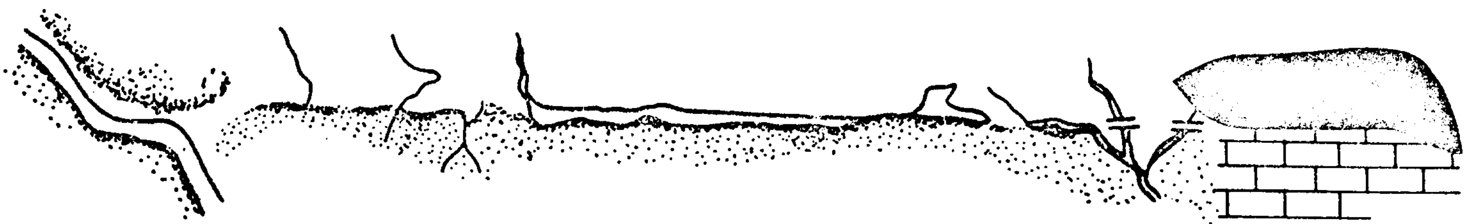
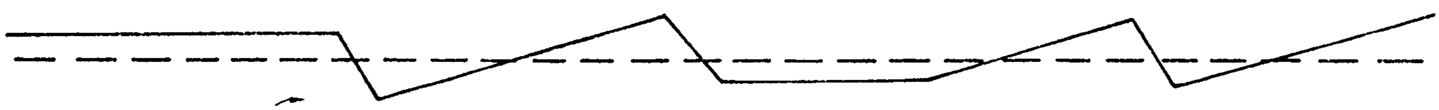


Fig. 12b – Structure contour map of the northern Big Horn Mountains, Wyoming, showing location and structural geometries of the Tensleep and Florence Pass lineaments. (After Hodgson, 1965)



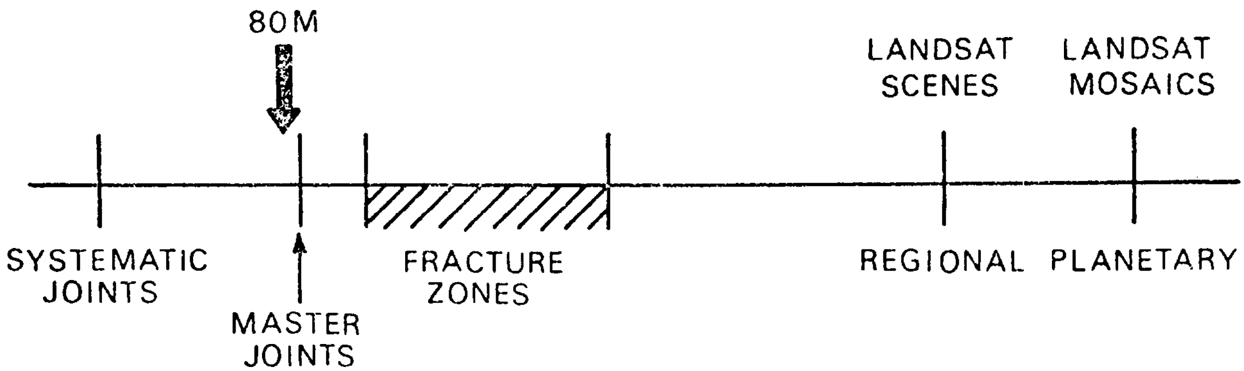
SCHEMATIC DIAGRAM INDICATING THE COMPOSITE EXPRESSION OF A LINEAMENT after HOBBS (1911)



SCHEMATIC DIAGRAM INDICATING THE COMPOSITE NATURE OF DISLOCATION LINES after HOBBS (1904)

Fig. 13 – Schematic diagrams showing the composite structural and physiographic aspects of lineaments.

RESOLUTION OF LANDSAT IMAGERY & INDIRECT IDENTIFICATION
OF LINEAR FEATURES (INFERENCE)



RESOLUTION OF LANDSAT IMAGERY & DIRECT IDENTIFICATION
OF LINEAR FEATURES (OBSERVATION)

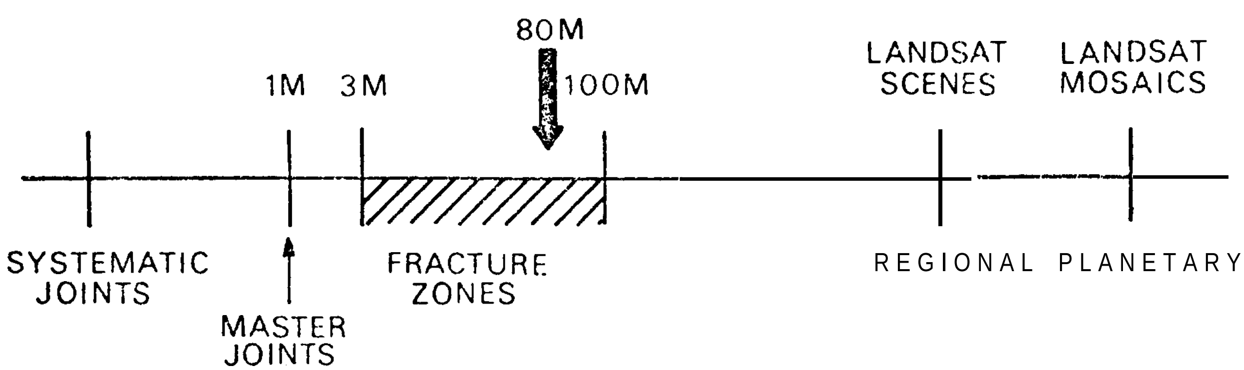


Fig. 14 – Smallest order of linear geologic structure seen on Landsat imagery by direct observation or by inference.

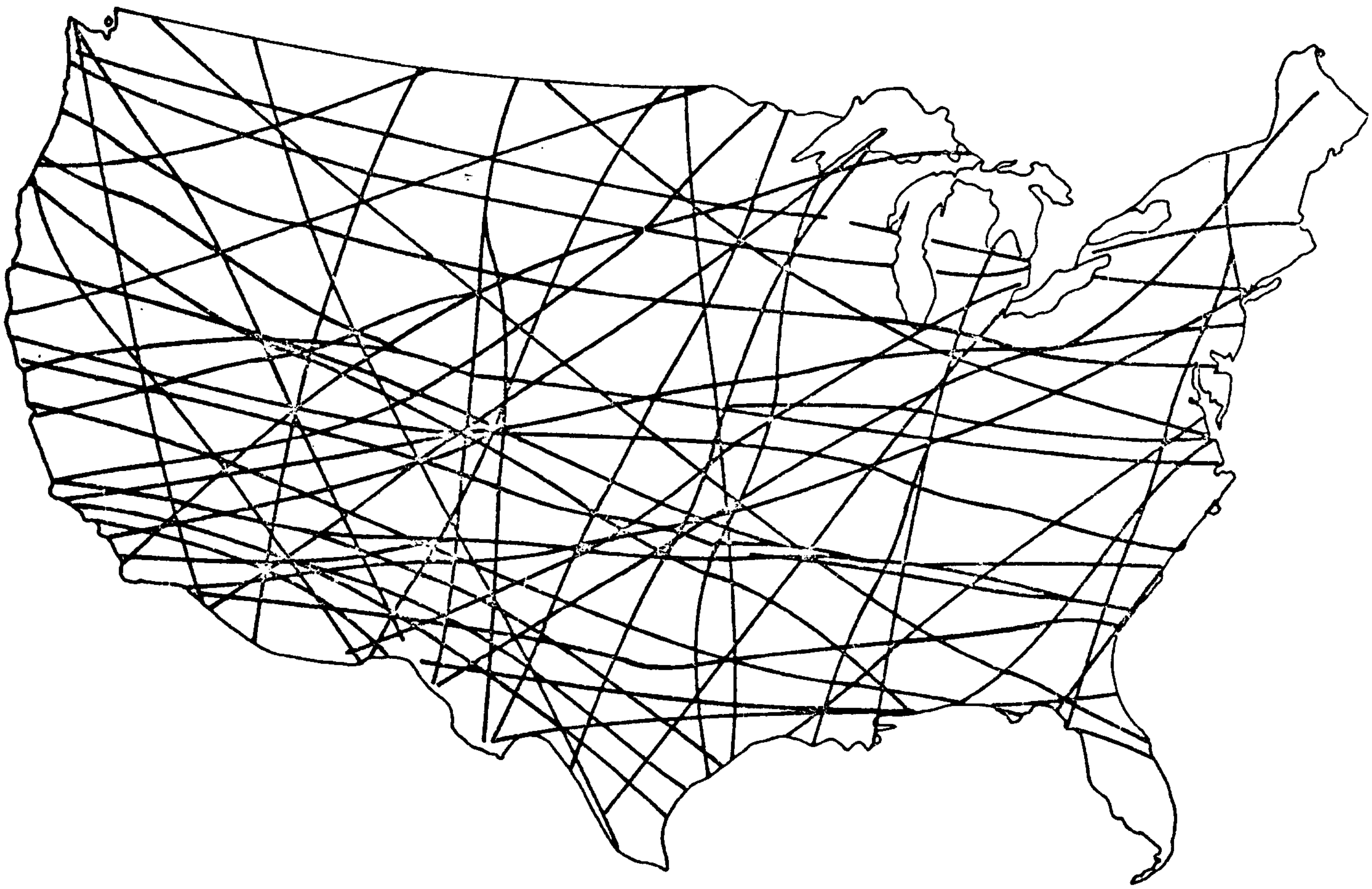


Fig. 15 — First order lineaments of the United States taken from the Band 5 Mosaic of the United States as published in the July, 1974 issue of Geotimes.

A DIGEST OF APPALACHIAN STRUCTURAL GEOLOGY

R. C. Shumaker - Department of Geology and Geography

West Virginia University

The Appalachian Basin comprises a small part of the asymmetric foreland trough which extends the full length of the Appalachian orogenic belt (figs. 1, 8). The northern portion of the foreland trough, discussed in part by Robin Ceiers, extends from eastern Canada to northern New Jersey. That portion of the foreland is narrow and has an adjacent imbricate thrust belt implaced during the Ordovician.

The central portion of the foreland trough expands westward in Pennsylvania and West Virginia to become the wide Appalachian Basin. Surface structure here is characterized by a vast area of broad folds (fig. 2). From Virginia southward the basement rises so that the Appalachian Basin disappears in that direction (fig. 3). Surface folds of the Central Appalachians are replaced southward by a belt of foreland imbricate thrusts, The major deformation that created the structure in rocks of the central and southern portion of the foreland occurred late in the Paleozoic (figs. 4, 5).

To discuss the structure within the Appalachian Basin it is convenient to consider two general types, basement structures and detached structures. Most of the folds and structural relief seen at the surface within the basin (figs. 4, 5) are caused by detached deformation. All of the structure is detached above a sole fault which rises upward thru the stratigraphic section away from the eastern core toward the continental interior (fig. 1). At least three major shale sections have been noted as major detachment horizons: the Rome, the Martinsburg, and the Middle Devonian "Brown" shale section (fig. 7).

In addition, the Silurian shale and salt is a detachment horizon. While the sole fault is important, it should be remembered that any of a multitude of incompetent units, mostly shales, can form detachment zones. Major structural changes that trend along strikes within the Appalachians generally correspond to the rise of termination of the basal detachment thrust (fig. 7).

Basement structure within the outer Plateau is distinctly different in time of origin and structural style from the detached structure. The basernent deformation started much earlier than the detached deformation. The earliest deformation of the Appalachian cycle appears to have been in Precambrian time. In the plateau the earliest dated movement is within the early Cambrian time. This early deformation appears to have been the most intense basement deformative event within the Appalachian Basin (figs. 8, 9). However, the core area to the east apparently underwent intense basement deformation at least from middle Paleozoic time through upper Paleozoic time. Basement deformation in the Appalachian Basin was not limited to the Cambrian event. The distribution and thickness of the various younger stratigraphic units within the basin suggests that certain of the basement faults moved to a lesser extent throughout the Paleozoic. The deepening and development of the broad basin reflects this observation (fig. 10).

One major trend of faulting, along the thirty-eighty parallel, was active during the late Paleozoic (figs. 1, 4). This "cross trending" basement fault zone is located, perhaps significantly, where the Central Appalachian detached fold style changes to the detached thrust style of the Southern Appalachians. Of undetermined significance is the occurrence of the most prolific production from the Devonian Shale near the intersection of the two trends and styles (fig. 11).

The influence of basement deformation and shape on detached structure has been noted for many years. Recent observations by many geologists have dealt with the interrelationship of basement faults and the upward ramping of the sole fault. The similarity of the trend of the major plateau folds and magnetic trends (basement) suggests that there is an interrelationship between the two styles of deformation within the shale-producing areas of the Appalachian Basin (figs. 12, 13).

Perhaps the most important single structural feature in respect to shale gas production is that of fracturing. Many geologists acquainted with the Devonian shale production relate permeability in the shale to fracturing. In as much as most of the production comes from unfaulted and comparatively undeformed structural areas, it seems likely that joints, and not faults, create the main zones of permeability for gas movement through the shale. It is difficult to assess the importance of jointing because little is known about fracture patterns within the southern portion of the Appalachian Basin. It has been tacitly assumed in the past that most joints relate to the Appalachian deformation since the joints do show a trend relationship to the folds and shape of the basin. However, recent investigations on fracturing have established that fractures may propagate upward through rocks, presumably the ultimate source being the basement. Other work suggest that topographic unloading is important in fracture development. Recently, it has also been found that latent, in situ stress within the rocks affects the direction of secondary fracture propagation, and that the induced direction often corresponds with one of the natural fracture trends. Whatever the cause of joints and joint patterns, much more must be known of their distribution and trend; and, much more must be known about both the distribution and trend of basement structures and the state of stress within the rocks before even preliminary answers can be obtained for this basin.

Geologists for many years have also noted that major lineaments cross the Appalachian Basin. Major lineaments such as those of Gwinn (1967) (fig. 14) or the 38th parallel lineament (Werner) (fig. 15) are being evaluated to establish if they are valid geologic discontinuities. If such lineaments are zones of deformation and/or intense fractures within the Devonian shale, then they may be prospective for gas production from the shale.

From the text of this paper it is clear that little can be said definitively about the relationship of regional surface structure to Devonian shale production. Only a few general observations can be made.

(1) Fracturing is essential to most shale production, and the Devonian shale production is seemingly no exception to this "rule."

(2) Certain basement faults influenced depositional thickness of the Devonian shale. If structure influenced the depositional environment, then structure may indirectly influence the geochemistry of the shale.

(3) Present production lies near the intersection of structures of varying style, trend, and age.

(4) Different structural styles should have different fracture patterns. Production characteristics may thus vary from one structural area to another.

(5) Present day stress and recent movement along fractures may be an important factor in shale production. We know very little about this!

(6) Exploration for fracture zones (lineaments?) is a most hazaradous task in that while "picking lines" on images is comparatively simple, selecting significant geologic lines or fracture zones is extremely difficult. Linear selection is only the first step in a long geologic journey that involves field work and correlation of the lines with regional and detailed geologic and geophysical data. This type of exploration should be undertaken by experienced and imaginative personnel.

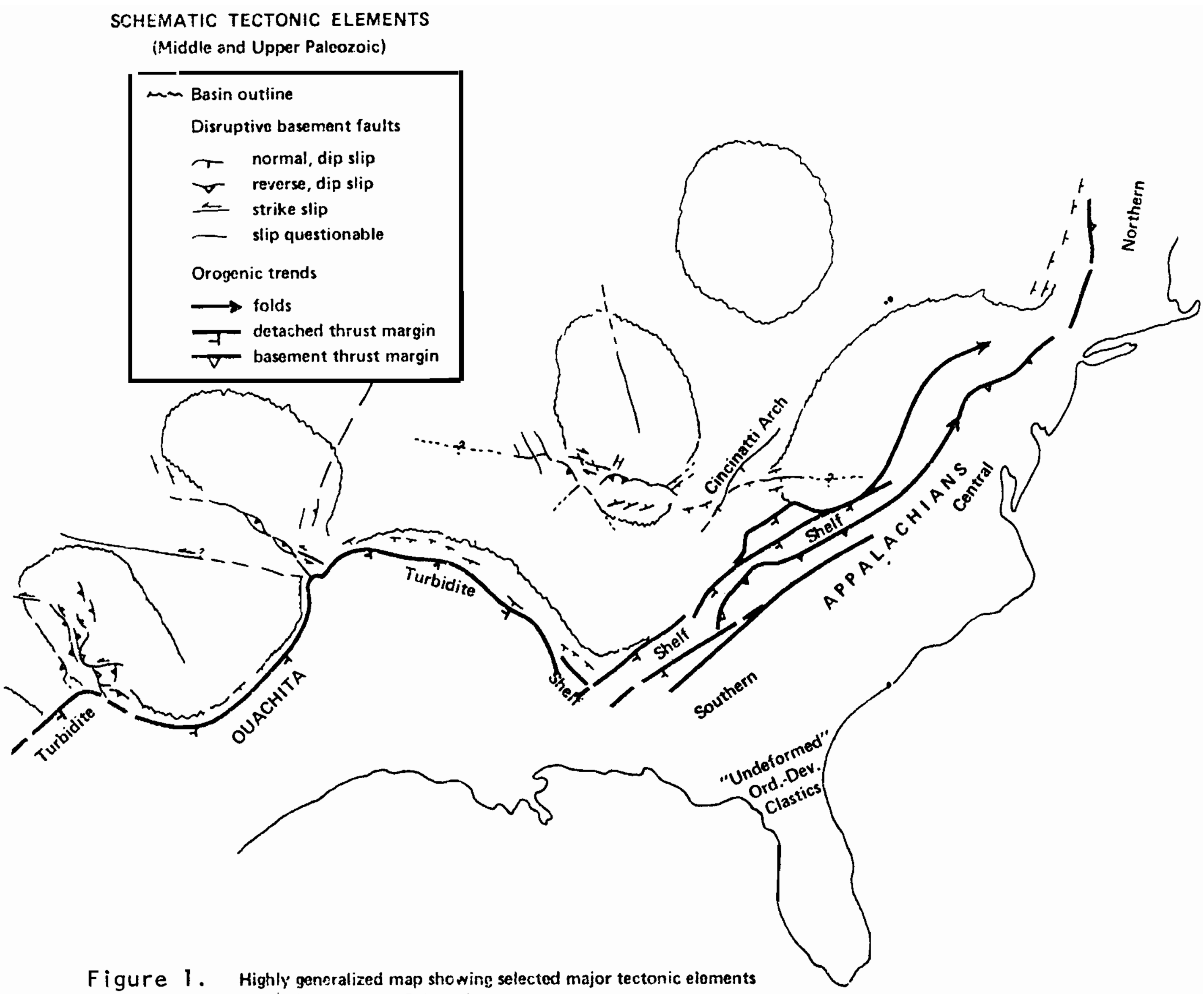
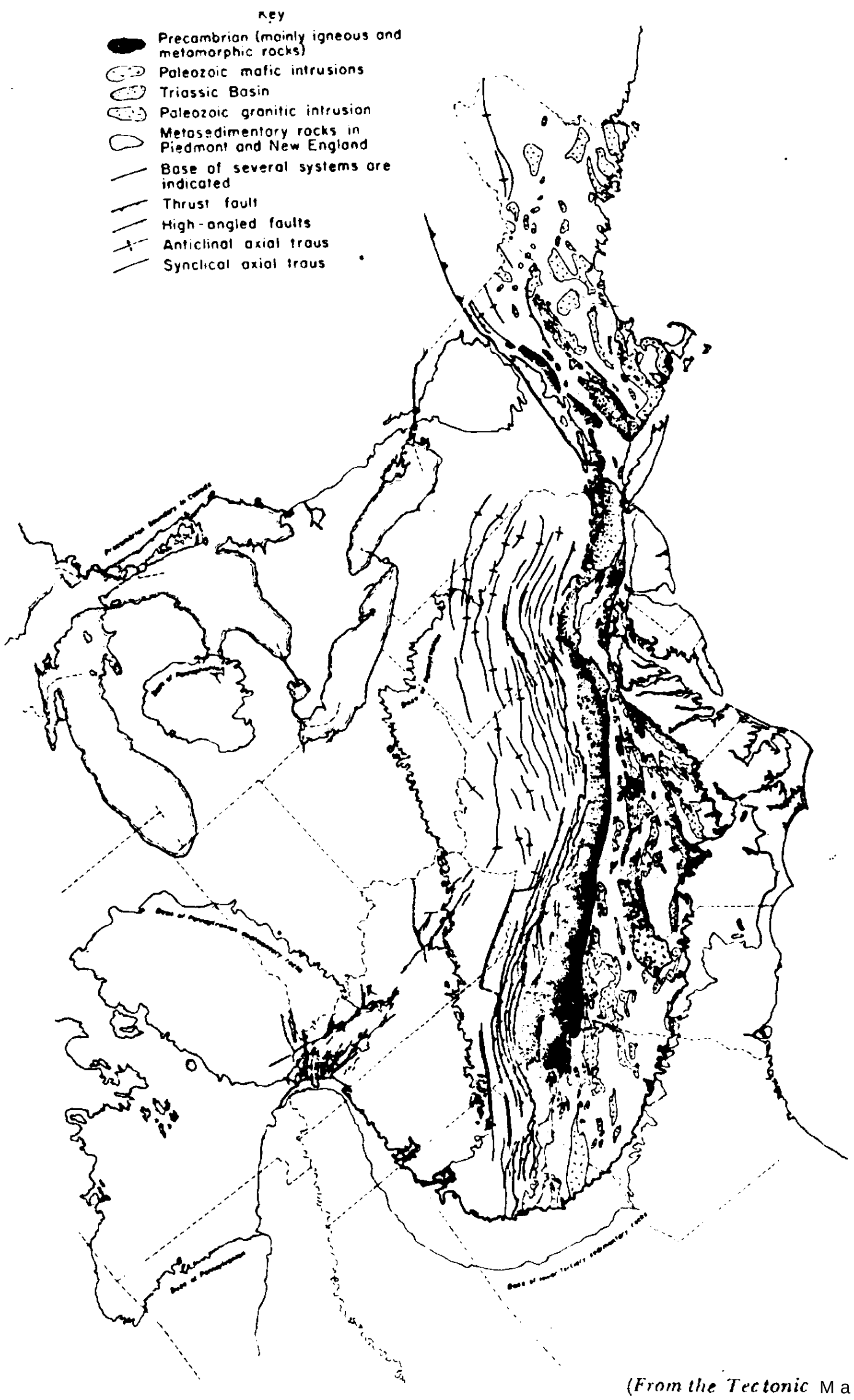


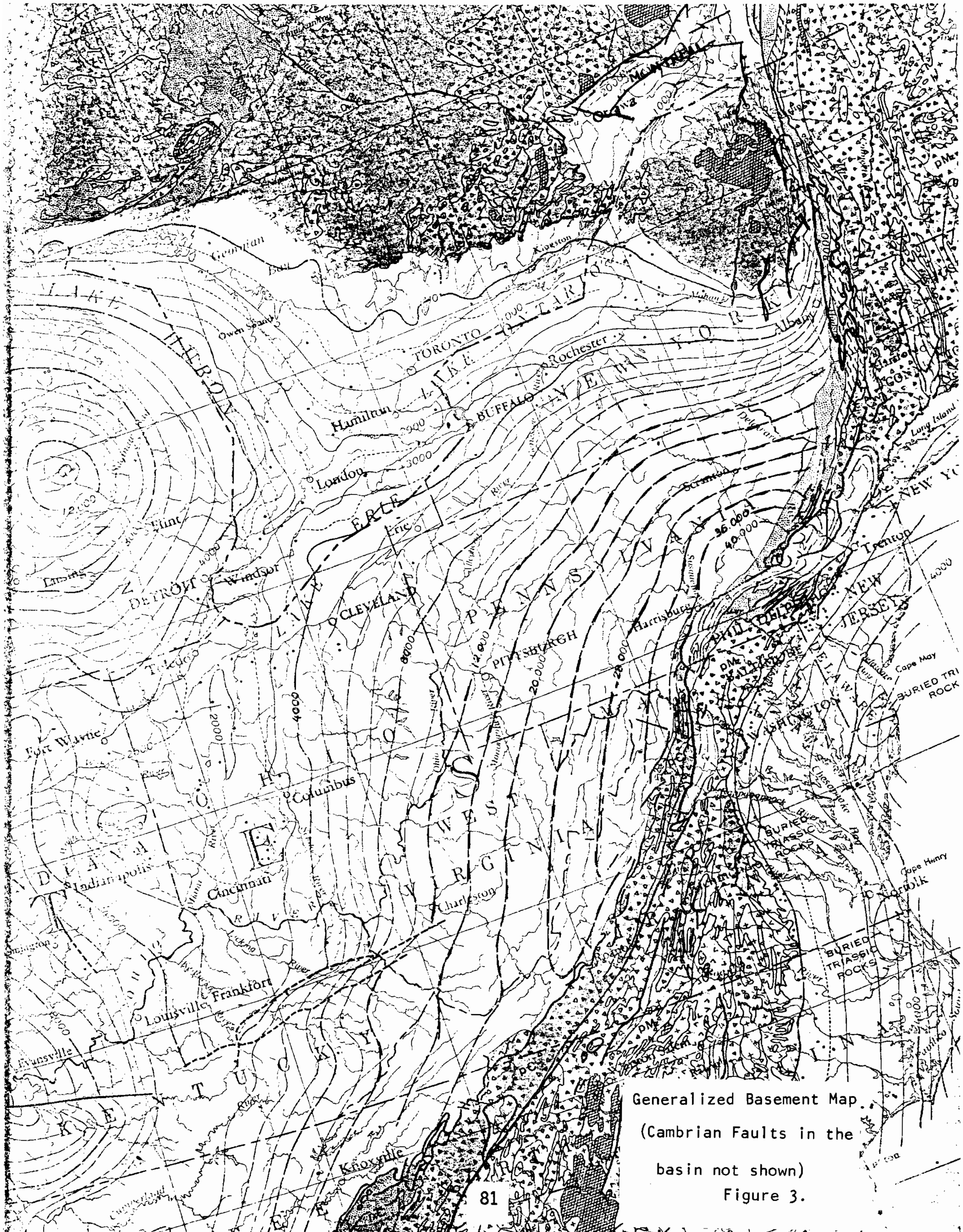
Figure 1. Highly generalized map showing selected major tectonic elements of middle and upper Paleozoic age.

Shumaker, 1975



(*From the Tectonic* Map of *the United States, 1961.*)

Figure 2.

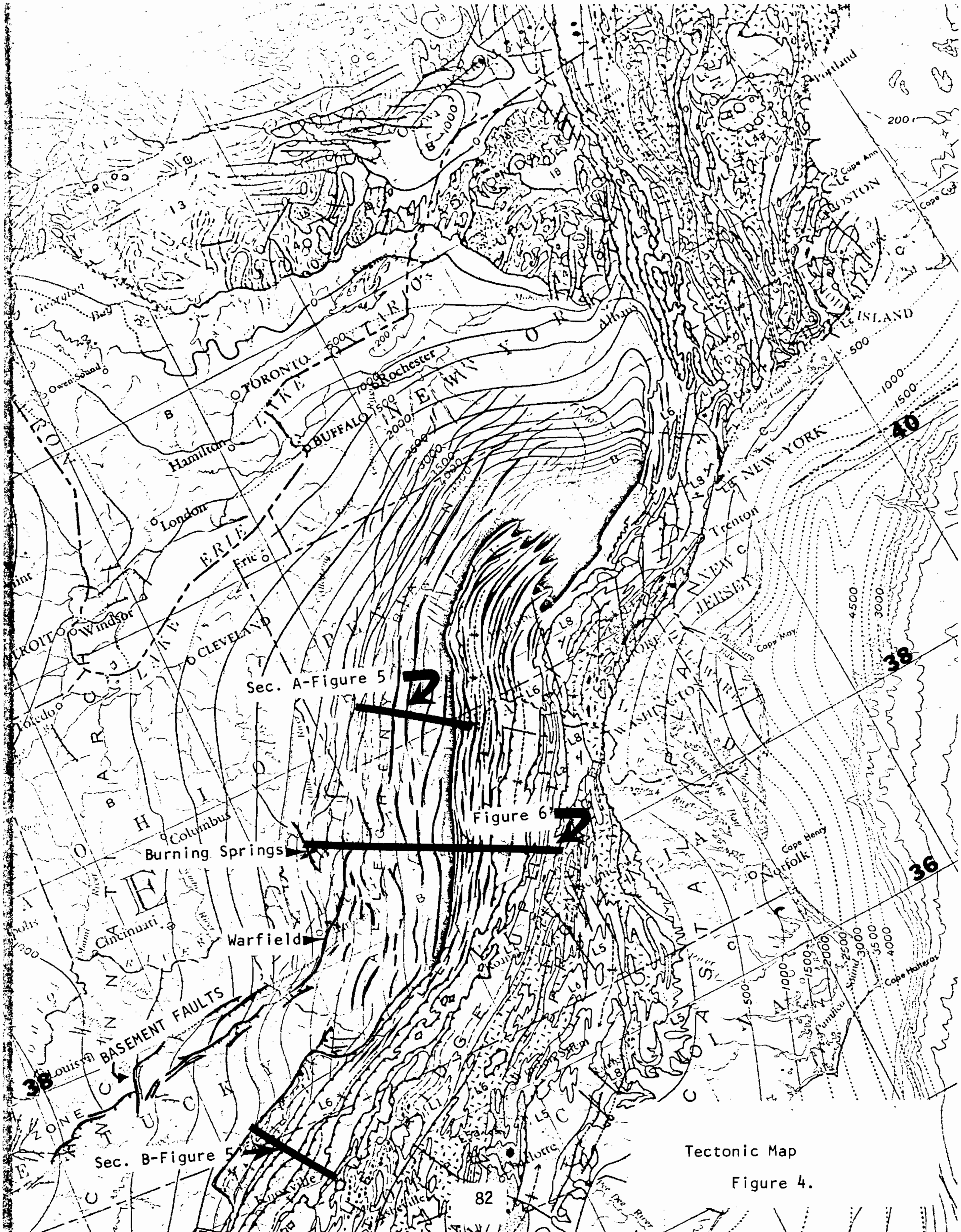


Generalized Basement Map

(Cambrian Faults in the

basin not shown)

Figure 3.



Tectonic Map

Figure 4.

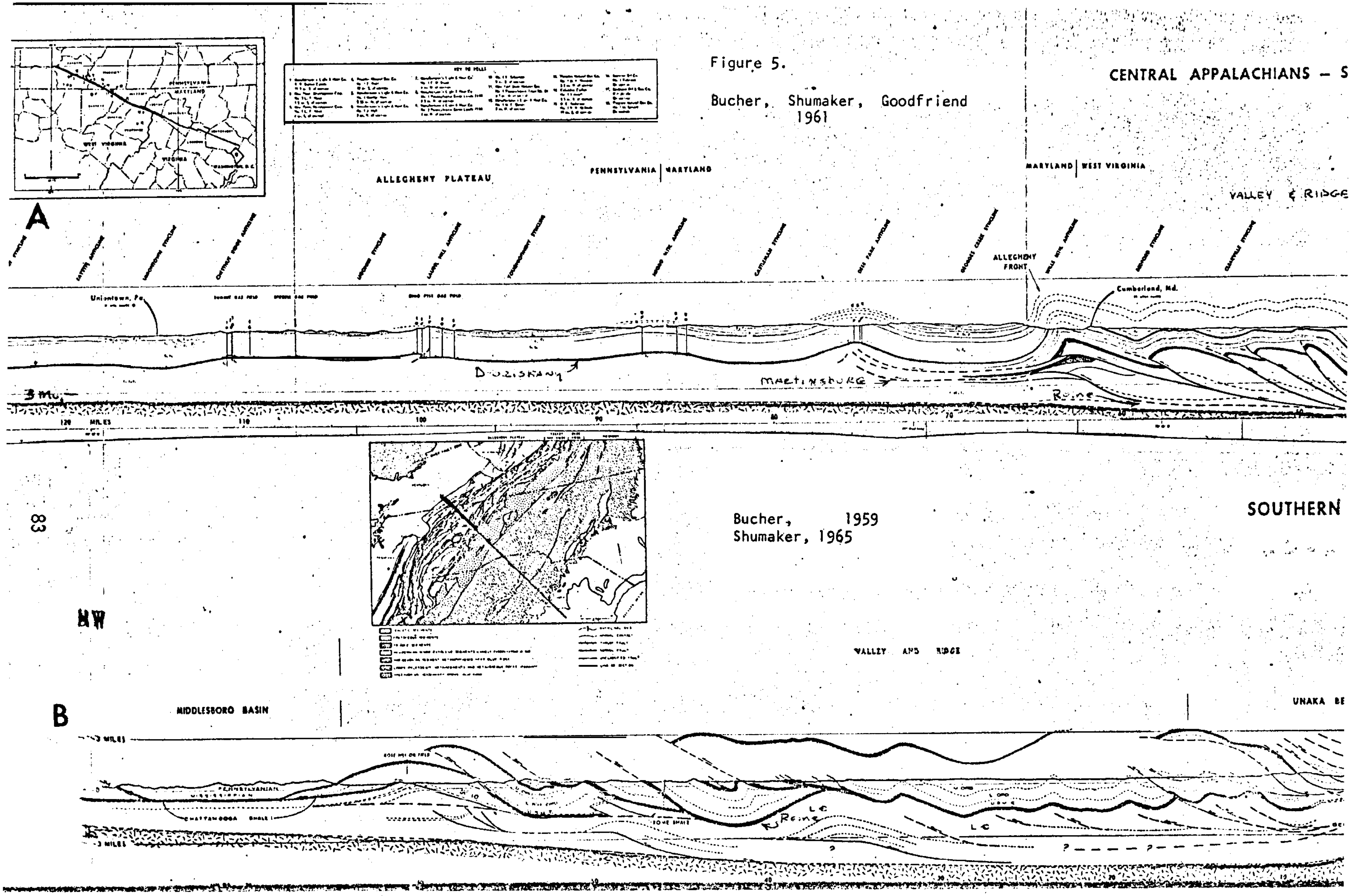


Figure 5.

Bucher, Shumaker, Goodfriend 1961

Bucher, 1959
Shumaker, 1965

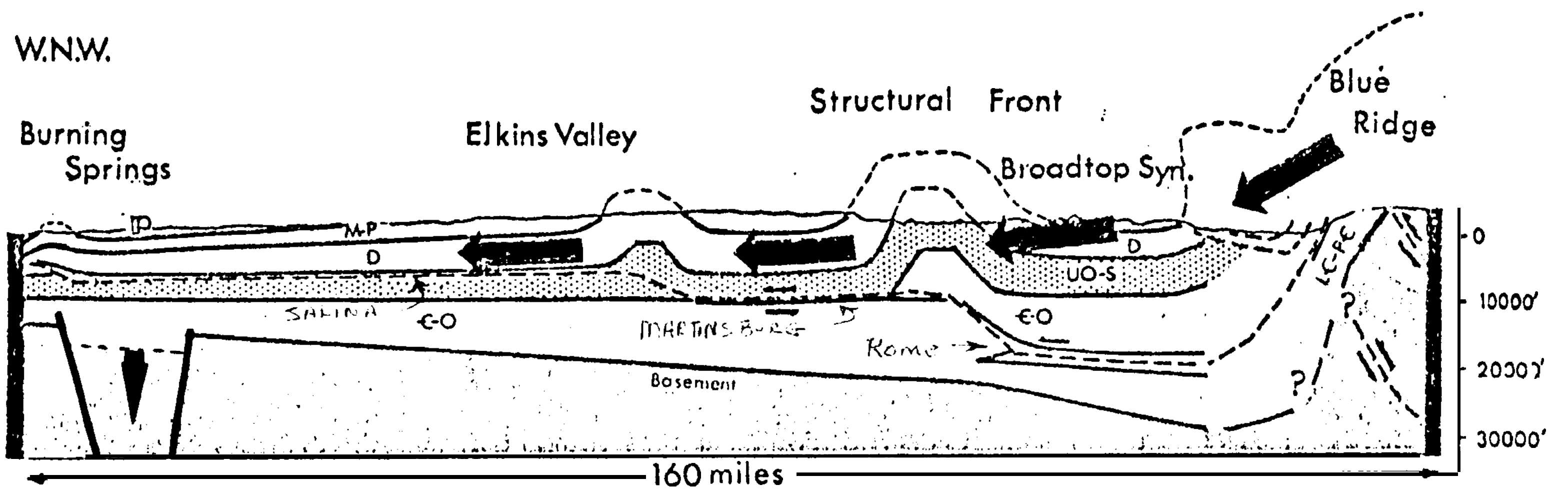
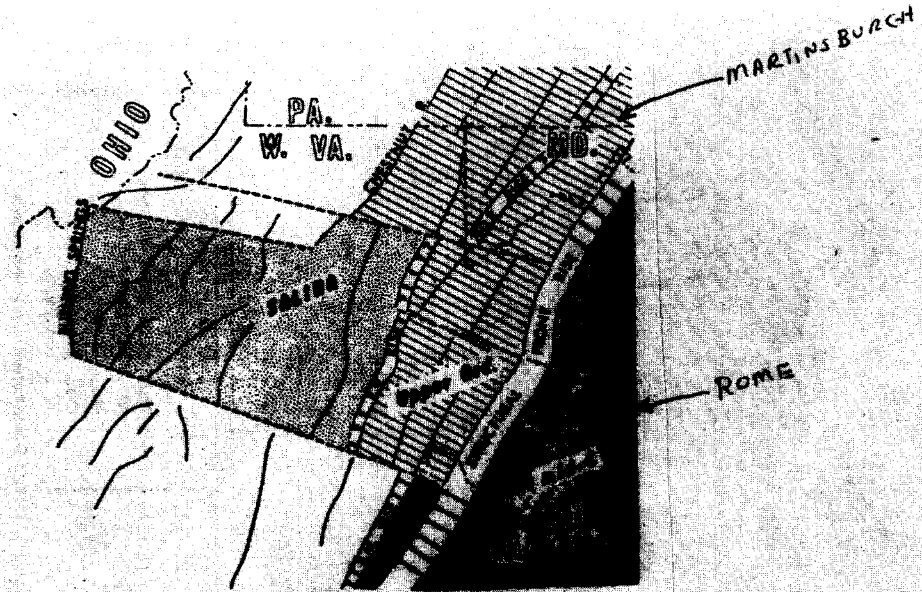


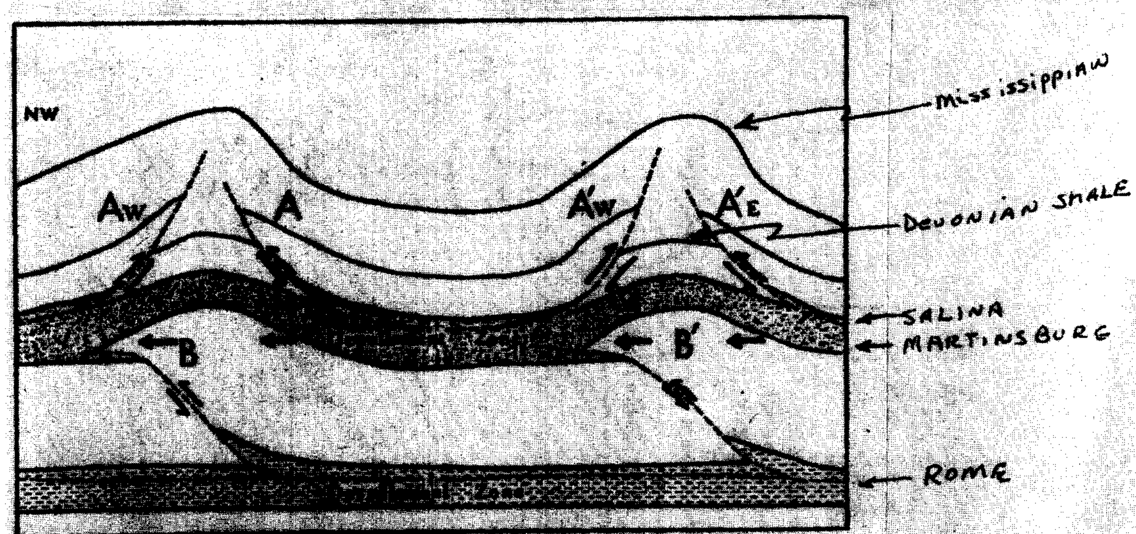
Figure 20. Schematic cross section of the Central Appalachians, Virginia-West Virginia, demonstrating the near-horizontal present-day attitudes of the décollement glide zones in the northwestern Valley and Ridge and Plateau provinces. A conservative interpretation of the rapid descent of the crystalline rocks of the Blue Ridge along a steep, slightly faulted flexure is shown here. In this interpretation, the major bedding thrust or thrusts must emerge as a bedding thrust in the eastern Great Valley or Blue Ridge area. It is conceivable, however, that the Blue Ridge is an unrooted mass, moved northwestward along a great thrust fault to overlie Paleozoic sedimentary rocks (Woolard, 1936; 1939; King, 1964). P = Permian; M-P = Mississippian-Pennsylvanian; D = Devonian; UO-S = Upper Ordovician-Silurian; and Є-O = Cambrian and Lower and Middle Ordovician

Modified · r Gwinn, 1967

Figure 6.



Sole Fault Level (Gwinn, 1967)



Two detached horizons

(From Gwinn, 1964.)

Figure 7.

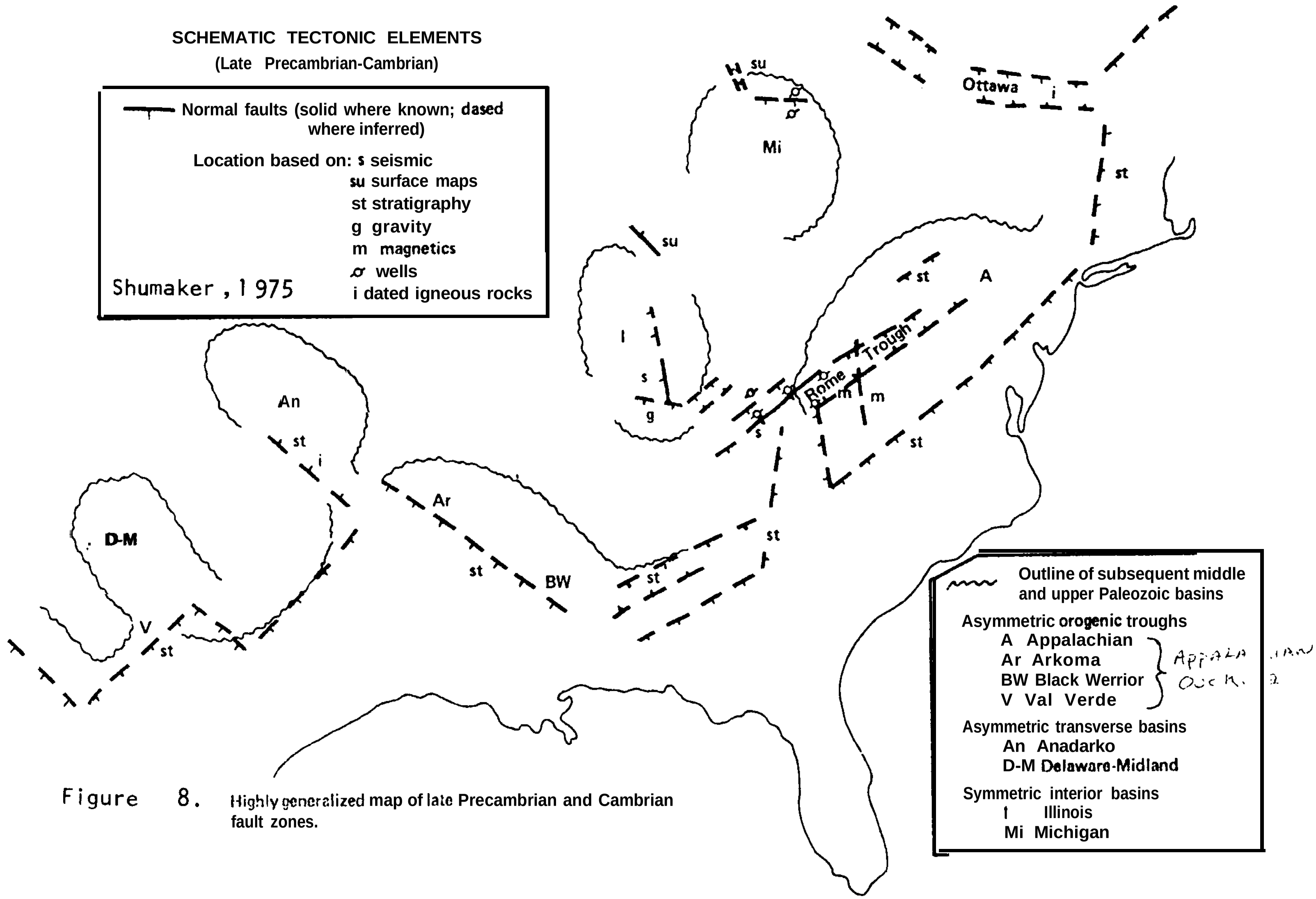


Figure 8. Highly generalized map of late Precambrian and Cambrian fault zones.

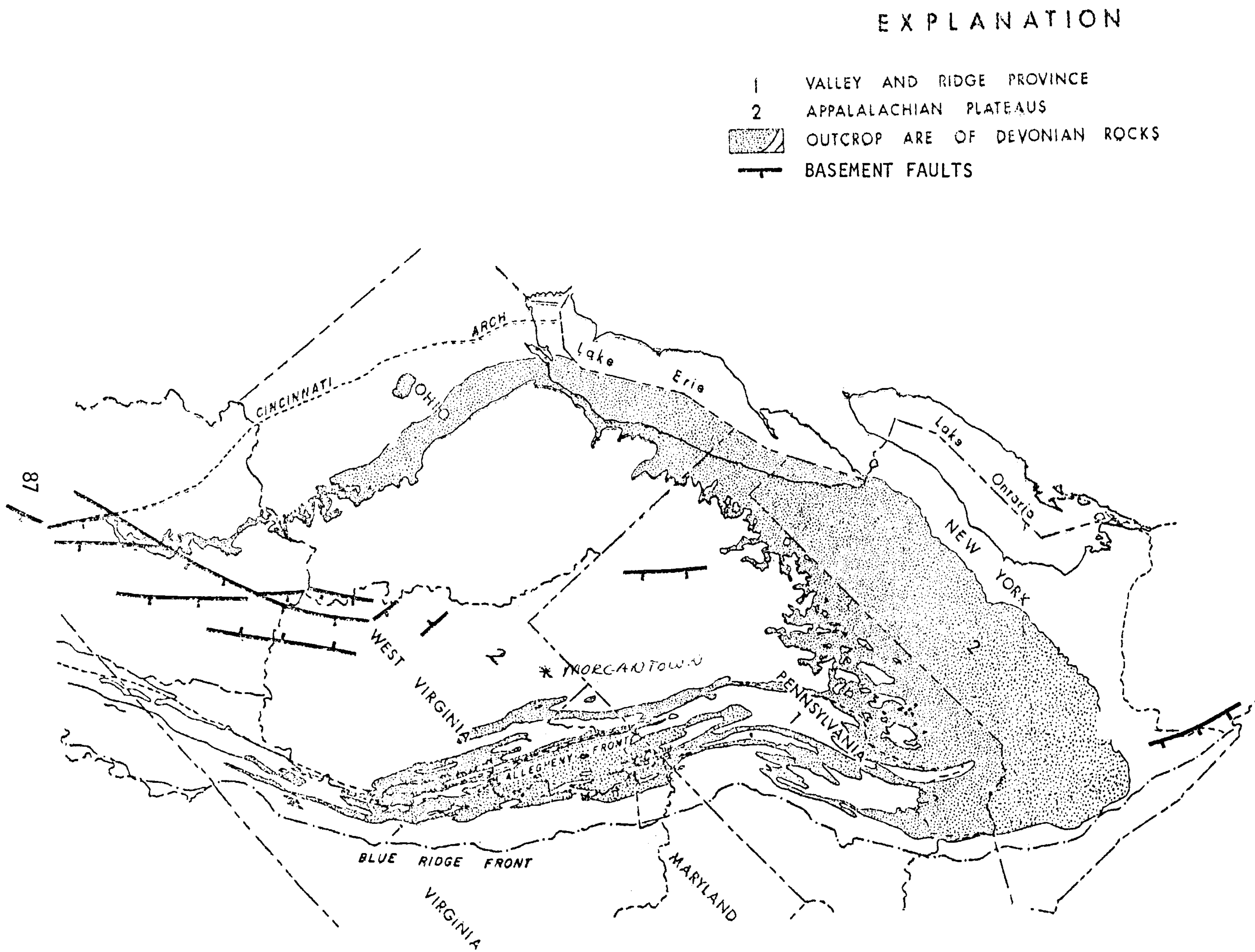

EXPLANATION
1 VALLEY AND RIDGE PROVINCE
2 APPALALACHIAN PLATEAUS
OUTCROP ARE OF DEVONIAN ROCKS
BASEMENT FAULTS
CINCINNATI ARCH
OHIO
Lake Erie
Lake Ontario
NEW YORK
PENNSYLVANIA
WEST VIRGINIA
MORGANTOWN
ALLEGHENY FRONT
BLUE RIDGE FRONT
MARYLAND
VIRGINIA

Figure 9.

EXPLANATION

1 VALLEY AND RIDGE PROVINCE

2 APPALALACHIAN PLATEAUS

OUTCROP ARE OF DEVONIAN ROCKS

—500— ISOPACH OF COMBINED THICKNESS OF BLACK SHALES OF DEVONIAN AGE

DeWitte, Perry, Wallace, 1975

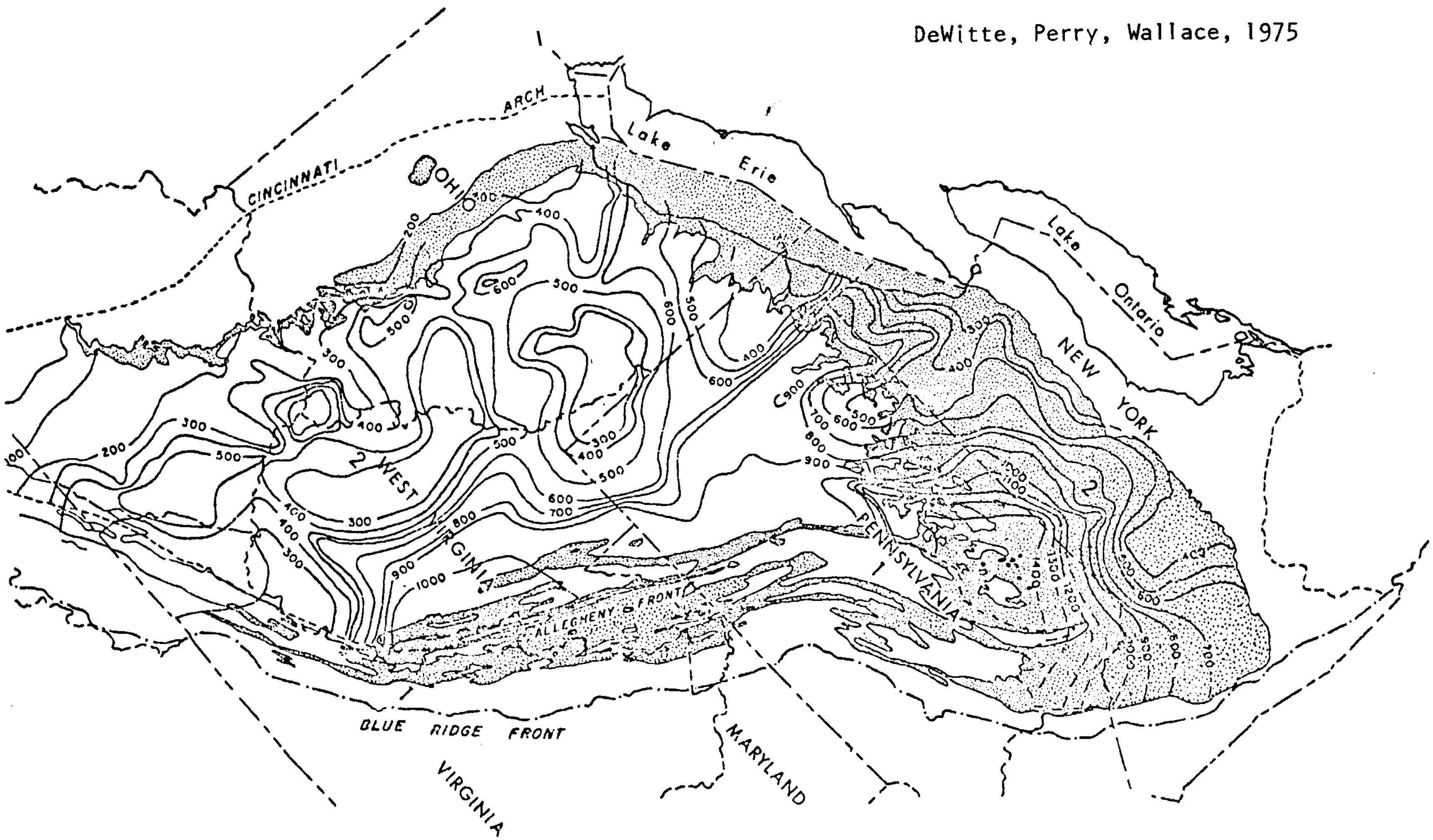


Figure 10.

EXPLANATION

1 VALLEY AND RIDGE PROVINCE
2 APPALALACHIAN PLATEAUS
OUTCROP ARE OF DEVONIAN ROCKS
DEVONIAN BLACK SHALE GAS PRODUCTION

DeWitte,Perry, **Wallace, 1975**

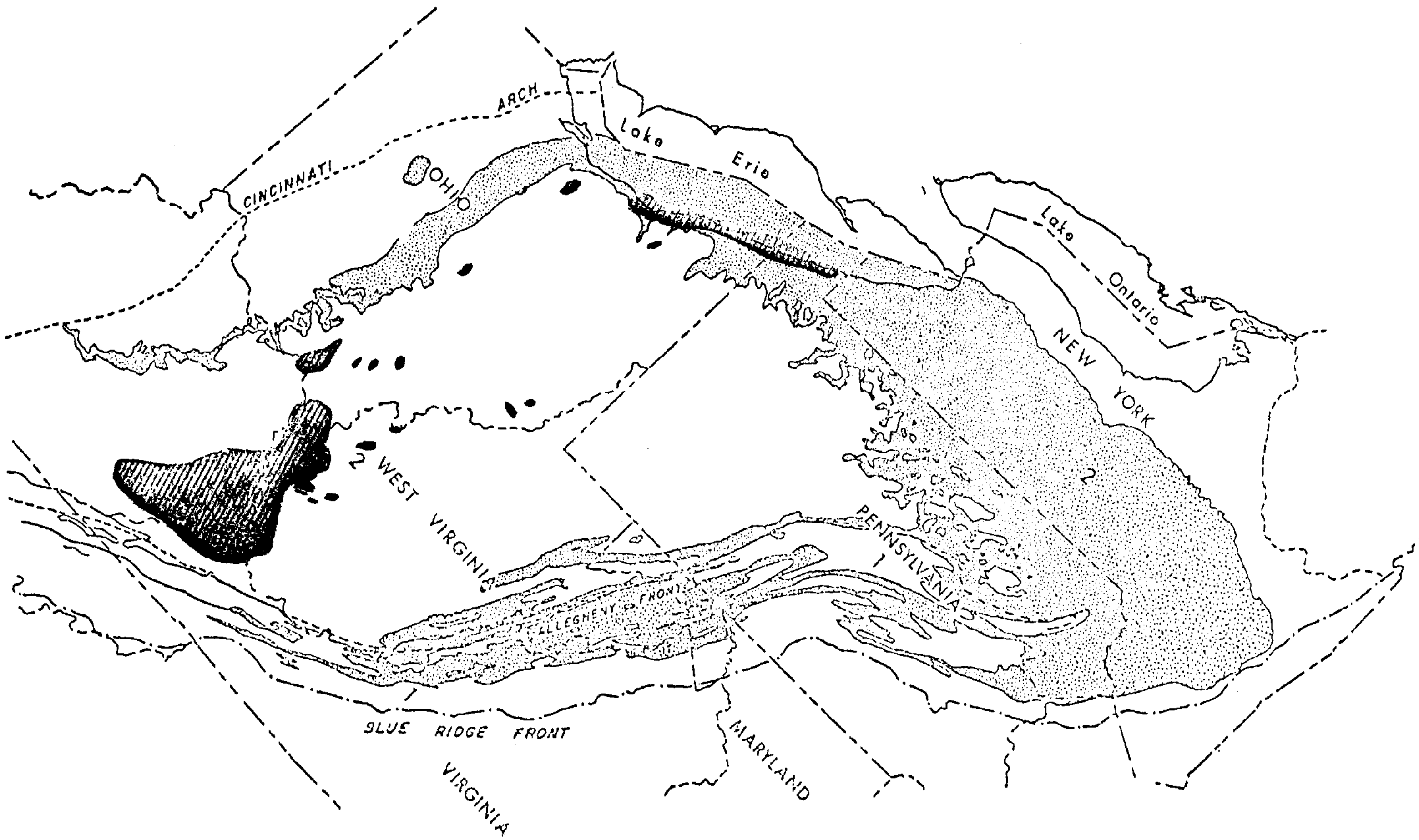


Figure 11.

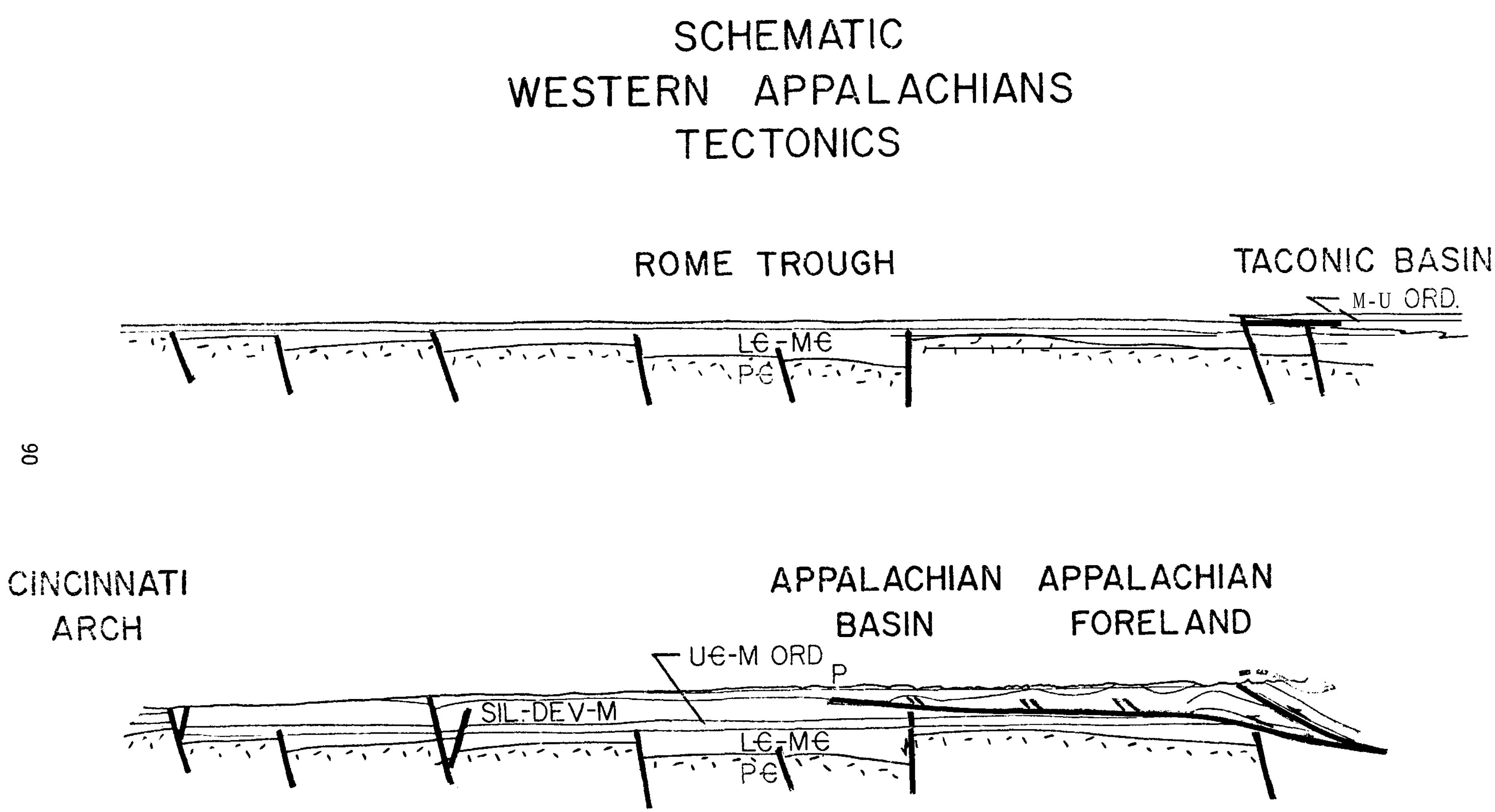


Figure 12. Shumaker, 1972

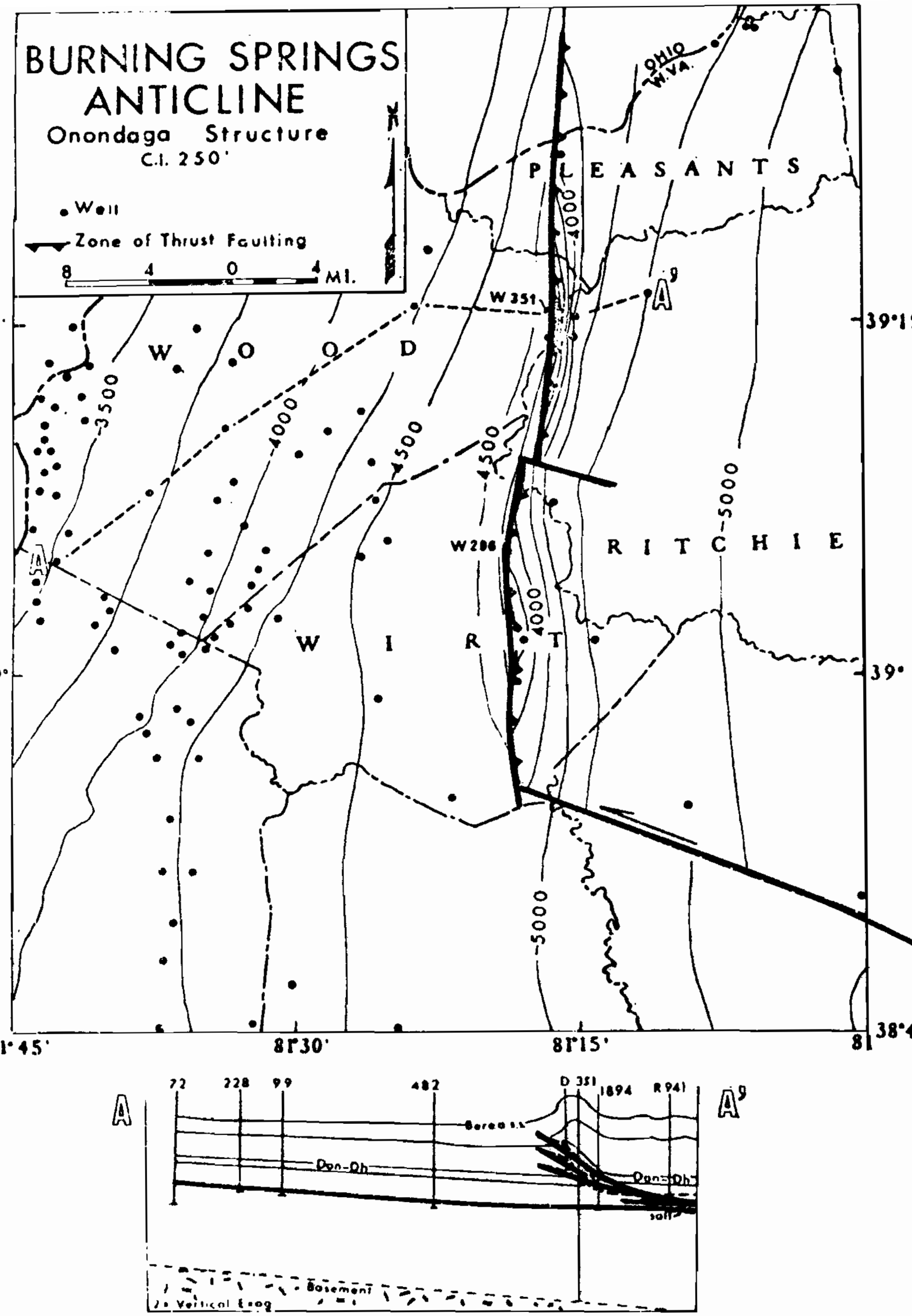
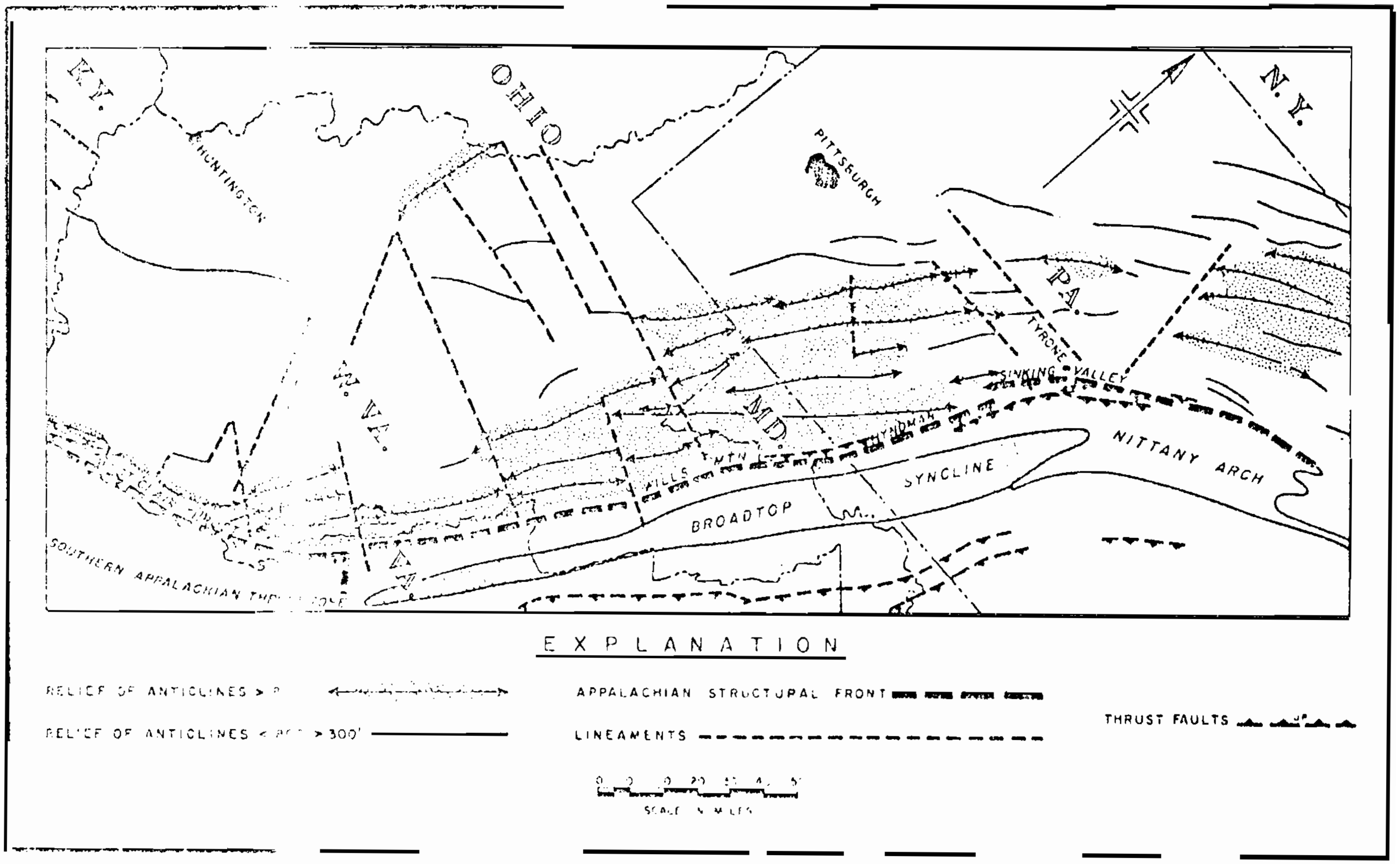
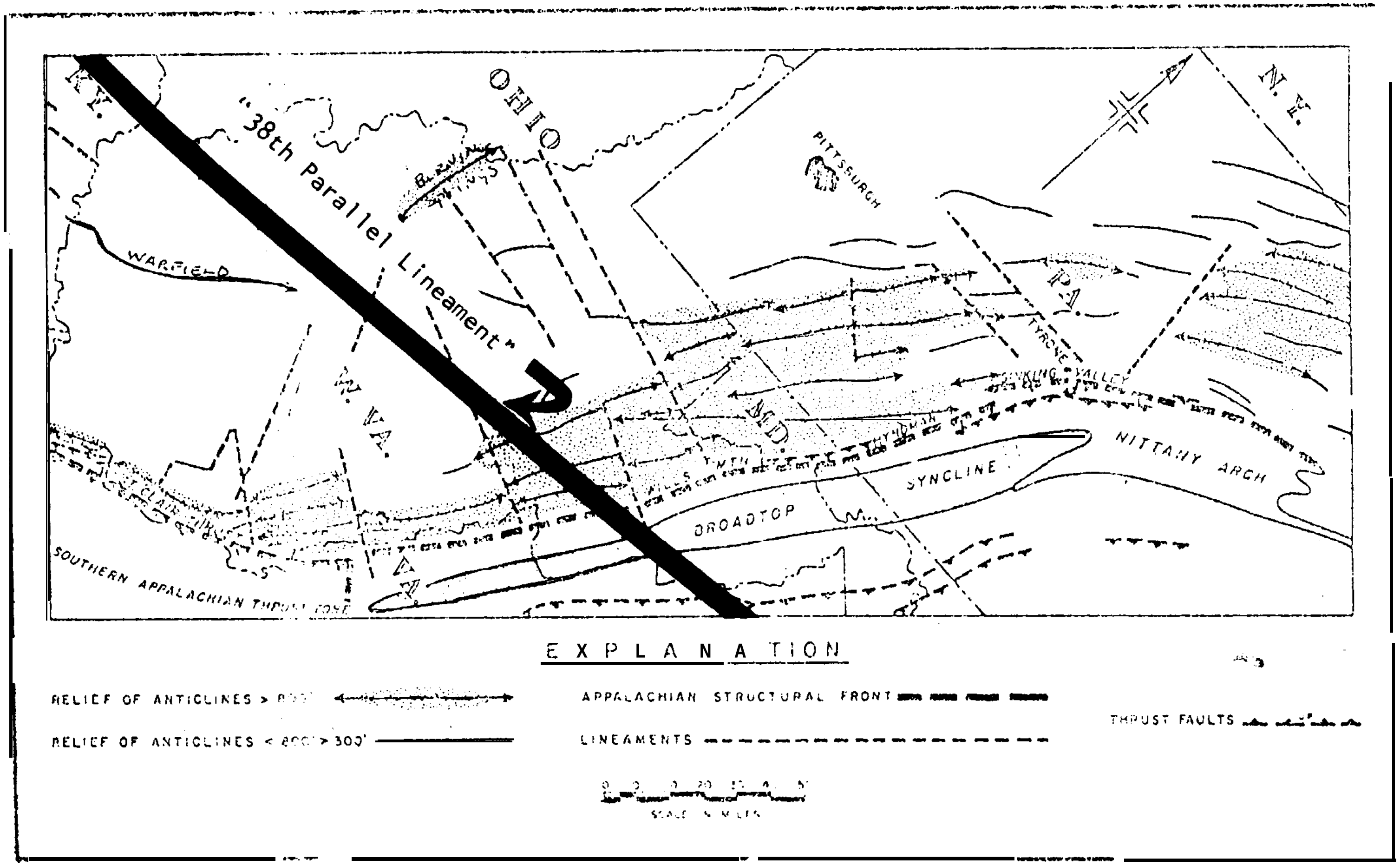

BURNING SPRINGS
ANTICLINE
Onondaga Structure
C.I. 250'
Well
Zone of Thrust Faulting
8 4 0 4 MI.
OHIO
W.VA.
PLEASANTS
WOOD
WIRT
RITCHIE
W 351
W 286
-3500
-4000
-4500
-5000
39°15'
39°
38°45'
81°45'
81°30'
81°15'
81
72
228
99
482
D 351
1894
R 941
Berea s.s.
Don-Oh
salt
Basement

Figure 13.



(From Gwinn, 1967.)

Figure 14.



E. Werner
after Gwinn, 1967.)
Figure 15

REMOTE SENSING FRACTURE STUDY - WESTERN VIRGINIA AND SOUTHEASTERN KENTUCKY

William M. Ryan - Columbia Gas Transmission Corporation

Gas production from relatively tight formations is common in the Appalachian Basin In western Virginia and southeastern Kentucky (Buchanan and Dickenson Counties, Virginia and southern Pike County, Kentucky - Columbia's Haysi Field) Columbia Gas undertook an extensive study to attempt to relate open flows and gas production to natural fracture zones. The area studied embraces approximately 238 square miles bounded by Latitudes 37°07'30"N and 37°22'30"N and Longitudes 82°07'30"W and 82°22'30'W.

Topographically, the terrain is rugged with 600 to 800 feet of relief common and a maximum relief of 1000 feet. Geologically, the area is at the eastern edge of the Pine Mountain overthrust. The Pine Mountain thrust fault is 125 miles long with the western edge being terminated by the Jacksboro Tear Fault with 10-11 miles of displacement, and on the east by the Russell Fork Fault with 2-4 miles displacement. The eastern edge of the fault system does not end with the Russell Fork Fault, but dies out in a series of tear faults east of Russell Fork. The Haysi area is within this tear-faulted zone and, therefore, lends itself well to a fracture study.

The main producing formation in this area is the Berea Siltstone at an average depth of 4000 feet. Average electric log porosities range from 3% to 7%, but open flows of over three million cubic feet per day have been encountered with Berea reserves on many wells projected to be one billion plus cubic feet of gas. The high open flows and good deliverability of these wells is attributed to fracture porosity. From sonic logs on one well with an open flow after hydraulic fracturing of 2.98 million cubic feet of gas per day, porosity averaged about 6% to 7% with 20% to 30% of that being fracture porosity.

In order to delineate fracture traces in the Haysi area, geologic mapping and seismic surveys have been combined with several remote sensing surveys including the following:

(1) Side Looking Radar Imagery (SLAR)
(2) Color Aerial Photography
(3) Black and White Infrared Photography
(4) Color Infrared Photography
(5) Thermal Infrared Imagery

Of the 78 Haysi wells drilled, 42% were drilled within major lineament zones. These wells have an average open flow after fracturing of 1866 Mcf/day. The average open flow after fracturing of wells not on major lineaments was 1042 Mcf/day. This is encouraging; however, the above figures include primary pays in the Greenbrier Limestone as well as primary and secondary zones in the Maxon and Ravencliff Sandstones and a few old wells that were shot--not hydraulically fractured. Considering only the hydraulically fractured Berea wells, those on or within 1500 feet of major lineation zones have an open flow after fracturing of 1287 Mcf/day and those more than 1500 feet from a lineation averaged only 637 Mcf/day. After addition of a structure map to the lineation study, reasons for good producing wells becomes even clearer. Many of the stronger lineations can be mapped as near vertical tear faults associated with Pine Mountain overthrust system, and many of the better wells are associated with the tear zones. These tear zones were not obvious on seismic or structure maps made prior to the lineation survey.

In conclusion, we feel that better wells are associated with natural fractured zones. In this type of geologic and topographic terrain, radar imagery is a useful tool in delineating natural fractured zones and black and white I.R. is useful in adding detail to the study. Nothing new was added by the other types of imagery, including night-time thermal I.R., that was not apparent on the radar and black and white infrared photography.

ORGANIC GEOCHEMISTRY APPLIED TO THE GEOLOGY OF SHALES

J. Barry Maynard - Department of Geology

University of Cincinnati

ABSTRACT

Most organic geochemical work being done today focuses on the organic matter itself. The questions asked are of two kinds: What can the organic matter tell us about the origin of life; and, what can it tell us about the transformation of organic matter in sediments, with particular regard to the generation of fossil fuels?

In addition to these studies, more organic geochemical work is needed on geological questions. Specifically, we need better ways to study shale geology. This rock type makes up the bulk of sedimentary rocks, but is poorly understood compared with sandstones and limestones. Can the organic matter in these rocks be used to help solve geological problems? Several studies on recent sediments suggest that the source of the organic matter, marine or terrigeneous, can be differentiated. Table 1 lists several geochemical variables related to source that are mappable, and may be useful in deciphering sources of organic matter in ancient rocks. Figure 1 shows how maps so developed might be used in an exploration program for fuel resources in the Devonian Black Shale.

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3. Gardner, W. S. and D. W. Menzel. Phenolic Aldehydes As Indicators of Terrestrially-Derived Organic Matter In The Sea. Geochim. Cosmochim. Acta. 38, 1974, pp. 813-822.

TABLE 1

POSSIBLE CEOCHEMICAL INDICATORS OF SOURCE OF

ORGANIC MATTER IN SHALES

Analysis	Technique	Significance
C^{12}/C^{13} ratio	Mass spectrometry	In recent sediments, high ratios are associated with non-marine organic matter, and the ratio does not change'with burial (Degens, 1969).
V/Ni ratio	Atomic Absorption	V is associated with non-marine organic matter in several shales (Lewan, personal communication).
Phenolic aldehydes	Liquid Chromatography	In recent sediments, the methoxyl content of organic matter decreases offshore (Gardner and Menzel, 1974).
C/O/H ratios	Carbon Analyzer	May indicate type of organic matter. Probably more useful as a maturation index, if the source is already known.
Aliphatic hydrocarbons and Aromatic hydrocarbons	Column Chromatography	Pennsylvanian shales show an increase in this ratio going seaward (Baker, 1972).

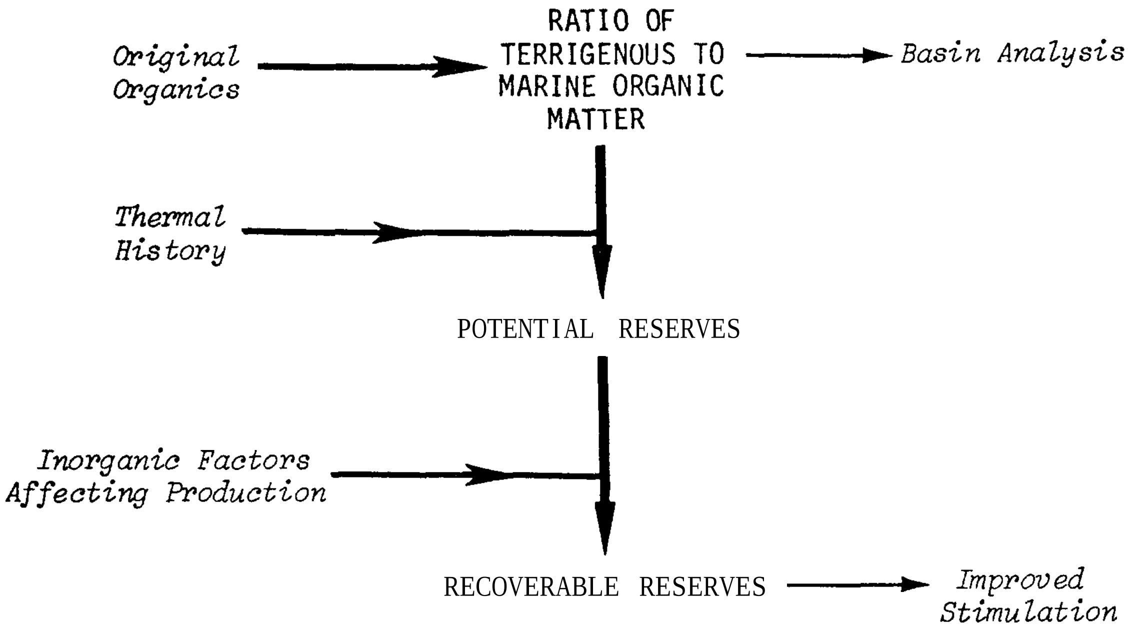

Figure 1. Flow chart shows how proposed determinations can lead to maps of potential and recoverable reserves; inorganic factors affecting production may include fracture density, shale fabric, bulk density, surface area, overburden, etc.

OPTICAL PROCESSING OF REMOTE SENSOR IMAGERY

George A. Rabshevsky - Photo Science, Inc.
(presently with Rainbow Systems, Inc.)

The consensus of opinion among geological scientists is that the most important step in the utilization of remote sensor imagery is the interpretation and analysis of the data. The image interpreter should above all be a competent geologist--especially in gas/oil or mineral/ore exploration projects--but he should also be skilled in every aspect of remote sensing, from image acquisition and sensor systems to image processing and interpretation. Such ideal qualifications are extremely difficult to find in a single individual, however, so that remote sensor imagery is often interpreted by "remote sensing specialists" lacking sufficient geologic training or by geologists unfamiliar with remote sensing technology. A team approach is sometimes useful, but it is extremely costly and time-consuming.

The "total qualification" requirement is desirable because the interpreter should be aware of the imperfections that may be introduced in the imagery at any step of the aerial photography/remote sensing mission. Furthermore, a knowledge of image processing techniques enables the interpreter to decide on what process to use for a particular application. Much time and effort can be saved in a project through the appropriate selection of a processing technique. Familiarity with image processing is especially desirable when utilizing LANDSAT imagery, since the mission planning and image acquisition steps are beyond the control of the data user and the interpreter is thus able to influence only the image processing and interpretation stages.

The interpretation of LANDSAT imagery for geological purposes is today performed primarily by specialists with a strong background in the earth sciences. The image processing step, on the other hand, is almost entirely mechanized; the interpreter merely selects the processing technique to be used and supplies the appropriate instructions.

The image processing technician can work with either of two formats: computer tape or film. Computer processing techniques are beyond the scope of this presentation; instead, only analog/optical techniques will be discussed here.

Optical processing techniques suitable for use on LANDSAT imagery may be broadly classified into two categories: (1) electromechanical-optical methods, and (2) photographic compositing methods (in color or monochrome). The electromechanical method makes use of various types of equipment to display and enhance the imagery on a screen. It converts LANDSAT images into false-color composites by enhancing certain themes through the use of appropriate combinations of filters, bands and density settings. The photographic method employs various films, papers and/or foils to process and enhance the film data. It foregoes the superimposed (multispectral) display of each channel; false-color renditions are produced photographically, directly on a paper or film base, from individually recombined narrow-band images. In some instances, mechanical and photographic methods are combined to produce enhanced false-color composites.

Various multispectral viewing and color density slicing devices are used in the electromechanical method. Viewers allow the operator to project single images or to superimpose up to four 70-mm LANDSAT images in registration on a rear-projection screen. The screen can then be photographed, either directly or with an optional photohead attachment, to yield reproductions of the displayed imagery. Color density slicing devices convert different density levels in transparencies or prints into different colors, for analysis and/or enhancement. Tranparencies are backlighted and scanned by a television camera and the video signal is automatically processed by a built-in microdensitometer and displayed on a color monitor screen.

The photographic methods bypass mechanical and electronic devices, processing black- and white film data directly onto a paper of film base. Because no intermediary lenses, screens or internegatives are used, the end product has higher resolution and color fidelity. Some of the photographic bases used are Ciba-Geigy Cibachrome film and paper, Agfacontour film, Diazo specialty foils, Dupont Cromalin foils and Kodak No. 37RC paper.

Whether the electromechanical or a photographic method is selected, the 70-mm, third-generation LANDSAT negatives (-3) or positives (+3) can be reprocessed to accentuate either land or water targets prior to final image enhancement. Usually, the unprocessed 70-mm film has a density range from a minimum value Dmin = 0.50 to a maximum D_{max} = 2.50. Due to this extreme contrast range, reproductions made in the D_{max} end of the negative virtually obliterate detail in the Dmin portion. Therefore, positive transparencies containing primarily land areas for study must be exposed at the expense of water areas, and vice versa.

Several other optical processing techniques are available for LANDSAT imagery enhancement and theme extraction. "Negative-positive" multispectral enhancement, for example, is a variation of the optical processing technique that comes under several names, such as Sabatier effect, edge enhancement, solarization, pseudocolor transformation, posterization, tone separation, optical ratioing, equidensitometry, theme extraction, color density slicing, and isoluminous additive color method.

The subject of optical processing of imagery is extremely difficult to comprehensively describe to the layman in concise form and in general terms. Nevertheless, as LANDSAT and other types of imagery become more widely used in terrain analysis and resource exploration, geologists will begin to learn about image processing and photo lab technicians will begin to appreciate the necessity of providing the finest photographic products for the geologist.

The following references will furnish more detailed information on optical image processing techniques to geologist who may need to deal with the subject:

1. Deutsch, M., and F. Ruggles, Optical Data Processing and Projected Applications of the ERTS-I Imagery Covering the 1973 Mississippi River Valley Floods. Water Res. Bull., v. 10, No. 5, '974, pp. 1023-1039.
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GEOPHYSICAL INVESTIGATIONS RELATED TO THE DEVONIAN SHALE OF THE EASTERN U.S.

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INTRODUCTION

The Devonian Shale section poses an interesting and challenging target for geophysical investigation. This discussion will address some of the requirements that should be met in order to have a successful geophysical exploration history. As one can easily recognize, some of the early efforts should be addressed to purely research projects, either heavily or totally backed by governmental agencies with the results made available to the industry at large which is interested in the area.

In later phases, exploration efforts would logically fall upon single companies or groups of companies.

The recommended line of attack and some general economic considerations are discussed.

PHASE I - GEOLOGIC FRAMEWORK ANALYSIS

A study of this sort by definition encompasses a large area and is regional by nature. The results of such an analysis should provide any interested party with a condensed view of the known geology at the time of the study's preparation.

Sources of Information

1. ERTS imagery
2. Published surface and photo geologic control
3. Well data files
4. Published or otherwise available gravity and magnetic data
5. Publicly available seismic control
6. Published reports and production histories

The output should include regional isopach studies of all major sedimentary units, estimated basement configuration map, fault trace map(s), and a composite anomaly production history map.

PHASE I -GEOLOGIC FRAMEWORK ANALYSIS (con't)

Analysis of existing subsurface data should include construction of synthetic seismograms, where available data permits, and regional evaluation of velocity and density data. Under ideal circumstances velocity and density data would be available to enable preparation of sufficient synthetic studies of a wide variety of situations from highly fractured productive section to unfractured unproductive section. However, it is the author's understanding that it is difficult to log this type of well and that many wells are quite old and predated modern logging techniques. As a bare minimum, a number of wells clearly exhibiting different situations and having well documented geological information, including some E-logs or radio active logs should be identified for analysis in a Phase II Seismic Research Project.

The key wells identified above should in part provide a basis for laying out the seismic reconnaissance program indicated in Phase III.

The logical extension of existing production would generally fall under projects of the Phase IV type. The framework study phase could possibly point to some field extension projects.

PHASE II - SEISMIC RESEARCH PROJECT

The purpose of this project would be to evaluate the seismic response of the geologic section at each of the "key" well locations. Information to be determined includes:

1. Amplitude of each reflection
2. Moveout velocity
3. Average velocity (time-depth)
4. Optimum source and recording frequency

The method to be followed would involve collection of an expanded spread velociy profile $(X^2 - T^2)$ centered across each well using the Vibroseis* source with several sweep ranges recorded in a broad band sense. Obviously, the layout shown in Figure 1 for this type of experiment cannot always be achieved in rugged terrain and such modifications as dictated by the terrain would be made, with care taken to

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PHASE II, SEISMIC RESEARCH PROJECT (con't)

avoid compromising the result. These analyses should provide accurate knowledge of the "target,' i.e., what we are looking for. Additionally, the optimum source and cable geometry for reconnaissance use should be determined through this effort.

The second type of experimental effort is aimed at evaluating near surface problems in terms of velocity and noise propagation. Evaluation sites should be chosen, using surface geologic data, to sample all major types of exposed lithology. The refraciton layout shown in Figure 2 will provide the required forward and reverse refraction control for depth and velocity evaluation. The use of bunched phones will allow the low velocity noise modes to be evaluated for strength and source.

The results of this type of experimental effort should be a set of firm recommendations as to correctional procedures for the near surface and seismometer arrays.

PHASE III - SEISMIC RECONNAISSANCE PROGRAMS

In the experimental work the Vibroseis* system was mentioned as the seismic source. There is some desire to compare sources when one begins to consider a program of any size; hence, the following comparison is made between two types of explosive source techniques and the vibrator.

Source 1 - Deep Hole Dynamite

This technique employs shot holes drilled to a depth greater than the disturbed or weathered zone.

Advantages

1. Large energy yield with broad spectrum in a single source emission.
2. When uphole control is measured at each shot excellent near surface control is obtained.
3. Disturbing scattering problems which may be present in the immediate near surface such as coarse gravels are only experienced on one leg.
4. Still the standard against which other methods are measured.

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PHASE III - SEISMIC RECONNAISSANCE PROGRAMS (con't)

Source 1 - Deep Hole Dynamite (con't)

Disadvantages

1. Require considerable expenditure in drilling in some areas.
2. Drill equipment is difficult to permit and operate in rough terrain.
3. Politically undesirable.
4. Difficult and expensive when multiple source patterns are desired.
5. Strictly an "off road" technique but limited to easy or moderate terrain in a multifold mode.

Source 2 - Mini Hole Dynamite

This technique employs a multiple charge pattern made up typically of one pound charges in ten foot holes. From five to eleven holes per pattern have been used with good success in the Southeastern U.S.

Advantages

1. Broad spectrum high energy source.
2. Allows pattern source elements.
3. Drilling is accomplished with highly portable buggy mounted or hand carried auger drills. Cross country capability in moderate terrain.
4. Very minor surface damage around shot holes.
5. Generally lower.

Disadvantages

1. Politically undesirable since explosives are still involved.
2. Near surface control is lacking and only simple elevation corrections are possible.
3. May be used in proximity to back country roads but still requires off-road permitting.
4. Drilling in very rocky terrain may prove too difficult for auger units.

Source 3 - Vibroseis*

This system employs mechanical vibrator units outputting a swept frequency signal of predetermined length and frequency content. Normally, three or more units are used simultaneously taking multiple patterned sweeps at each location.

Advantages

1. Highly mobile source with controlled

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Source 3 - Vibroseis* (con't)

Advantages (con't)

spectrum adapts easily to pattern source layouts.

2. Works easily along roads and trails which are generally more easily permitted. Low permit costs.
3. Generally enjoys higher production rates than explosive methods.
4. No drilling required. Generally lower field costs for multifold.
5. Controlled frequency spectrum which can be matched to problem.

Disadvantages

1. Not well suited to cross-country work except in gentle open terrain.
2. No near surface control is inherent in the system; hence, only simple elevation corrections can be made.
3. Requires special preliminary processing in the form of vertical stack and sweep removal. Can be overcome with computer field recording equipment.
4. Low energy output causes this type of source to be more disturbed by ambient noises. Early stage processes can compensate against this in many cases.

For purely reconnaissance effort the author feels that a well conceived Vibroseis* program along existing roadways offers the best opportunity to acquire multifold coverage over a large area with minimum cost.

Two objectives are apparent in this type program. One is the Devonian section and the other prime objective is definition of the basement configuration. The maximum leverage in multifold seismic work occurs at depth equal offset. To accomodate the two objectives, an assymetric split spread as shown in Figure 3 is recommended. Since the normal field geometry will involve crooked surface traverses, a processing system capable of developing the correct stack combinations and utilizing the limited 3-Dimensional coverage created by the line

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Source 3 - Vibroseis* (con't)

bends is a must. Automated residual static corrections should be employed prior to making moveout velocity estimations. This type of process usually is quite successful in compensating for unknowns in the near surface.

The velocity analysis technique should sample multiple depth point sets which contain a good offset selection and provide time and velocity information on a discrete event basis to allow analysis of potential gradients within the zone of interest.

The interpretation of this type of data should involve structure and isopach analysis of all major geologic units. Additionally, amplitude and velocity mapping should be undertaken particularly with respect to the Devonian section. This interpretation will be greatly enhanced by the sort of information which would be documented in the experimental program recommended earlier.

Presumably a better estimate of near surface velocities could be employed in conjunction with documented surface geology to provide high quality elevation corrections. The $X^2 - T^2$ work should provide a basis for interpreting the velocity data derived from the multifold program and also provide a means of evaluating relative amplitudes and frequency content.

From the reconnaissance program prospect size areas should be identifiable for more detailed effort either as drillable or as targets for the Phase IV type 3-D detailing work.

PHASE IV - 3-D DETAIL

The utilization of 3-D techniques to provide detail control allows one to improve the signal-to-noise ratio of the data by means of three dimensional migration stack or three dimensional dip filtering or both.

Of the two three dimensional processes,

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PHASE IV - 3-D DETAIL (con't)

the migration stack is the more powerful. If properly employed, this process should reassembly scattered primary signal energy to its original subsurface plane, yielding a true vertical slice in every record section. The disturbing diffracted events will be reduced to single point events and the proper anticlinal, synclinal shapes should be resolved.

To use the 3-D migration stack one requires a series of uniformly spaced input traces. One may obtain this sort of configuration by collecting a series of closely spaced (220 to 440 feet) multifold lines. However, in rugged terrain, this is generally not practical. In these situations a system employing a series of cable "LOOPS" can be employed.

A cable consisting of 24, 48, 96 or more groups is laid out along road loops, trails or other access and the source elements are employed along the same path as the cable, or possibly at some alternate locations, the intention being to completely saturate a given area with subsurface coverage. The first processing step then uses the X-Y coordinates of each shot and receiver to determine the theoretical reflecting point of that pair and the stack "bin" in which it belongs. Stack "bins" are organized in parallel, equally spaced strips across the area called "stack tracks." The "stack tracks" are then the equally spaced inputs required for the 3-D migration.

Detailed structural information can be derived from this sort of data collection and processing. Fault placement, structural shape and size are better represented. A real amplitude analysis can be more readily performed and utilization of horizontal record sections (SEISCROPS*) become feasible.

From the standpoint of economics, one may find that the 3-D LOOP approach is less cost'y in field data collection than conventional "line at a time" approaches. The processing will generally be the more expensive item. However, one may employ

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PHASE IV - 3-D DETAIL (con't)

a limited amount of processing to obtain a loose grid and determine from that stage whether or not to continue into the closer spaced, more expensive processing.

An excellent coverage of 3-D migration and problems is contained in Wm. S. French's paper entitled "Migration and Three-Dimensional Interpretation" presented at the Denver Geophysical Society, 1975 Continuing Education Symposium.

CONCLUDING REMARKS

The stages of geological and geophysical effort generally outlined should provide the necessary exploration data to successfully define new production if, in fact, reasonable geophysical attributes can be associated with Devonian shale production. The Phase I and II research efforts are designed to evaluate the geophysically important properties and determine if further efforts are warranted.

Should major Phase III and IV efforts be judged desirable, they would be most cost-effectively handled by forming groups of companies interested in particular geographic areas. By this cost-sharing mechanism, individual companies can have access to more data than they could individually hope to acquire.

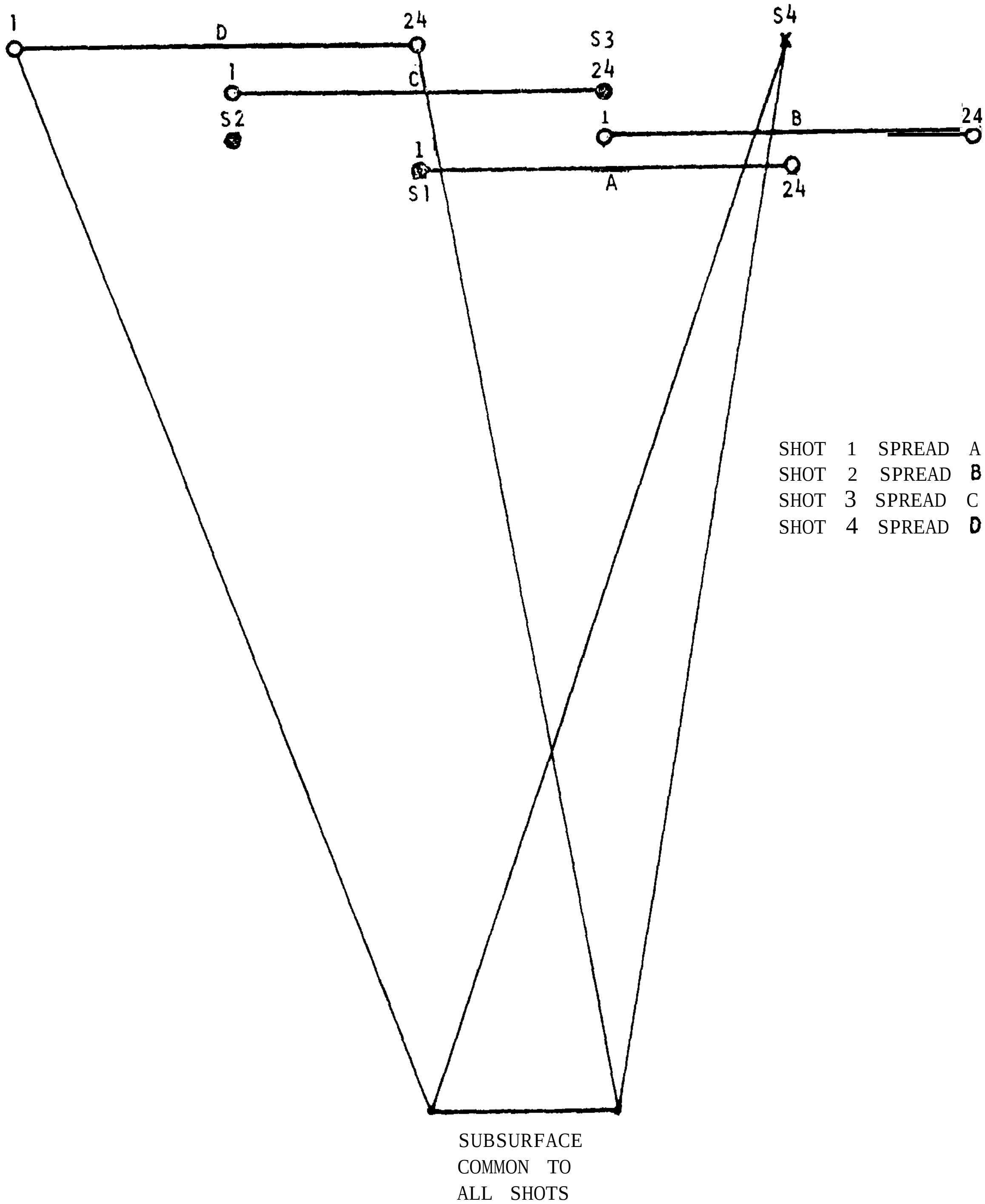
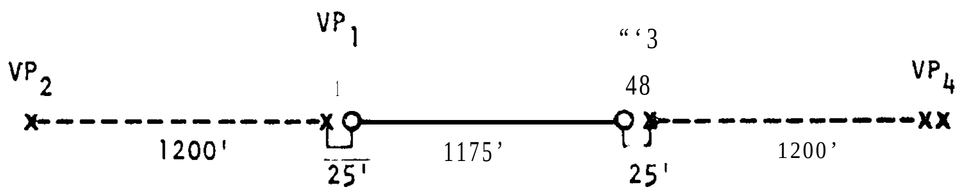


Figure 1. Shooting Plan for Expanded Spread Analysis



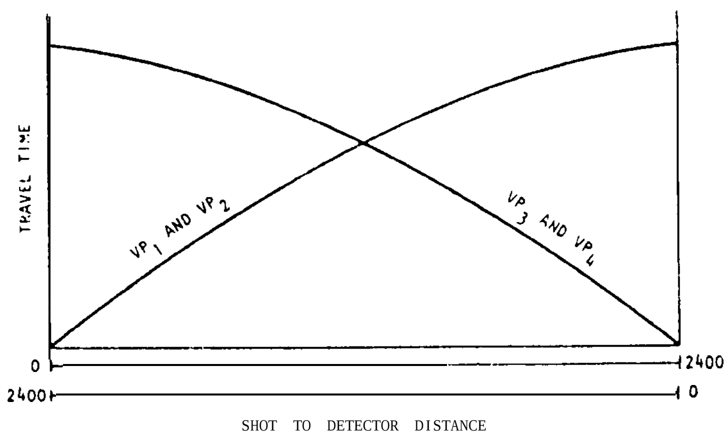


Figure 2. Refraction Analysis Layout

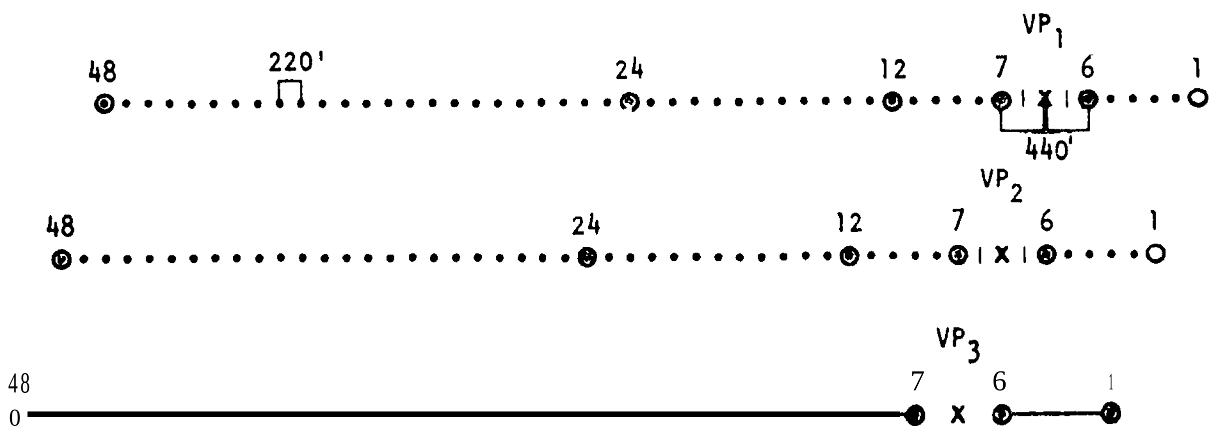


Figure 3. Geometry Proposed Reconnaissance Shots Spaced 440', Groups 220' (Nominal Coverage 1200%)

HYDRAULIC FRACTURING - A SUMMARY

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ACKNOWLEDGEMENT

The author wishes to express his appreciation to Halliburton Services for the opportunity to prepare and present this paper.

ABSTRACT

This paper presents a brief summary of hydraulic fracturing to date. This includes comments on both conventional hydraulic fracturing and massive hydraulic fracturing (MHF).

INTRODUCTION

The hydraulic fracturing process, developed on a commercial scale in 1949, has been the most successful stimulation tool available to the petroleum industry since that time. Hydraulic fracturing is employed primarily to increase production from oil- or gas-bearing formations; and, many formations are now producing which could not have been produced economically without hydraulic fracturing. In the area of oil and gas recovery, hydraulic fracturing is employed to either (1) bypass formation damage and/or (2) stimulate the zones of interest.

A number of factors should be considered prior to conducting a hydraulic fracturing treatment. These relate to the conditions of the wellbore, the reservoir and the economics involved.

With the increased world demand for petroleum products, there has been a tremendous increase in well-stimulation efforts to recover oil and gas from formations which were previously thought to be uneconomical. Hydraulic fracturing as a stimulation tool is a large portion of this effort; and, for this reason, we are seeing many new techniques which improve on the success of hydraulic fracturing. Massive Hydraulic Fracturing is one of the newer techniques.

Knowing the value and application of these new techniques gives the production engineer a valuable tool to help increase the production of oil or gas from a subject well or wells.

DISCUSSION

HYDRAULIC FRACTURING

Objectives

Hydraulic fracturing is used primarily to bypass formation damage and/or stimulate the zone of interest. In either of these cases, the objective is to generate a fracture system which has the desired geometry and sufficient flow capacity for the formation.

For stimulation, the effective wellbore radius is increased to give the higher production rate. As shown in the following equation of Darcy's Law for radial liquid flow, the expected production rate prior to stimulation can be determined:

$$Q = \frac{7.07\ kh\ (P_e - P_w)}{\mu \ln(r_e / r_w)}$$

where:

- Q = production rate, bpd
- k = permeability, md.
- h = height of productive zone, ft.
- P_e = reservoir pressure, psi.
- P_w = pressure at wellbore while producing at rate Q, psi.
- μ = viscosity of the flowing reservoir fluic, cp.
- r_e = drainage radius for well, ft.
- r_w = wellbore radius, ft.

The hydraulic fracturing treatment does not physically enlarge the wellbore; but, since a fracture is initiated at the wellbore outward, the result is an increase in the effective wellbore radius. As an example using the above equation, by increasing the effective wellbore radius from a value of 0.33 ft. (0.1 m) to 100 ft. (30.48 m) the production rate, Q, would be increased by a factor of approximately 3.5 for a drainage radius of 1000 ft. (304.8 m). Work by Prats[1] indicates that the effective wellbore radius may be approximated as being equal to one-quarter the total fracture length generated by the treatment, if the fracture is vertical and has infinite conductivity.

Objectives in Hydraulic Fracturing (con't)

Thus, for stimulation, it would be desirable to obtain a long, highly conductive fracture system.

Considerations Prior To Hydraulic Fracturing

There are several factors which should be considered prior to conducting a hydraulic fracturing treatment. Some of these are: (1) the possibility of wellbore damage, (2) the formation flow capacity, (3) the existing reserves and/or depletion, and (4) the economics.

A wells's productivity may be reduced due to formation damage around the wellbore, This damage may exist because of naturally occurring clays, fluid loss and mud cake build-up during drilling , or from scales, emulsions or paraffin deposition during the production history of the well. Evaluation of the extent of wellbore damage is helpful in determining the type of treatment required to either remove or bypass this restriction to production. The extent of wellbore damage may be determined by production tests, pressure tests, and production history.

In many cases, this damage may be removed by acid washing or remedial treatments such as matrix acidizing. In come cases, the damage is sufficiently deep or inert to remedial treatments that it must be bypassed through the use of a hydraulic fracturing treatment. If the formation flow capacity is sufficiently high, a small-volume fracturing treatment may be all that is required to bring the well up to its expected production.

Formation flow capacity is an important formation characteristic when we consider a well's production potential or how the well might respond to a hydraulic fracturing treatment. This important characteristic may be evaluated from core analysis, production information and pressure testing. Evaluation of the formation flow capacity may indicate high formation flow capacity and wellbore damage. In this case with high formation flow capacity, reservoir energy and a damaged wellbore, removal of or bypassing the damage may be all that is necessary to bring the well up to its full potential. However, if this evaluation indicates low formation flow capacity, regardless of wellbore damage, a deep penetrating hydraulic fracture may be required to bring the well up to an economical production rate.

Of course, one of the most important considerations prior to conducting a hydraulic fracturing treatment would be the amount of hydrocarbon reserves and the extent of depletion. This information may come from initial estimates of producible reserves and cumulative production information to date. Original reservoir pressure and current reservoir pressure information may be used to indicate reservoir depletion. However, the type of recovery mechanism should be known. In the case of a water drive, the existing reservoir pressure may not be indicative of hydrocarbon depletion.

The cost of the stimulation treatment and the expected gain in the production following the stimulation may be used in the evaluation of the economics of the treatment.

The geometry of the fracture system is important to the overall results of the stimulation treatment. The design of the treatment will vary depending upon the expected fracture geometry. Hydraulic fracturing theory tells us that the induced fracture will be oriented perpendicular to the least principal stress existing in the formation. The fracture may be vertical, horizontal or, in some case, at an angle with respect to the wellbore. In most cases, particularly at the depths being drilled today, evidence indicates hydraulic fractures are primarily oriented vertically. Further, theory and laboratory work indicate that vertical fractures extend in two directions from the wellbore, 180^{0} opposed. Since the majority of hydraulic fractures are oriented vertically, the following discussion will be based upon vertical fractures.

It is important that the fracture system extends vertically through the zones of interest, i.e., that the vertical fracture height is sufficient for optimum stimulation. This generated fracture height will influence to a large degree the penetration of the fracture into the reservoir, laterally, away from the wellbore. This penetration or fracture length is important to the stimulation of the zones of interest as has been shown above by the effective wellbore radius approach. However, this approach assumes the fracture system has infinite flow capacity. The fracture system is normally thought to have a finite flow capacity. Ideally, the induced fracture would not close following the release of hydraulic pressure, resulting in a very high flow capacity. Unfortunately, in most cases the fracture closes or heals if steps are not taken to keep it open. This is supported by data presented by Howard and Fast[2] where wells fractured with no propping agent showed a sharper decline than wells fractured using a propping agent.

Since in most cases, a proppant, such as sand or high-strength glass beads, is used to obtain the final fracture flow capacity, there are many options available to us in the selection of the type, size and amount of proppant. In some cases, acids are used in high-acid solubility formations to obtain flow capacity. This will be discussed later in this paper.

The parameters affecting the production increase following a stimulation treatment are discussed by McGuire and Sikora[3] and Tinsley et al.[4] Tinsley's work indicates that the conductive fracture height to net formation height (hf/hi) ratio, the fracture flow capacity to formation permeability ($k_f w_f/k_i$) ratio, and the conductive fracture length to drainage radius (L/r,) ratio are the most significant factors in the production increase following a hydraulic fracturing treatment. As the fracture flow capacity increases with respect to the formation permeability, the

Considerations Prior To Hydraulic Fracturing (con't)

relative capacity increases. For a low relative capacity value, the effect of fracture length on production increase is significant. This is to say that since the fracture system does not have sufficient flow capacity for the formation, the fracture length does not matter. However, for higher relative capacity values, the effects of length become more important. By the use of these types of equations, the expected results from a stimulation treatment may be evaluated. This approach would lend itself to optimization of the type of treatment required to attain the necessary length, flow capacity, etc., for the least amount of money.

Considerations in Designing Hydraulic Fracturing Treatments

There are many factors which should be considered when designing the hydraulic fracturing treatment for a given well. Some of the formation characteristics which are important to the design are permeability, porosity, reservoir pressure, rock hardness, acid solubility, and fluid sensitivity.

The formation permeability will dictate the amount of flow capacity needed in the fracture for stimulation. In addition, the fluid loss to the formation during the treatment is a function of the formation permeability. If the permeability is high, fluid loss additives will be needed to assist in the control of this loss. Loss of the hydraulic fracturing fluid to the formation may result in a fracture volume much smaller than that necessary for stimulation. If the permeability is low, the volume of fracturing fluid lost to the formation may be small; but, due to capillary forces, fluid that is lost may be held very tightly by the formation. In the case of a low permeability gas well, by increasing the pore space fluid saturation along the fracture face, the effective permeability to gas is reduced. This may result in very slow clean-up following the treatment, or permanent damage to the fracture face permeability to gas, if there is insufficient reservoir

Considerations in Designing Hydraulic Fracturing Treatments (con't)

pressure to recover this lost fluid.

The formation porosity and the fluid content of the, pore space partially dictate the type of fluid which will be produced, and will also influence the amount of fluid lost ot the formation during the stimulation treatment.

The reservoir pressure may be a measure of reservoir depletion and may be used as an indicator of remaining reserves. This pressure will also be the source of energy to move the producible fluids to the fracture system and into the wellbore. In addition, the reservoir pressure provides resistance to fluid loss during the treatment and assists in the recovery of the lost fluid following the treatment.

If a propping agent is employed in the hydraulic fracturing treatment to maintain a desired flow capacity, the hardness of the formation and its effect on the proppant should be considered. If the rock is very hard, the proppant may have a tendency to crush; or, in a soft, perhaps poorly consolidated rock, the proppant may embed into the formation. In either of these cases, the result would be a loss in fracture flow capacity. Other rock properties, such as elasticity and Poisson's Ratio, should also be considered, as they affect the geometry of the created fracture.

The acid solubility of the formation may be sufficient to allow generation of fracture flow capacity by etching the fracture face with acid. In this case, an acid may be used as the fracturing fluid and the flow capacity would be generated while this fluid was being placed in the fracture.

In formations such as a sandstone with a calcareous cement, an acid base fracturing fluid may be detrimental, causing the release of fines as the acid would preferentially react with the calcareous material.

For the last few years, approximately 75-80% of all hydraulic fracturing treatments employing propping agents have been conducted with water-base fluids. There are

Considerations in Designing Hydraulic Fracturing Treatments (con't)

several advantages to using water-base fluids for fracture generation and proppant placement. These advantages are related to safety in handling and to the vast number of chemicals available for imparting viscosity to the water, reducing pipe friction pressures during injection, controlling fluid loss to the formation, etc. However, one of the disadvantages of water-base fracturing fluid is its potentially detrimental effect to the formation due to swelling and migration of clay minerals. In almost all water-base fracturing fluids, potassium chloride or other clay-stabilizing materials are employed to help reduce the potential damage.

There are formations which are sufficiently water sensitive that aqueous base fluids should not be used even with clay-control materials added. Laboratory tests may be conducted with representative samples from the formations to be treated to ascertain whether an oil-, water-, or acid-base fluid would be more compatible with the formation. These tests usually include X-ray diffraction analysis, immersion tests in which pieces of the formation are subjected to various fluids to determine the quantity of fines released, and flow tests in which the various fluids are flowed through core samples to evaluate the detrimental effects of the fluid flowing into the formation. Tests to determine acid solubility and flow capacity from acid etching may distate whether a fracture-acidizfng treatment would be beneficial.

If it is determined that a propping agent may be more advantageous than an acid to develop fracture flow capacity, evaluations should be made to determine the best proppant type, size and amount for the treatment. These tests are usually conducted by placing the proppants between core samples from the zone to be treated and applying the expected closure pressure. From these tests, the amounts of embedment, crushing, and fracture flow capacity are determined.

With the base fluid and means of obtaining

Considerations in Designing Hydraulic Fracturing Treatments (con't)

flow capacity determined, the treatment volume, fluid viscosity, injection rate, and other treatment variables should be evaluated. These variables may best be evaluated through the use of equations developed from model studies and theoretical aspects of proppant transport and the spending of acid in fracture systems. In most cases, a number of potential treatments are calculated where injection rates, fluid viscosities, fluid volumes, etc., are varied. For each set of variables, i.e., one rate, one fluid viscosity, one fluid volume, etc., the production increase is normally calculated so the potential treatments may be compared. The cost of each of these treatments may also be compared so that the economics can be evaluated.

MASSIVE HYDRAULIC FRACTURING

The current demand for natural gas is encouraging exploration and completion of extremely low-permeability gas wells. Some of these have been successfully stimulated with large volume hydraulic fracturing treatments, while others have been somewhat less successful. One of the factors that should be considered in stimulating these tight gas zones by hydraulic fracturing is that of fluid retention. With the small capillaries, capillary pressure is high, and fluid which is embibed into the pore space may be very difficult to remove. If it is not removed from the pore space, a loss in the permeability to gas results. This fluid retention can be aggravated by high surface tension fluids, reaction of the fluid or chemicals in the fluid with minerals surrounding the pore space, etc. In addition to knowing the type of minerals associated with the pore space, we must know how detrimental the reaction of the fluid and its components are to regaining the relative permeability to gas. In laboratory testing to determine detrimental effects to gas permeability, core samples from various rock types are saturated with a test fluid, and pressure is applied to determine the pressure required to just initiate fluid flow.

MASSIVE HYDRAULIC FRACTURING (con't)

This pressure relates to capillary pressure and threshold pressure. Following these tests, methane gas is flowed through the core samples and regained gas permeability is measured versus time. These tests can be run with various fluids to determine the relative compatibility of various fluids with the rock from a regained gas permeability effect.

Based upon information gained from petrographic studies of low-permeability sandstones, it has been seen that improved clay control materials may be necessary to make the fracturing fluid compatible with the formation.

Clay control, when using an aqueous base fluid, in the past has been based upon the concept of ion exchange. With this concept, a more stabilizing cation replaces the existing cation resulting in clay control. As discussed by Hower and Black! the potassium ion is a very efficient clay control cation.

However, when we consider the large quantities and types of clays associated with the formation pore space in some low- permeability sands, we see that we may need more than cation exchange in the swelling clays. We see many clay platelets composed of swelling clays (montmorillonite, mixed layer, etc.) and non-swelling clays (illite, kaolinite, chlorite, etc.). With a large quantity and variety of clays, a newer concept considers a blanketing effect with polymers to protect the clays from swelling and migrating. Chemicals to achieve this concept are hydroxy aluminum! zirconyl-chloride[7] and multicationic organic polymers. Each of these types of chemicals can serve to achieve the required clay control if they are used correctly. Each has limitations related to permanency of clay control, type of fluid which can be used to place the chemical, etc.

In addition to controlling clay swelling and migration when treating very low-permeability formations, it is also important to satisfy as many of the reactive sights on the clays as possible to reduce the reaction of various fracturing fluid chemicals with the clay. Fracturing fluid chemicals which might react adversely with the clays would be the organic polymers used to lower the surface tension of the fracturing fluid, etc. The end result of these chemicals reacting with the clay may be increased fluid retention which may result in lower regained gas permeability.

There have been a number of new developments in the last few years related to improved gelling agents for fracturing fluids. One of the most significant developments has been in the area of extremely high viscosity water-base gels. These fluids have the ability to transport proppant greater distances from the wellbore and to give better distribution of the proppant within the fracture than do lower viscosity fluids.

As shown in Figure 1, the lower viscosity fluids allow proppant to settle, building up a proppant bed. The fluid which loses the proppant proceeds on out into the reservoir, creating additional fracture length. The theoretical result of most low-viscosity, fluid-fracturing treatments is a propped length which is normally considerably shorter than the created length. In addition, the propped height may not be sufficient to cover all of the net pay intervals in the vertical direction.

In the case of the extremely high viscosity fluids, the proppant settling rate is sufficiently low that the proppant may be considered to be in suspended flow. This would result in a proppant distribution as shown in Figure 2. With this type fluid, the proppant may be carried a greater distance from the wellbore and completely cover the entire vertical fracture height. The apparent viscosity of these fluids, as with other non-Newtonian fluids, is a function of the rate of shear to which the fluid is subjected. Without shear, these fluids can have a semi-solid consistency, and a measure of viscosity or apparent viscosity, as it is normally considered, is not possible. However, as this type fluid is sheared, such as being pumped through tubular goods or through a fracture, it may be considered as a non-Newtonian fluid, and its non-Newtonian fluid properties determined. These fluid properties allow determination of friction pressures during the pumping of this fluid and the apparent viscosity expected. Rheological studies and field data indicate these fluids will pump at the friction pressure expected for water, or less. Thus, the tubular goods friction pressure is expected to be low; but, the viscosity characteristics required for proppant transport and generation of fracturing width are developed.

With the hydraulic fracturing treatment fluid volumes continually increasing, there is more concern about the cost of the fluid per gallon. Treatment volumes of 3000,000 gallons are becoming commonplace in some areas; and, several treatments have been conducted using 500,000 gallons of fluid. Because of this concern for cost of the fracturing fluid, as well as a need for other desirable properties, an emulsion system was developed for fracturing operations. This is an emulsion system[8] containing between 50 and80% of an internal phase comprising a liquid hydrocarbon such as diesel, kerosene, or crude oil, and from 20 to 50% of an external water phase. The external water phase contains a thickening agent such as guar gum or synthetic polymers. The emulsion exhibits a high viscosity which is not primarily dependent on the oil viscosity, but is dependent upon the properties of the gelled water external phase and on the concentration of the internal oil phase. This system allows the development of a high viscosity fracturing fluid which is relatively inexpensive. This fluid has been used very effectively in several areas, most notably in Massive Hydraulic Fracturing work in the Rocky Mountain area.[9]

In an attempt to improve on some of the undesirable properties of some of the fracturing fluids, such as fluid retention in low-permeability gas wells, foams were developed for use as fracturing fluids. The reported advantages to foam as a fracturing fluid are excellent proppant

MASSIVE HYDRAULIC FRACTURING (con't)

transport, low fluid loss to the formation, rapid cleanup, etc. At the time of this writing, foam-frac fluids are being evaluated in several different areas and it will be some time before wells can be accurately field evaluated from a performance standpoint.

Massive Hydraulic Fracturing (MHF) is a somewhat loosely defined term for the large volume treatments being conducted in low-permeability gas sands. The term massive hydraulic fracturing has been defined, based upon fluid volume, sand volume, long or massive intervals, and the length of the conductive fracture. A commonly accepted definition for MHF today is: a fracture resulting in conductive length of at least 1000 feet in each direction from the wellbore.

As pointed out earlier, production increase theory indicates that extremely long, conductive fractures are necessary in low-permeability formations for adequate gas production rates.

To conduct treatments of this size there are many factors which have to be considered.

The first of these factors would be the fluid required to carry propping agent to these great distances from the wellbore. The potential fluids were discussed briefly above. One of the requirements of the fluid is that it remains stable for long periods of time, 4-12 hours, at elevated temperatures. This requires tailoring the fluid to give the time and temperature stability required as well as the reduction in viscosity later for fluid recovery. The fluids being the most successfully employed in MHF work are the cross-linked guar gum and guar gum derivative gel systems, and the emulsion system previously discussed. In addition to the gel stability and breaking characteristics, these fluids have many of the other desired fracturing fluid properties.

In these large treatments, as much as 1.4 million pounds of sand per treatment have been used as the propping agent. It has become commonplace to use in excess of

0.5 million pounds of sand for these large treatments. The type and size of sand to be used is important. Normally a high quality sand with sufficient strength and particle size control is varied from as small as 100 mesh to 10-20 mesh throughout the treatment. The purpose of this size variation is to achieve the desired proppant distribution. Since the proppant settling rate in any fluid is a function of the proppant size, smaller proppants are normally used in the first part of the treatment where the fluid is becoming less viscous due to temperature thinning. This smaller particle in the lower viscosity fluid will be carried to the distances required in the early part of the treatment and, as the fluid has less temperature thinning (latter part of job), larger proppant sizes are normally used.

With large fluid volumes, sand volumes, equipment requirements, etc., a great deal of pre-planning is required to coordinate jobs of this size. An overall coordination effort by the operator and service company personnel is required before and during the treatment.

FRACTURE FLOW CAPACITY GENERATING TECHNIQUES

There have been a number of stimulation techniques developed to assist in obtaining greater production increase and a more sustained production increase than with some of the other, more conventional techniques. Some of these techniques are being used in the Massive Hydraulic Fracturing treatments being conducted in various parts of the United States.

New proppant placement techniques have been developed which allow an improved distribution of proppant when extremely long conductive fractures are desired. When we consider the best approach to carrying proppant to great distances into the reservoir, the first thought would be to use a fracturing fluid which would not allow the proppant to settle, i.e., an extremely high viscosity fracturing fluid. One disadvantage to this extremely high viscosity fluid is that with large volumes, the fracture width generated may be excessive; and, therefore, the volume required to place proppant great distances from the wellbore becomes excessive. In addition, it is possible that this excessive fracture width may cause an increase in the created fracture height, causing the fracture to go out of zone, perhaps into non-productive or water-productive zones. To maintain the proppant transport characteristics of the extremely high viscosity gel but not to place excessive pressure in the fracture, the technique devised employs a step-and-repeat treatment that creates a pattern of recurring propped and unpropped sections within a fracture!' This pattern promotes extremely high flow capacity and deeper fracture penetration within the formation.

A conventional fracturing treatment has three phases. Expressed in a simplified manner, they are: first, pumping a volume of fluid without proppant; second, the actual treatment-pumping the fluid carrying theproppant; and third, displacing the proppant to the formation, or the flush.

This new technique uses several combinations of the first and second of these phases in a multiple or step-and repeat manner. In the first phase, a low-viscosity fluid serves as the pad and, subsequently, as the spacer. Repeated injection of this inexpensive, low-viscosity fluid creates the unpropped sections and permits the formation of extreme fracture length at very little additional cost. In each each of the second phases, any one of the highly viscous fracture fluids may be employed as the proppant carrier because of their excellent transport characteristics, i.e., allowing suspension of the proppant throughout the entire fracture height. The lower viscosity fluid penetrates the higher viscosity fluid, giving a pillar effect for high fracture flow capacity. At the conclusion of the entire treatment, a low-viscosity fluid is used for the flush. Excellent results have been obtained with this new technique.

Another proppant placement technique which is now being used for several formations is that of placing a partial monolayer proppant system in the fracture. This

FRACTURE FLOW CAPACITY GENERATING TECHNIQUES (con't)

technique employs the extremely high viscosity fluids and is a potential alternative to placing large quantities of proppant in these thicker fluids. The advantage to this type of system is the high flow capacity which could be developed. In the early days of hydraulic fracturing, most people felt that fractures were horizontal; in this fracture geometry, partial monolayer proppant distribution could conceivably be obtained. Several procedures, including soluble spacers, were employed in many jobs to assist in obtaining the partial monolayer distribution. When people in the industry became more aware of in situ stresses and the theories of fracture orientation, it became more apparent that most fractures were oriented vertically rather than horizontally. Evaluations of proppant transport in low-viscosity fluids indicate that it would be very difficult to obtain a partial monolayer system using low-viscosity fluids in a vertical fracture system. With the development of the extremely high viscosity fluids, it is now possible to design treatments for partial monolayer proppant distribution in a vertical fracture. Consideration must be given to the possibility of the partial monolayer proppant system crushing due to the small number of grains supporting the formation closure pressure. Also, the formation must be sufficiently competent that it does not allow embedment of the proppant into the fracture face, allowing fracture closure.

Another technique and application for the more viscous fluids is the use of simultaneous acid stimulation. In some carbonate formations, the zones are relatively homogeneous in terms of acid solubility. This may mean that in a fracture acidizing treatment, rock will be dissolved uniformly from the face of the fracture. Upon removal of the hydraulic pressure, the frac-may heal sufficiently that the remaining flow capacity is insufficient for the formation. Also, fluid loss during an acid stimulation treatment may prevent live acid from reaching to the lengths necessary for stimulation. This fluid loss may

FRACTURE FLOW CAPACITY GENERATING TECHNIQUES (con't)

also cause a softening of the fracture face, resulting in the release of numerous fines and/or a fracture which can close almost entirely.

To eliminate some of these problems, a volume of viscous fluid is injected to create the fracture width required, to control fluid loss, and to assist in more efficient fracture flow capacity generation from the acid that follows. Laboratory model studies indicate the acid will develop flow channels through the high viscosity gel, and acid etching will take place along the wall of these channels. The net result from this type treatment is high flow capacity channels extending deeper into the reservoir than may have been possible before. Excellent results have been observed with this technique.

In laboratory model studies, it has been noted that when different density fluids are alternately injected into a fracture, they do not mix, but stratify, in the fracture. This observation has lead to a controlled density acidizing concept.[11] As an example, by injecting a weighted brine into a fracture and following this with a less dense acid, model studies indicate that the acid goes over the top of the denser fluid. This can also be conducted where the acid is the more dense fluid. By using this technique, protection of a particular zone can be accomplished. This protection becomes necessary when fractures extend into water-bearing or other undesirable zones. This technique places the acid and, therefore, the fracture flow capacity where it is needed.

CONCLUSIONS

Hydraulic fracturing has been in use now for more than 25 years. During this time, there have been many advances which have improved the results of fracture stimulation. The production increase curves made available recently allow the determination of the fracture flow capacity required for stimulation, and also indicate the necessary fracture extension. With these requirements known, the treatment may be designed around

CONCLUSIONS (con't)

optimum fluid volume, viscosity, injection rate, proppant size, acid type, etc.

Massive hydraulic fracturing treatments and new fracture flow capacity generating methods are allowing us to stimulate formations which could not have previously been economically stimulated.

Research in all phases of hydraulic fracturing is continuing and, undoubtedly, additional new developments will be forthcoming to meet the challenges of the future.

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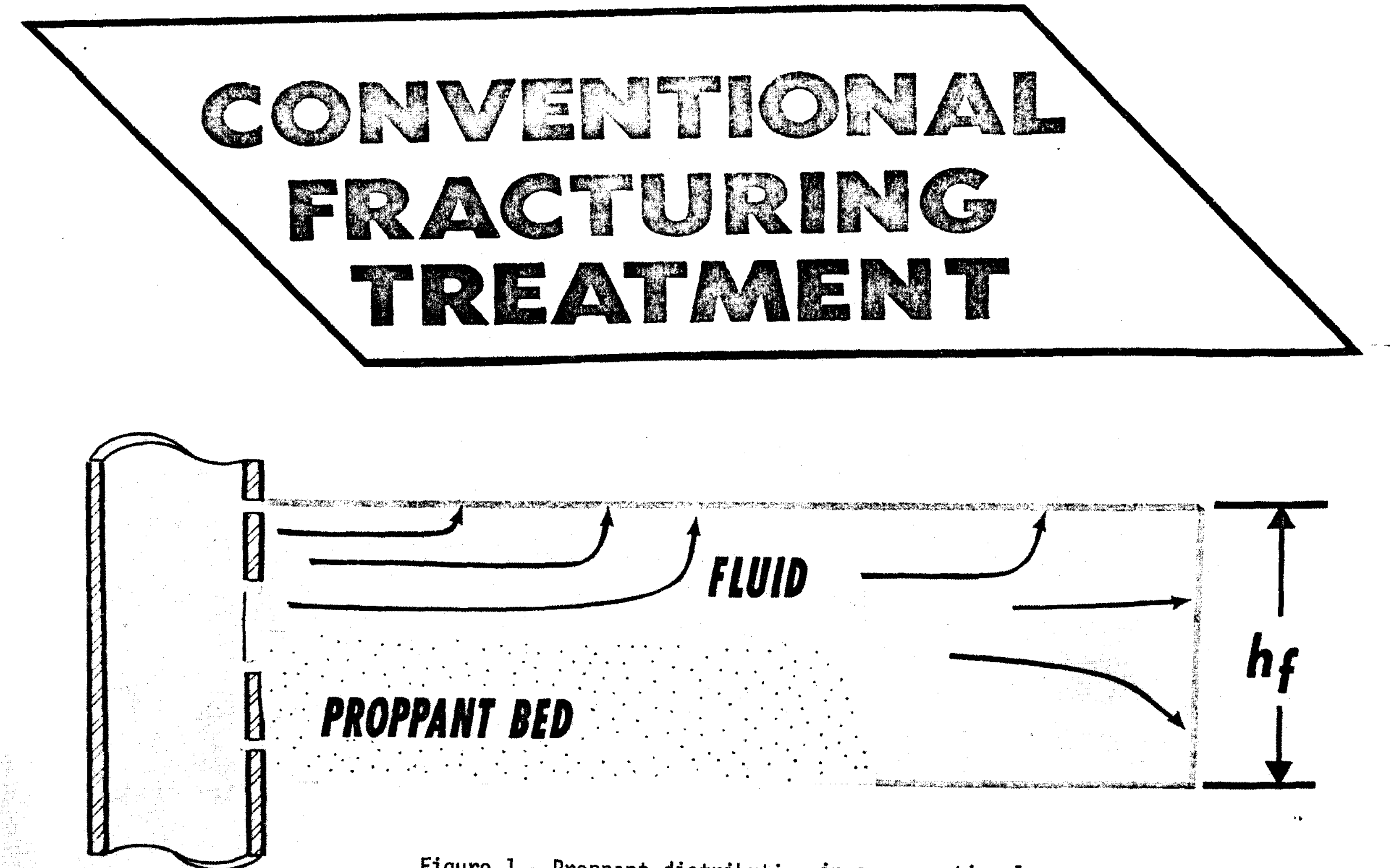

Figure 1 - Proppant distribution in a conventional, low fluid viscosity fracturing treatment. Illustrated in one wing of vertical fracture, h_f is the created fracture height.

VISCOUS FLUID

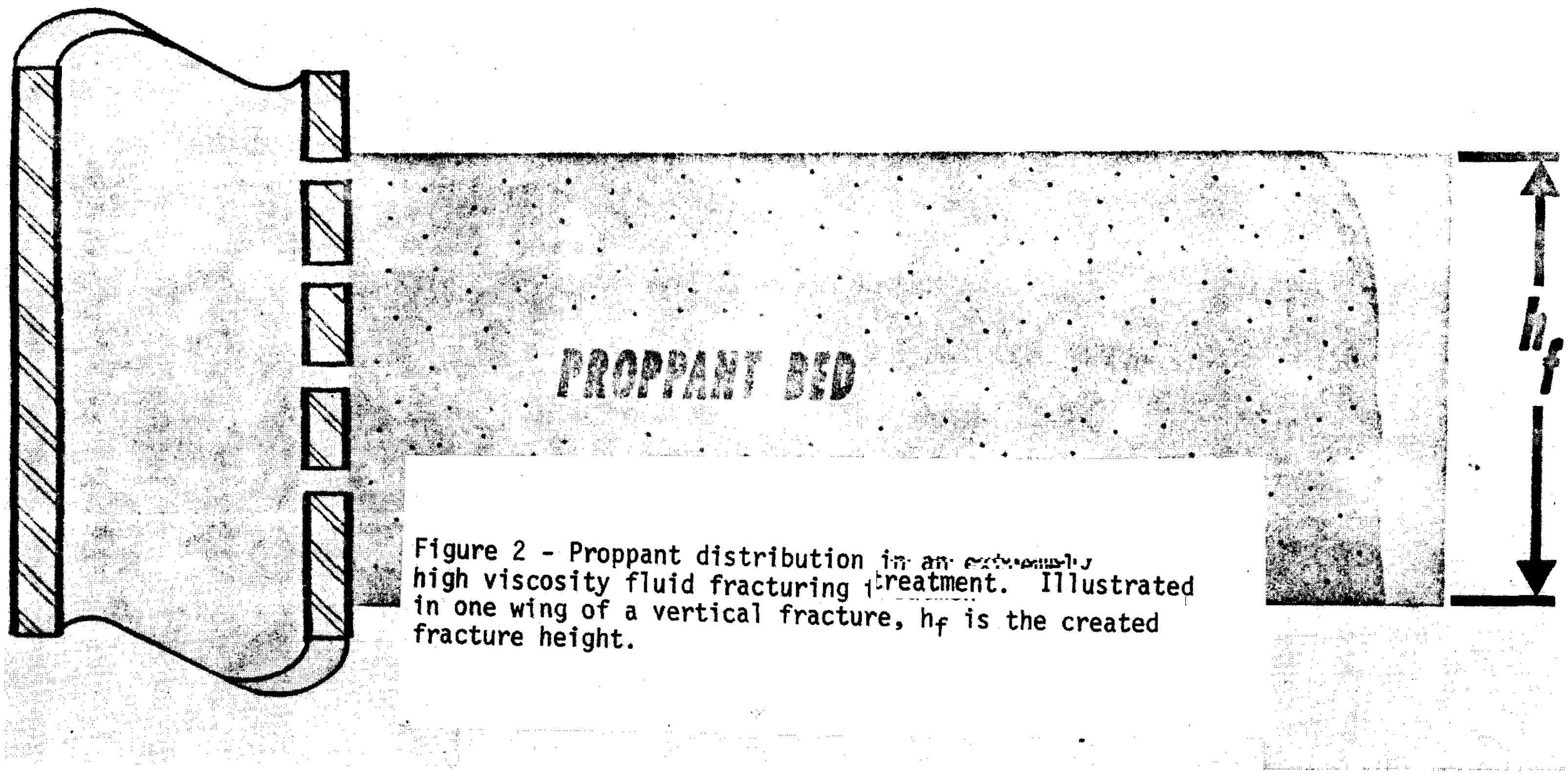

Figure 2 - Proppant distribution in an extremely high viscosity fluid fracturing treatment. Illustrated in one wing of a vertical fracture, h_f is the created fracture height.

ESTIMATING RESERVES FROM FRACTURED RESERVOIRS

Forrest A. Garb - H. J. Gruy and Associates, Inc.

The methods for determining the oil and gas reserves in a naturally fractured reservoir can be divided into two groups, depending upon the development stage of the reservoir in question. At initial discovery, many reservoir parameters remain unknowns. The boundaries of the reservoir may be inferred from geophysical data, but in all probability, reserve estimates will be required before actual boundaries are determined by drilling. Estimates of petrophysical properties, reservoir boundaries, producing limits, reserves and producing rates will be requested by management in order to establish budgets, and in order to develop operational plans. At this early stage in the development of a reservoir, the best tool we have developed for estimating reserves is a micro-performance analysis based on the pressure behavior observed during well testing. This pressure transient analysis may be performed on either drawdown or buildup pressure data resulting from carefully designed test procedures. If two or more wells are available with sufficient proximity to allow interference test to be performed, so much the better. An interference test involves the production of one well, while observing the resulting pressure behavior in an offset well or wells.

To aid in the determination of reservoir configuration, H. J. Gruy and Associates, Inc. has developed a suite of analytical and numerical programs to study the pressure transient behavior observed during a test on a single well. The field-observed data from the test is compared in a computer to the theoretical pressure performance that would result considering all of the factors known about the well, while adjusting the reservoir geometry and volume. A standard deviation between the observed and calculated data is determined, and geometry and configuration are automatically adjusted until an optimum standard deviation is achieved. More frequently than not, a distinct optimum is observed for a single geometric assumption, although sometimes more than one geometry will yield a standard deviation within the tolerance or precision of the pressure instruments being used. In this instance, geophysics or area geological knowledge must be used to select between the indicated geometries.

The several geometries included in our current programming are:

(1) a well in the center of a circular drainage pattern,

(2) a well bounded on one side by a barrier,

(3) a well bounded by two parallel boundaries where the distance between the boundaries and between the well and the boundaries can be varied,

(4) a well bounded by three orthogonal boundaries with all distances variable,

(5) a completely enclosed orthogonal reservoir with the well located anywhere within the boundaries, and

(6) a wedge-shaped reservoir with the angle of the wedge and the location of the well variable.

The results of this program have yielded definitive reservoir configuration on about 80% of the tests performed until date. On one assignment, approximately 1.5 million dollars in drilling funds were saved when test performed on wells indicated proposed step-out locations to be beyond the limits of the reservoir. These locations were subsequently farmed out to other operators, were drilled and were found non-productive.

A pressure transient is a pressure disturbance created by altering the equilibrium of the fluids in a reservoir system. A pressure transient test in a hydrocarbon reservoir has been compared to throwing a stone in a pool of water. When the stone hits the water, surface ripples radiate outward from the point of disturbance. When the ripples hit the edge of the pool, they will be reflected back toward the disturbance point. If one carefully measured the time it took for the disturbance to proceed to the boundary and return to the disturbance point and knew the velocity of a ripple on the interface between air and water, he could calculate accurately the distance to the boundary. He would not be able to tell the direction of the boundary, only its distance. In the well test case, opening the well to produce from a stabilized shut-in condition, or shutting in the well from a stabilized flow condition, is equivalent to throwing the stone. Pressure transients radiate outward from the disturbance point and are reflected back by the boundaries of the reservoir. These pressure transients are recorded on highly sensitive bottom-hole pressure guages and the distances to the boundaries are calculated considering the wave velocity in the reservoir fluid. This velocity, of course, varies widely, contingent on the contents of the reservoir rock, with velocities in gas being much slower than for oil or water. Gas being a "soft" system, i.e., highly compressible, there is attentuation of the pressure transient and frequently longer test periods creating larger amplitude pressures that must be taken into consideration in the test design. This is like throwing a larger stone, as in the water pond case, only the distances to the barriers can be determined. Compass direction depends upon geophysical or area geological knowledge.

Once a reservoir size has been estimated, an approximation of the reserves contained in that reservoir easily follows. Early in the life of a large reservoir, a test such as this executed for a reasonable test period may result in no boundary determination, but even this is a useful analysis. The test does prove the reserves for the existing well and confirms the viability of any offset location within the radius of investigations.

A second approach to a similar problem is termed the numerical simulation approach. If a reasonable approximation of the reservoir geometry is believed known, a network of orthogonal cells can be gridded together to represent the reservoir configuration and volume. Permeabilities, boundaries, fracture systems and other unknowns can be adjusted in the simulation until reasonable agreement between the observed field data and the calculated pressure performance is achieved. While this technique is very flexible and will allow a more accurate study for non-ideal reservoirs, it is a more complex approach to the problem, requiring better reservoir definition than is often available early in its life. It remains the best tool in those instances where it can be applied. Numerical simulation for comparison to observed field tests is frequently used to determine fracture existence, magnitude and orientation.

As a reservoir is developed by drilling, the resulting subsurface geology more adequately defines the reservoir configuration. The producing limits of the field can be used to volumetrically determine the in-place hydrocarbons, provided representative values of the formation's petrophysical properties can be estimated. Electric well log analyses and core analyses are the most frequently used tools for estimating porosity and water saturation. These techniques, however, are estimates determined from microscopic samples of the reservoir. A several magnitude increase in confidence for these important considerations will result if a pressure transient analysis is included in the program. Pressure transient analyses have the advantage of integrating the area investigated, thus, yielding averages for the area of investigation. While these averages may not necessarily be applicable to the entire reservoir, they will, in general, be superior to petrophysical estimates based on the microscopic techniques. The estimates of the fracture orientation and magnitude will become fundamentals for calculating the productivity of the formation and the well. This productivity projection, along with economic considerations, will also determine the recovery factor for the hydrocarbons in place.

Estimation of reserves from mature fractured reservoirs does not require significantly different techniques than any other reservoir. The classical pressure production performance will react much the same way as for a non-fractured reservoir, if representative pressure data are successfully recorded. An analysis might be with an automobile tire. If one lets one cubic foot of air from a tire and finds the pressure to have decreased to one-half of the initial value, then, ignoring non-ideal gas considerations , one could reasonably estimate the tire to have contained two cubic feet of air to start with. Applying this to natural gas reservoirs, this requires that accurate production and stabilized pressure date be recorded. In a fractured reservoir having high flow capacity in the fracture, but very low permeability in the matrix feeding these fractures, stabilized or representative pressures may not be achievable within reasonable test times. H. J. Gruy Associates, Inc. has developed a program which has proven very satisfactory for determining reserves in fractured reservoirs having a producing life of sufficient duration to allow the wells being tested to have a stabilized drainage pattern. In low permeability reservoirs, stabilized production may not be achieved for as much as three years after opening the reservoir to produce. This calculation technique, originally developed for application in the San Juan Basin, does not require the wells to be shut in at all and can yield very adequate estimates of reserves based on observed flowing pressure data. The calculation procedure is a trial and error one, thereby requiring the use of the high-speed digital computer. While the equations on which the calculation is based are well-acepted ones within industry, the application of the equations is unique in concept. The calculation accepts the established principle that the coefficient of deliverability "C" in the Bureau of Mines equation: $Q = C(P_f^2 - P_s^2)^n$ becomes a constant when the drainage area of the well becomes a constant. This recognized fact is regardless of shape, configuration or location of a well within the drainage pattern.. The calculation procedure iterates on different assumptions of gas, initiallly in-place calculating the coefficcient "C" from three or more sets of test data taken after the well has achieved stabilization. The calculated "C's" are averaged and a standard deviation between each "C" and the average is determined. The initial gas in-place assumption that results in the minimum standard deviation between each "C" and the average of all "C's" is the best estimate of the initial gas in-place volume.

The basic principles discussed above apply to oil reservoirs as well. By proper substitution of the governing flow equations and PVT parameters, oil reserves can be estimated by an identical procedure.

QUEBEC LOWLANDS: OVERVIEW AND HYDROCARBON POTENTIAL

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ACKNOWLEDGEMENTS

The author expresses his gratitude towards SOQUIP for allowing him to publish this paper.

It is also important to acknowledge the data acquisition and key exploration carried out by Shell Canada Limited in this area till 1974 without which this paper would not have been possible.

INTRODUCTION

The area with which this paper is concerned is situated in the province of Quebec, roughly between Montreal and Quebec city, approximately 200 miles in length by 50 miles in width, that is to say, approximately 10,000 square miles. The sequence of Cambrian and Ordovician clastics and carbonates lies unconformably on the Precambrian shield. This sequence, dipping to the southeast, varies in thickness from a few hundred feet in the northwest to over 20,000 feet in the southeast.

SOQUIP has been actively drilling in this area for two years and has just completed stimulation of 4 wells, 3 in the fractured shales. Thus, it would seem an opportune time to review the region.

GEOLOGY

In more geologic detail, we seee that a relatively complete sequence is present from the Cambrian to Ordovician, either from outcrop (fig. 1) or from wells. The lithostratigraphic table (fig. 2) shows the principal breakdown of the groups.

The Potsdam Group is divided into two formations: the Basal Covey Hill Formation and the overlying Chateauguay Formation. The underlying formation, in general, is unconformably deposited directly on the Precambrian basement and is composed principally of feldspathic, poorly sorted, cemented, reddish sands deposited in a fresh water, often beach or ba environment.

The overlying Chateauguay Formation was deposited unconformably on the Covey Hill as a clean, generally well cemented, buff to white, quartz sand.

In the upper part of the Chateauguay Formation, a marine influence is evident from an interbedding of carbonates and sandstones. This marine influence becomes dominant in the deposition of the overlying Beekmantown Group. This group, composed mainly of light to dark grey dolomite, is commonly coarsely crystalline, but becomes vuggy in part.

This dolomite is overlain, often unconformably, by the Chazy Group. The base of this group is, in type section, a calcareous light grey sandstone, and is overlain by limestones and shaly limestones. In subsurface, facies vary considerably.

The Chazy Group was followed in some regions by a hiatus and, in other regions, by the direct deposition of the Black River Group. This group is composed in outcrop of grey dolomites overlain by grey limestones; and in subsurface, particularly in the northeast, it is composed entirely of limestones. Wide scale submergence of the basin followed the deposition of the Black River and gave rise to limestones of the Trenton Group.

Generally, the Trenton Group is characterized by thin-bedded limestones of many different petrographic types. In the upper Trenton, the limestone becomes progressively more and more shaly with gradual deepening of the basin or upheaval of the hinterland.

The change from the Trenton carbonate sequence to the black, massive, calcareous shales of the Utica Group seems abrupt in outcrop but is more gradational in subsurface to the northeast. This shale, with a thickness of up to 1200 feet, is noted for its odour of petroleum when freshly broken. The distinctive black shales give way to slightly calcareous, grey, thinly interbedded shales and

GEOLOGY (con't)

siltstones of the Lorraine Group.

This Lorraine Group is a flyschoid sequence and has a maximum thickness of over 5000 feet. Facies changes are present in subsurface and the group varies from grey shales and fine siltstones to siltstones and fine sandstones. Overlying this group, molassic red shales and sandstones of the Richmond Group are encountered, bringing to a close known deposition in the basin.

In examining the geologic map of the Low-1 ands (fig. 1), there are several other features which must be mentioned. In the region of Montreal, Cretaceous intrusions occur. These are the Monteregian intrusives, which are composed of gabbro and nepheline syenite or related alkaline rock. In the southeastern border of the Lowlands, two zones are evident trending northeast to southwest. The inner zone, the St. Germain Complex, is compiled of thrust faulted and folded Lorraine, Utica and Trenton Groups. This is the zone of major interest in regard to fractured shales. The outer and larger zone consists of nappes of Appalachian rocks which have been thrusted into place in mid-Ordovician times. These zones, much more complex than the rest of the Quebec Lowlands, lead us into a discussion of the tectonics. However, it is necessary to conclude the resume on the geology by noting that Pleistocene glacial and alluvial deposits cover all but a small percentage of the bedrock, making surface geology and interpretation relatively difficult.

TECTONICS

The tectonic history is quite complicated (fig. 3). Two fault systems exist: a system of normal faults related to the Precambrian shield and a system of thrusts found in the southeastern half of the basin, which originated during the first Appalachian orogenesis, the Taconic Orogeny. These are of importance as it is this fracturation which has created the fractured shales.

The normal faults have been active since the Cambrian and have played a major part in the depositional history of the

TECTONICS (con't)

sediments, particularly in the northwest. Two principal fault directions are seen in seismic and outcrop (fig. 1). The major fault pattern trends northeast-southwest, and a secondary fault pattern trends in an east-west direction.

The Taconic Orogeny of late Ordovician time has also greatly affected this basin and is the cause of a second system of faulting, namely a series of thrust faults from the southeast to the northwest. This orogeny is observed to have a gradually decreasing effect on the basin from the southeast to northwest, by the decreasing extent and severity of the thrusting system (fig. 3).

From the fieldwork, seismic and drilling, it is possible to divide the basin into four tectonically different regions (figs. 3, 4). From the northwest to southeast, these are:

-The platform zone: where only normal faulting is present

-The external zone: where the lithologi-

-The internal zone: sequence is affected

-The nappe zone: to varying degrees by the thrust faulting

The platform zone

It is the northeast-southwest system of faults that has the major influence on deposition within this zone. In some cases throws of up to 3000 feet are known. This fault pattern is present not only in this zone but throughout the basin and shows a definite step-faulted pattern deepening to the southeast into the basin (fig. 6).

The external zone

The external zone is the least disturbed of the three thrusted zones. The thrusting, associated with the Taconic Orogeny, affects only the upper part of the lithological column, the Utica and Lorraine shales and siltstones. It is this zone which is of major interest to us today. The underlying Ordovician carbonates and Cambrian sands are practically undisturbed. These thrust faults are clearly evident on electric logs and, in some cases, show major movements, with several hundred feet of repeated sequence.

The external zone (con't)

Prior to the thrust faulting, the normal faulting was active and fractured the rock in a specific system of fractures. The thrusting, representing a posterior and completely different system of movement, has opened the initial fracture system. This open fracture system, seen in outcrop and cores, is of major interest in exploration. The northwestern limit of the external zone, as defined on subsurface and surface work, appears to be generally associated with one or more major normal faults (fig. 3). The southeastern limit is more difficult to define as in this direction the thrusting is stronger and begins to affect the carbonates as well.

The internal zone

Here the thrusting has affected the sedimentary sequence, including the Ordovician carbonates and Cambrian sands. This zone of thrusting is naturally varied and complicated. Seismic and drilling have indicated simple thrusted structures in some regions, while multiple "haystack" type imbrications, showing several repetitions , are encountered elsewhere. In this zone also open fractures are found. These are probably, as in the external zone, due to either the opening of an earlier normal fracture system by thrusting or opening of the thrusts system by reactivated normal fault eustatic compensation.

The nappe zone

Imbrications of the carbonates and sands are not limited only to the internal zone, but are present also in the nappe zone. In this zone, due to upheaval and compression of the platform-associated subduction zone, gravity sliding and thrusting at the beginning of this Taconic Orogeny have carried deep basinal sediments from the southeast over the previously described platform edge sediments.

This classification of the Lowlands into these four tectonic regions, using the two faults systems, is of major importance. It allows us to outline the major zones of exploration and localize the style of trap possible.

HYDROCARBON POTENTIAL

As is evident from the previous discussion on the tectonics, trap possibilities are numerous. Generally speaking, the structural divisions outlined above determine the type of trap which may be considered as the primary target. Prior to examining the potential of the Quebec Lowlands in each of these structural divisions, an outline of the source potential for the whole basin is necessary.

From the laboratory studies it is found that the shales and siltstones of the Lorraine Group and particularly the Utica Group form the principal source rocks in the Quebec Lowlands. Organic matter reaches up to 3% of the Utica and somewhat less for the Lorraine. Reflectance studies, on bitumen residue, and preservation of organic material (Chitinozoa, etc.) have been carried out on these groups. These show the-degree of carbonization, or state of maturation, is advanced and the main potential is for gas. This is confirmed by the gas shows throughout the Lowlands which vary between 88% and 96% C_1.

Hydrocarbon search within the platform zone has been active since 1885 with over 150 wells drilled. Only 15% of these have tested the complete sequence (fig. 5). From this, it is evident that in this platform zone, with a surface area of 5400 square miles, exploration is far from exhausted. It is of particular interest that the majority of the wells have had gas shows, while the shales and siltstones of the Utica and Lorraine Groups contain gas shows in practically all cases.

Within the platform zone, with its facies changes and normal faulting, traps are anticlinal, fault closed, or due to pinch-outs or facies changes (fig. 6).

It has been a search for primary porosity in the Cambrian Potsdam sands which has occupied and continues to occupy the effort of petroleum exploration in the platform area.

In the external zone, an area of 900 square miles, only 13 wells have been drilled (fig. 7). Nine of these wells are situated in the region of St. Hyacinthe, with depths varying from 1300' to 3500' and have drilled only the shales of the Richmond Group and the Upper Lorraine Group. All encountered gas shows. The four remaining wells, Villeroy No. 1 and No. 2, Ste. Francoise Romaine No. 1, and l'Ancienne Lorette No. 1 were drilled in the northeast to an average depth of 7000' and have tested the shale/siltstone, Lorraine Utica sequence and the underlying sequence to basement. It is the thrusting within the Utica Lorraine shales and siltstones which is of major interest and wherein the major exploration effort is headed (fig. 8). In the wells drilled, it was found that where thrusting occurs in the shale sequence, gas shows are present (fig. 9).

These fractured fault zones, which in some cases gave large gas flows, are limited vertically to several feet or tens of feet, but have large aerial or horizontal plane of influence. It is believed that we can map the fractured fault zones on seismic. One such zone, which is gas filled in a well, has been mapped over an area of many square miles.

Although seismic control is better in some area than others, fault plane structures similar to the drilled area (fig. 8) are seen throughout the 900 square miles of the external zone. This obviously means potential for this play is extremely good.

The major problem in such a play is permeability. Clearly where fractures exist they tap the gas in the shale and siltstone porosity and act as permeability channels. In the recent months SOQUIP has been stimulating these fractured shales in an effort to increase the fracture system and, thus, production.

Within the Quebec Lowlands, the internal and nappe zones, from the point of view of hydrocarbon potential, may be grouped together. As pointed out in the discussion on tectonics in these zones, the sedimentary sequence has been thrust to the northwest as large, often imbricated, sheets (fig. 10). It is the carbonate

HYDROCARBON POTENTIAL (con't)

sequence within these sheets or slices which has proven the most prospective.

MARKETS

It is predicted that in Quebec energy requirements to 1979 will include an annual compound growth rath of 14.1% for natural gas, the highest of any province in Canada (fig. 12). However, in 1973 Montreal consumed only 63 Bcf of gas. When one considers that the population of Montreal is 2.5 million, one sees the potential of expansion as great.

Lack of any system of gas pipelines in this area makes threshold values higher than normal and necessitates well-defined reserves prior to commitment to a gathering and transmission system. This is particularly true when dealing with unconventional reservoirs or low deliverability wells.

However, from the above figures, coupled with a Montreal-Quebec city population of over 3 million and a possible price of $2.00/Mcf, it is obvious that a considerable market potential exists in and around the Ouebec Lowlands. It is only a matter now of proving the reserves to satisfy the expected growth rate of this area.

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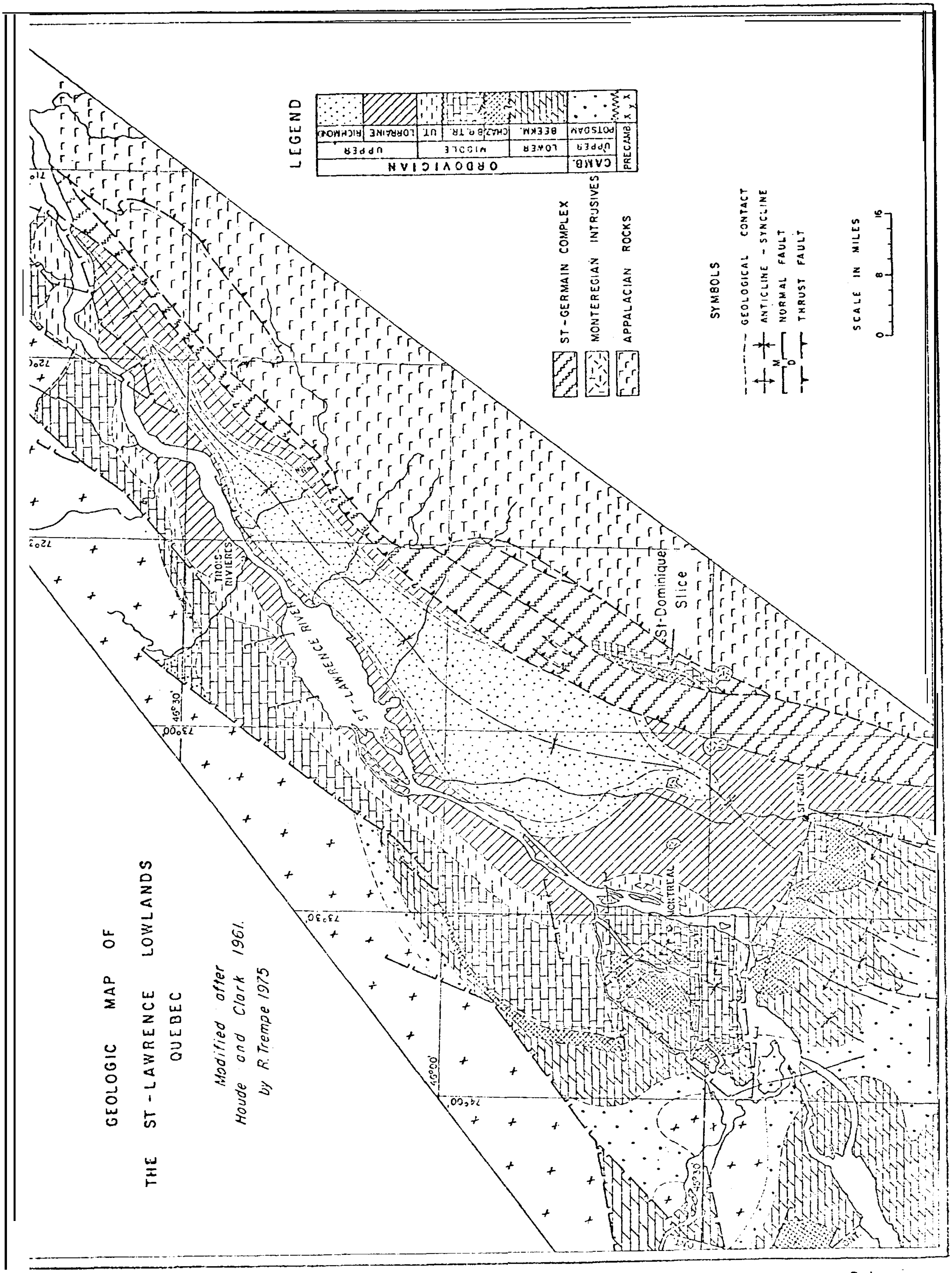
GEOLOGIC MAP OF
THE ST-LAWRENCE LOWLANDS
QUEBEC
Modified after
Houde and Clark 1961.
by R. Trempe 1975
LEGEND
ORDOVICIAN
UPPER
RICHMOND
LORRAINE
UT.
MIDDLE
CHAZ.B.R.TR.
LOWER
BEEKM.
CAMB.
UPPER
POTSDAM
PRECAMB.
ST-GERMAIN COMPLEX
MONTEREGIAN INTRUSIVES
APPALACIAN ROCKS
SYMBOLS
GEOLOGICAL CONTACT
ANTICLINE - SYNCLINE
NORMAL FAULT
THRUST FAULT
SCALE IN MILES
0
8
16
St-Dominique
Slice
ST-LAWRENCE RIVER
TROIS RIVIERES
MONTREAL
ST-JEAN
46°30'
46°00'
73°00'
73°30'
74°00'
72°00'
71°

Beiers
Fig. 1

SYSTEM		SERIES	ST-LAWRENCE LOWLANDS GROUPS/FORMATIONS		GENERALISED LITHOLOGICAL CHARACTER
ORDOVICIAN	U	CINCINNATIAN	RICHMOND		RED SHALES AND SILTSTOSE
			LORRAINE		INTERBEDDED SHALES AND SILTSTONE
			UTICA		BLACK SHALES
	M	CHAMPLANIAN	TRENTON		THIN BEDDED LIMESTONE
			BLACK RIVER		LIMESTONE
			CHAZY		LIMESTONE AND DOLOMITE
	L	CANADIAN	BEEKMANTOWN	BEAUHARNOIS FM.	DOLOMITES
				THERESE FM.	
CAMBRIAN	U	CROIXAN	POTSDAM	CHATEAUGUAY FM.	QUARTZ SANDS
				COVEY HILL FM.	FELDSPATHIC SANDS

Beiers
Fig.2

SCHEMATIC CROSS SECTION OF THE ST. LAWRENCE LOWLANDS

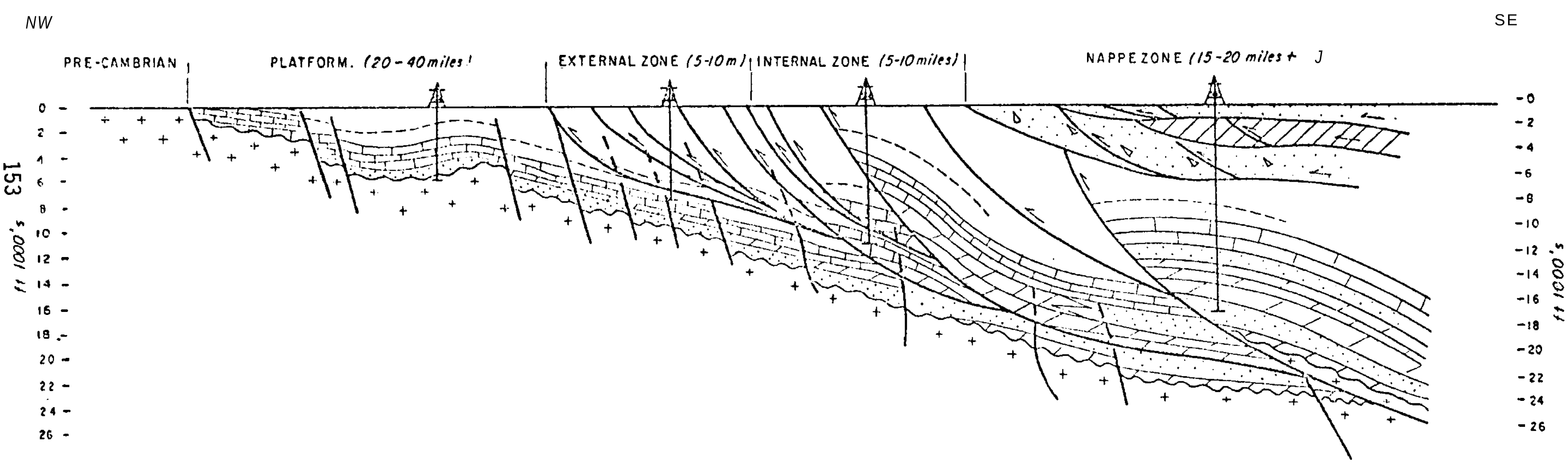

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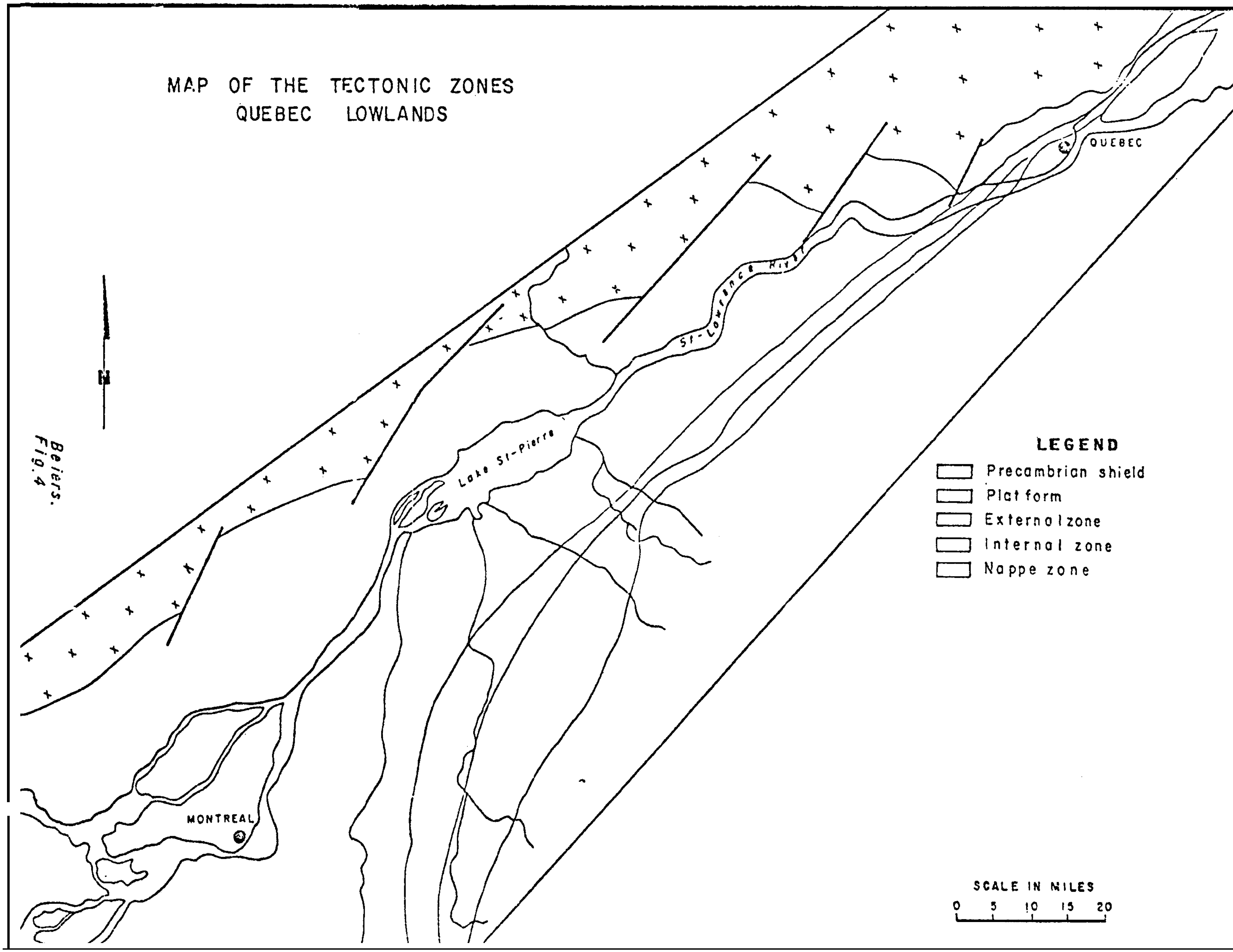
Fig.3


MAP OF THE TECTONIC ZONES
QUEBEC LOWLANDS
N
QUEBEC
St-Lawrence River
Lake St-Pierre
MONTREAL
LEGEND
Precambrian shield
Platform
Externalzone
Internal zone
Nappe zone
SCALE IN MILES
0 5 10 15 20
Beiers.
Fig.4

WELLS DRILLED IN THE PLATFORMS ZONES QUEBEC LOWLANDS

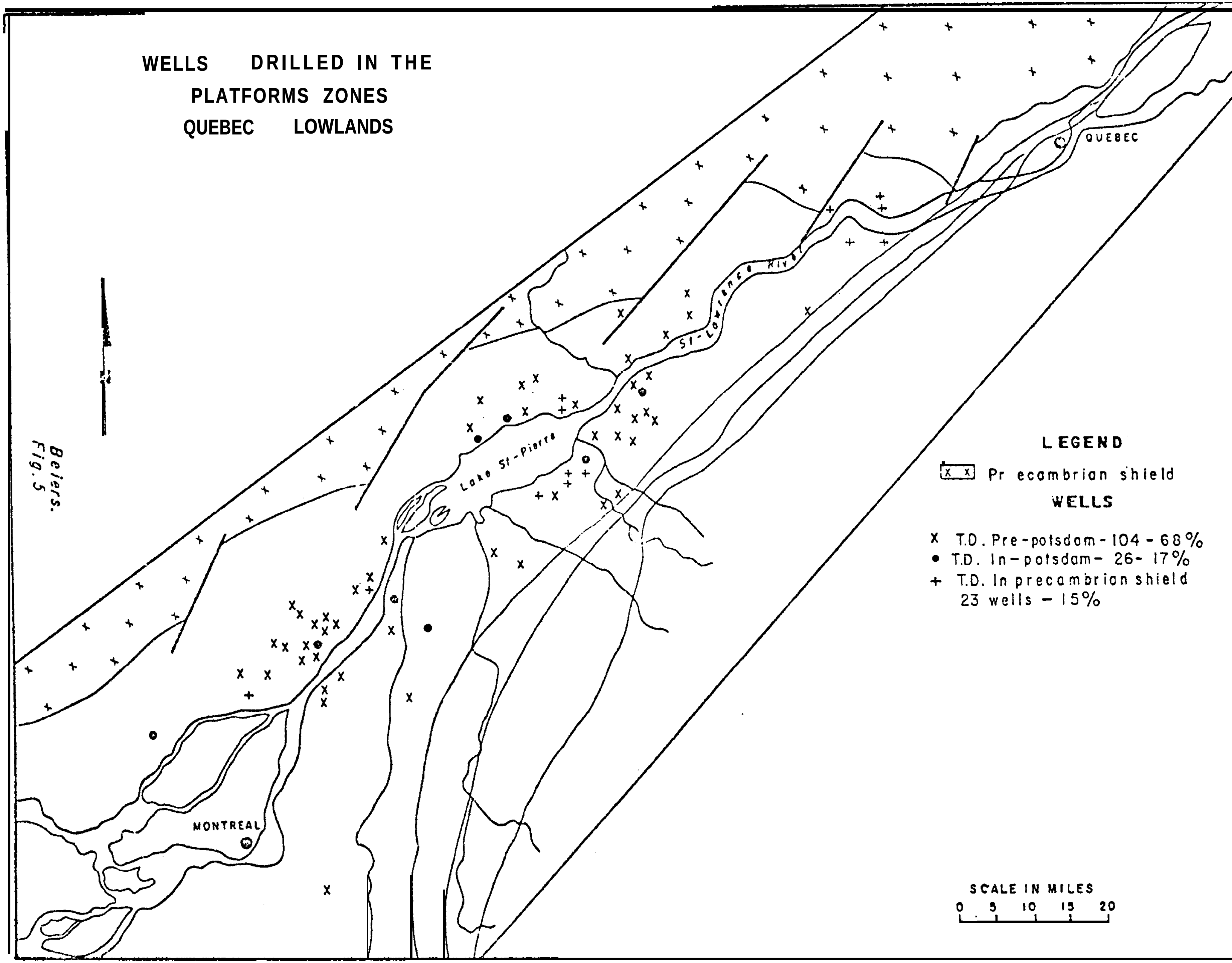


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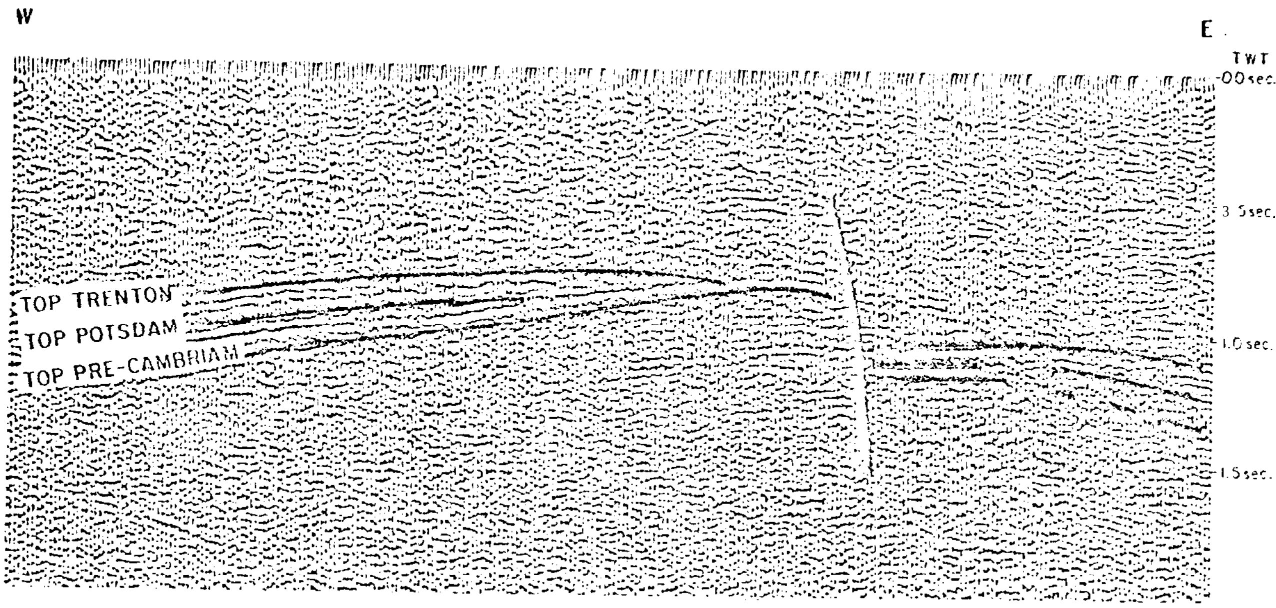
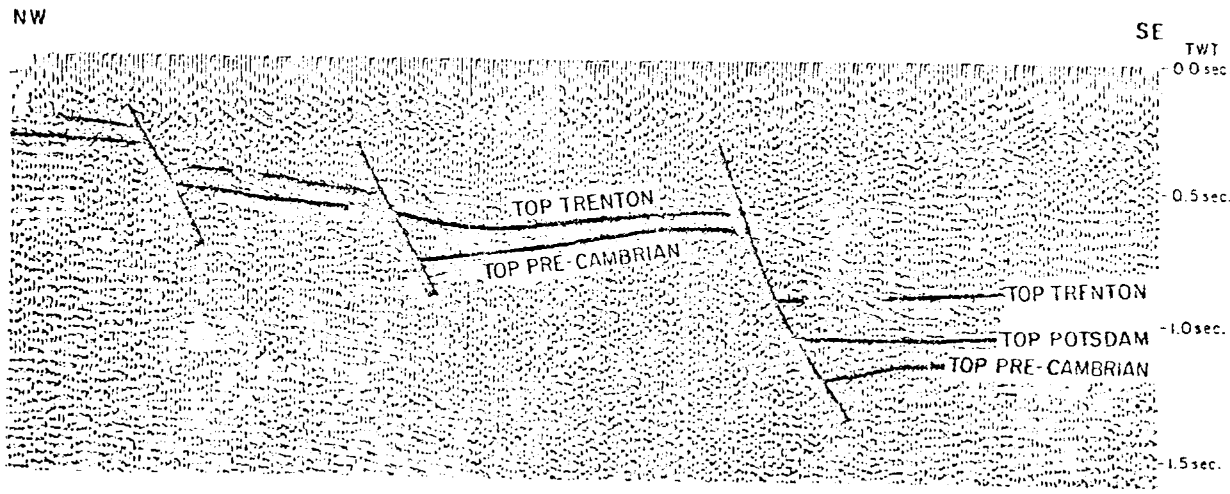
Fig. 5



a) BASEMENT HIGH PINCHOUT

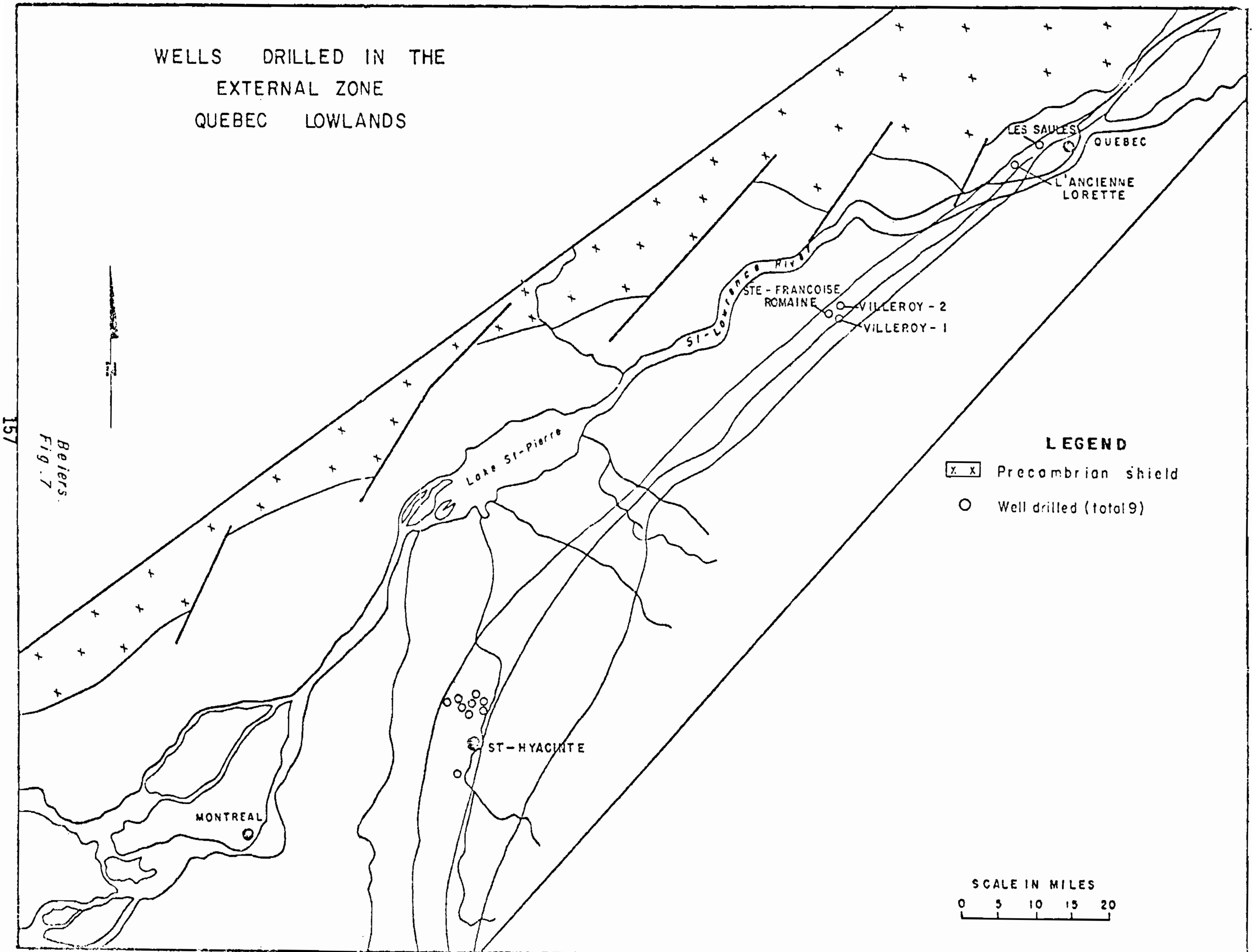


b) STEP FAULTING AND ASSOCIATED FAULT TRAPS

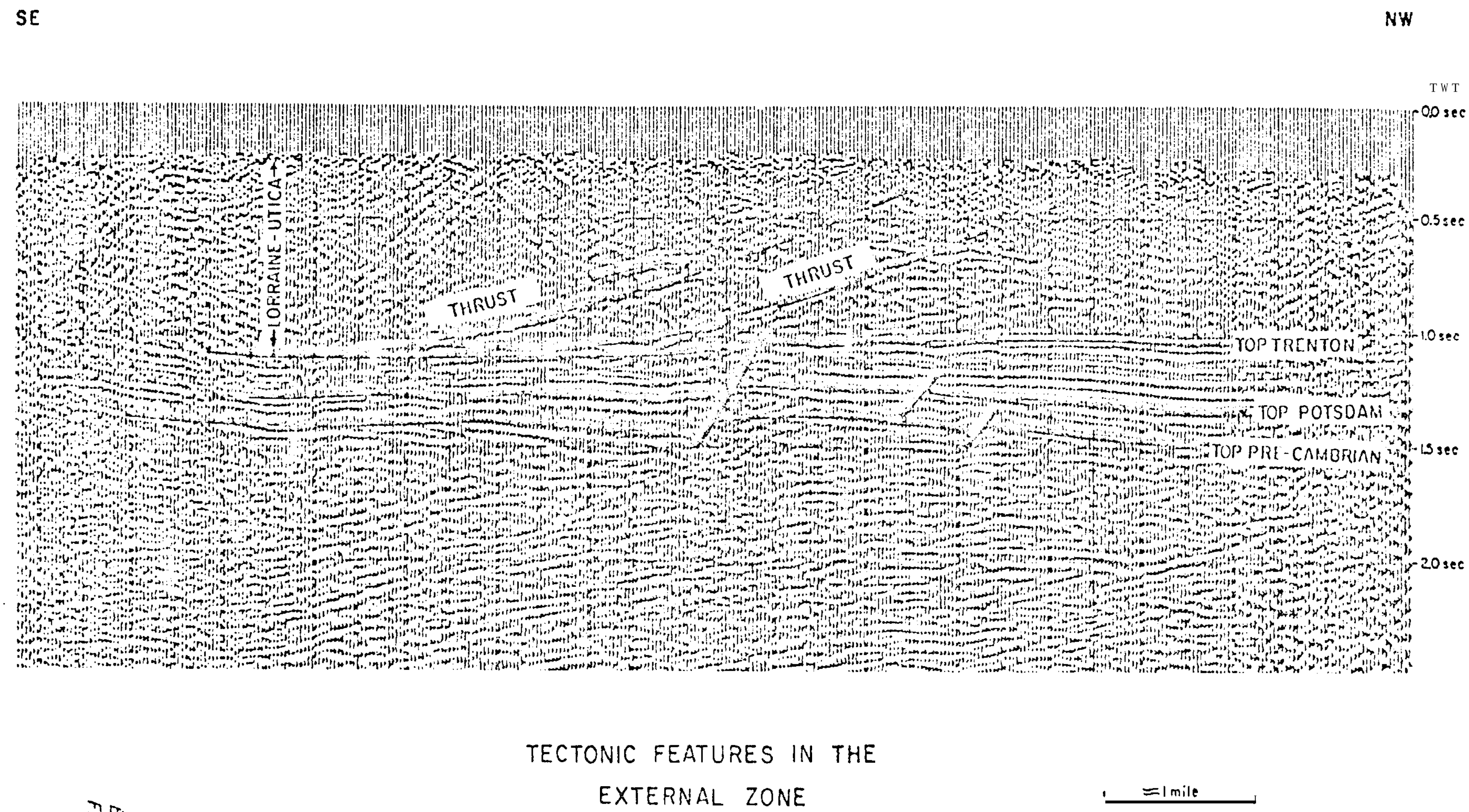
TECTONIC FEATURES IN
THE PLATFORM ZONE
QUEBEC LOWLANDS

≃ 1 mile

Beiers
Fig. 6

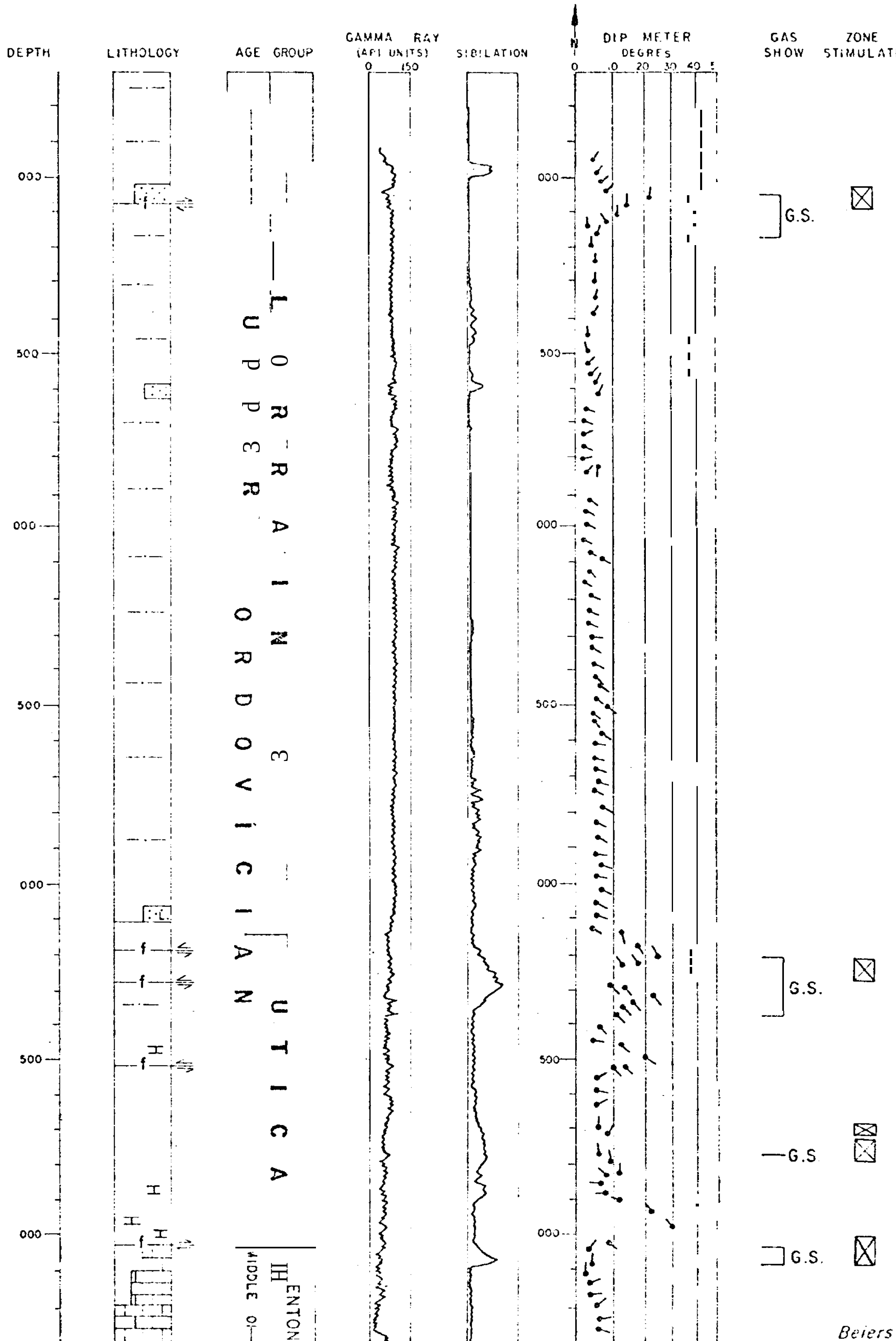

WELLS DRILLED IN THE
EXTERNAL ZONE
QUEBEC LOWLANDS
LEGEND
Precambrian shield
Well drilled (total 9)
SCALE IN MILES
0 5 10 15 20
LES SAULES
QUEBEC
L'ANCIENNE
LORETTE
St-Lawrence Riv.
STE-FRANCOISE
ROMAINE
VILLEROY - 2
VILLEROY - 1
Lake St-Pierre
ST-HYACINTE
MONTREAL

Beiers.
Fig. 7

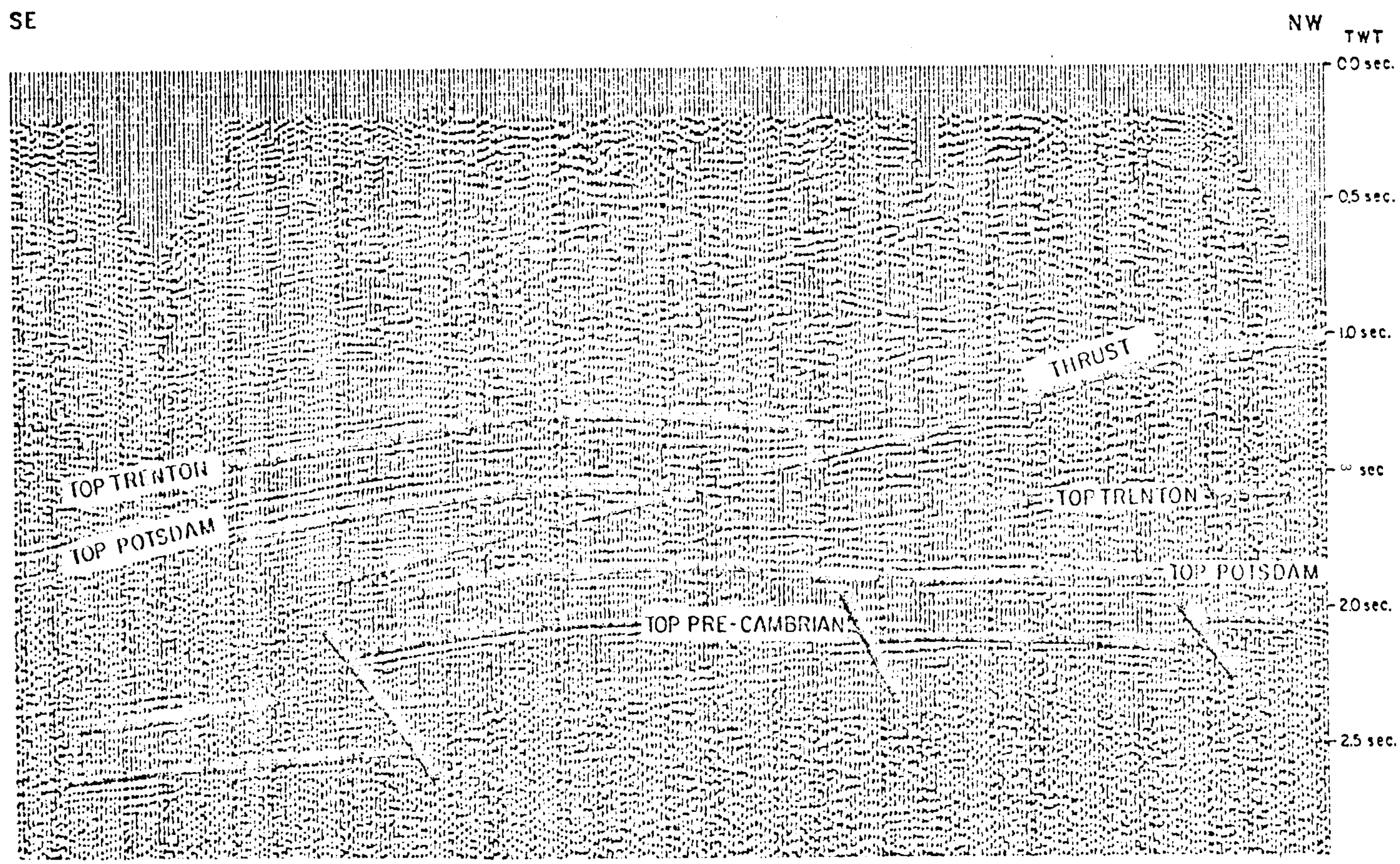


TECTONIC FEATURES IN THE
EXTERNAL ZONE
QUEBEC LOWLANDS

Beiers
Fig. 8


DEPTH
LITHOLOGY
AGE GROUP
GAMMA RAY
(API UNITS)
0 150
SIBILATION
N
DIP METER
DEGREES
0 10 20 30 40
GAS SHOW
ZONE STIMULATE
UPPER ORDOVICIAN
LORRAINE
UTICA
TRENTON
G.S.
G.S.
G.S
G.S.

Beiers
Fig.9



TECTONIC FEATURES IN
THE INTERNAL AND NAPPE ZONE
QUEBEC LOWLANDS

≃ 1 mile

Beiers
Fig. *10*

WELLS DRILLED IN THE INTERNAL AND NAPPE ZONES QUEBEC LOWLANDS

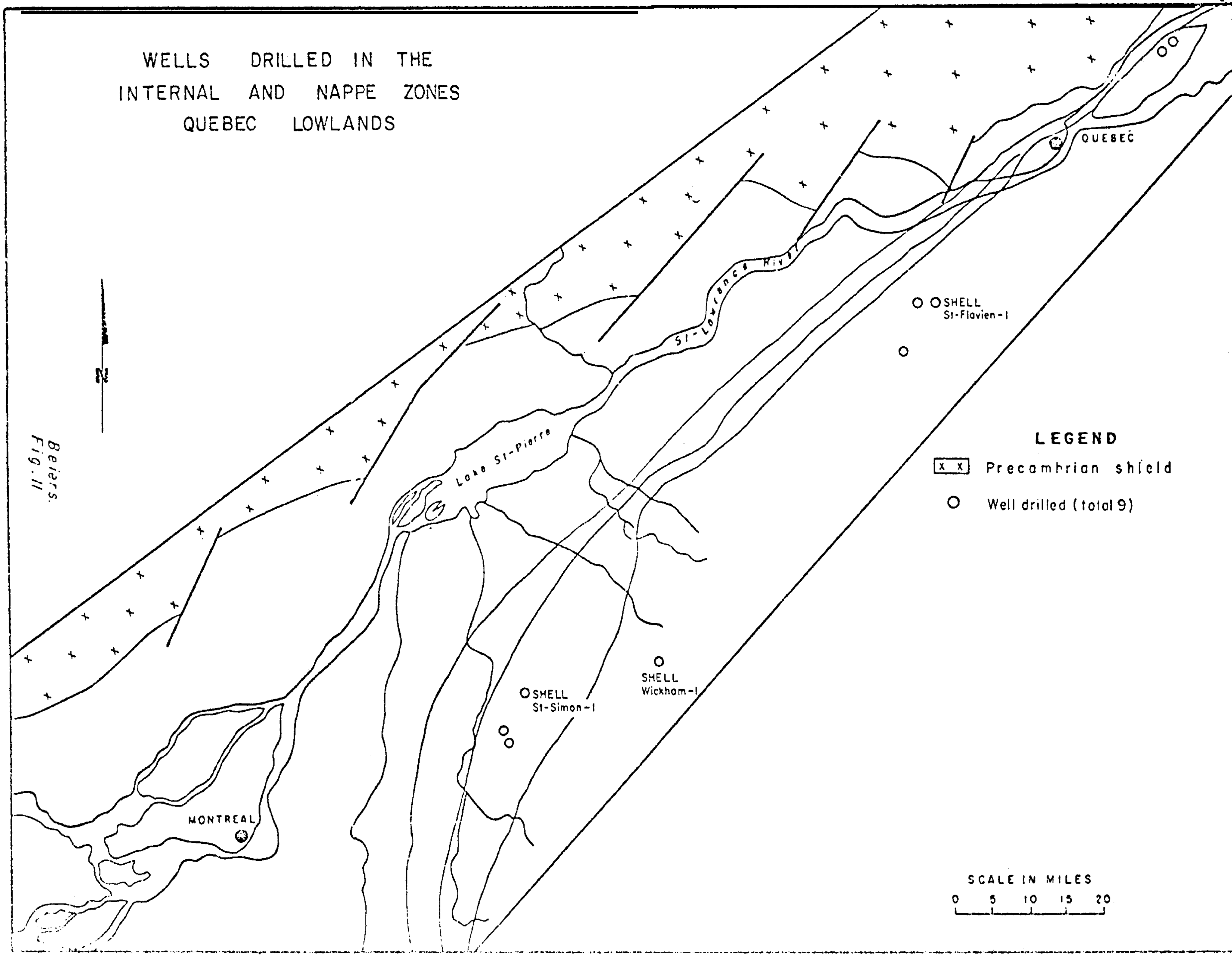


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Fig. II

THE NEW ALBANY SHALE AND EQUIVALENT STRATA IN INDIANA

Leroy E. Becker and Stanley J. Keller - Indiana Geological Survey

ABSTRACT

The New Albany Shale and its equivalent strata are exposed at outcrop and present in the subsurface in two areas in Indiana: the Illinois and Michigan Basins (fig. 1), which are separated by the Cincinnati Arch. Some natural gas has been produced from the New Albany in a few areas; and, oil has also been produced from it in laboratory experiments.

ILLINOIS BASIN

Borden, in 1874, first proposed the name New Albany Black Slate for exposures of slate-like rock near New Albany where it crops out for 5 miles along the Ohio River. Regionally, the New Albany outcrop strikes northwestward in a belt from 5 to 15 miles wide from southeastern to northwestern Indiana (fig. 1). In several counties, the New Albany Shale is covered by glacial drift and is exposed in only a few stream-beds or road cuts. Its thickness does not vary much at outcrop, ranging from 80 to 100 feet. West of the outcrop belt, the New Albany Shale is present everywhere beneath younger rocks.

Lineback (1970, p. 10) divided the outcrop New Albany Shale into five members, which in ascending order are: Blocher, Selmier, Morgan Trail, Camp Run, and Clegg Creek (fig. 2).

In the subsurface southwest of the Cincinnati Arch, the New Albany has been divided into the following units, in ascending order as follows:

Blocher Member

The Blocher Member of the New Albany consists mainly of brownish-black carbon-rich calcareous to dolomitic shale. On electric logs it is the high-resistivity unit in the lower part of the New Albany. This member

Blocher Member (con't)

has been mapped by Collinson and others (1967, p. 959) and Lineback (1970, p. 18).

Undifferentiated members

Unnamed units above the Blocher Member are composed predominantly of brownish-black and dark greenish-gray shales.

Hannibal Member

The name Hannibal is applied to a greenish-gray shale unit that lies between the top of the black shales that constitute the main part of the New Albany and the base of the Rockford Limestone.

The New Albany is slightly less than 100 feet thick in Harrison County and increases in thickness westward to about 300 feet in southwestern Indiana (fig. 3). Easily recognized in the subsurface, it is a very useful structural marker. A structural map (fig. 4) indicates that it lies at a depth of 4,000 feet below sea level in southwestern Indiana.

MICHIGAN BASIN

Another large area of black and gray shales that cen be correlated with the New Albany lies north of the Cincinnati Arch (fig. 1). These rocks are part of the Michigan Basin sequence and were continuous with the New Albany Shale before erosion removed Upper Devonian rocks from the crest of the Cincinnati Arch.

The New Albany equivalent formations in the Michigan Basin are, from oldest to youngest, Antrim Shale, Ellsworth Shale, and Sunbury Shale (fig. 2). These units reach their maximum thickness of 340 feet in Elkhart and Lagrange Counties and thin westward to 190 feet and eastward to 250 feet (fig. 3). From their subcrop beneath the glacial drift, these units dip northeastward to Steuben County, where they reach their lowest subsurface elevation of +275 feet. The Antrim, Ellsworth, and Sunbury are covered by thick glacial drift throughout northern Indiana. In Steuben and Lagrange Counties and part of Elkhart County, the New Albany equivalents are overlain by Mississippian rocks of younger age, specifically the Coldwater Shale.

The general stratigraphy of the New Albany

MICHIGAN BASIN (con't)

equivalents in the Michigan Basin portion of northern Indiana is as follows from oldest to youngest:

Antrim Shale

A black fissile shale containing spores, with some greenish-gray shale layers in the lower third of the unit. It ranges from 65 to 200 feet in thickness, reaching a maximum in Steuben County and thinning progressively westward.

Ellsworth Shale

The lower part consists of alternating beds of gray-green shale and black shale, and the number of black shale beds diminishes upward. The upper part consists of grayish-green shale with a few thin limestone or dolomite lenses. The Ellsworth ranges in thickness from 60 feet in Steuben County to 300 feet in Elkart County.

Sunbury Shale

A black shale less than 10 feet thick.

HARRISON COUNTY

Early History of Gas Use

Cox (1872, pp. 146-147) reported that a well bored to a depth of 1,050 feet at Corydon, Harrison Corydon, Harrison County for salt brine encountered small quantities of gas that would ignite and burn. In 1878, Collett (1879, p. 417) described gas springs in the bed of the Ohio River near Rosewood and Tobacco Landing.

Salt was very important to the eary settlers, but it was not always readily available. The need for salt prompted the pioneers to drill wells for salt water. Then, to evaporate the water, the gas associated with the salt water was used as a source of fuel. From this humble begining, Indiana had its first gas production from shale. As in some places the supply of gas exceed that needed for evaporation, and gas was also used as a fuel for other purposes.

First Commercial Production

Commercial gas production from the New Albany Shale has come from seven fields in

First Commercial Production (con't)

Harrison County, one field in Martin County and two small fields in Daviess County (fig. 5).

Between 1885 and 1925 seven gas fields were developed in Harrison County (fig. 5). After the discovery of the New Boston Field, gas was proped across the Ohio River to a gas field in Kentucy and, eventually, to Louisville.

The largest gas field, Laconia, was discovered in 1915 and had 106 gas wells. Completion depths averaged 700 feet, and the average initial daily production per well was 220,000 cubic feet (fig. 5).

Most of the gas production occus in a zone 15 to 30 feet into the New Albany. The effective pore space in the New Albany reservoirs probably consists of fractures and joints. The productive capacity of most wells is low, but the average life is about 20 years. Because the New Albany Shale yielded a large volume of salt water along with the gas, many wells could not be operated economically. They were, therefor, closed in or abandoned even though they were capable of producing 10,000 to 30,000 cubic feet daily.

MARTIN COUNTY

The Loogootee North gas field, discovered in 1902, produces from the New Albany Shale at a depth of 1,500 feet (fig. 5). Twelve gas wells with an average initial daily production of 780,000 cubic feet have been completed. The gas produced is sweet and has a BTU rating of about 980 (Sorgenfrei, 1952, p. 11).

All wells in this field have been shot with nitroglycerine, which has increased the gas production several fold. The gas occurs in the upper 50 feet of the New Albany, and salt water has been encountered in the lower part. The last few wells drilled in the field were completed in the upper part of the New Albany, but did not encounter salt water. As in the fields in Harrison County, the effective pore space in the New Albany in Martin County probably consists of fractures and joints. At one time, the field furnished a local brick and

MARTIN COUNTY (con't)

tile factory with about 750,000 cubic feet of gas daily. Now all but one well has been abandoned.

DAVIESS COUNTY

Two small gas fields have been found in the New Albany in Daviess County (fig. 5). Both are one-well fields. Glendale, discovered in 1940, has been abandoned, but Branble, a 1974 discovery, is still active.

OIL FROM THE NEW ALBANY SHALE

It has long been recognized that the New Albany Shale, when heated, yields a little oil and gas (Duden, 1897, p. 109; Ashley, 1917, p. 319; Reeves, 1922, p. 1093). The analyses by Reeves indicated that the New Albany yielded from 6 to 14 gallons of oil per ton (p. 1092-1093).

The Geochemistry Section of the Indiana Geological Survey has some unpublished data on oil yields from the New Albany Shale. Samples collected from the Standard Materials Quarry, T. 3 N., R. 9 E., Jefferson County, and from the Berry Materials Quarry, T. 6 N., R. 8 E., Jennings County, and analyzed by the Geochemistry Section indicated oil yields ranging from 2.4 to 9.1 gallons of oil per ton of shale. A core sample of New Albany Shale from Indiana Geological Survey drill hole 99, sec. 28, T. 27 N., R. 7 W., Jasper County, was analyzed by the Laramie Petroleum Research Center, Laramie, Wyoming. The oil yield in that sample ranged between 0.2 and 5.1 gallons of oil per ton of shale.

AVAILABILITY OF DATA

The Indiana Geological Survey in Bloomington has geologic information for most of the tests holes drilled to the New Albany. This information includes driller's logs, geophysical logs, drill cuttings, cores, and scout tickets. There are 1,775 drill cuttings, 60 cores, and about 800 geophysical logs for the estimated 2,300 wells that have penetrated the New Albany. This information can be of great value in understanding and evaluating the black shale in Indiana.

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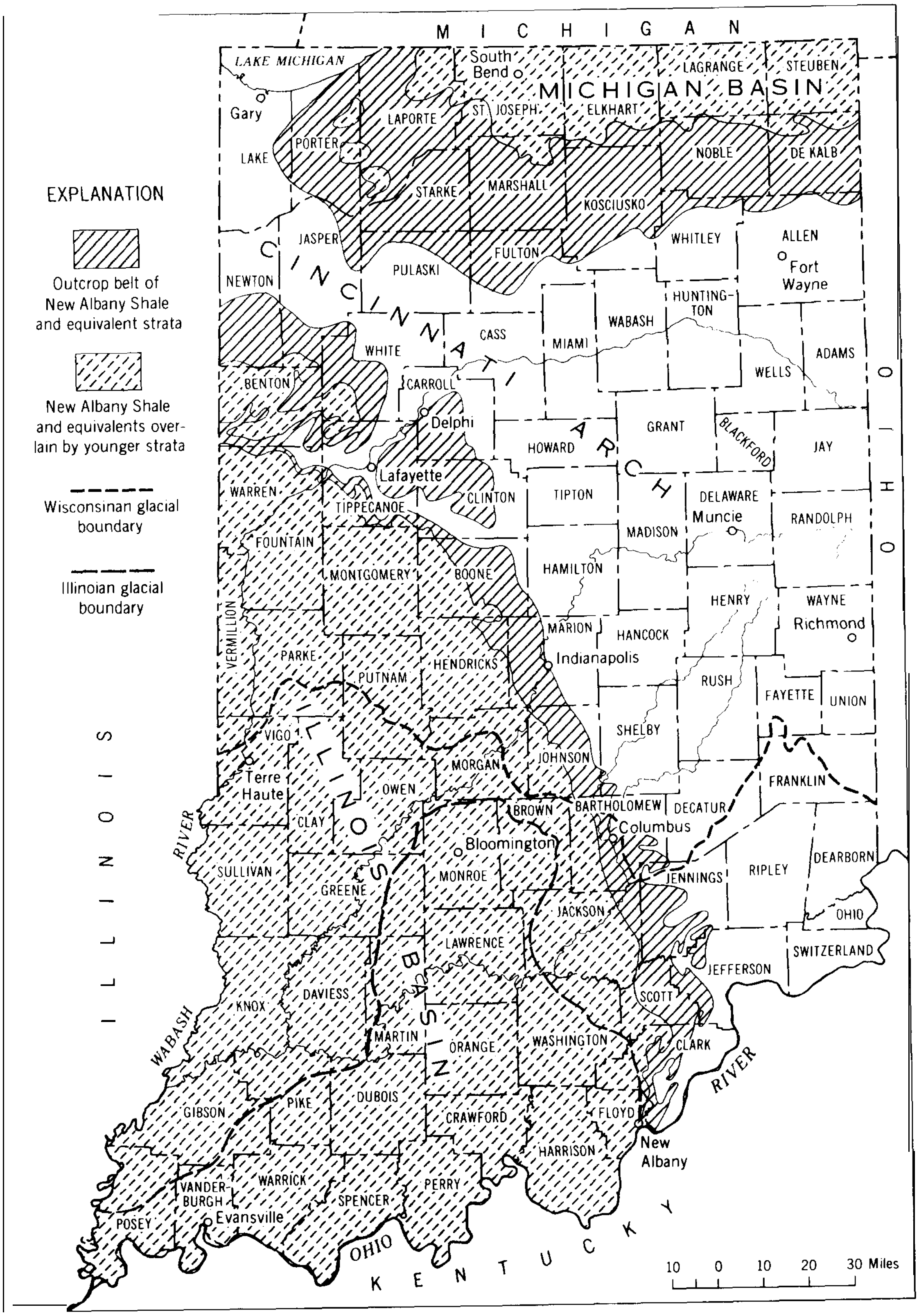


Figure 1. Map of Indiana showing distribution of the New Albany Shale and equivalent strata. Geology from Indiana Geological Survey Atlas Map 9, 1956. From Lineback, 1970.

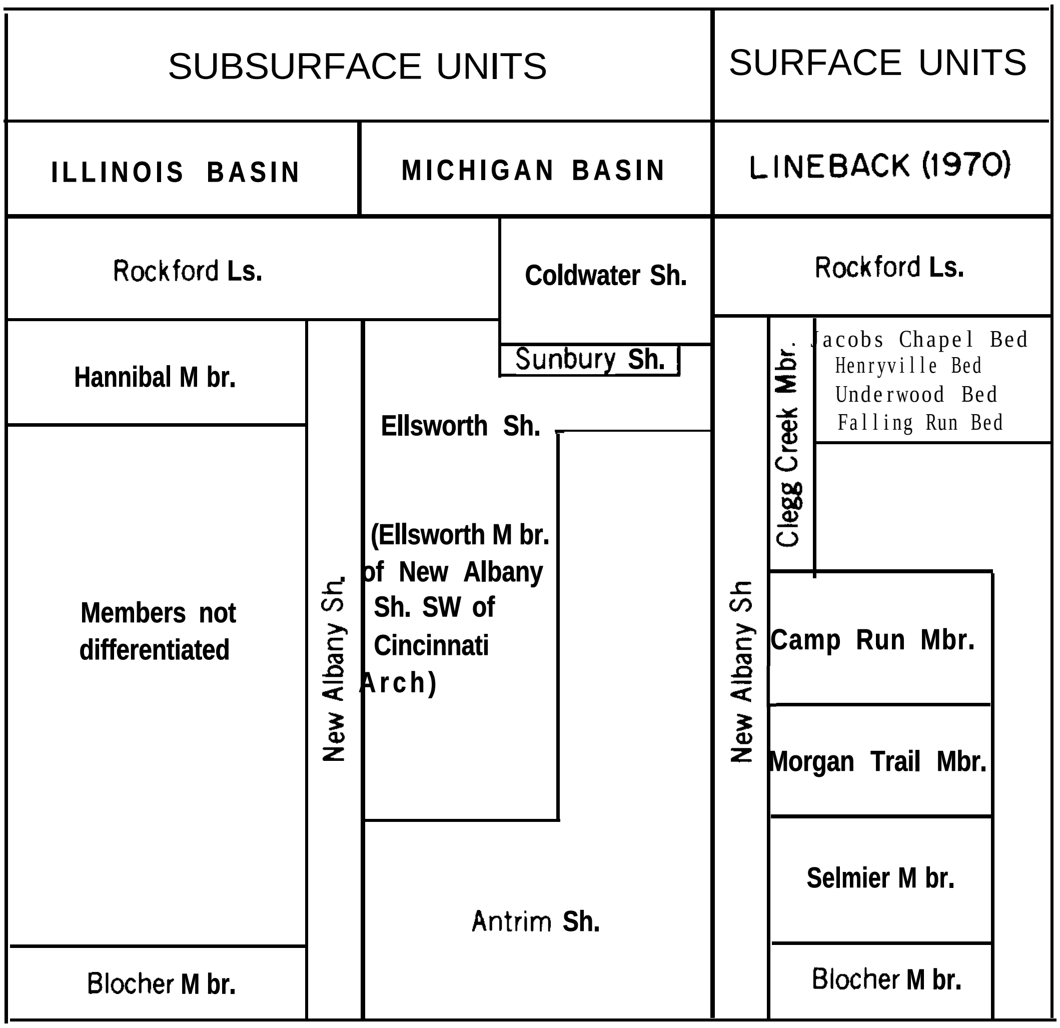


Figure 2. Correlation of the New Albany Shale.

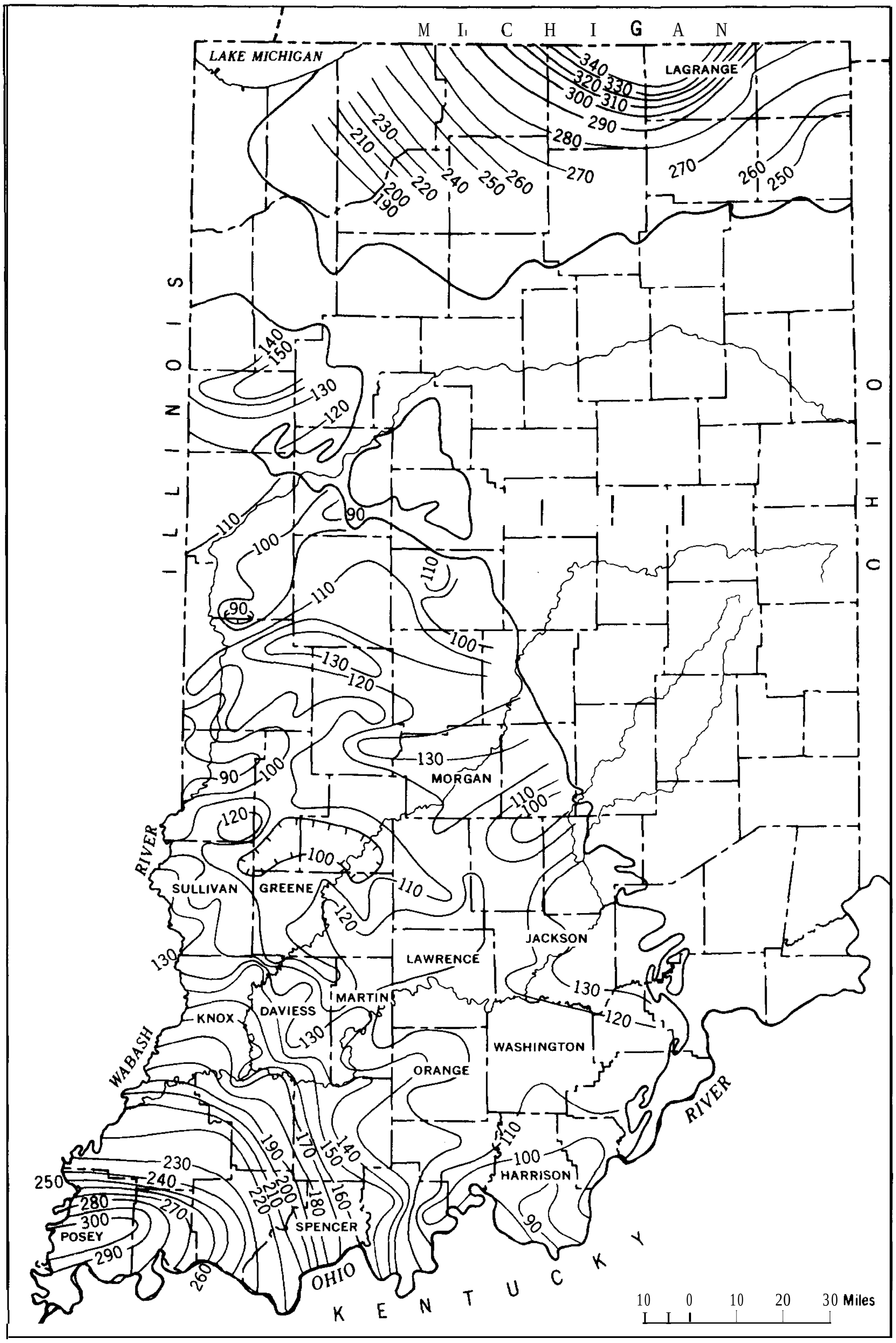


Figure 3. Isopach map showing thickness of the New Albany Shale and equivalent strata. Contour interval 10 feet. From Lineback, 1970.

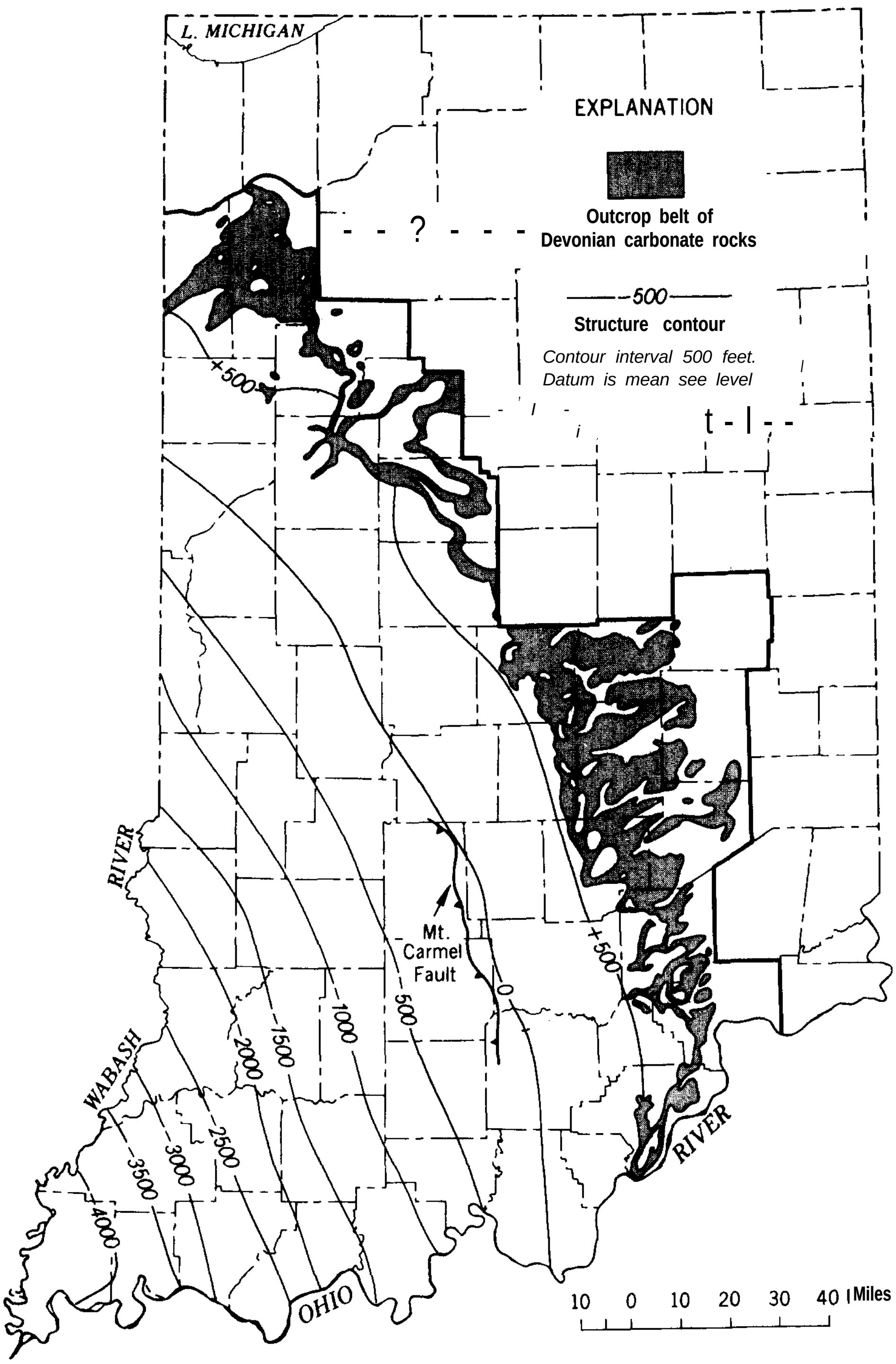


Figure 4. Map showing structure on base of the New Albany **Shale.**
From Becker, 1974.

No.	County	Field name	Discovery year	Number of wells	Average initial production	Average depth	Present status 1975
1	Daviess	Bramble	1974	1	250MCF/24	1,700	Active
2	Daviess	Glendale	1940	1	750MCF/24	2,100	Abandoned
3	Harrison	Corydon	1923	15	11 0MCF/24	800	80% Abandoned
4	Harrison	Elizabeth	1925	1	Gas	750	Abandoned
5	Harrison	Laconia	1915	106	220MCF/24	700	95% Abandoned
6	Harrison	New Boston	1885	13	245MCF/24	450	60% Abandoned
7	Harrison	New Middletown	1923	26	120MCF/24	750	65% Abandoned
8	Harrison	Rosewood	189.5	21	225MCF/24	300	90% Abandoned
9	Harrison	Rosewood North		4	Gas	300	Abandoned
10	Martin	Loogootee North	1902	12	780MCF/24	1,500	92% Abandoned

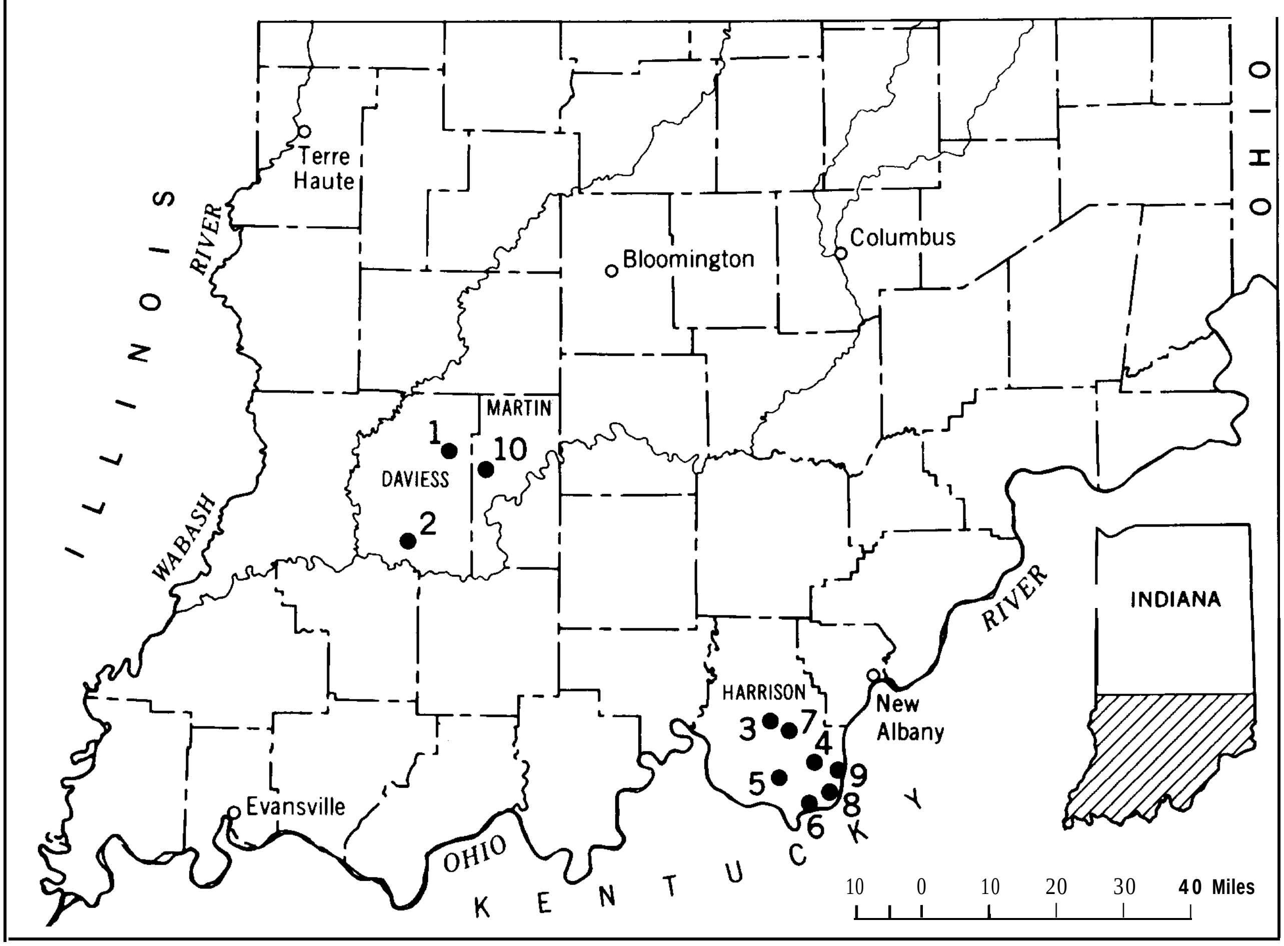


Figure 5. Map showing locations of gas fields producing from the New Albany Shale.

STIMULATION OF THE DEVONIAN SHALE

J. L. Norton - Dowell

The following paper is devoted to the techniques which have worked in different areas in the past, to some factors which affect shale stimulation, and to possible future techniques.

METHODS OF STIMULATION

1. SHOOTING: This method has been used successfully for years to stimulate shale production. However, this is generally a well bore type treatment with very small horizontal penetration into the zone.

2. WATER FRACTURING: This method has been used successfully for the past ten to fifteen years.

3. GAS FRAC: This method has had only limited use, but is being considered since it is not a water based fluid.

4. METHANOL FRAC: To improve water recovery 30% methanol has been used in the frac fluid.

5. FOAM FRAC: This is a relatively new technique which replaced 75% of the water in the fracture with nitrogen.

TYPICAL CORE ANALYSIS

The chart which follows gives the general parameters for the shale whenever it is encountered. The composition will vary somewhat from area to area; however, illite is generally the main clay mineral, with varying amounts of kaolinite, chlorite and, only rarely, montmorilinite. The porosity and permeability are extremely low as indicated.

Table I

TYPICAL CORE ANALYSIS

SAMPLE DEPTH (FEET)	PERMEABILITY	POROSITY
3737-42	Less than 0.01	1.8
3815-19	Less than 0.01	1.7
3819-23	Less than 0.01	1.5
3814-23 (stringer)	Less than 0.01	2.0

BASIC ASSUMPTION

From the table above and prior experience, we can then make two basic assumptions concerning the stimulation of the Devonian Shale: Production is from natural fractures and water is detrimental to the shale.

The extremely low porosities and permeabilities would not permit economical production. Natural fractures are the only way to explain production. Wells with good natural shows have probably been drilled through highly fractured zones, allowing a good gas flow to the well bore. These fractures are probably the longer, open interconnected natural fractures. Wells in approximately the same area with poorer shows do not have the natural fracture development nor fracture density.

The purpose of stimulation then, is to connect as many natural fractures as possible to the well bore by means of an induced hydraulic fracture.

The natural fractures are essential for production, but they reduce the effectiveness of inducing hydraulic fractures. Fluid is lost at a high rate as induced fractures intersect natural fractures. Many of the natural fractures are too small to accept sand, so as frac fluid is lost, the sand concentration is increased in the induced fractures. By intersecting enough natural fractures the fluid loss would be so high that a screen out would occur in the induced fracture. This fluid loss must be controlled to insure adequate penetration for proper stimulation. The conventional methods for fluid loss control

BASIC ASSUMPTION (con't)

do not function properly in the fractured Devonian Shale. Normal fluid loss materials are too small to bridge most natural fractures. Increasing the viscosity will not effectively control the loss to fractures either.

FLUID LOSS CONTROL

The use of 80/100 sand apparently functions quite well in the fracture situation. The sand is large enough to bridge small fractures to reduce the movement of fluid to them. Sand will probably move into some of the fractures prior to bridging, which will tend to prop these natrual fractures during production. This is an advantage of 80/100 sand over conventional fluid loss additives; it has conductivity. Also, the 80/100 sand will be carried further down the induced fracture before settling out. The conductivity is less than 20/40, but is still adequate to allow gas production. The result is longer proped fractures than those occurring with conventional treatment.

Horizontal penetration can be greatly improved. The fluid normally lost into a natural fracture during the normal frac job reduces the penetration.

80/100 sand will reduce the amount of fluid normally lost to the intersected fractures, and will remain in the induced fracture to effectively lengthen the penetration.

The second basic assumption mentioned above is that water is detrimental to the shale stability.

There is laboratory data which shows that shale is affected by different water-base fluids. Shales exposed to water in a well bore will often heave and slough. The same reaction can cause problems within the induced fracture. As fracture faces are exposed to water for long periods of time, sloughing can occur which could plug the fracture porosity.

Table II

TYPICAL COMPOSITION		
X-RAY DISTRACTION ANALYSIS		
SAMPLE (DEPTH)	MAJOR (25-100%)	LOW (less than 15%)
3815-19	Quartz	Kaolinite, Illite, Goethite, Orthoclase, Calcite
3815-23 (stringer)	Quartz	Kaolinite, Illite, Anhydrite, Orthoclase, Goethite, Calcite

The table above shows that clays make up a good portion of the shale. Illite, Chlorite, and Kwolinite are the major clay minerals. These minerals are the so called "Non-swelling" clays. They actually do swell when contacted by fresh water, but the swelling is not as pronounced as in montmorilinite.

Table III

FORMATION	% CLAY	% IRON
Berea	2-15%	2.5
Benson	2-8%	2.1
Devonian Shale	10-50%	1.3
Clinton	2-11%	1.3
Injun	2-11%	1.8
Oriskany	3-3%	1.2

This table shows a comparison of percent of clay and iron in different formations. The amount of true clay in the shale is nearly always higher than either sandstone or limestone.

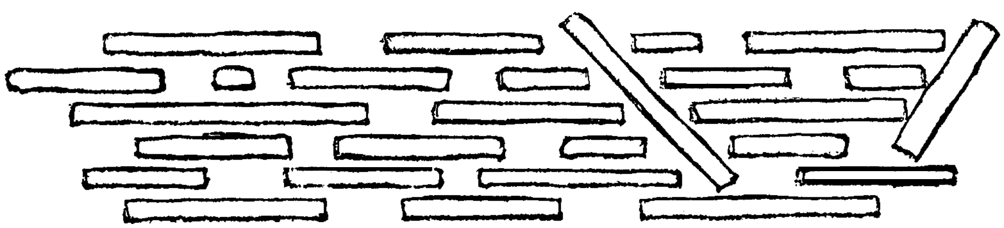
Clay migration has long been recognized as a problem; however, the mechanism which triggers it is not wholly understood.

CLAY DISPERSION THEORY

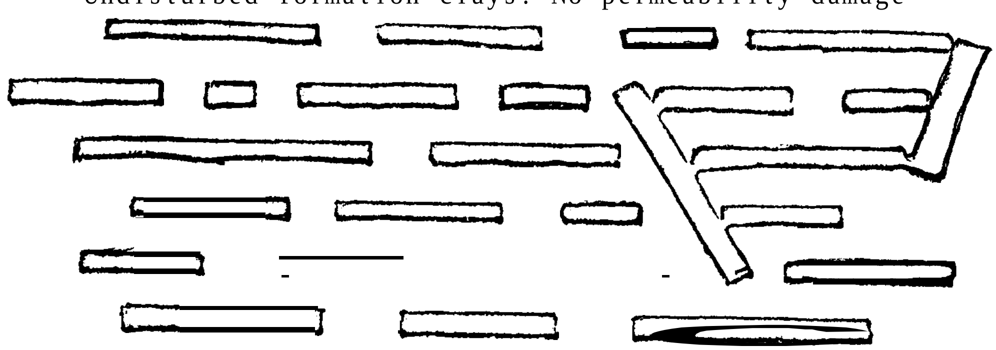
Here are just a few of the people who have done considerable work on particle migration.

YEAR	AUTHOR	COMPANY
1950	P. H. Monaghan, et al.	Exxon
1960	G. O. Bernard, et al.	Pure
1963	G. H. Hewitt	Marathon
1964	T. O. Jones	Amoco
1965	N. Mugan	Atlantic Richfield
1966	D. H. Gray, et al.	Univ. of California
1967	H. C. H. Darley	Shell

Jones found, for example, that by maintaining a certain ratio of Ca ions to Na ions in test brines, he could control clay damage. Murrgan found that even in constant salt concentrations small changes in pH could drastically affect clay dispersion. Nearly all the studies concluded that, regardless of the reason, clay dispersion and migration could cause severe permeability reduction.



Undisturbed formation clays. No permeability damage



Water swollen clays.

Figure 1

Figure 1 illustrates what happens when water contacts even supposedly "Non-swelling" clays. Due to the chemical imperfections in its make-up, each clay platelet exhibits a net negative charge which tends to repel other adjacent platelets. Each platelet is surrounded by an atmosphere of cations. These positive charges neutralize the negative charge of the platelets and maintain the platelets in electrostatic equilibrium. The greater the number of positive charges, the closer the platelets will be held together or the more compact the clay particles will be.

PERMEABILITY DAMAGE AFTER PARTICLE MIGRATION

Once clay particles have been dispersed in the formation fluids, they are capable of moving into the permeability during production, and may create a log jam effect in the pore space.

Permeability or fracture damage can be prevented by stabilizing clay particles to prevent dispersion. This can be done with a strong cationic material. The monovalent cations sodium and potassium have charges of +1 and provide a minimum stabilizing influence on clay particles.

The divalent cations, such as calcium and magnesium have a charge of +2. Such divalent cations are not just two times stronger than monovalent cations as stabilizing agents; they are several times stronger since the attraction between cations and clay particles increases exponentially as the charge of the ion.

The hydrolyzable metal ions zirconium and titanium have valences of +4 and +3, respectively. Because of the exponential relationship, they would be expected to be 30-60 times as strong as the monovalent ions in stabilizing clays. However, these material form polynuclear ions in aqueous solutions and perform as ions of much higher charge.

Monovalent Cations

Na^+ K^+ Li^+

Divalent Cations

Ca^{++} Mg^{++} Ba^{++}

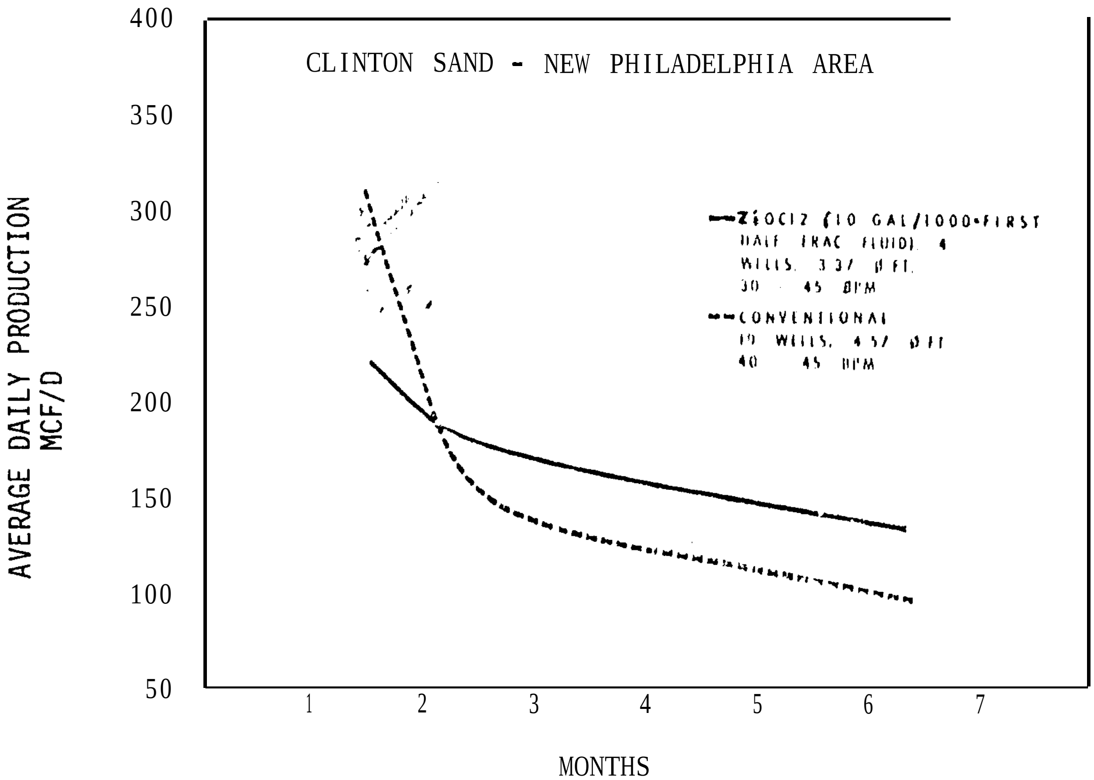
Hydrolyzable Metal Cations

Zr^{++++} Ti tttt

Hydroxyl bridges form between the zirconium ions creating a structure called a polynuclear ion which has a charge of +20. This form of the ion is only an average. Polynuclear zirconium ions have been formed with measured charges as high as +40. Due to this high positive charge, this ion is millions of times stronger as a clay stabilizer than calcium ions with a +2 charge.

FIELD RESULTS ON CLINTON

AVERAGE PRODUCTION COMPARISON



Laboratory studies have shown the effectiveness of zirconium ion as a clay stabilizing agent. The graph above represents field data from the Clinton in Ohio, using Dowell's L-42 (Zirconium ion) as the stabilizing agent. Since the shale contains as much or more clay as the Clinton, this material has an application in water base treatment in the shale.

ADVANTAGES OF L-42

1. It stabilizes all varieties of clay immediately on contact.

2. Stabilization is permanent, natural formation fluids will not effect or remove it.

3. It can be used in a wide range of fluids including acid.

4. It is simple to apply.

LIQUID RETENTION

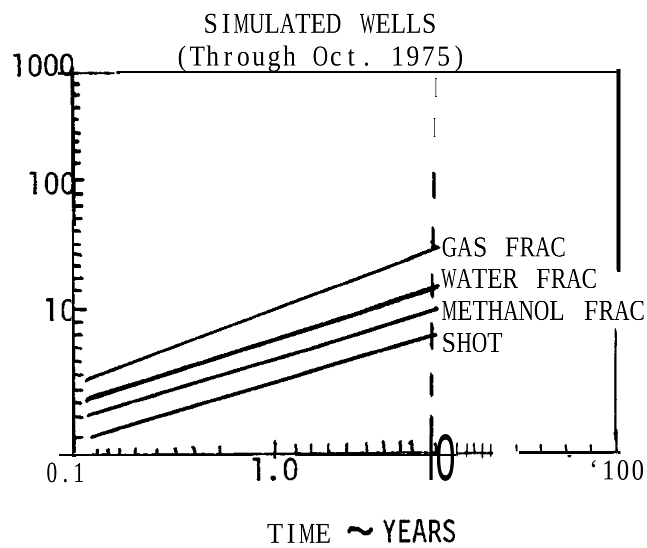
The small hairline fractures present in the shale can act like capillaries similar to permeability in sandstones. Water retained by this method can reduce the relative permeability to gas. The use of Methanol has worked well in quick removal of water by lowering the surface tension.

DOWELL SURFACTANT F-75

Surfactants have also functioned quite well in this capacity. A new material (F-75) introduced recently can lower the surface tension of water below that of 30% Methanol.

1. Reduces surface tension 8-12 Dynes/CM lower than any other surfactants.

2. Provides lowest surface tension even for aqueous stimulation fluids.



This graph shows a comparison of shale wells which are stimulated by various methods. Included are (7-10) shot wells, (4-6) Methanol Fracs, and (2) Gas Fracs. After two years the Gas Frac's wells are 30%+ higher than the other type treatments. The Gas Fracs were smaller volumes and rate than the conventional Water Fracs. This is a good indication that water is detrimental to the shale.

POSSIBLE FUTURE TECHNIQUES

Foam Frac is a step in the right direction. The water phase of the frac fluid is reduced by replacing it with N_2 and a surfactant which creates a foam. By reducing the amount of water, its effect on the formation

POSSIBLE FUTURE TECHNIQUES (con't)

should be reduced. Although the initial results to date have not been as good as anticipated, this is a technique which has high potential in the future.

Water Frac has been used effectively in the past and will be used in the future. By improving the additives and techniques the results should improve.

Massive Frac is being used successfully in other areas and should have application in the shale.

Gas Frac has been proven to be an effective stimulation technique and, as economics improve, Gas Frac or a similar technique should have application.

CONCLUSIONS

1. Devonian can be effectively stimulated.

2. Large volumes should provide deeper penetrations and more extensive drainage network.

3. Fluid loss of frac fluid must be controlled. 100 mesh sand should be beneficial.

4. Clay control agents (Heavy metal ions) should be used in water base fluids, including foam.

5. Experience will help determine the best frac fluid.

EFFECT OF IN SITU STRESS ON INDUCED FRACTURES

William K. Overbey, Jr.- E.R.D.A.

Morgantown Energy Research Center

ABSTRACT

The Morgantown Energy Research Center, Petroleum and Natural Gas Extraction Research Group of the United States Energy Research and Development Administration (formerly the Bureau of Mines) has been involved in field and laboratory studies since 1966 to learn as much as possible about fracture systems in the earth's crust, and how these fractures can be utilized to improve fossil fuels extraction processes. From existing theory we built a larger theory base and postulated several hypotheses that we set out systematically to test. We have successfully demonstrated that a definite relationship exists between surface rock jointing, the principal compressive stress orientation, deeper fractures in petroleum and natural gas reservoirs, and the direction of induced hydraulic fracturing. This relationship seems to hold true in gently folded rocks but has not been tested in strongly folded rocks. This led to the postulation that fracture orientation could be predicted for rather large geologic regions with scattered test results. With this orientation data we have been conducting tests to determine the length of hydraulic fractures, and have initiated a program of drilling wells deviated in a selected direction so as to cross the maximum number of natural fractures in the reservoir, thus improving production. We are also testing the inducing of multiple stages of hydraulic fracturing from the inclined borehole to improve oil and gas production. We expect to continue these studies and ultimately to develop tools and techniques which will allow us to

ABSTRACT (con't)

measure deep stresses and then to alter them to improve oil and gas production from highly fractured reservoirs.

INTRODUCTION

Earth scientists have long been aware that the earth is extensively and complexly fractured, and that many of these fractures were once conduits for mineral-laden fluids. Most mineral ores are associated with fractures which have a particular orientation as a result of a given set of stresses. Thus, mining operations are often controlled by the orientation of the ore-filled fractures.

Similarly, faults and fractures in hydrocarbon-producing horizons have, almost from the beginning of the industry, been recognized as factors affecting hydrocarbon migration, accumulation, and production. This is particularly true of carbonate and less permeable sandstone and shale reservoirs. Efforts to determine the nature and extent of these subsurface fracture systems and their importance in determining hydrocarbon reserves and reservoir fluid flow during production, commonly have not been very successful.

The Petroleum and Natural Gas Extraction Research Group of the Morgantown Energy Research Center of the United States Energy Research and Development Administration (formerly Bureau of Mines, Department of Interior) since 1967 has been conducting investigations to determine the following: (1) the mechanisms that generate fracture systems, (2) the relationships of fractures to petroleum accumulations, (3) techniques for mapping zones of intense fracturing, (4) the relationships of the azimuths of hydraulically induced fractures to these systems, (5) the lateral extent and geometry of hydraulic fractures, (6) the dynamics of the rock-fluid system during fluid injection operations, and (7) various patterns of well spacing and methods of well drilling which will maximize the efficiency of oil and gas production and of gas storage reservoirs.

SCOPE OF INVESTIGATIONS

Research is being conducted on various methods for mapping fractures or linear features on various types of remote sensing imagery for correlation with surface stress measurements and oriented core directional physical property measurements, the general purpose of which is to predict the orientation of hydraulically induced fractures in several structural domains within a petroliferous basin, primarily in the plateau and gently folded belts. This information can then be applied to any of several fossil fuel extraction processes such as oil and gas produciton, methane drainage from coal mines in advance of mining, coal mining operations to prevent roof falls, underground gasification of coal, in situ retorting of oil shales, and production of gas from gas shales (Devonian Brown Shales).

The scale of these investigations ranges from the microscopic to the macroscopic. Most of the parameters that may influence the directional properties of reservoir rocks are being studied. Field observation data relating to the orientation of surface elements such as joint strike measurements and in situ stress measurements (obtained from the study of lineaments on satellite imagery, aerial photography, and side-look radar imagery) are believed to represent the total elastic anisotropic reaction of the surface rocks investigated to various tectonic forces and stress fields acting throughout the geologic past, and the effects of those fields and forces on gross surface textural or topographic features.

Correlated data are used to determine the parameters which should control the orientation of induced fractures in the study area, and to determine what techniques might be applied to overcome certain oil and gas production problems or coal mining problems, or other fossil fuel extraction problems. These techniques are being used to project the effects of in situ stresses without being able to measure and orient them at depth.

THEORY

The outer layers of the earth's crust are composed of rocks which, when stressed, commonly fail by fracturing. Thus, the earth's crust is rather extensively fractured very near the surface (upper 5000 feet). A fracture, by our definition is a geologic feature having a unique genetic origin related to a particular structural condition of stress and resultant strain. It usually represents a discrete break in the rock layers of the earth's crust. Faults and joints are common types or fractures most often mapped by earth scientists.

I would suggest that there are two major classes of fractures according to genetic origin. These are (1) exogenous--which have their origin on the surface of the earth and are propagated downward, and (2) endogenous--which have their origin within the crust and are propagated upwards toward the surface. Most joint swarms, and most faults are examples of endogenous fractures. One can argue very strongly for still a third class which I would call reactivated. These are fractures which may have originally been exogenous in origin but because of subsequent burial and later reactivation are propagated toward the surface and may have the appearance of endogenous fractures.

Since fractures are generated as a result of a particular set of stress conditions (usually regional in nature), a large number of fractures could result from a single orogenic event or causitive stress. Laboratory studies long ago demonstrated that three types of fractures result from compressive stresses. They are (1) compressional (extensional or parallel to the principal compressive stress), (2) tensional (oriented normal to the principal compressive stress), and (3) shear (generally found at angles of 28^{o} to 45^{o} on either side of the compressive stress orientation).

WORKING HYPOTHESIS

From an extensive search of the literature on jointing and fracturing, we were able to make the following observations:

WORKING HYPOTHESIS (con't)

(1) Surface rocks are jointed systematically and nonsystematically.

(2) Joints may be formed as a result of forces produced by compression, tension, shear, fatigue, dessication, heating, and cooling.

(3) There is less variation in corn-pass orientation of joints in fine-grained rocks than coarse-grained rocks.

(4) Joints may be opened or filled with clay or chemical cements.

(5) Open joints in rocks may be encountered at depths to hundreds or thousands of feet in areas where the internal pore pressure approaches the minimum field stress of the rock.

(6) Most sedimentary rocks have an internal fabric orientation resulting from the mode of deposition of the fock.

From these observations, we made the following postulations which form the basic working hypothesis we have been testing.

Most of the systematic joints found in rocks result from regional and worldwide stresses. The stress field has changed orientation during the geologic past, producing several well-developed joint trends in most areas. Vertical hydraulically induced wellbore fractures will be oriented in a direction which represents the path of least resistance. This means that the fracture orientation will be parallel to the principal horizontal compressive stress, or normal to the axis of minimum field stress of the rock. In the absence of a fairly strong horizontal component of the stress field, the internal rock fabric orientation (anisotropy), as it contributes to the directional tensile strength properties of the rock, will be the prime controller of the induced fracture orientation. The directional tensile strength properties are controlled by the structural, stratigraphic, and sedimentrological aspects of the rock's geologic history.

Some hydraulic fractures may exit the wellbore following an open oil joint trend, but as the propagating fluid meets resistance, the direction of propagation will change to an orientation which is parallel to the

WORKING HYPOTHESIS (con't)

principal horizontal stress direction and normal to the axis of least horizontal stress.

Surface joint and other textural features such as stream segments, valleys, and ridges indicate directions of potential planes of weakness and can be analyzed and correlated with surface stress measurements to indicate the possible indigenous fracture pattern in a hydrocarbon reservoir and the most likely orientation of induced hydraulic fractures.

RESULTS OF INVESTIGATIONS

In 1967, we started work to relate jointing to the orientation of hydraulic fractures for prediction purposes. Results of our first field study conducted in the area of the Bradford Oil Field, near Bradford, Pennsylvania, showed a very definite correlation between a surface joint set and the direction of the induced hydraulic fracturing (fig. 1).

In our second field study, conducted in the area of the Logan Oil Filed and the Laurel Gas Storage Field in Hocking County, Ohio, we began measuring surface rock stress orientation to confirm the relationship between joint orientation and induced hydraulic fracturing. In the Laurel Gas Field, we were able to obtain an oriented core, and found good trend correlation between fractures mapped from the oriented core, a surface joint set, linear trends mapped on aerial photos, and the direction of induced hydraulic fracturing.

As shown in Figure 2, these stress orientations made in a shallow outcropping sandstone correlated very well with the direction of induced hydraulic fracturing and the trend of oriented core fractures obtained from the Clinton sand at 3000 feet in depth. Hubbert and Willis (1957), Kehle (1964) and Dunlap (1968) published papers on the relationship of tectonic stress to the orientation of hydraulic fractures. Komar (1972) confirmed this work in the laboratory and examined stress ratios between maximum principle stress and least principle stress.

RESULTS OF INVESTIGATIONS - (con't)

As shown in Figure 3 and according to existing theory, hydraulic fractures are induced parallel to the maximum principle stress orientation in the earth and normal or nearly perpendicular to the orientation of the least principle stress axis. As illustrated in Figure 4, from Komar's report, when the difference between the two horizontal components of the stress field is in the neighborhood of 50 to 150 pounds per square inch, there is some variation in the orientation of the induced hydraulic fractures; whereas, when the difference between the stresses is nearly 1:3 or greater than 200 psi, the orientation in the fracture is fairly well controlled by the direction of the principle stress orientation.

The effects of stress on hydraulic fracture orientation is shown in Figure 5. In the upper part of the illustration there is a large difference between the two components of the stress field, and the orientation is strongly controlled by the larger stress orientation. In the bottom part of the illustration, the stress levels are about equal and the fracture has been induced in a direction other than that which might be dictated by the dominant jointing direction.

Figure 6 is a postulated fracture system developed after hydraulic fracturing in an area in which the stress ratios are near unity. I would conclude that the magnitude of the stress field components will determine whether or not a fracture is induced in a particular direction, or whether it will follow the natural planes of weakness that are available to dissipate hydraulic energy.

After our initial success in measuring the stress and correlating it with direction of induced hydraulic fracturing in Hocking County, Ohio, stress measurements were made in a number of areas in Ohio and compared with surface jointing trends, as illustrated in Figure 7. The results of stress measurements made over a period of seven years are depicted in Figure 8. The measurement location, principle stress

RESULTS OF INVESTIGATIONS (con't)

orientation, and the method of obtaining those measurements depicted in Figure 8 are shown in Table 1. The results indicated that surface jointing can be used to predict the orientation of hydraulically induced fractures and that these orientations would appear to remain fairly constant over a wide area.

Although we have made a number of measurements throughout the Appalachian area, we are still not quite certain of the entire significance of these measurements and the interaction of all the different mechanisms which have combined to produce fractures throughout the sedimentary column which might affect the ultimate orientation or the present orientation of induced hydraulic fracturing. I would interpret the nearly east-west orientation of most of the stress measurements in the Appalachian area as being related to rather large regional east-west oriented lateral stresses that are perhaps related to the movement of the Atlantic oceanic plate away from the mid-Atlantic ridge and beneath the eastern U.S. continental plate.

Thus, in recent years, we have collected data which have indicated that orientation of subsurface fractures is related to fractures which can be measured on the surface. Also, there appears to be no great rotation of the stress field or the direction of induced hydraulic fracturing with depth in the gently folded plateau region of the Appalachian Basin. However, data collected during the past year from cores taken from the Devonian Shale section in Kentucy, West Virginia, and Ohio indicate that there are certain zones in which there are a plurality of fractures, and that all of the fractures appear to be open. Therefore, it is quite difficult to ascertain from surface measurements which fracture direction might be related to the direction of induced hydraulic fracture or the principle stress direction in all cases. For this reason, it now is apparent that a technique must be developed which would measure magnitude and orientation of the stress field at depth in oil and gas wells.

MECHANISTIC THEORY

In trying to fully ascertain the effects of stress orientation on induced hydraulic fracturing, particularly as related to the Devonian Shale, it became necessary to evaluate the various mechanism which may have generated fractures in the shale. I have proposed that there are three basic mechanisms (or combinations of these three) which may have generated the fractures in the Devonian Shale. The first model is a model produced by deep-seated basement faulting and periodic reactivation of these faults. Model 1 (fig. 9) illustrates the type of fracture which may be present in the Cottageville Gas Field, Jackson County, West Virginia. Periodic reactivation and movement of Precambrian and Cambrian fault zones has produced fracturing which would probably have propagated upwards into the Devonian Shale. Model 2 (fig. 10) illustrates fractures generated by low angle thrust faulting during the upper Paleozoic Appalachian deformation. For instance, fracturing of this type should be found above and in front of the Pine Mountain thrust sheet in southwestern Virginia and eastern Kentucky. Model 3 (fig. 11) I call the litho-stratigraphic dilatency model. Fractures found in the shale in this case are generally the result of uplift produced by erosion at the surface. The bottom of the illustration shows two zones in the shale section which have more fractures and the property of being somewhat more brittle than the adjacent units. As erosion removes approximately 2000 feet of overburden, many additional fractures form in the same zone as a result of the volume increase caused by the reduction of overburden pressure and the resultant crustal uplift. There are clues as to how we might explore for fractures or fractured reservoirs created by the mechanisms illustrated in Models 1 and 2; yet, a new technique will have to be developed to explore for high densities of fractures generated by the mechanisms in Model 3.

In trying to make regional interpretations regarding the significance of the stress orientation measurements made during the past seven years, it becomes necessary to know exactly how stress trajectories react when crossing structures, and the effect of the rotation of principle stress during the last seventy-five million years of continental drift associated with the opening of the Atlantic Ocean. As illustrated in Figure 12, the original Paleozoic stress orientation σ_{1O} was normal to the anticlinal and synclinal axes shown. However, the present stress orientation is a function of continental drift; that stress is at an angle to the axes of the anticlinal structures. The present stress direction is indicated by the direction of σ_{1P}. The significance here is that the shear fracture trends which were established and related to the original Paleozoic stress orientation and which produced the anticlines and synclines in this region are now parallel to the present extension stress orientation. The combined effect of Paleozoic fracture trends and present day stress orientation could induce hydraulic fractures askew to the trend of the Paleozoic fracture axis of the anticlines or synclines.

According to stress analysists, the stress trajectory of Model 2 (fig. 13) does not occur. However, I am not completely convinced that the situation cannot or does not exist within the Appalachian area. Figure 13 illustrates a drastic change in the stress trajectory approaching the axis of anticlines or synclines. The dominant mode of failure is tensile failure along the axis of the structure. If this is the case, then we might expect to see changes in the stress trajectory as we cross the Rome trough.

Figure 14 shows the structure of the Precambrian basin rock in parts of the Appalachian area as mapped by Harris (USGS) in 1975. Harris has projected a continuation of the Rome trough in approximately a North 45° East direction across most of West Virginia into Pennsylvania. A postulation of stress trajectories in the Appalachian area based on the few measurements made by ERDA is illustrated in Figure 15. Postulated trajectories show a generally North 50° to 40° East trend following the Rome trough in Kentucky, through West Virginia and into Pennsylvania. If the North 70° to 90°

MECHANISTIC THEORY (con't)

East stress trajectories of eastern West Virginia turn and head North 40° East in the Rome trough as illustrated, then this would have considerable impact upon the types of operations that are conducted in oil and gas fields in this region, not only on types of exploration techniques such as directional drilling, but also on most other extraction techniques.

It is quite interesting to note that the bulk of the oil and gas production which occurs in the Appalachian region generally follows a trend outlined by the east stress trajectories from eastern Kentucky into north-central Pennsylvania. This is true particularly for production from Devonian age shales and sandstones. It is quite possible that periodic or episodic movement and rejuvination of old fractures or fault planes in this region may have had some minor effect upon the depositional patterns throughout the Devonian. Perhaps we can resolve this problem in the future by making a series of stress measurements across the Rome trough and in other areas of Pennsylvania, West Virginia and Ohio where stress trajectories have not been determined.

The possible effects of stress orientation on Devonian shale gas production is illustrated in Figure 16 where the normal spacing of approximately one hundred and sixty acres is shown for shale wells. The usual spacing which is done without regard to stress orientation is shown in the top part of the illustration; whereas, the bottom shows spacing which is double the usual in the direction parallel to the principle stress orientation. The wells are spaced considerably closer in the direction parallel to the minimum principle stress or the intermediate principle stress. Spacing utilizing stress relationships should not produce any significant interference in the production between the wells; and, it may be a more efficient pattern for drilling shale wells.

It has been found that the rate and pressure at which fluids are injected into wells will determine whether they follow

MECHANISTIC THEORY (con't)

natural fractures or whether they create new fractures in the reservoir. High pressures and high flow rates will promote the break down of the formation as dictated by the in situ stress field, while lower pressures and rates may allow the fluids to seek the paths of least resistance (natural fractures). Thus, the well patterns and spacing are important to the economical and conservational aspects of secondary recovery of oil presently, and natural gas in the future.

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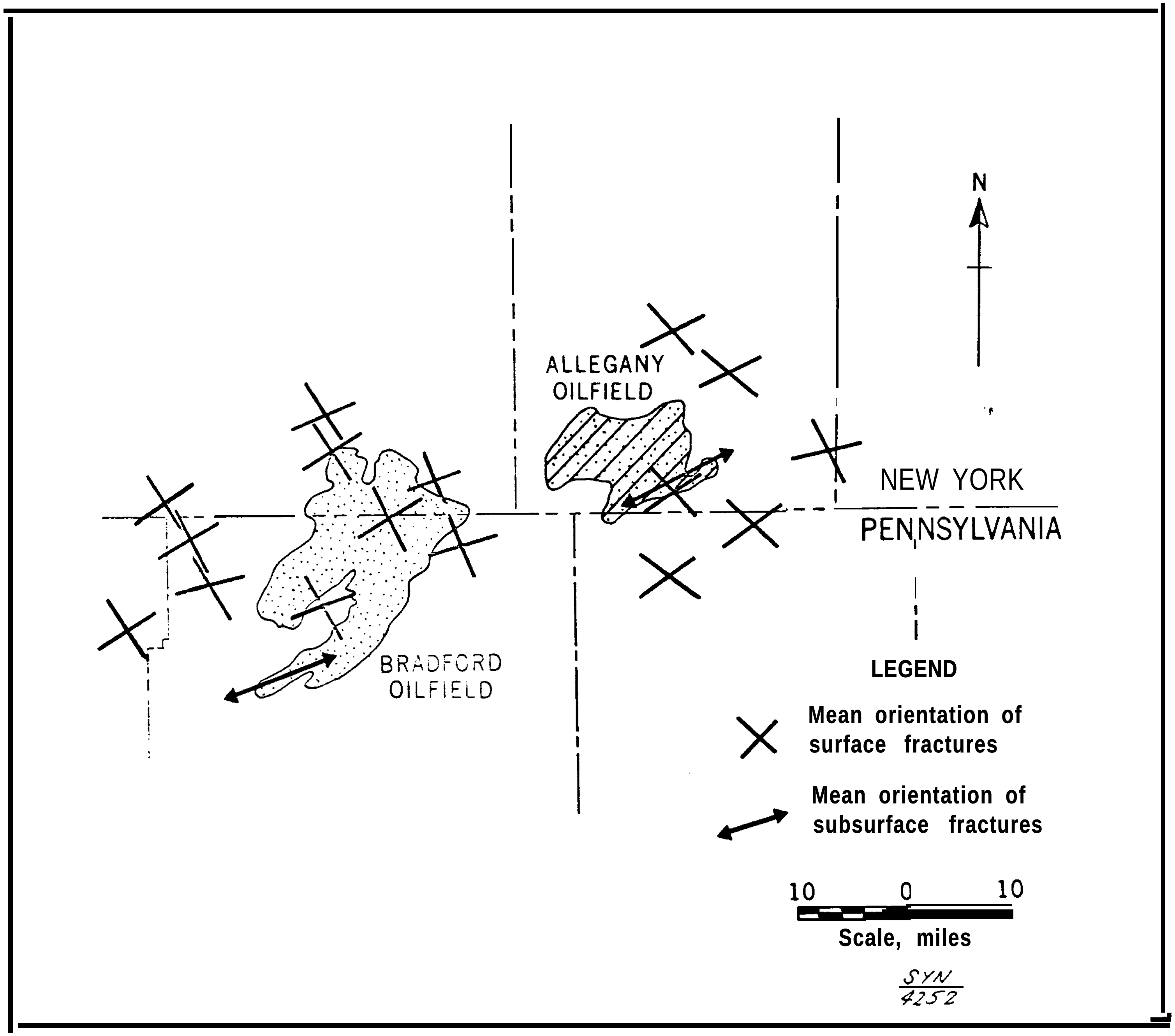


FIGURE 1 - CORRELATION OF MEAN SURFACE JOINT ORIENTATIONS WITH MEAN ORIENTATIONS OF HYDRAULICALLY INDUCED FRACTURES IN THE BRADFORD AND ALLEGHENY OIL FIELDS

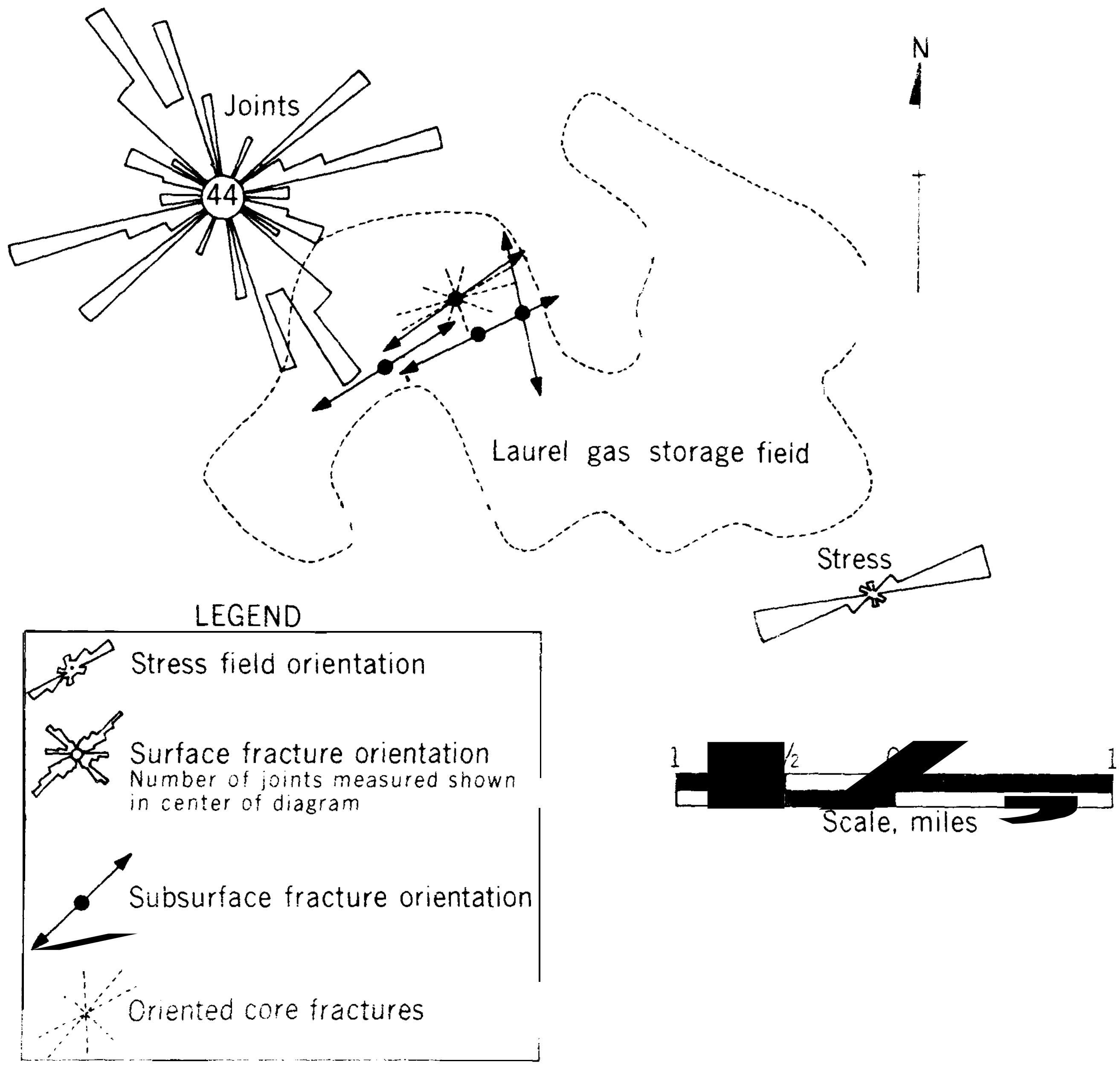


FIGURE 2 - RELATIONSHIP OF SURFACE FRACTURES TO SUBSURFACE FRACTURES ORIENTATION AND ORIENTED CORE FRACTURE ORIENTATION IN LOGAN COUNTY, OHIO

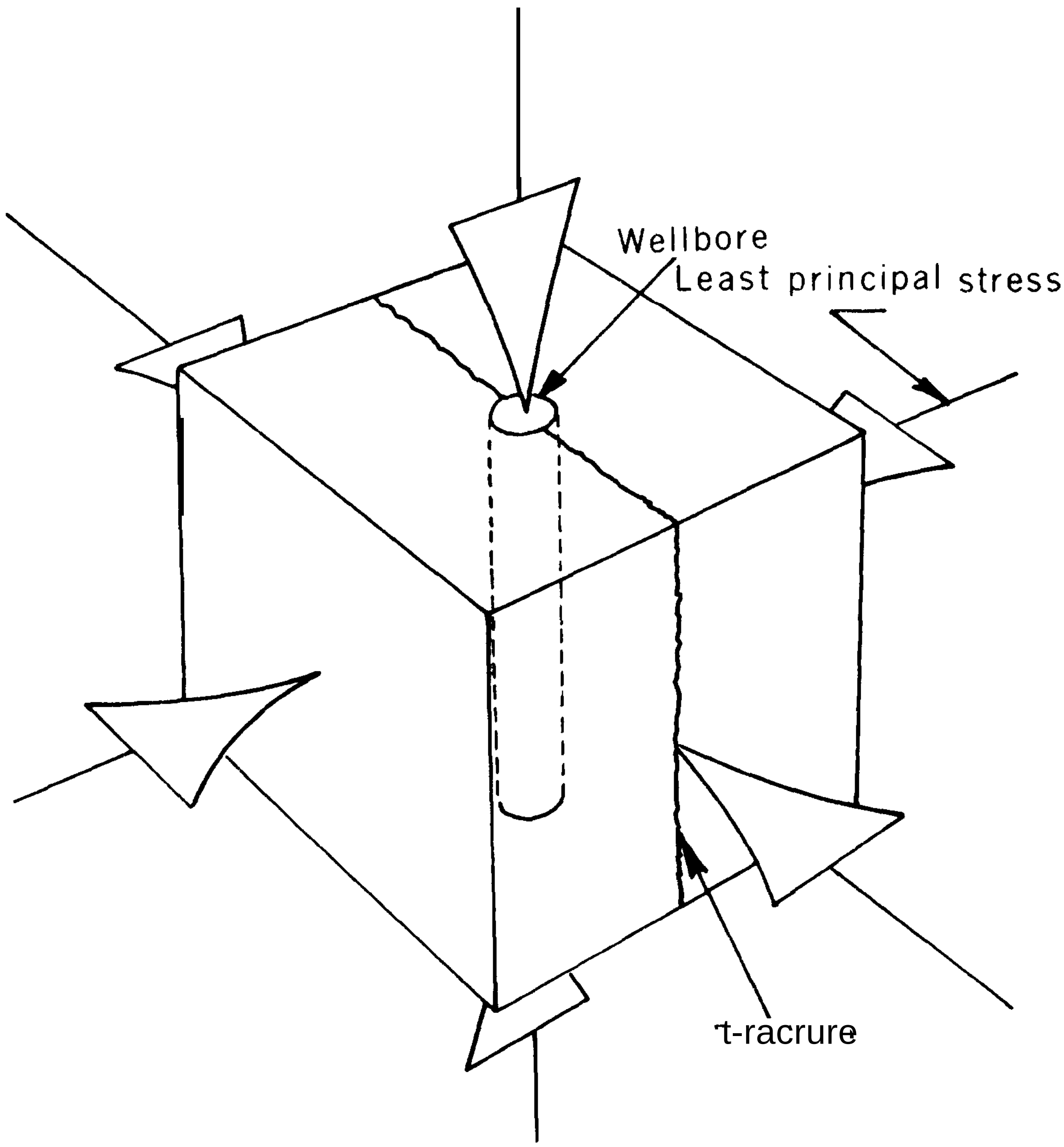


FIGURE 3 - DIAGRAM STATING RELATIONSHIP OF
MAXIMUM PRINCIPLE STRESS AND LEAST PRINCIPLE STRESS
TO THE PLAIN OF AN INDUCED HYDRAULIC FRACTURE

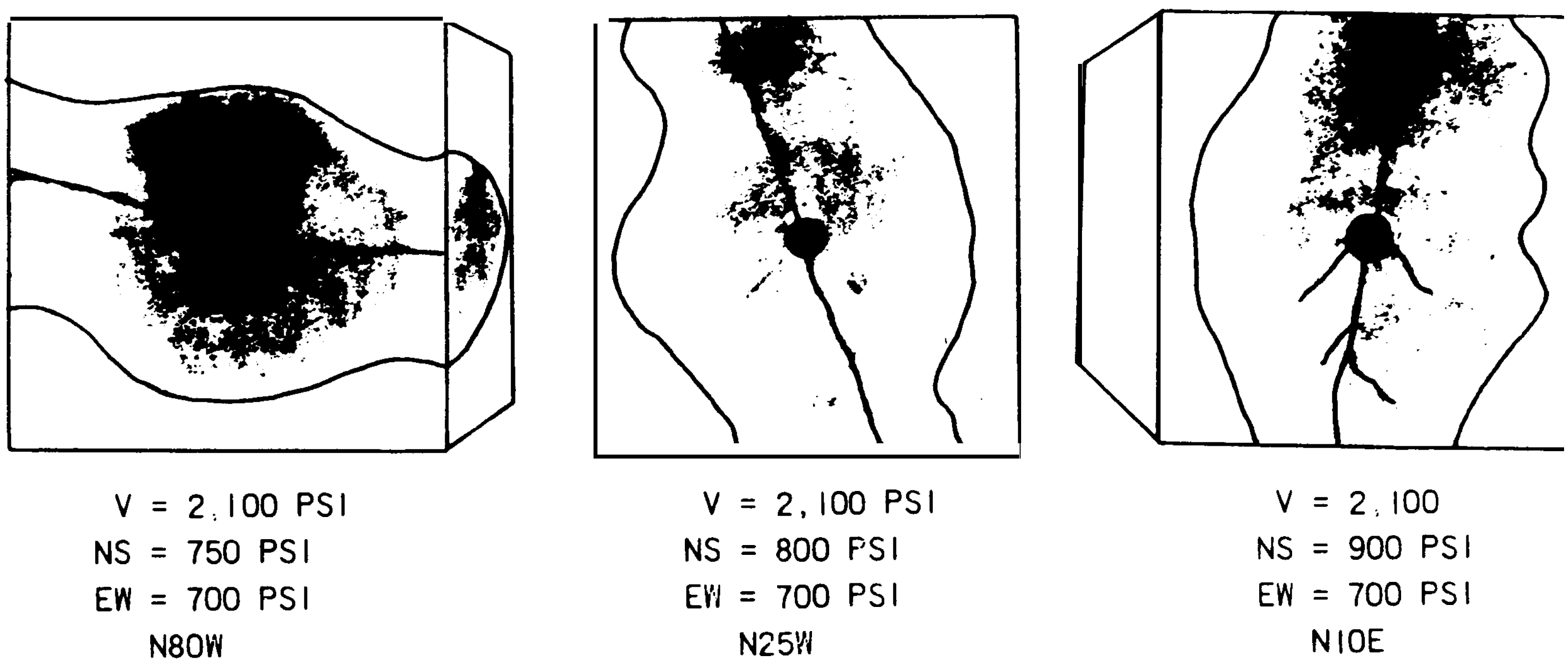


FIGURE 4 - VARIATION OF FRACTURE ORIENTATION WITH STRESS
(C. A. KOMAR, 1972, FEATURES INFLUENCING FRACTURE INITIATION AND ORIENTATION)

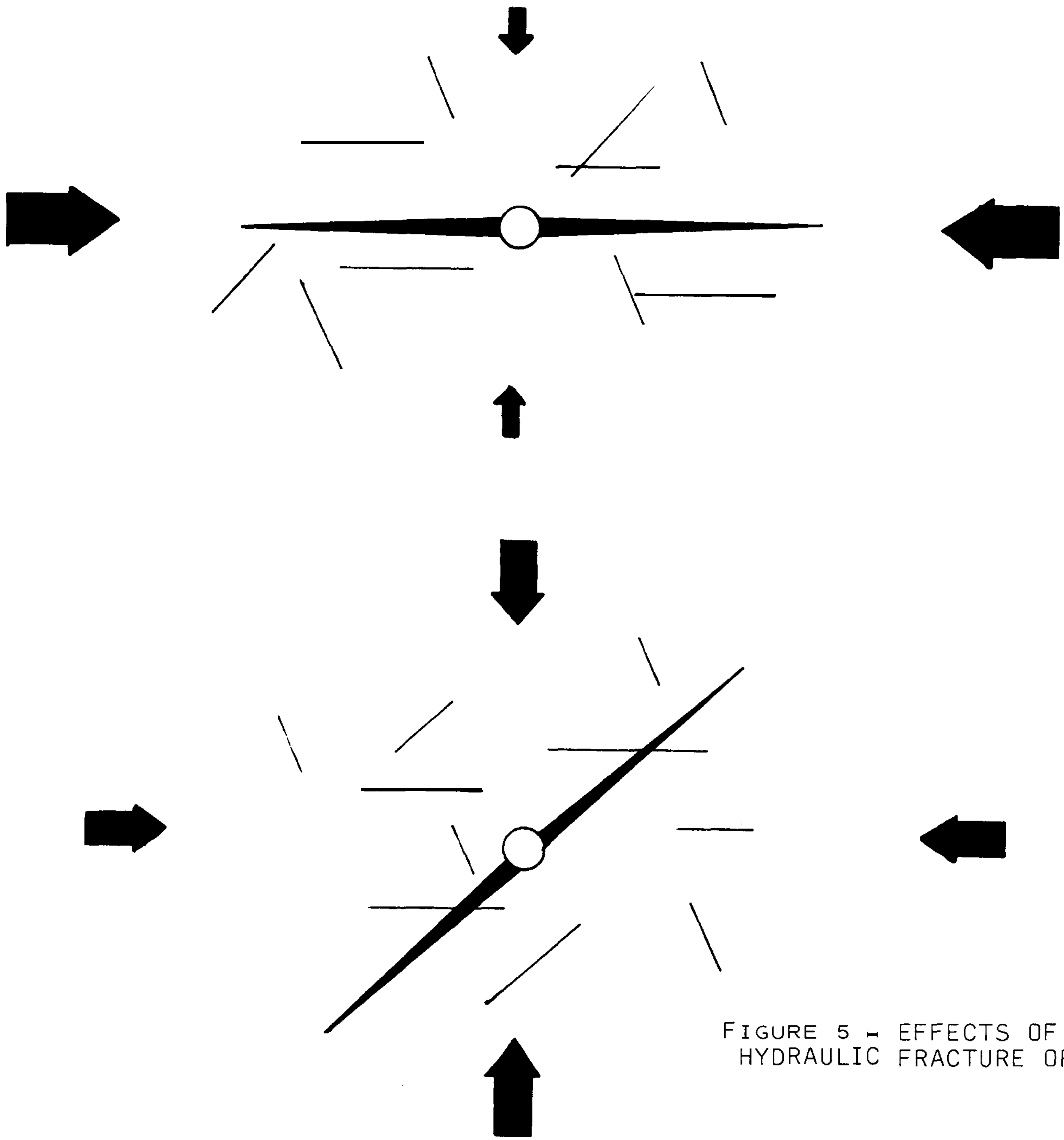


FIGURE 5 - EFFECTS OF STRESS ON HYDRAULIC FRACTURE ORIENTATION

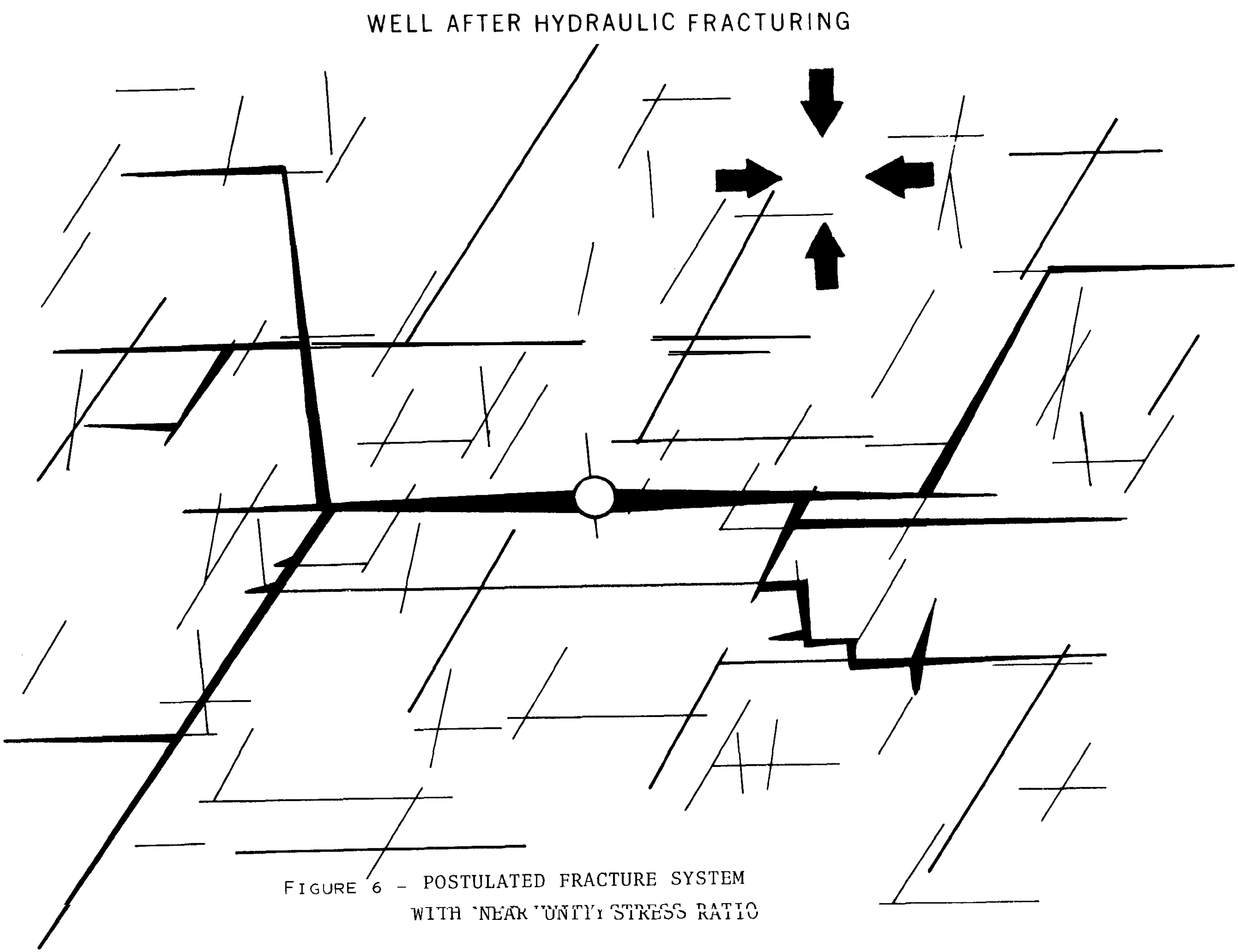
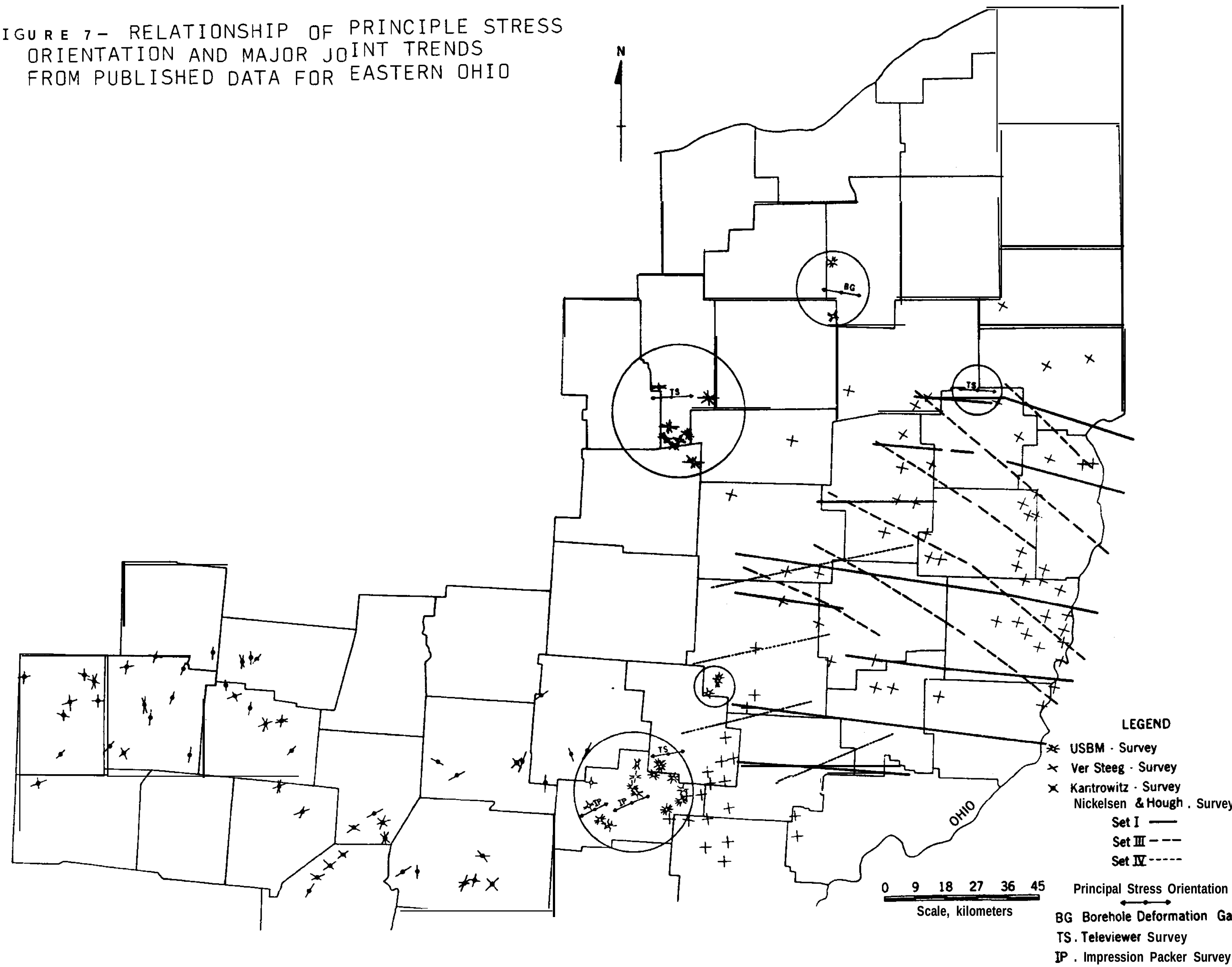


FIGURE 6 - POSTULATED FRACTURE SYSTEM
WITH NEAR UNITY STRESS RATIO

FIGURE 7- RELATIONSHIP OF PRINCIPLE STRESS ORIENTATION AND MAJOR JOINT TRENDS FROM PUBLISHED DATA FOR EASTERN OHIO



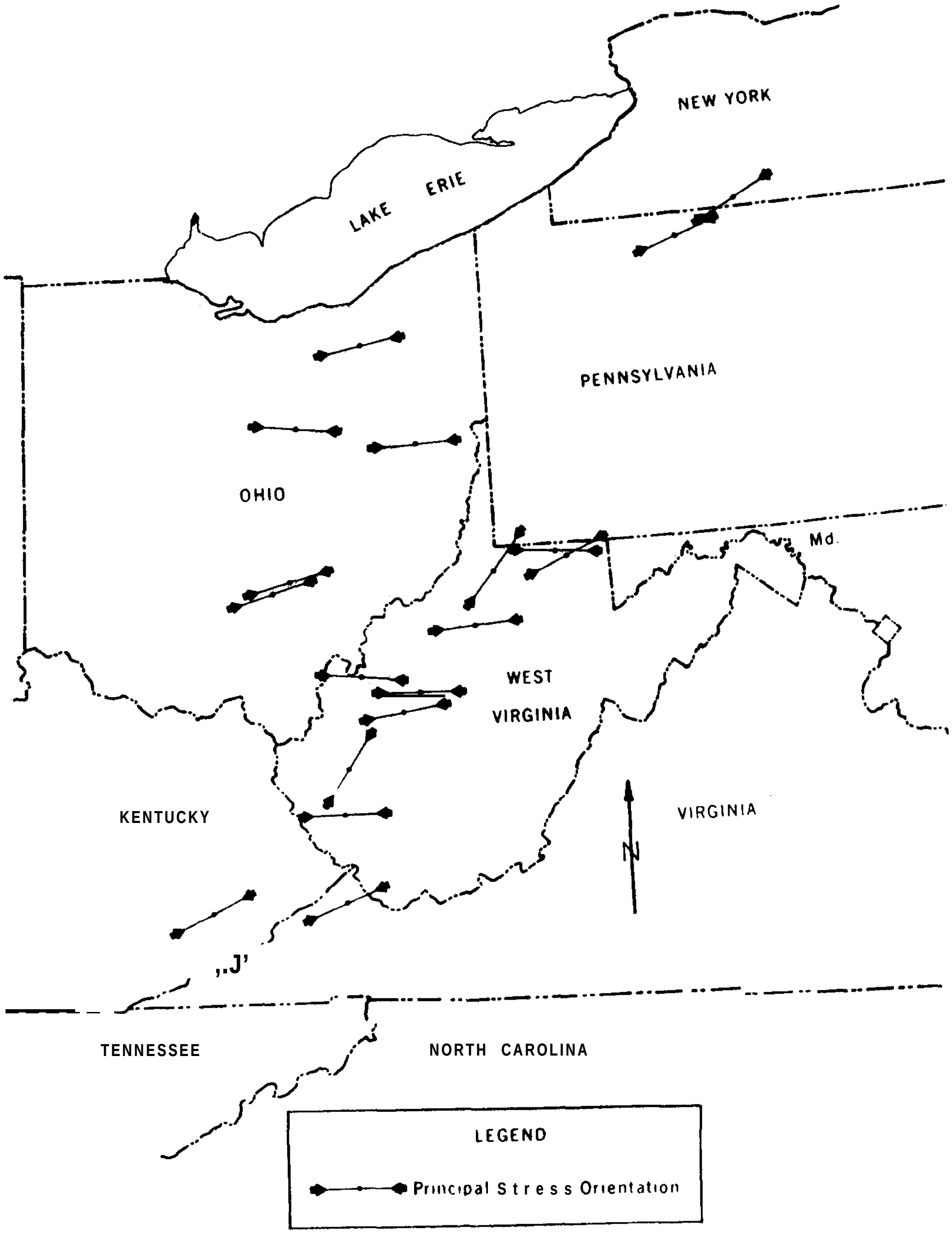


FIGURE 8 - RESULTS OF PRINCIPLE STRESS ORIENTATION MEASUREMENTS MADE BY U. S. BUREAU OF MINES AND ERDA IN THE APPALACHIAN REGION (SEE TABLE 1 FOR DETAILS)

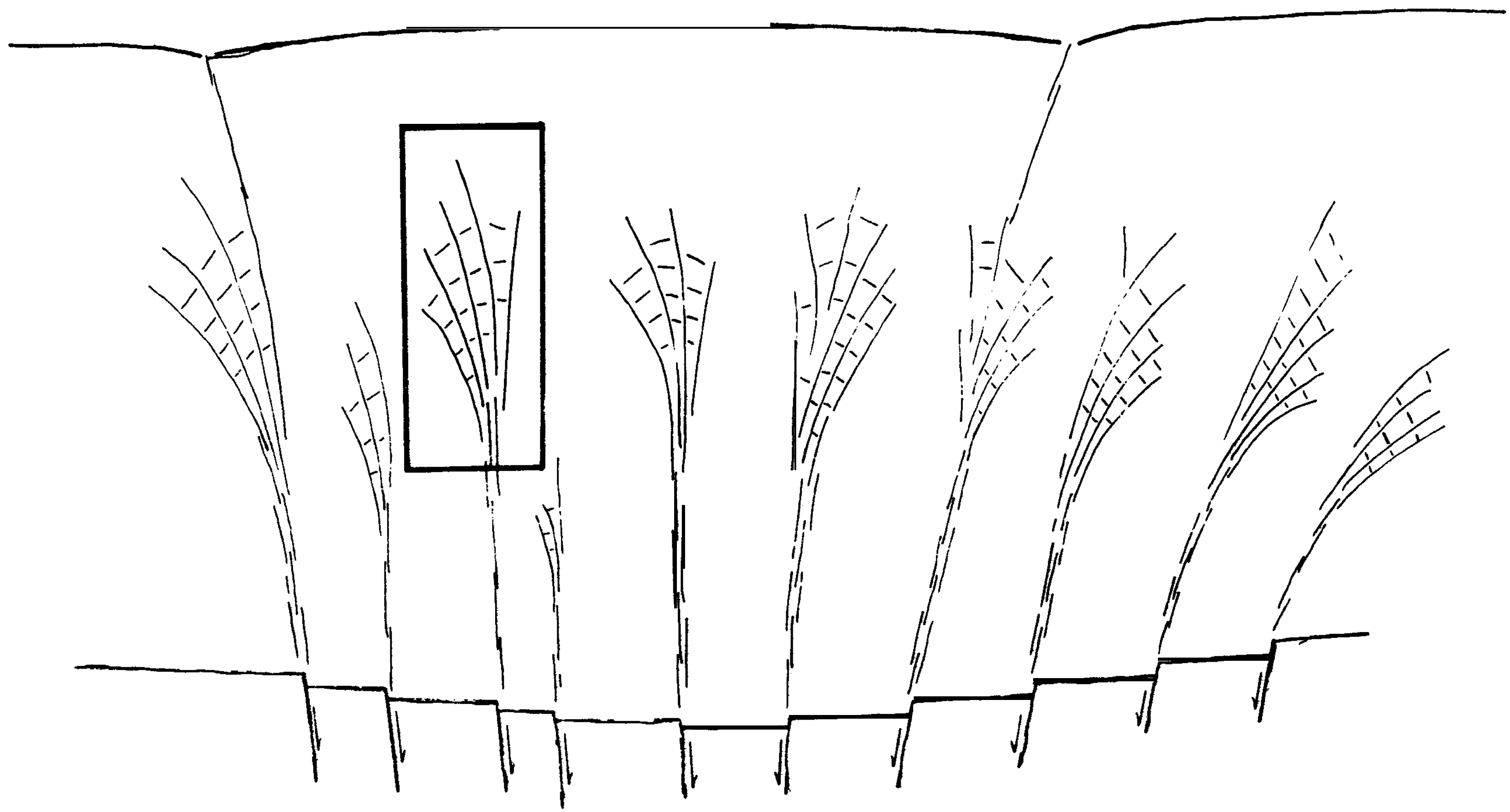


FIGURE 9

FRACTURES GENERATED BY DEEP SEATED BASEMENT FAULTING AND PROPAGATED UPWARDS INTO THE DEVONIAN SHALES

MODEL 1

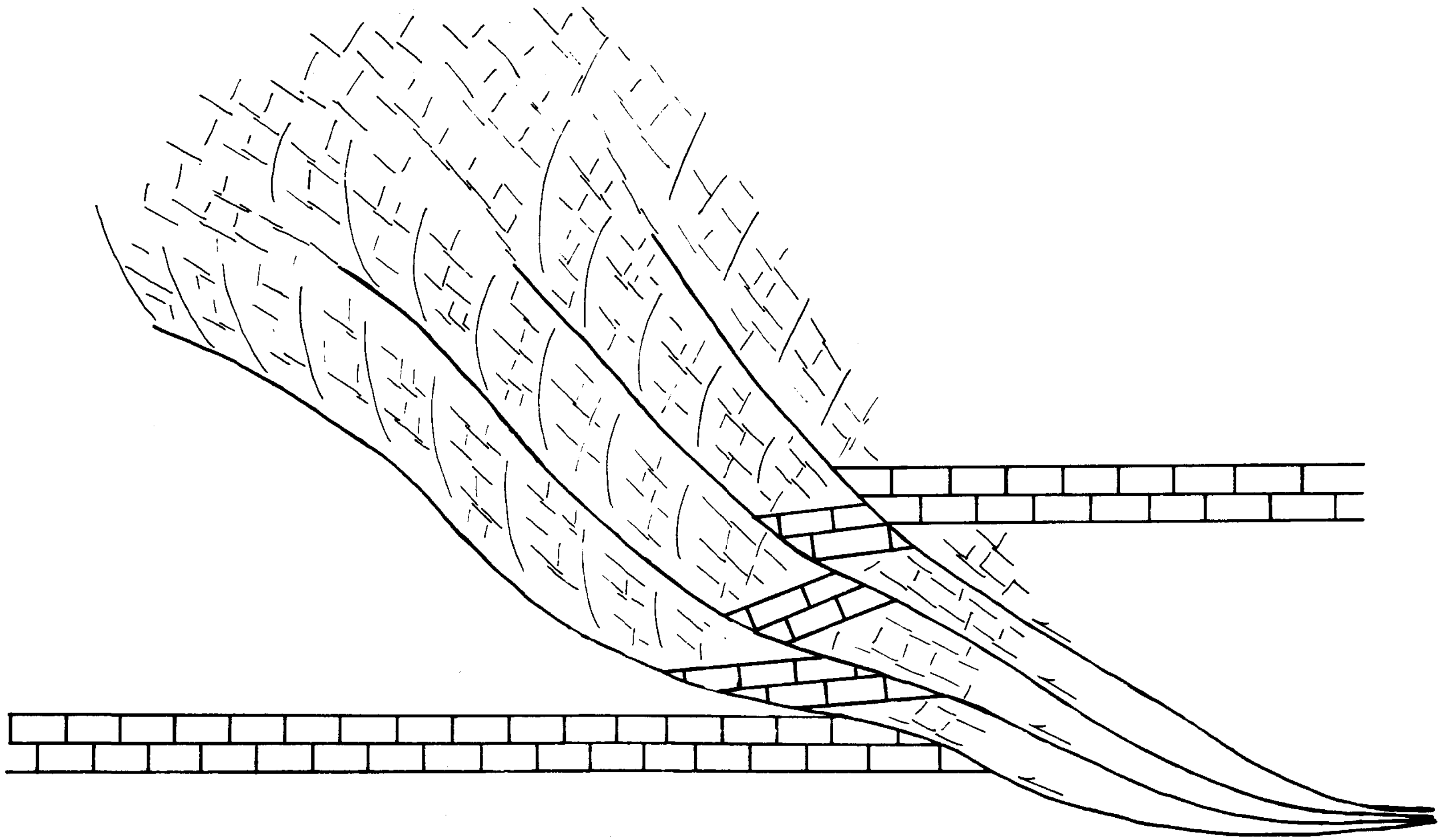


FIGURE 10

FRACTURES GENERATED BY LOW-ANGLE THRUST FAULTING

DURING THE APPALACHIAN OROGENY

MODEL 2

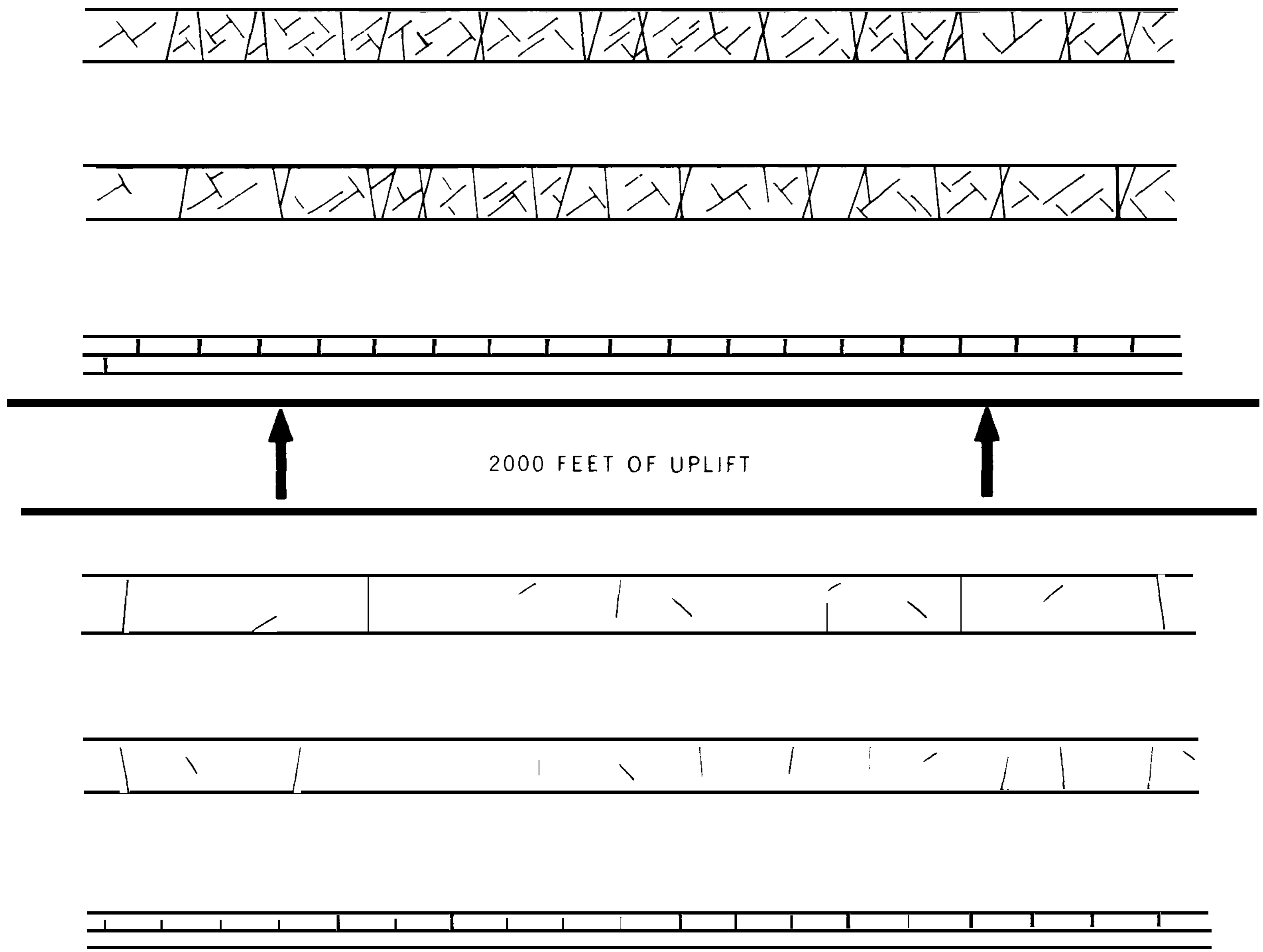
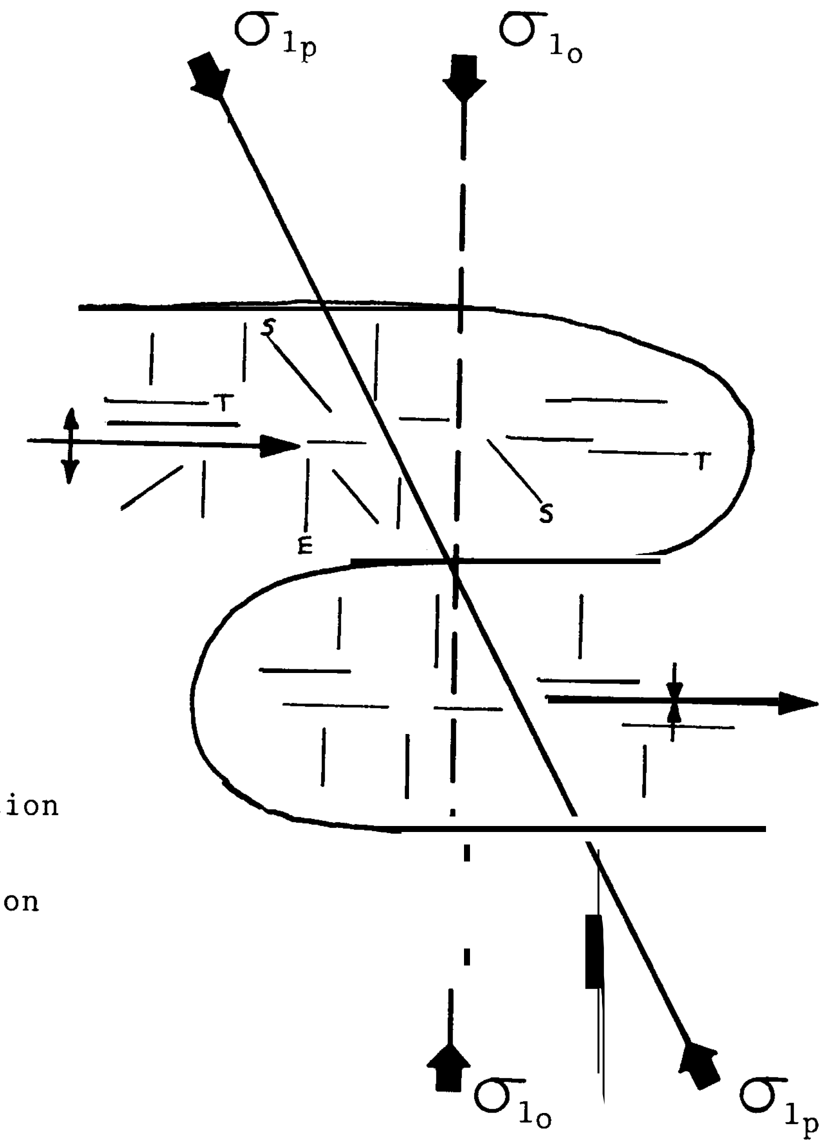


FIGURE 11 - FRACTURES GENERATED INTERNALLY AS A RESULT OF DILATENCY OF SHALE CAUSED BY EROSION AND UPLIFT OF ROCK COLUMN
MODEL 3

FIGURE 12 MODEL 1
Stress Trajectory across structure

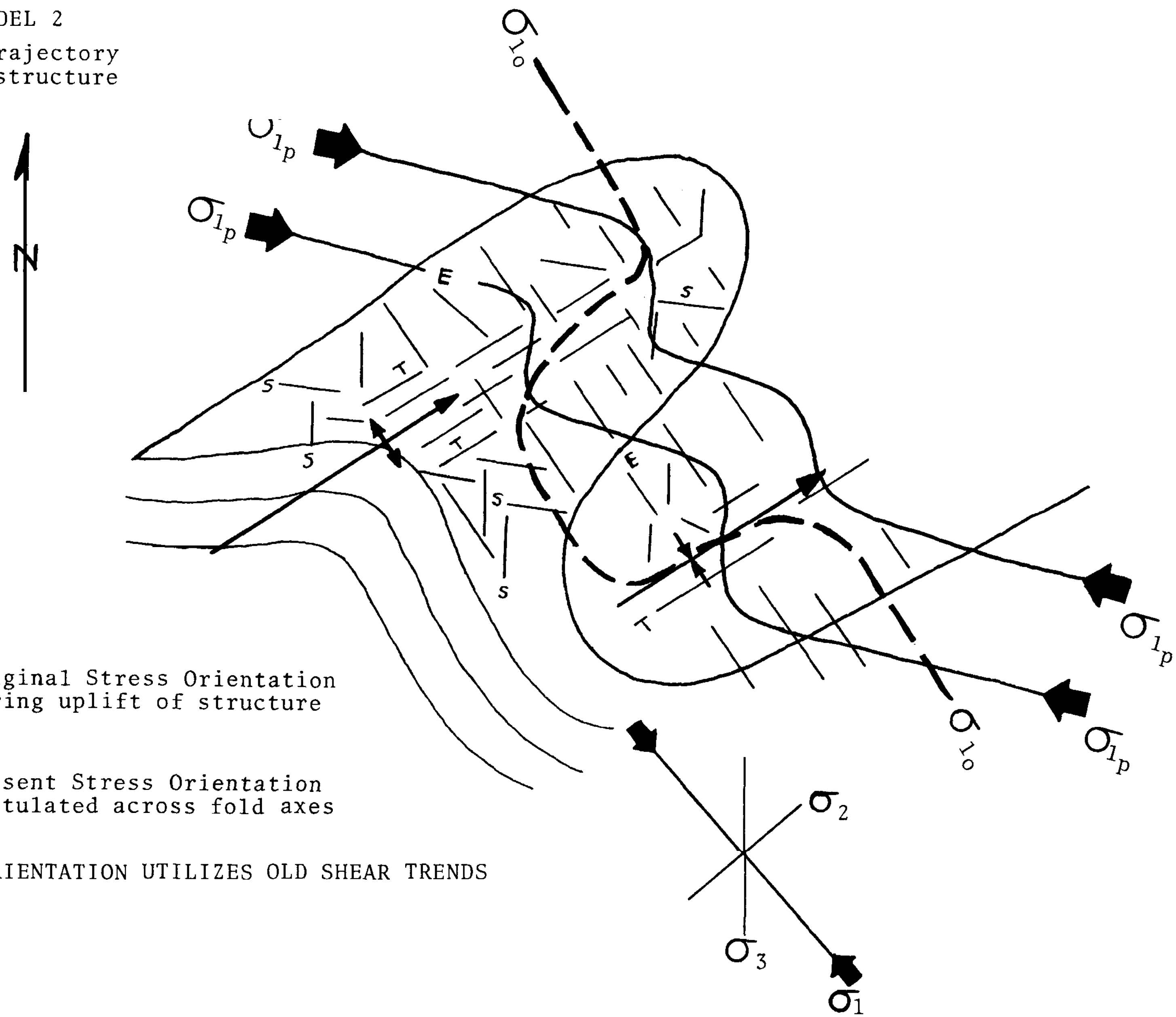


σ_{1_o} Original Stress Orientation

σ_{1_p} Present Stress Orientation

MODEL 2

FIGURE 1 3-Stress Trajectory across structure

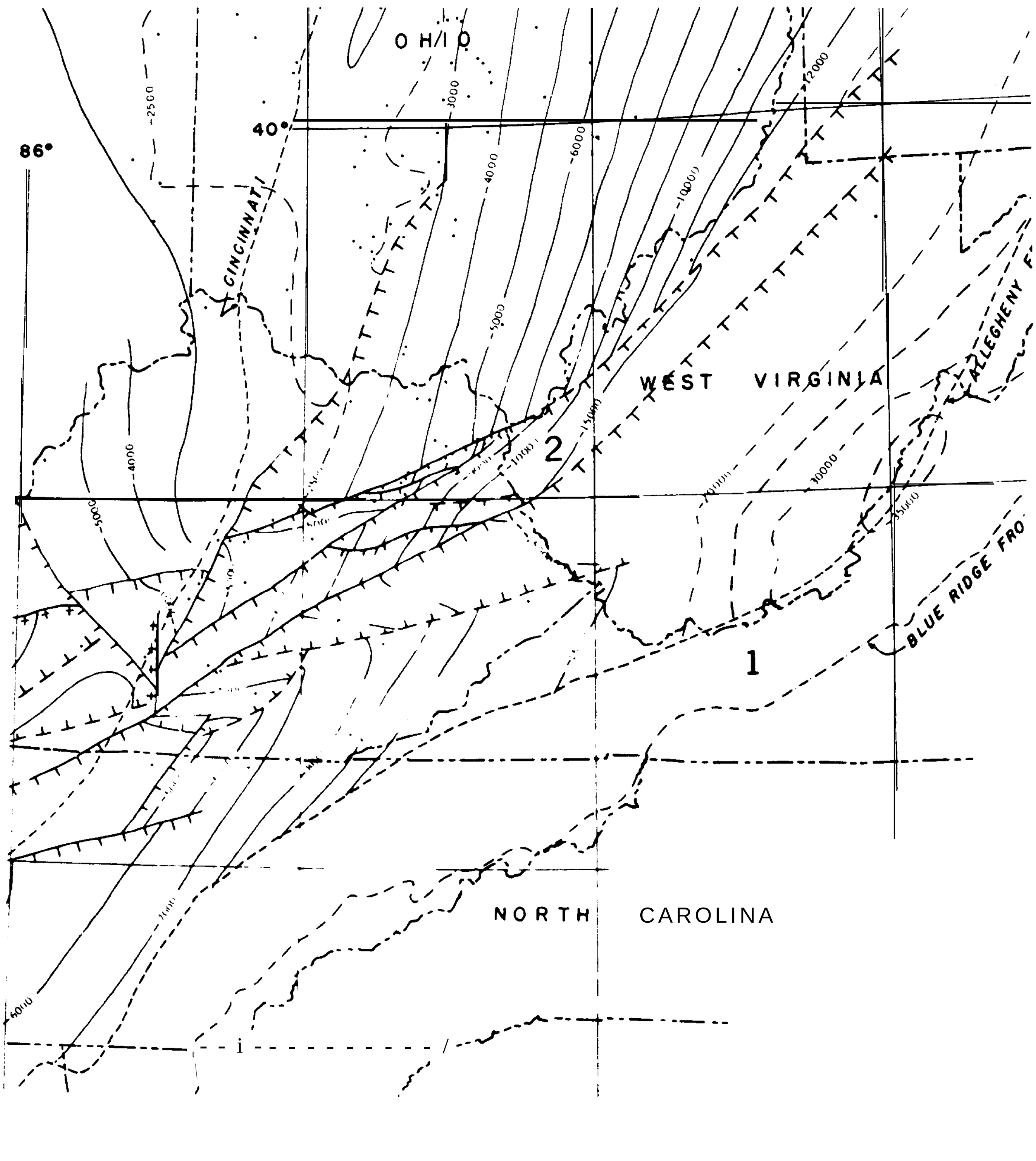


σ_{1_o} Original Stress Orientation during uplift of structure

σ_{1_p} Present Stress Orientation postulated across fold axes

NEW ORIENTATION UTILIZES OLD SHEAR TRENDS

FIGURE 14 - STRUCTURE ON PRECAMBRIAN BASEMENT ROCKS IN CENTRAL AND SOUTHERN APPALACHIAN AREA, AFTER HARRIS USGS MAP I-917 D, 1975



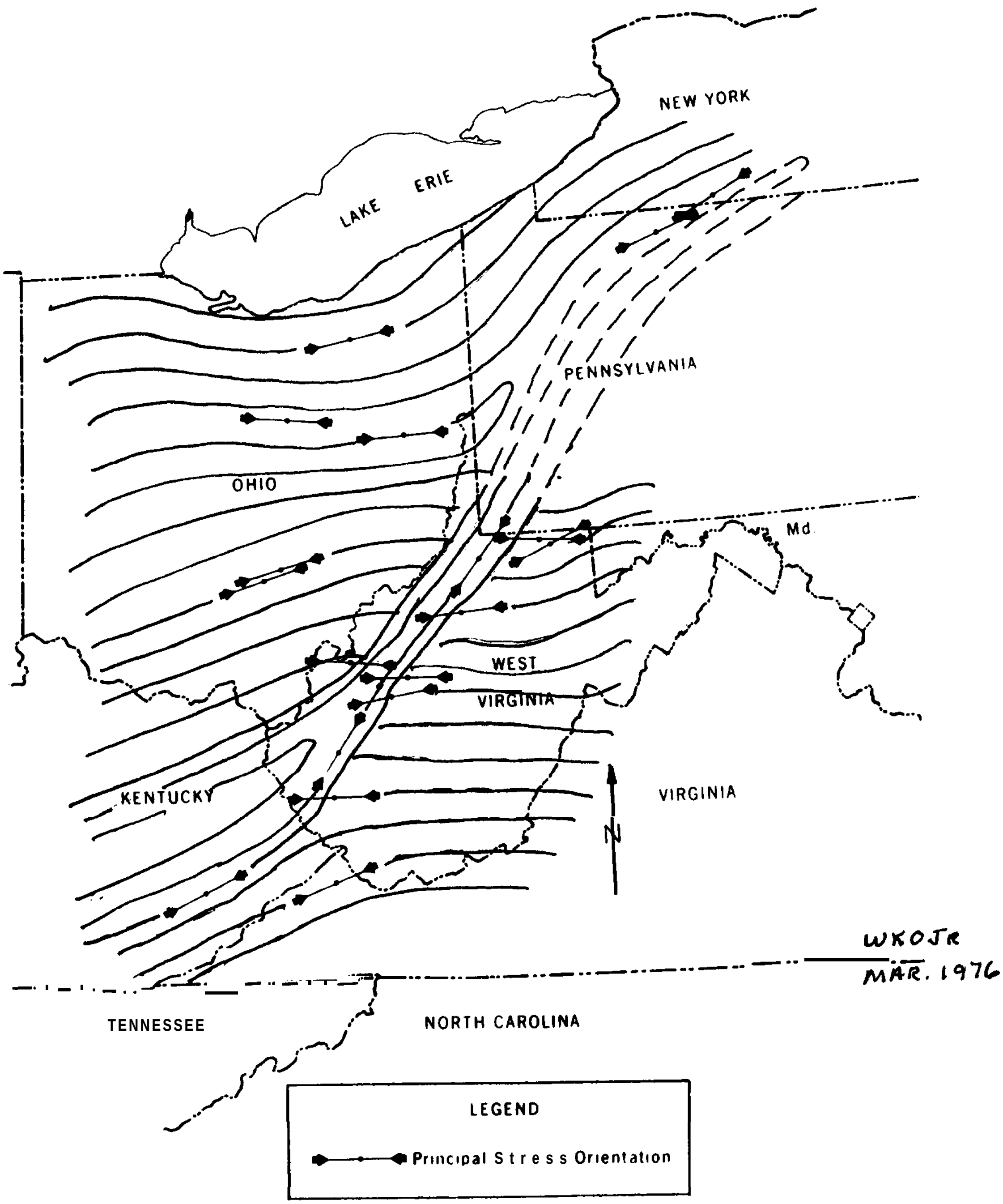
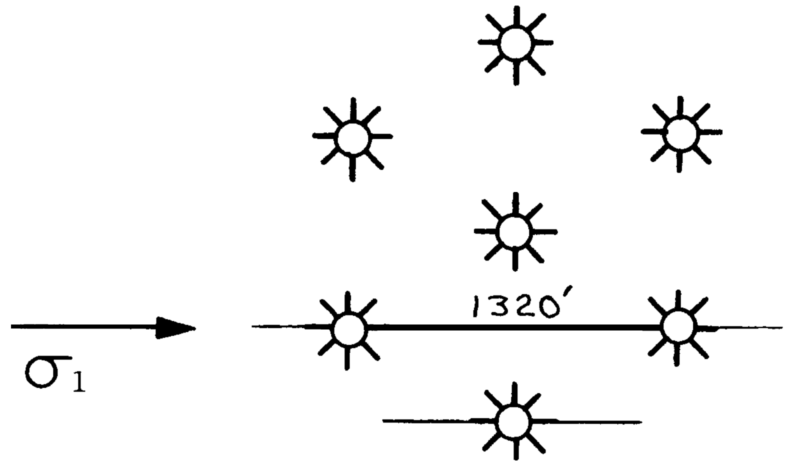
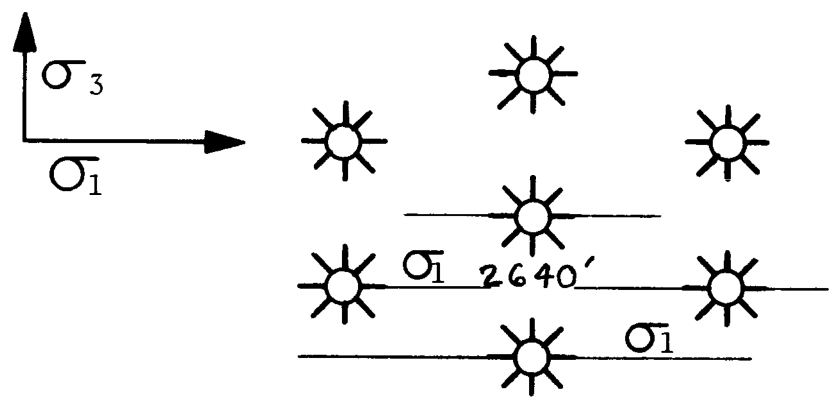


FIGURE 15 - POSTULATED STRESS TRAJECTORIES FOR CENTRAL APPALACHIAN REGION BASED ON TRAJECTORY MODEL 2 AND DATA FROM ERDA MEASUREMENTS



Normal drilling pattern for shale gas wells = 160 acre spacing for wells - no regard given to stress orientation



Suggested Devonian shale gas well drilling pattern based on stress orientation

FIGURE 16 - SUGGESTED CHANGES AND DRILLING PATTERNS IN THE DEVONIAN SHALE TO TAKE ADVANTAGE OF STRESS ORIENTATION AND THE ORIENTATION OF INDUCED HYDRAULIC FRACTURING

TABLE 1

MEASUREMENT LOCATION	PRINCIPAL STRESS ORIENTATION	METHOD OF MEASUREMENT
Hocking State Forest [5] Logan, Ohio	N 75° E	BHD
Laural Gas Storage Field [5] Laural Twp., Hocking Co., Ohio	N 73° E	BHD & IP
Puskarich Quarry [4] Scherrodsville, Ohio	N 88° E	BHD
Barberton Mine [6] Barberton, Ohio	N 80° E	BHD
Mohican State Forest [7] Loudenville, Ohio	N 83° W	BHD
Bradford Oil Field [8] McKean Co., Pennsylvania	N 70° E	IP
Allegany Oil Field [10] Allegany Co., New York	N 62° E	IP
Chief Logan State Park [9] Logan Co., West Virginia	N 87° W	BHD
Lincoln Co., West Virginia [1]	N 37° E	IP
Roane Co., West Virginia [1]	N 87° W N 83° E	TS TS
Jackson Co., West Virginia [2] Baeden Site	N 82° W	BHD
Doddridge Co., West Virginia [1]	N 87° E	TS
Monongalia Co., West Virginia [3] Oeage Site	N 84° W	IP
Phillips Petroleum [4] Morgantown, West Virginia	N 66° E	BHD
Wetzel Co., West Virginia [2] Pricetown Site	N 40° E *	BHD
Buchanan Co., Virginia [4]	N 71° E	BHD
Perry Co., Kentucky [2] Hazard Site	N 67° E	BHD

* = Results Questionable
BHD = Borehole Deformation Gage (USBM)
IP = Impression Packer Survey
TS = Televiewer Survey

FRACTURE INVESTIGATION OF THE DEVONIANSHALE USING GEOPHYSICAL WELL LOGGING TECHNIQUES

John I. Myung - Seismograph Service Corporation
Birdwell Interpretation Section

Conventional well logs and interpretation methods do not provide sufficient information to evaluate the productive gas zones of the Devonian shale in the Appalachian area. The major gas accumulations are believed to occur in fracture systems in close proximity to the source beds. With this premise in mind, an approach to locating and evaluating the fractures and showing evidence of the source beds has been formulated.

The approaches to evaluating the fractures in the shale are discussed as follows:

(1) Empty Borehole Logging Program and Computer Data Presentation

(2) Seisviewer Survey

(3) Applications of the 3-D Velocity Log

EMPTY BOREHOLE LOGGING PROGRAM AND COMPUTER DATA PRESENTATION

The empty borehole logging program to evaluate the shale formation is extremely important since most operators are concerned about washouts and caving caused by filling the borehole with fluid. The Devonian shale is particularly sensitive to water. The following should be considered an essential empty borehole logging program with currently available logs:

Gamma-Ray Log
Formation Density Log
Induction Log
Temperature Log
Sibilation Survey

Since conventional interpretation techniques using the above combination of logs do not provide a conclusive result in identifying potential pay zones in shale, a new concept and technique directed toward evaluating potential productive zones has been employed.

Gamma Ray, Formation Density Induction Logs

The Production Index utilizes the first three logs which measure the gamma radiation, bulk density, and resistivity of the formation penetrated. A number of logs recorded in the Devonian shale indicate that some anomalies occurred on the Gamma-Ray, Density and Induction Logs. Commonly, in the zones of interest, the gamma-ray intensity and resistivity increase while density decreases. This effect is not always representative of a pay zone. Sometimes only one or two logs react as indicated.

The anomalies are interpreted in terms of fracturing and as evidence of source beds in the following ways. The increase in gamma radiation is attributed to zones rich in organic matter. The decrease in bulk density is a result of increased porosity due to fracturing and/or the lower density value of kerogen, which is sometimes present in shale. The increase in resistivity is a result of gas-filled fractures and/or increased kerogen content. Therefore, an attempt was made to combine all three values from the three logs to express a simple numbering system which is called the Production Index. The mathematical relationship formulated to derive the Production Index is shown below.

$$\text{Production Index} = \frac{G + R}{D_b}$$

where: $G = \dfrac{\text{API units from Gamma-Ray logs}}{\text{Average API units of Shale}}$

$R = \dfrac{\text{Resistivity from Induction Log}}{\text{Average Resistivity of Shale}}$

D_b = The bulk density from a Density Log

The average API value for the Devonian shale is normally 200 and the average resistivity of the shale is approximately 15 to 20 ohm m/m. However, these average values should be established based on logs recorded at specific localities. Figures 1 through 3 illustrate a continuous plot of the Production Index from three sets of field data obtained from West Virginia and Ohio. The interval from 3406 to 3656 feet on Figure 1, showing a high Production Index, also proved to be highly fractured based on the seisviewer survey. It is intended to prove that the higher Production Index is proportionately related to the

Gamma Ray, Formation Density Induction Logs (con't)

number of gas productive fractures developed in the shale formation. Therefore, it is important to establish a threshold criterion of the Production Index number. This can be accomplished by relating it to the production data to identify the potentially productive gas pay zones from the shale formation. Continued field investigation of production data compared to the computed production index derived from logs will verify this new technique as valid analytical method.

Kerogen, although not considered to be of commercial value, is important in that it is believed to indicate the close proximity of gas source beds. The kerogen content is displayed on the log in terms of its yield of oil in gallons per ton. The equation used to compute the yield is shown below.

$$\text{YIELD} = 496.325(D_b)^{-.6} - 285.176$$

where D_b is the bulk density read from the density log.

Temperature Logs

The Temperature Log is normally run to observe gas entry into the borehole. Recently the Joule-Thomson expansion temperature theory was applied to determine the thermal fracture index from the temperature log. The fracture index scale should provide information on the magnitude of the fracture system present in the formation. The Joule-Thomson expansion temperature (theoretical) can be determined from Figure 4 with a prior knowledge of the reservoir pressure and temperature. The gas temperature due to expansion determines the zero on the fracture index scale. The gradient temperature is considered to be a fracture index of 100. It is assumed that a 100% fractured formation is a fracture system that is extensive enough to heat the expanding gas to the gradient temperature before it enters the borehole.

Figure 5 illustrates a comparison of two temperature logs run in the same borehole, one before and one after hydraulically fracturing the formation. The temperature over the zone of interest after fracturing was considerably higher due to heating of

Temperature Logs (con't)

the expanding gas in the increased fracture system to approximately the formation temperature. The theoretical Joule-Thomson temperature established from Figure 4 indicated $50^{o}F$, which is assigned a fracture index of zero, while a temperature of $90^{o}F$ established from the geothermal gradient is considered to be 100% on the fracture index scale. Ten equal divisions were made between these two points as shown in Figure 5. Another sample log illustrating the thermal fracture index obtained from the temperature logs is shown in Figure 6. The fracture index before fracturing indicated 54%, and after fracture treatment indicated 92%. Thus, the temperature log can be used as a method to estimate the fracture index from the Joule-Thomson expansion temperature. Comparison studies of the fracture index with sufficient field data should be able to predict the volume of gas increase as a result of hydraulic fracturing stimulation.

Sibilation Survey

The Sibilation Survey has been successfully employed in locating collar leaks, channeling, and other types of small leaks in gas storage wells. Recently, this service has been employed to locate small potential gas zones producing through fractured systems such as thin shale laminations or low permeable formations. Field tests indicate that a qualitative evaluation of a possible pay zone can be made with this survey.

The instrument consists of a dual detector section containing two piezo-electric tranaducers, one of high sensitivity and one of low sensitivity. These transducers have a frequency response in the 40 khz. range; therefore, most noises caused by movement of the instrument and gas flow in the borehole past the instrument are not in their recording range. However, gas movement through small orifices such as formation porosity at the borehole wall or pinhole leaks create high frequency sounds in the 40 khz. range and, thus, will be recorded.

Figure 7 illustrates a sibilation survey conducted in the shale formation where no

Sibilation Survey (con't)

indication of a temperature anomaly is shown on the log. At the depth of 3278 feet, a high noise level is recorded that indicates some movement of gas. It could be possible that this gas may not be entering the borehole since the sibilation instrument is capable of response to high frequency noise beyond the borehole. However, the log is indicative of the presence of a fracture where gas is moving through the fracture system. Figure 8 also illustrates a comparison of the temperature and sibilation survey performed in the Berea Sandstone in Virginia. The gas movement is occuring at the interval of 3480 to 3560 feet.

The sibilation survey can be a valuable instrument in evaluating a fractured shale system typical of the Devonian shales, since the instrument is extremely sensitive to high frequency noise created by gas movement.

SEISVIEWER SURVEY

The Seisviewer is an acoustical device designed primarily to evaluate fractured reservoirs. It consists of a downhole scanning instrument with its multiconductor cable and a surface panel. The downhole scanning instrument, comprising a motor-driven acoustical transducer and a fluxgate magnetometer, rotates at 3 revolutions per second to produce a high resolution acoustic picture of the borehole. The resulting log is oriented to a north marker signal from the fluxgate magnetometer. The acoustical transducer is pulsed at a rate of 2,000 times per second, with the focused acoustical beam directed at the borehole wall. The amplitude of the signal reflected from the wall depends upon the acoustical impedance of the wall rock and associated physical properties of the wall. Fractured or highly distrubed zones are recognized by a poor or no reflected signal. The advantage of this system over photographic or TV systems is that this instrument can be operated in drilling mud, oil, or any type of fluid, and in holes from four inches to twelve inches in diameter.

The detected acoustical signals are amplified along with the magnetic north

SEISVIEWER SURVEY (con't)

marker pulse and transmitted to the surface through the multiconductor cable.

The surface panel combines this downhole information to produce the acoustical picture of the borehole wall. The actual operation might be compared to a somewhat simplified television presentation. An oscillograph sweep is triggered by the north marker signal and its intensity is modulated by the detected return signal from the wall. The horizontal line spacing is controlled by the logging speed. The completed picture is a compilation of a multitude of transducer scans which, when photographed, combine to make a log picture of the borehole wall. The flux-gate magnetometer triggers the oscillograph sweep producing the scan and subsequent retrace, orienting the left edge of the picture at magnetic north. In effect, the picture of the borehole is as though the borehole cylinder were split vertically at magnetic north and laid out flat. The angle of dip can be computed from the following equation:

$$\text{Angle} = \tan^{-1}\frac{h}{d}$$

In this equation, d is the diameter of the hole and h is the distance from the trough to the crest of the sinusoidal waveform measured on the log. The trough of the waveform indicates the direction of the dip which can be read from the log orientation as shown in Figure 9.

Figure 10 provides an example of the determination of dip angle and bearing from a log. There are two high-angle fractures which nearly intersect within the borehole. The attitude of the fractures indicate that the two planes cross each other a short distance beyond the borehole. The two fractures shown are representative of the orientation and angle of dip of two sets of fractures that extended over 40' of borehole. The calculated angle of dip of the fracture between 5561 and 5562 feet is 58^{o}; and, from the low point of the trough, the direction of dip is N 70 E. The other fracture which occurs between 5562 and 5564 feet has a calculated dip of 74^{o} and the direction of the dip is

SEISVIEWER SURVEY (con't)

N 45 W.

Most operators feel reluctant to put water in the borehole because the shale is extremely sensitive to water, but during the operation of the Seisviewer in recent Devonian shale wells the borehole condition was good for at least 12 hours. It is recommended that the seisviewer survey be performed just prior to running the casing into the borehole.

Figure 11 illustrates a seisviewer log run in the Devonian shale formation in West Virginia. The records indicate that multiple vertical fractures are present throughout the interval. The fracture indicated in the shape of a loop shown in the interval of 3580 to 3600 feet is a near vertical fracture, as shown in the core photographs in Figure 12a. The direction of dip of the fracture plane is South-Southeast. Another pair of vertical fractures shown at the same interval are assumed to be drilling-induced and in the North-South direction. Another core photo is shown in Figure 12b. This particular seisviewer survey was taken with a low frequency transmitter within the range of 600 khz. The instrument was tested with machine cut simulated fractures with widths of 1/4", 1/8", 1/16" and 1/32". The vertical fractures are clearly indicated with the low frequency transducer in fresh water as shown in Figure 13.

APPLICATIONS OF THE 3-D VELOCITY LOG

The presence of fractures, joints, or other discontinuities in the rocks will interfere with the transmission of any type of wave energy through the rock. It is generally accepted that fractures can be recognized by the reductions of the amplitudes of compressional and shear waves. Experimental work by Morris[1] has shown that the angle at which a fracture plane crosses a borehole affects the attenuation of acoustical signals. Theoretically, horizontal fractures should cause little attenuation of the compressional waves; on the other hand, the shear waves are significantly attenuated by these same fractures. Knopoff[2] has calculated curves of transmission coefficents for plane compressional and shear waves across an infinitely thin

APPLICATIONS OF THE 3-D VELOCITY LOG (con't)

lubricated crack in an infinite medium. Figure 14 is taken from Knopoff's curves for a hard carbonate formation with a Poisson's ratio of 0.3. This figure indicates the amplitude of the shear wave should be more diagnostic in identifying fractures when the fractures lie at a very low or very high dip angle. Conversely, the amplitude of the compressional waves should be more sensitive to fracture dips between 33^{o} and 78^{o}.

Morris, et al. reported that a compressional wave is little attenuated at vertical and horizontal fractures and considerably attenuated at a 45^{o} fracture angle. Conversely, a shear wave is most attenuated at vertical and horizontal fractures. His experimental results show that the compressional transmission coefficients compare to Knopoff's, but lower transmission coefficients were found for the shear velocity at low angle dips as compared with Knopoff's curves in Figure 14.

Figure 15 is a log from granite in the state of New Hampshire. In Zone C of this log, the compressional wave is not attenuated while the shear wave amplitude is severely reduced due to a low angle or horizontal fracture, which agrees with Knopoff's calculated curves shown in Figure 14.

The strong energy arrivals for both compressional and shear waves in Zone B indicate that no fracture is present. In Zone A, both the compressional and shear waves are attenuated, probably due to the presence of a high angle fracture.

A short spaced 3-D velocity log can also be run to determine the presence of fractures, as thin as 1/16" in width. Figure 16 illustrates a comparison of the 3-D velocity log run with a three foot spacing and a seisviwer log. The presence of fractures are indicated on both surveys.

The 3-D Velocity log is capable of recording the total wave form including the compressional and shear waves. These data, combined with the information from the density log, are used to compute elastic properties by using the theory of elastic wave propogation, assuming the rocks are elastic. In rock mechanics, Young's Modulus is often used as a strength modulus and related to the tensile or compressive strength of rocks. Thus, it is used in foundation investigation or in roof rock subsidence prediction studies.

Using Eaton's[3] fracture gradient equation, the formation fracture gradient can be computed from the following equation:

$$P_f = \left(\frac{S}{D} - \frac{Pe}{D}\right)\left(\frac{\nu}{1-\nu}\right) + \frac{Pe}{D}$$

where: P_f = Fracture Pressure

S = Overburden Pressure

Pe = Pore Pressure

D = Depth

ν = Poisson's Ratio

The oberburden pressure can be estimated by integrating the Density log and the pore pressure can be approximated from a pore pressure gradient of 0.465 of psi/ft if no over-pressured zone is present. Poisson's Ratio as determined from 3-D velocity log is used in the above equation to obtain the formation fracture pressure gradient. The fracture pressure gradient is plotted with the elastic properties as illustrated in Figure 17. It would be interesting to observe and compare the computed and the actual field measurements of the fracture pressure. Once the fracture pressure is well controlled from this computed value, then the zone of the stimulated interval may be identified by knowing the expected fracture pressure, particularly when a long interval is treated with the limited entry technique.

This paper was presented and written with the thought that experience and continued comparison of field data with the methods formulated in this paper will enhance our understanding and evaluation of the Devonian fractured shale reservoirs.

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2. Knopoff, L., _et al_. Seismic Scattering Project. Institute of Geophysics, UCLA, 2nd Ann. Rpt., 1957, Chap. 12.

3. Eaton, B. A. Fracture Gradient Prediction and Its Application in Oilfield Operations. Jour. Petrol. Tech., June 1971, pp. 727-730.

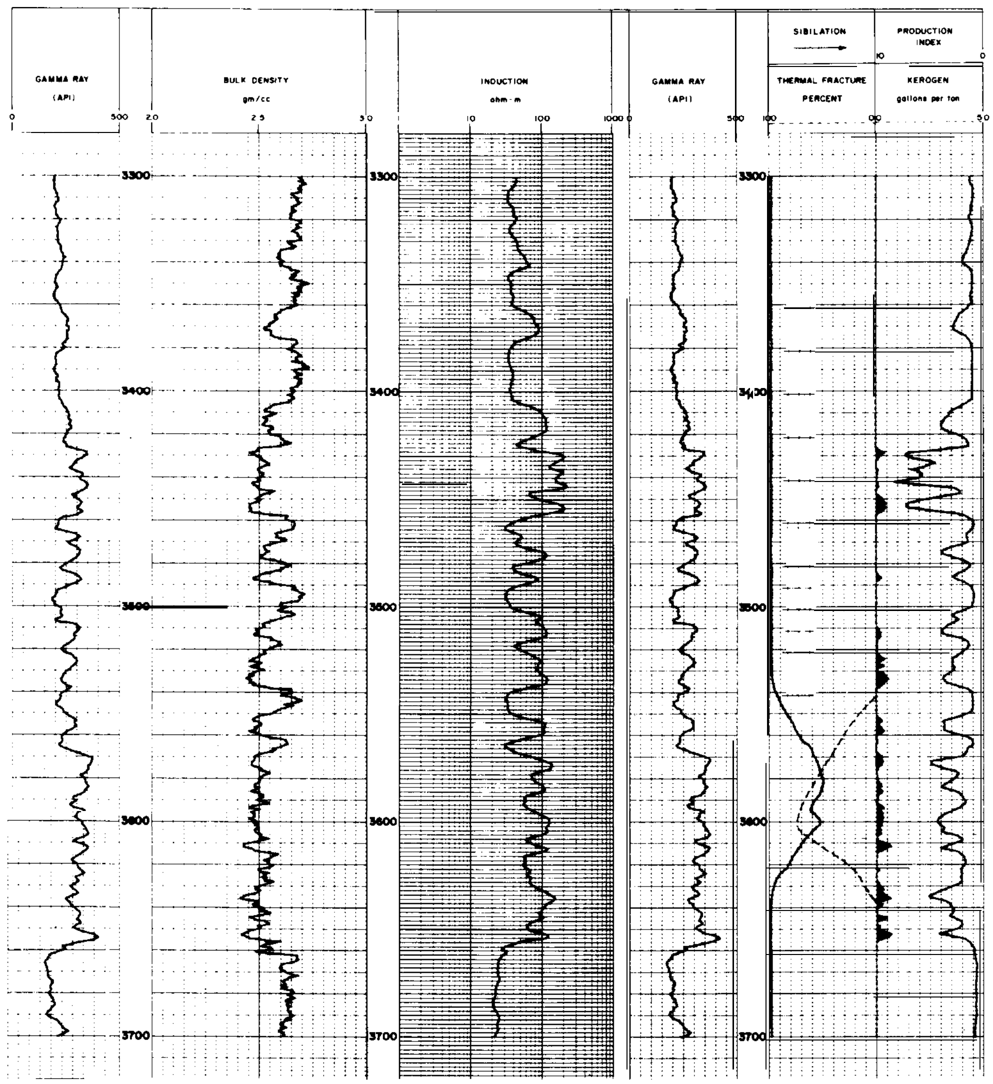


Figure 1. Empty Hole Logging Program

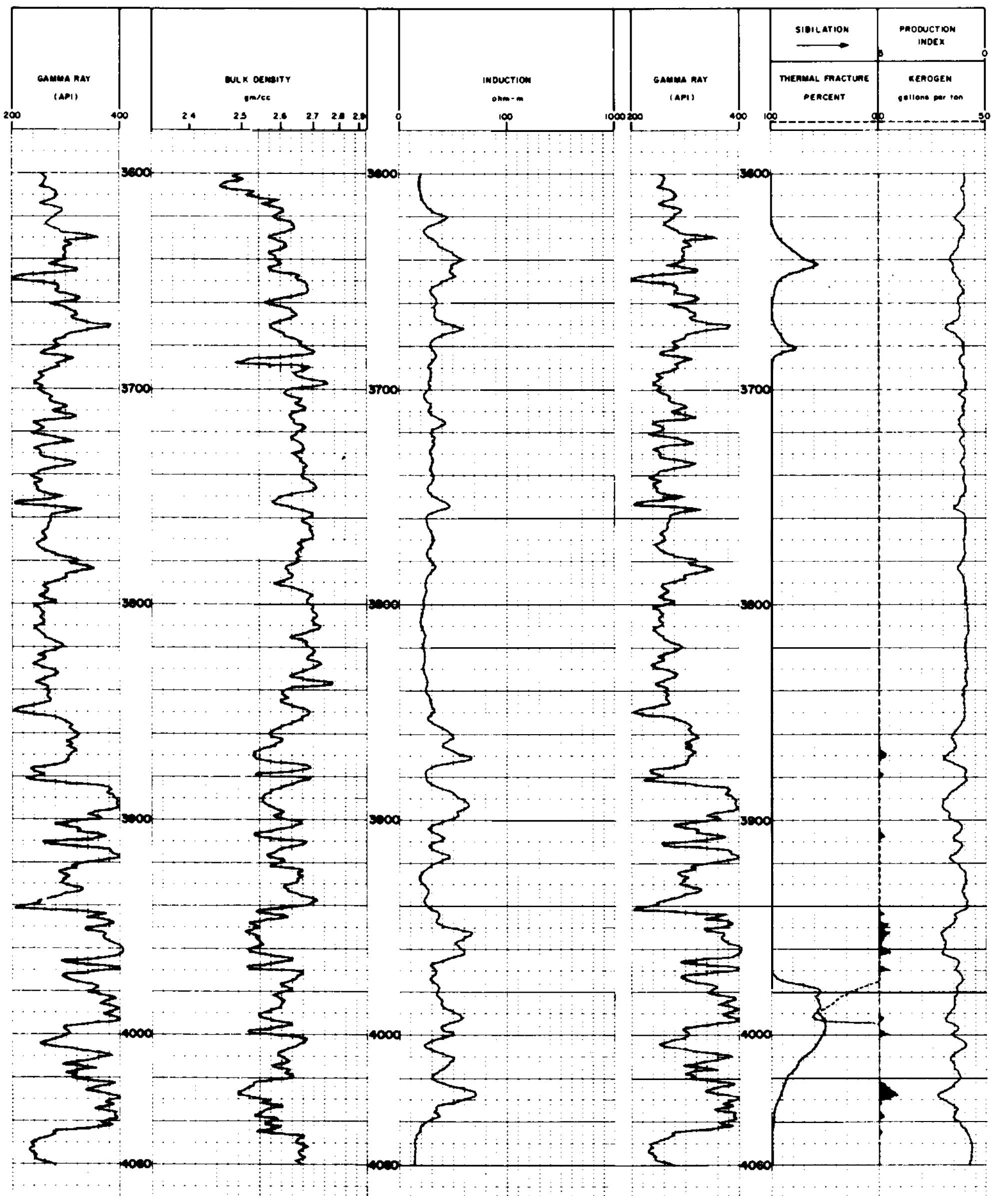


Figure 2. Empty Ho.e Logging Program

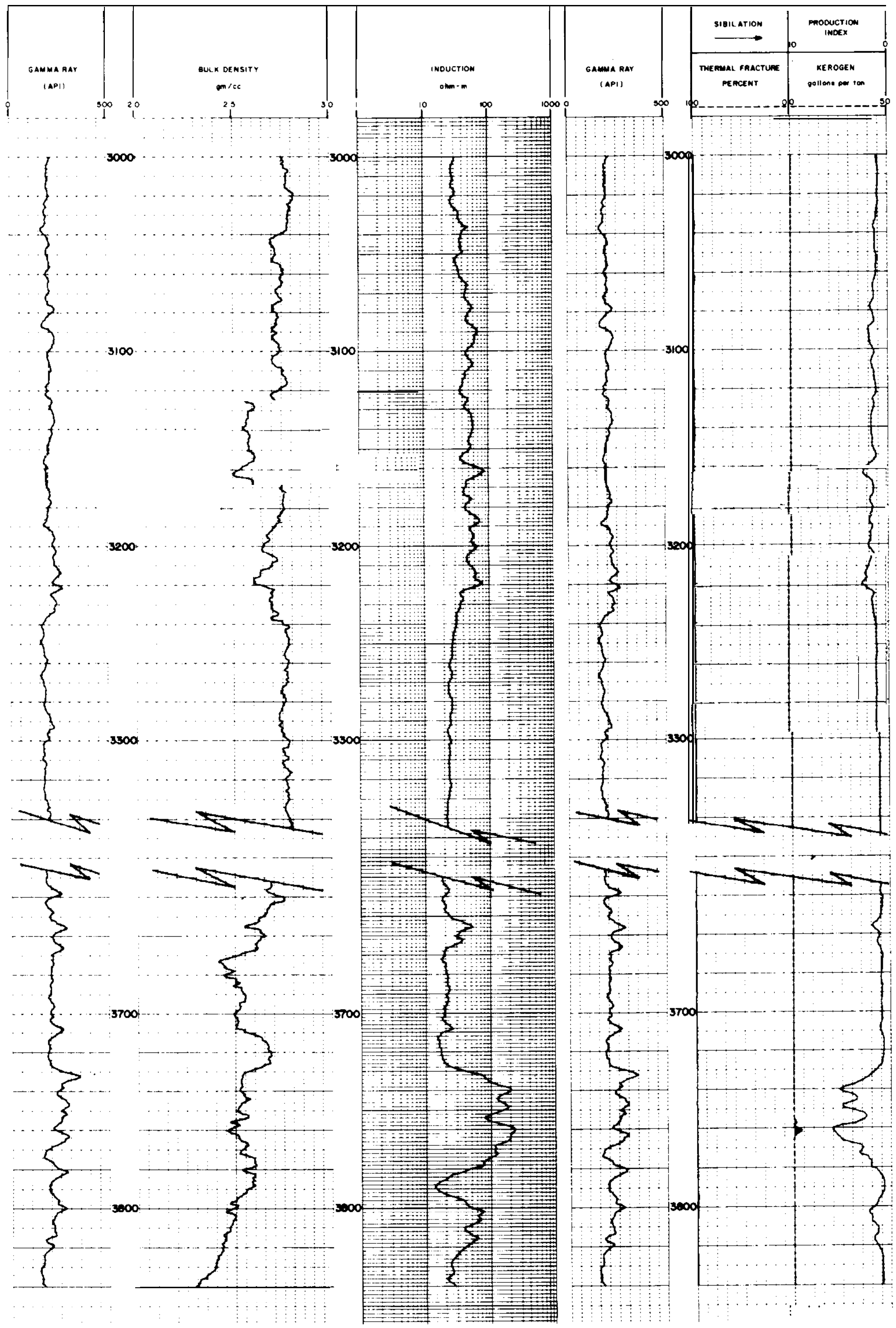


Figure 3. Empty Hole Logging Program

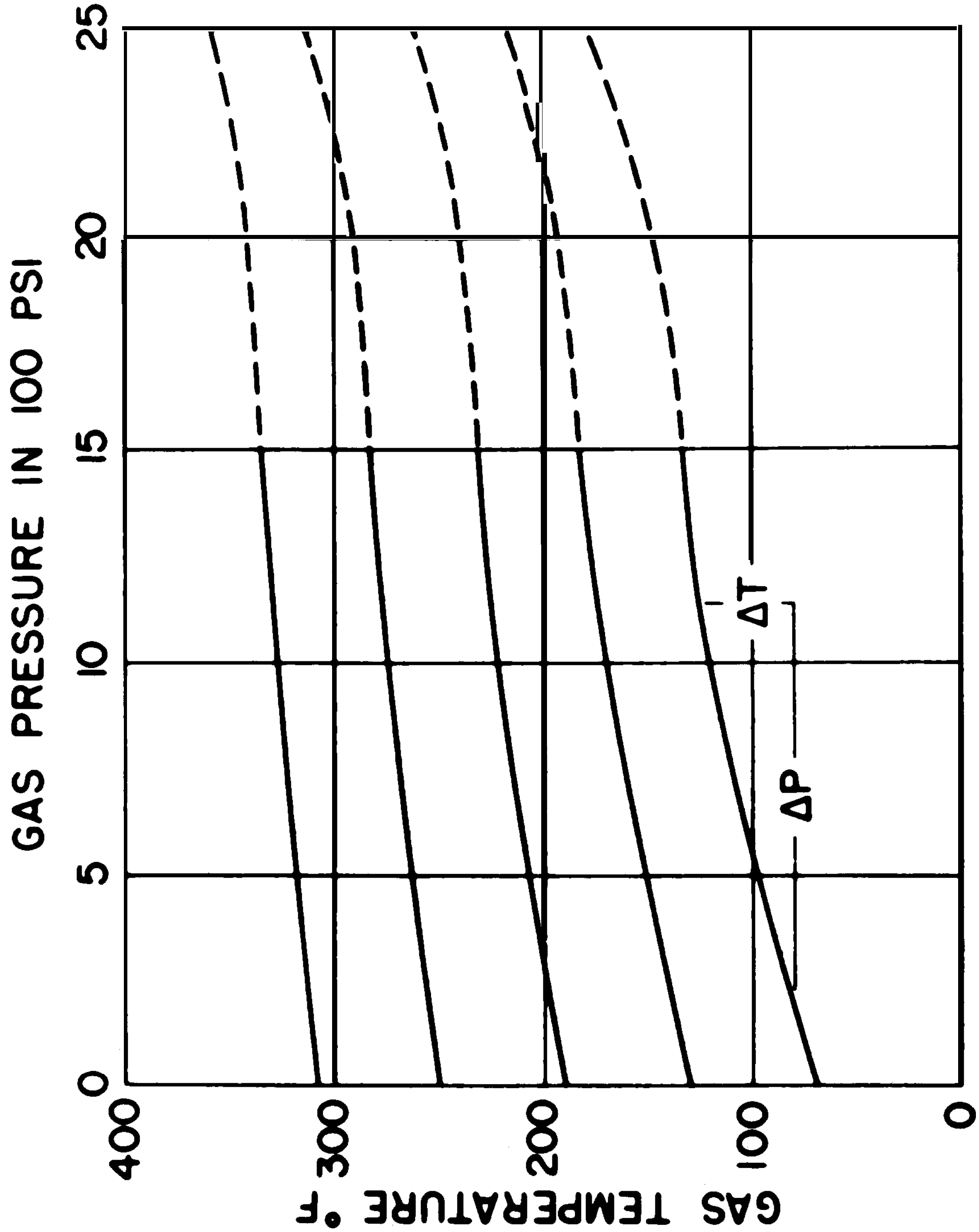


Figure 4. Joule-Thomson Effect: Gas Temperature Change Due To Expansion

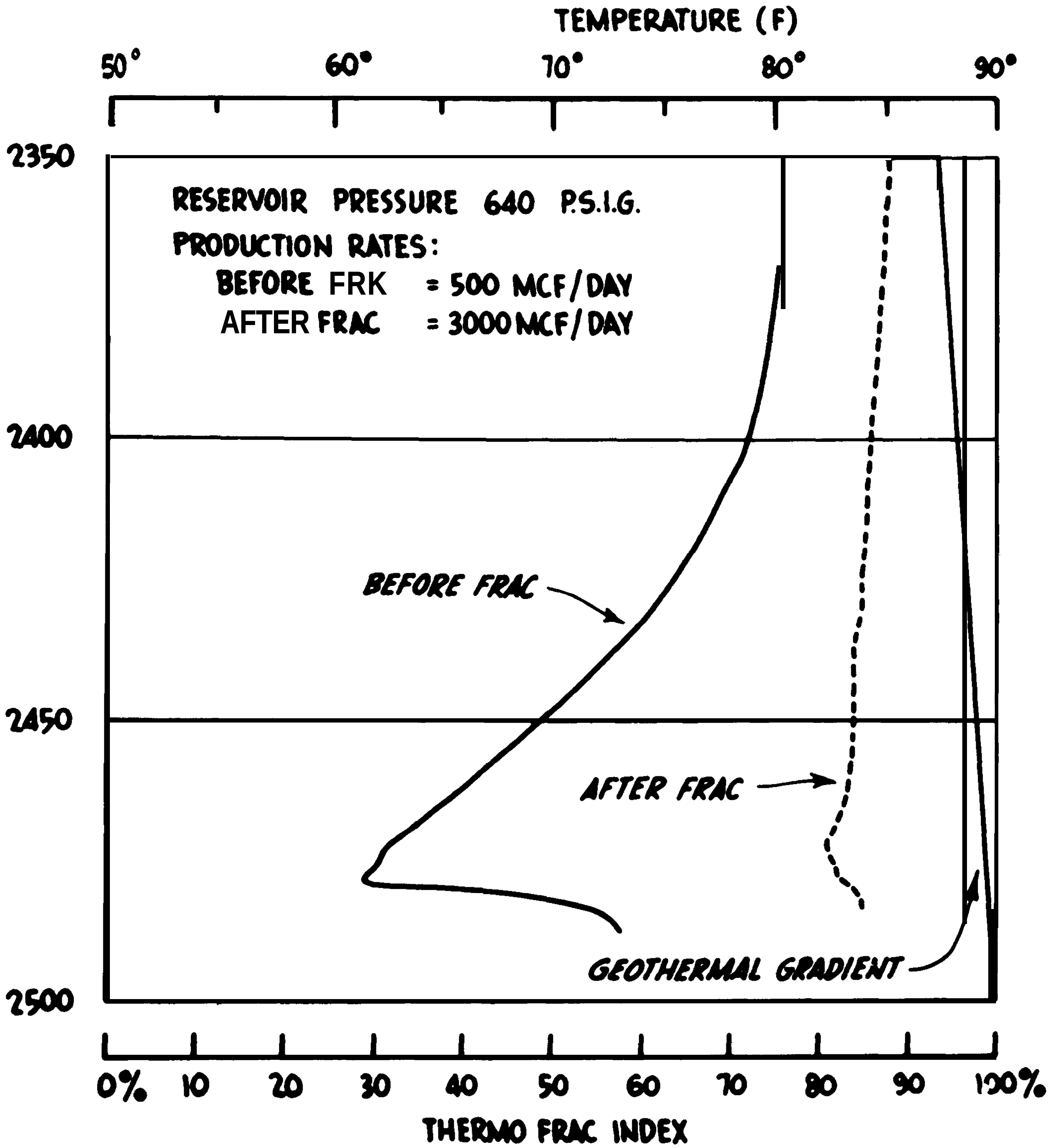


Figure 5. Temperature Logs (Before and After Fracturing)

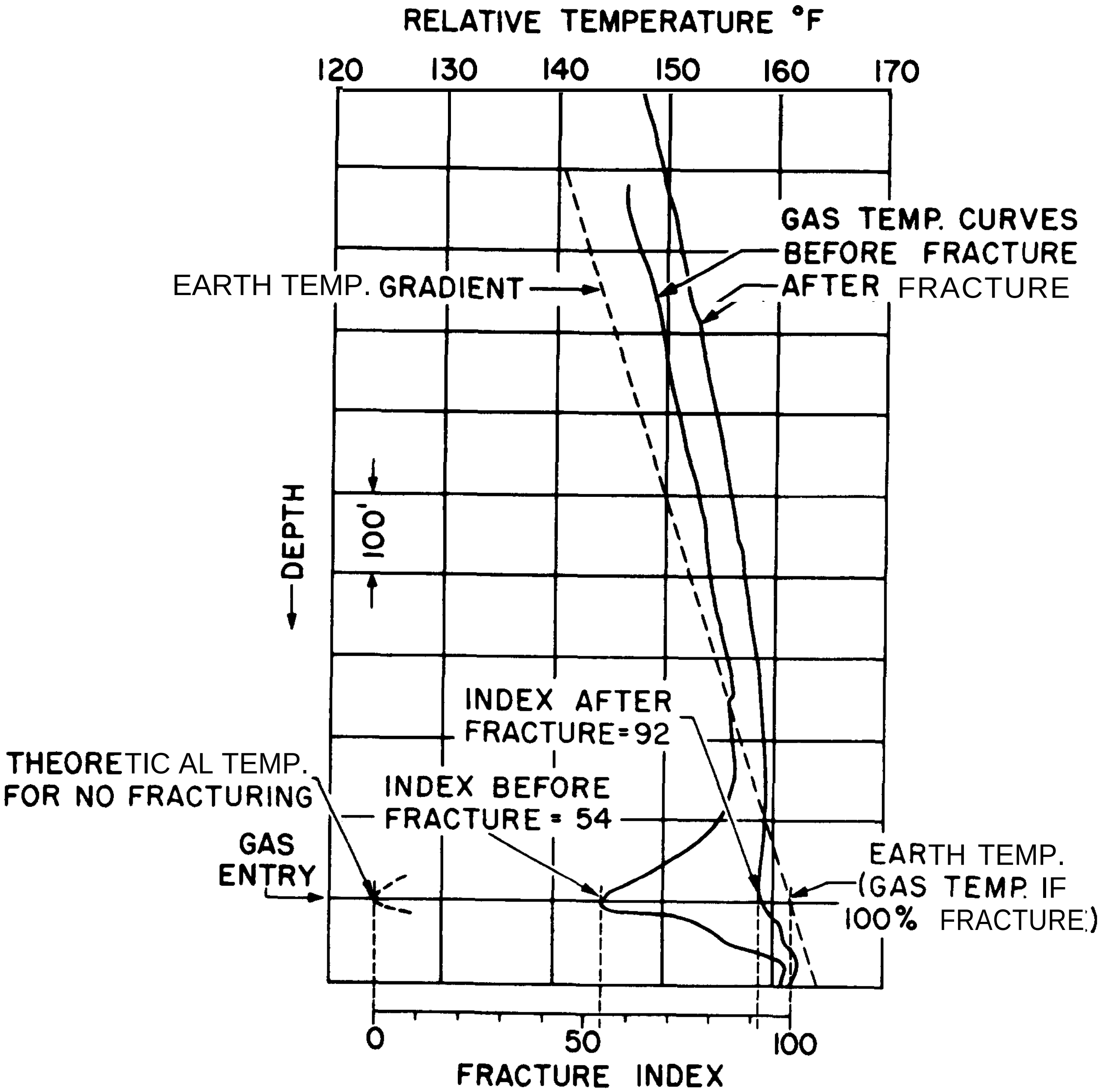


Figure 6. Temperature Logs (Before and After Fracturing)

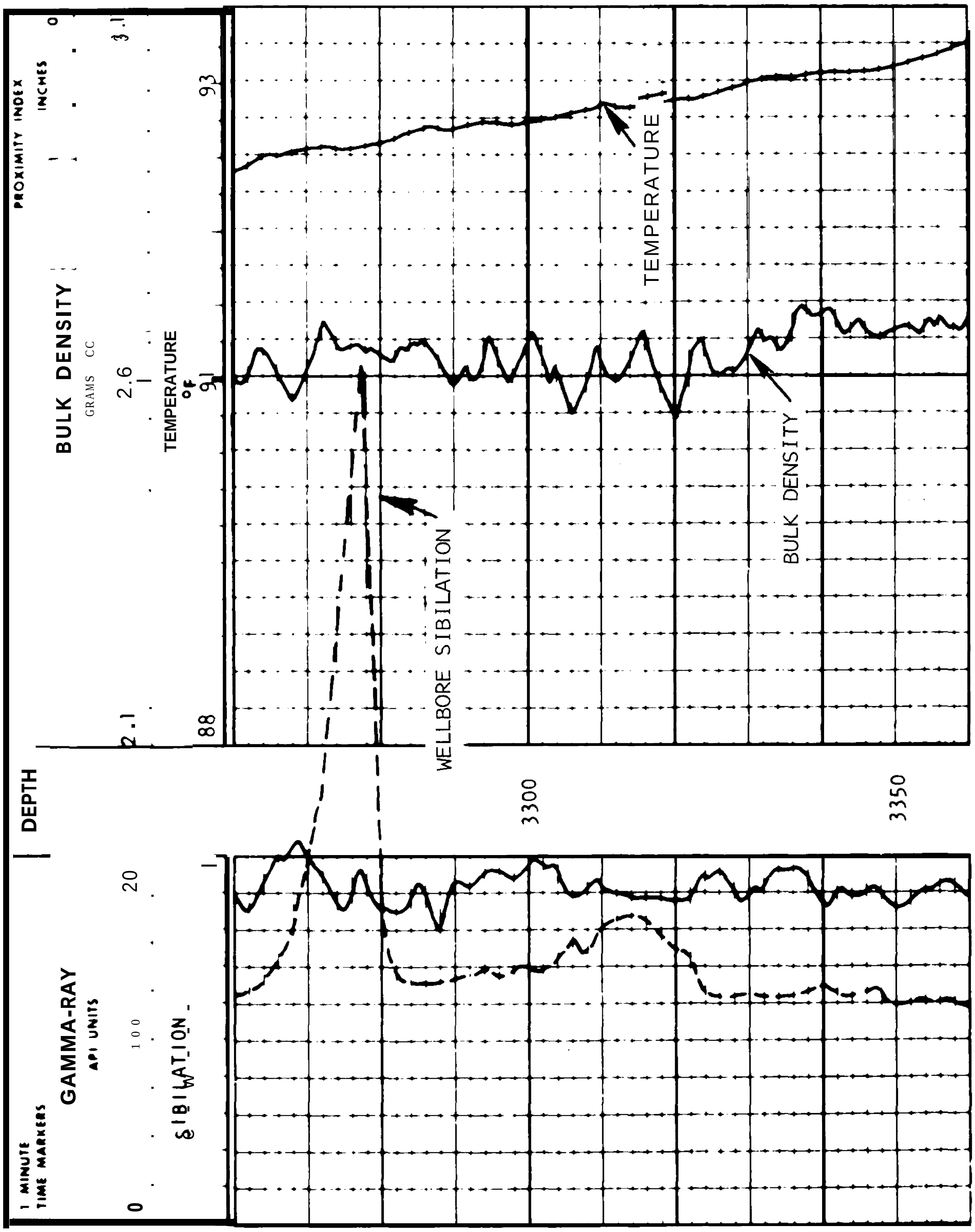


Figure 7. Wellbore Sibilation Survey and Temperature Log

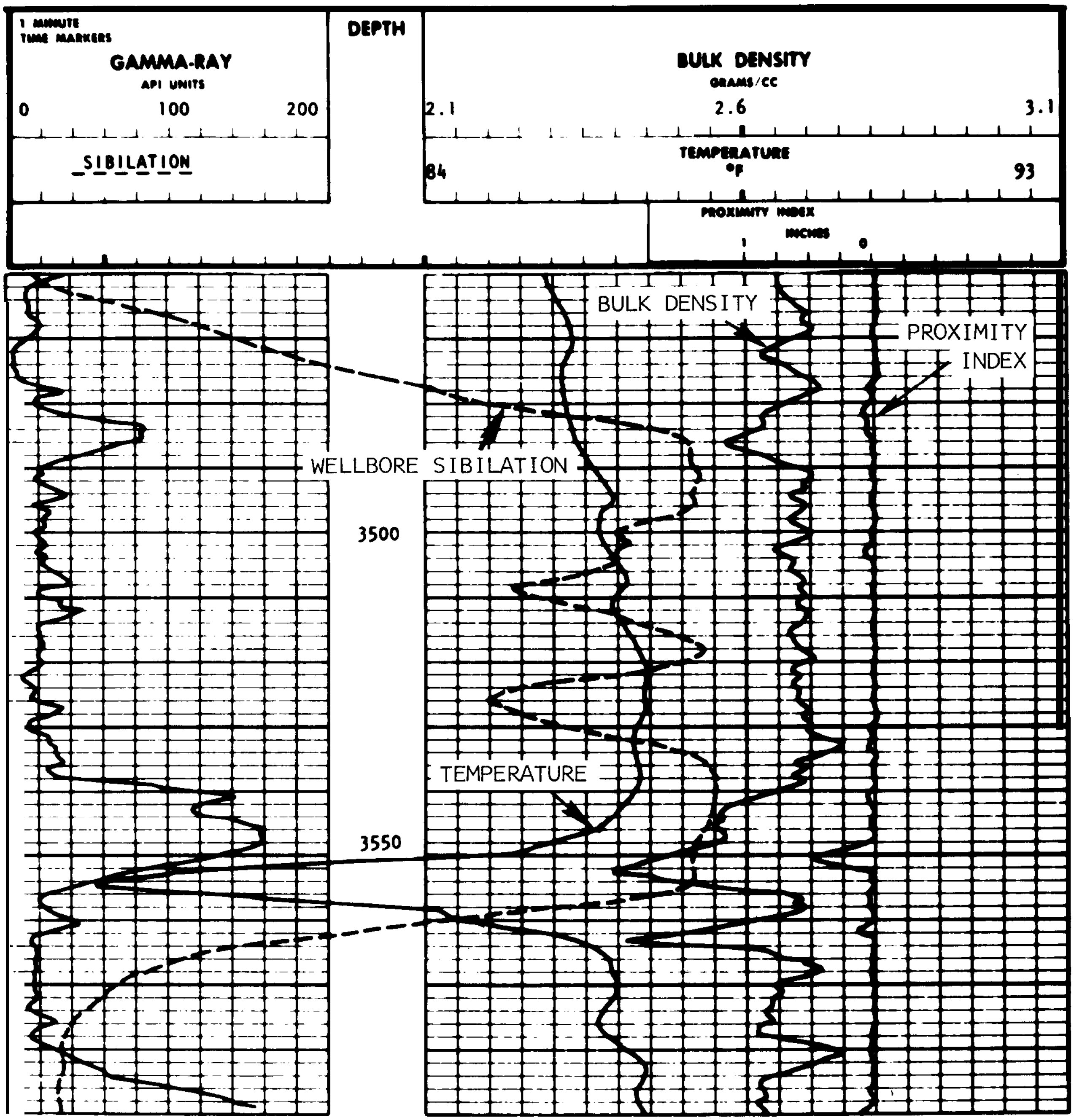


Figure 8. Wellbore Sibilation Survey and Temperature Log

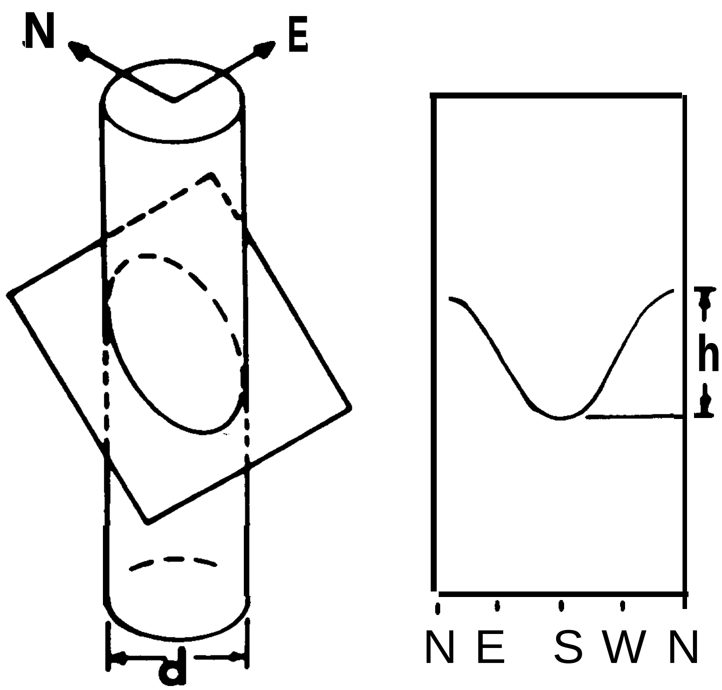


Figure 9. Isometric Drawing of Fracture Plane
Intersecting the Borehole

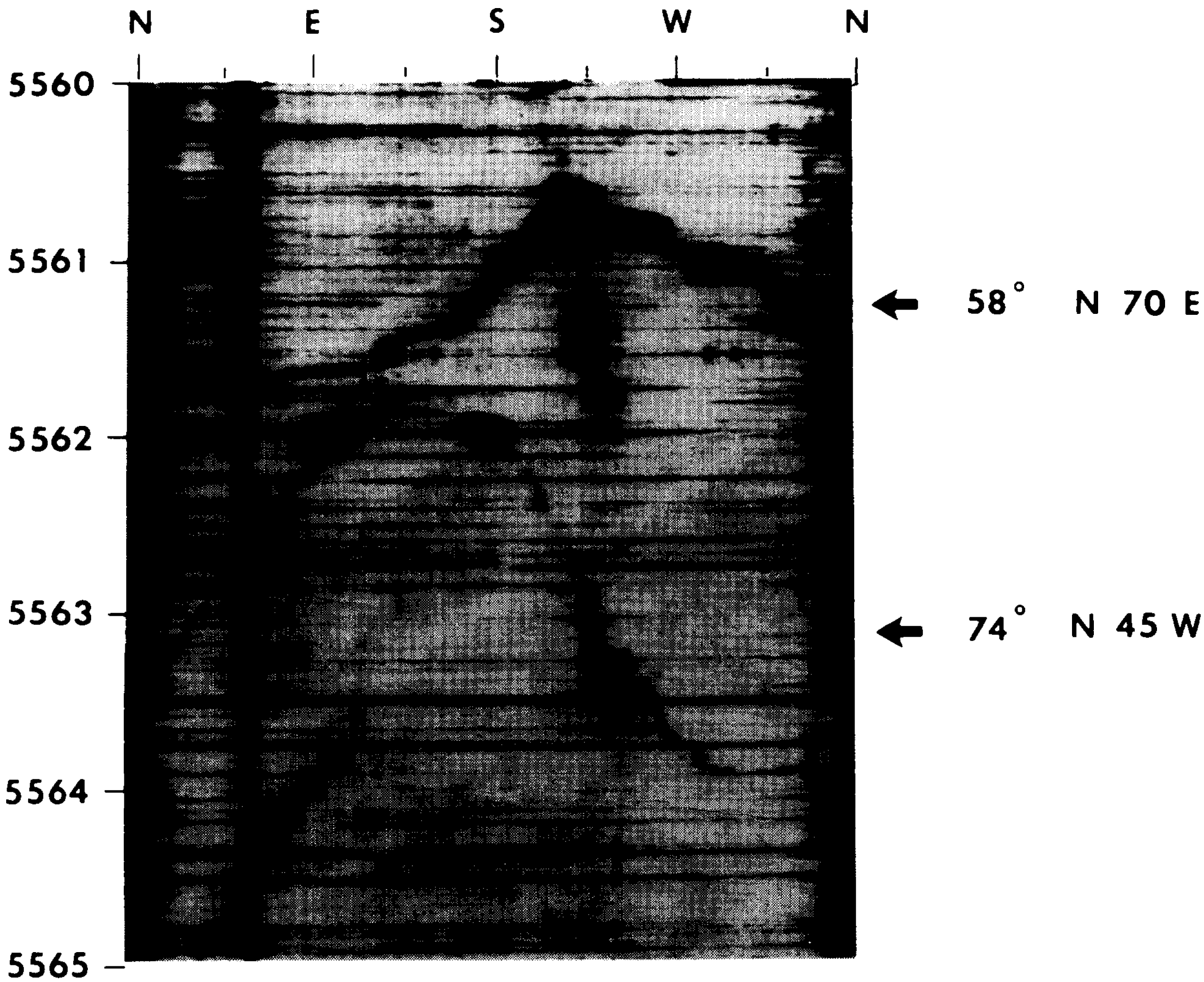


Figure 10. High Angle Fractures Intersecting Near Borehole
(After Caldwell and Strabala)

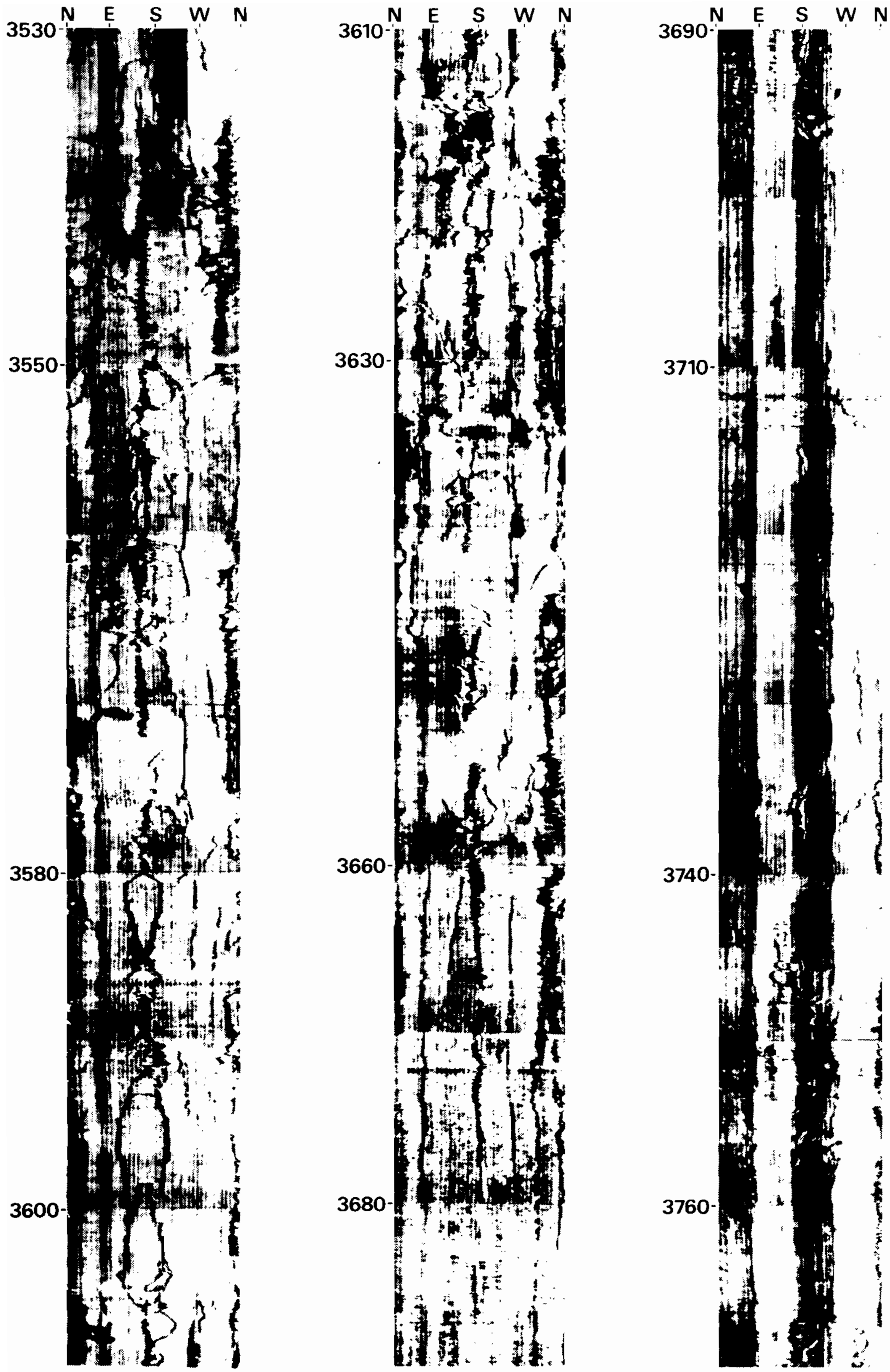
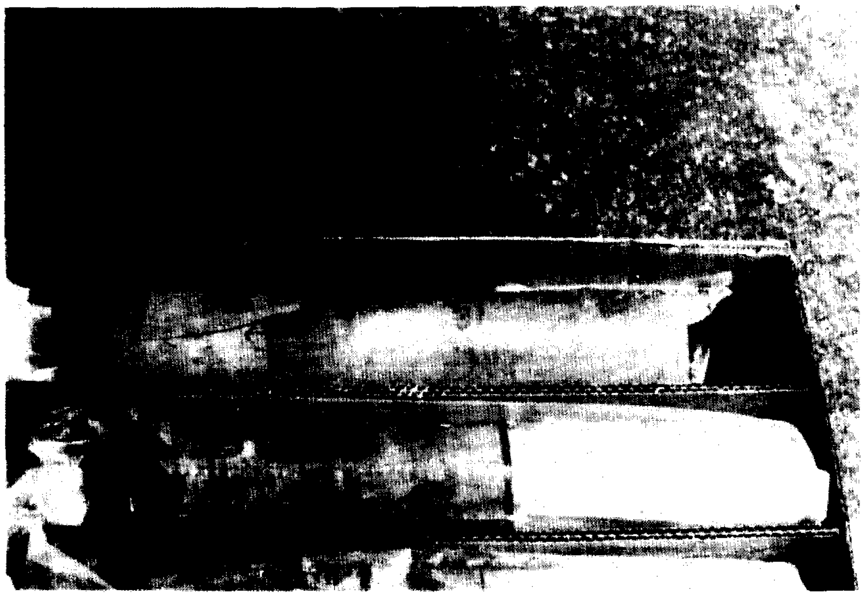
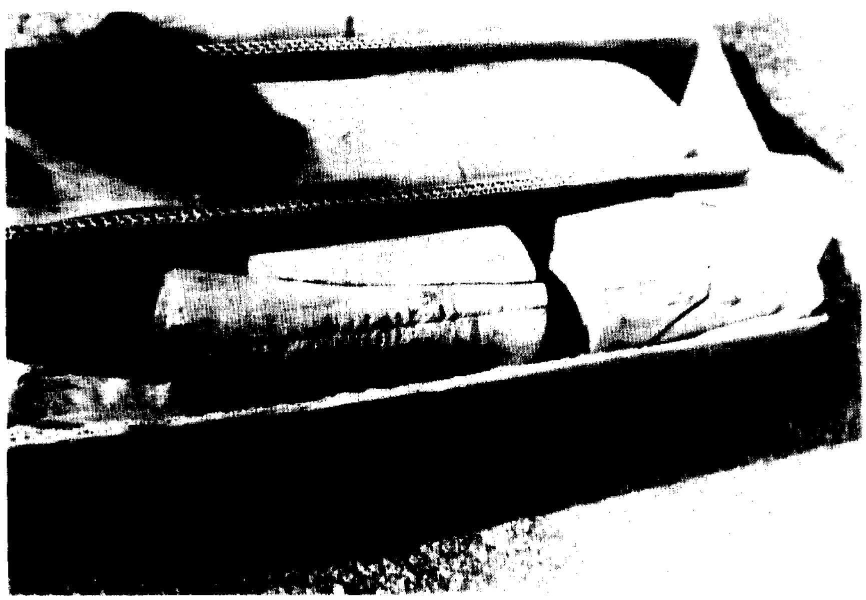


Figure 11. Seisviewer Log



(A)



(B)

Figure 12. Core Photgraphs

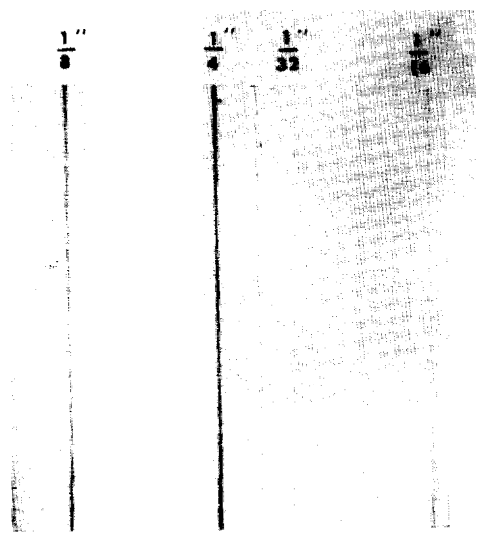


Figure 13. Simulated Vertical Fractures (Machined)

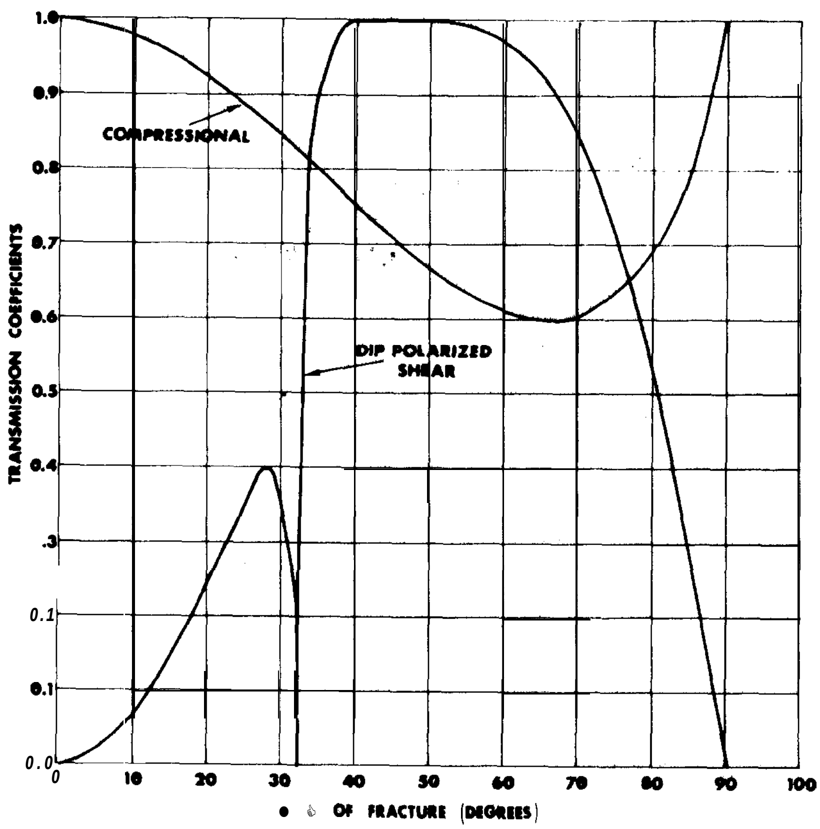


Figure 14. Knopoff's curves.

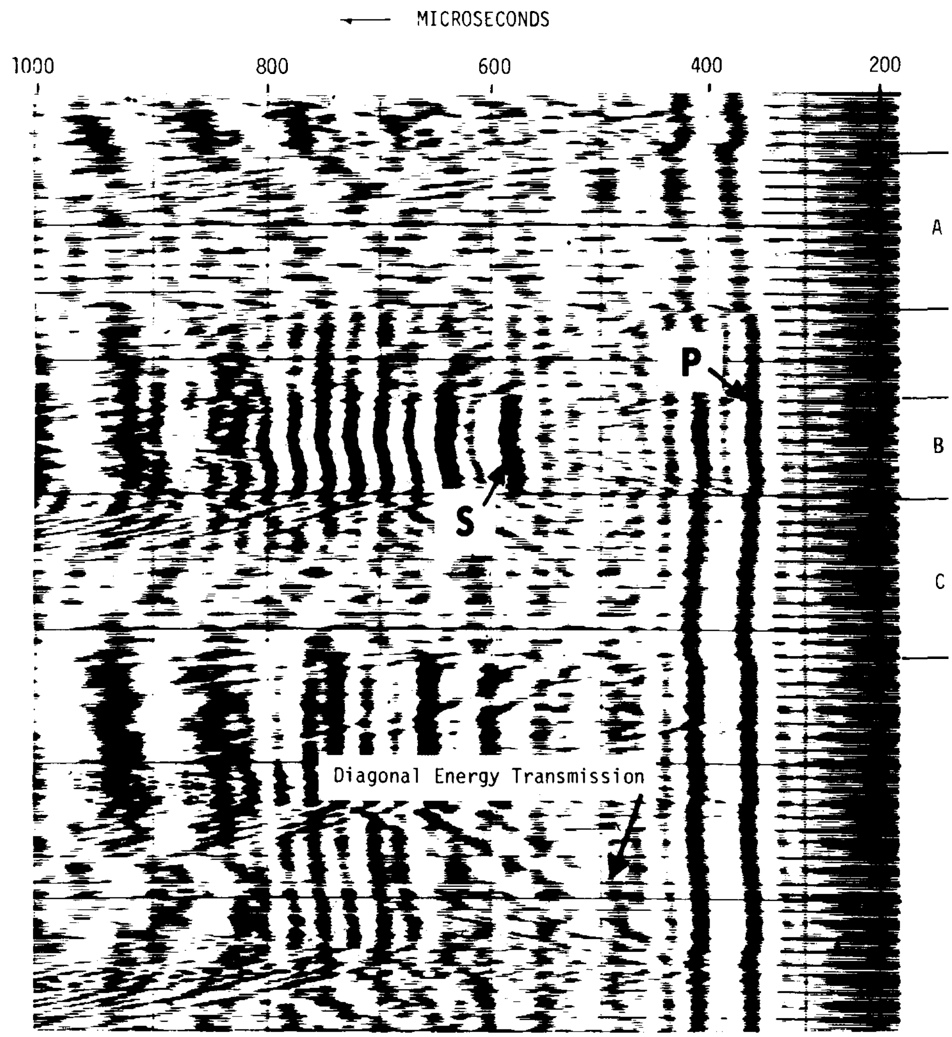


Figure 15. 3-D Velocity Log in Granite.

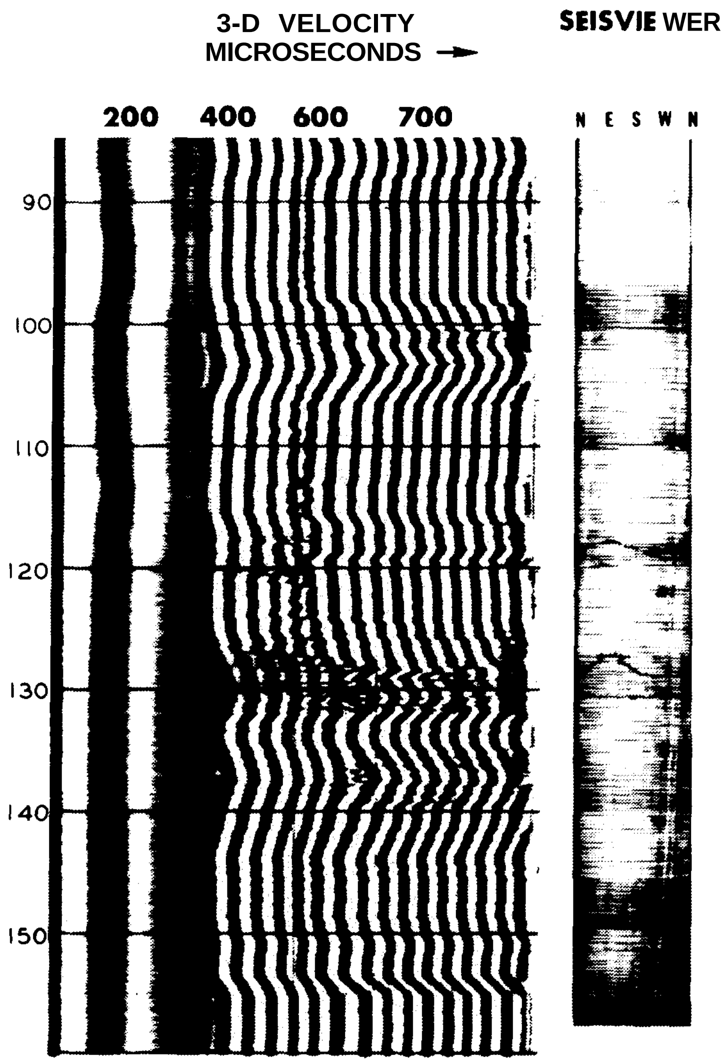


Figure 16. 3-D Velocity and Seisviewer Logs

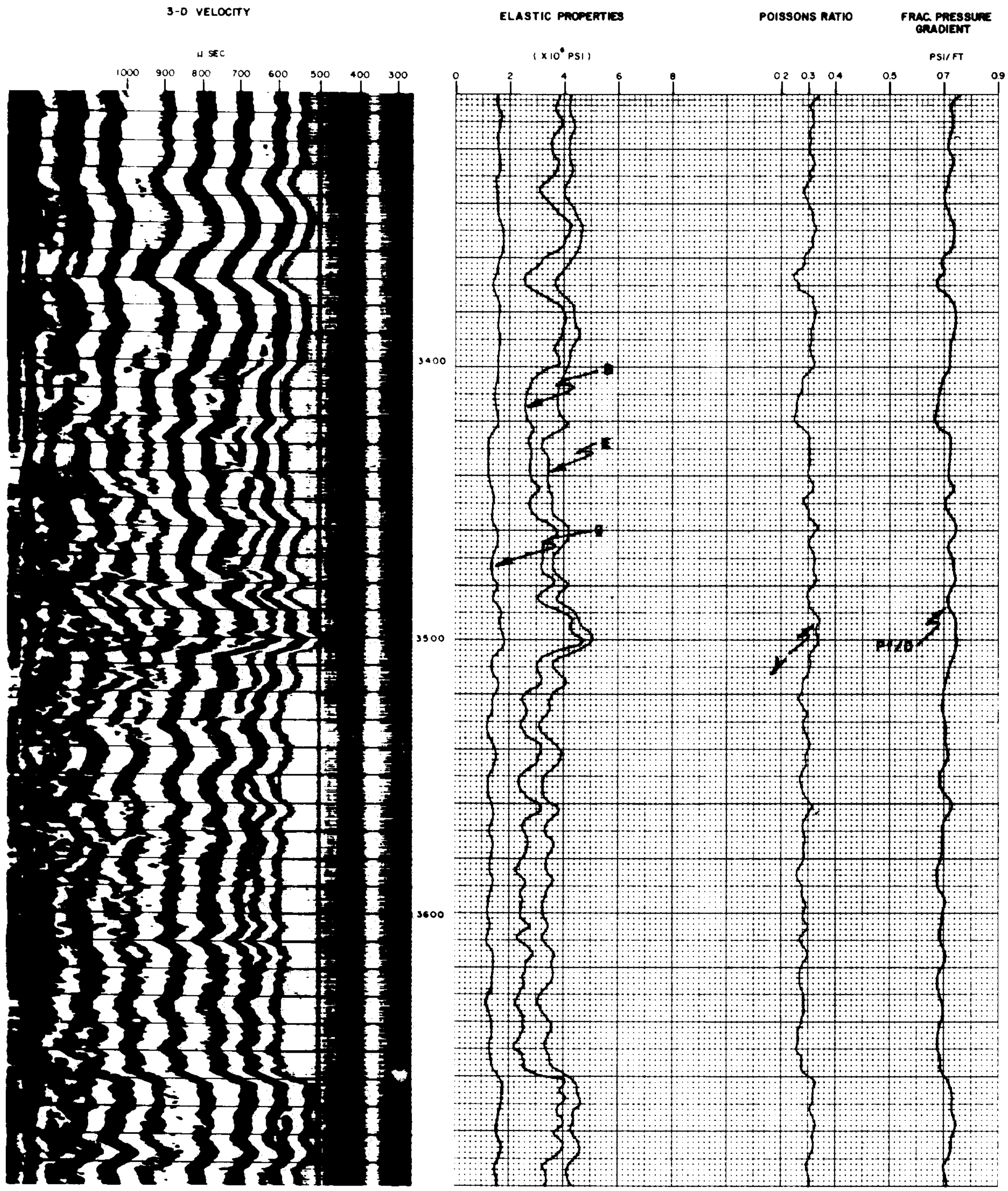


Figure 17. 3-D Velocity Log - Elastic Properties - Fracture Pressure Gradient

DEGASSIFICATION OF DEVONIAN SHALES

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INTRODUCTION

Work related to the development of gas bearing Devonian shales as a major national energy resource has focused on two major areas. The first area has to do with the study of the rock itself: its hydrocarbon content, permeability, mineralogy, etc.[1,2] The second area is concerned with fractures (both natural and artificial) in the rock.[3] It is clear that both kinds of studies will continue to be important components of any resource development program, as both fractures and hydrocarbons releasable from the shale matrix are necessary to a producing well.

Even this broadly stated formulation suggests mathematical modeling and characterization. Such modeling must contain the relevant parameters from both fracture and bulk rock investigations. At best, such models will eventually form the basis of an accurate means of predicting well output. Perhaps more realistically, they will allow evaluation and assessment of stimulation techniques, logging methods, and optimizing well location. At the least, such models should serve to focus attention on those parameters associated with gas production.

This paper is divided into four sections. In the theoretical part, we make a necessary (mathematical) distinction between small and large fractures. In the experimental and results sections, we present a small selection of our laboratory results concerning hydrocarbon content, diffusivity and adsorptivity of a few samples of Devonian shales. Finally, in the conclusion, we present a mathematical model that

INTRODUCTION (con't)

relates these results to well productivity

THEORETICAL

In this section we discuss the difference between flow in large channels and small channels and discuss in molecular terms the flow out from bulk rock into the macro fracture system. Shales consist of layered clay minerals with free spacing between the layers. These spacings are expected to be connected to channels between clay crystals (grain boundaries) which in turn are connected to successively larger fractures resulting finally in access to a network of a few fractures of macroscopic dimensions which afford access to the well bore hole.

The dynamics of flow are intrinsically different in small channels as oppossed to large channels. This difference arises fundamentally from the different collision properties of a gas molecule in the two cases.[4]

Most of the transport properties of a gas are a function of its collision dynamics and, to an excellent degree of approximation, such properties as the viscosity and diffusion coefficient are purely a function of the average molecular speed, $\bar{c}$, and the average distance between collisions (the mean free path, x). The mean free path between collision of gaseous molecules, λg, is

$$\lambda_g = \frac{}{\sqrt{2}\,\pi\,\sigma^2 N}$$

where

$\pi\sigma^2$ = collision cross section

N' = concentration of the gas in molecules/cc.

At standard conditions, $\lambda_g = 10^{-5}$ cm. However, a molecule collides, in general, not only with other molecules, but also with the walls. The total rate of collision r, of a given molecule is thus a sum of its collision rate (r_g) with other gas molecules and the (average) collision rate (r_w) with the walls. Since $r = \frac{\bar{c}}{A}$ we get

$$\frac{1}{\lambda} = \frac{1}{\lambda_g} + \frac{1}{\lambda_w}$$

For the sake of approximate calculation, $\lambda w \cong d_m$ where d_m is the channel width (i.e., the minimum channel dimension). It should be noted that when λ_g and λ_w are of widely disparate size, λ is approximately equal to the smaller. This is simply a reflection that in small channels and/or at low pressures wall collisions become relatively important; whereas, at high pressures and/or large channel sizes, gas-gas collisions are the predominating factor.

Flow through a circular channel is given by[6]

$$J_N = \frac{\pi r^4 P \nabla P}{8 \eta RT}$$

where:

J_N = flux in moles/sec cm^2

r = radius of the tube

η = gas vescosity

R = gas constant

P = pressure

The large power dependence on tube radius, r, is in part a consequence of the fact (in contrast to wall collisions) that the average collision takes place in a frame of reference moving down the tube at the flow rate. Darcy has generalized this relationship in

$$J = \frac{K}{\eta} P \quad P$$

where:

∇P is the pressure gradient

K = permeability

Darcy's law has been found to be applicable for a great number of flow systems such as packed beds of sand and chromatographic columns, wherein K is treated as an empirical parameter reflecting the average permeability associated with each channel. The gaseous viscosity η is given by[5]

$$\eta = \frac{\rho \bar{c} \lambda}{2}$$

ρ = density of the gas

$\bar{c}$ = average gas velocity

It should be noted that since λ and ρ are inversely and directly proportional to pressure respectively, the net result is that η has no pressure dependence. However, for small channel sizes λ is independent of pressure, η directly proportional to pressure, and since P is directly proportional to C, the gas concentration equation can be rewritten

THEORETICAL (con't)

$$J = -D \nabla C$$

or Ficks first law where D is the diffusion constant. It is useful to note that D is given for this case approximately by a modification of the ideal gas diffusion constant[5]

$$D = \tfrac{1}{2} R_F \, \varepsilon \, \bar{c} \, \lambda$$

where:

R_F = the chromatographic relation ratio which accounts for the time molecules remain adsorbed on the walls(8)

ε = a geometric factor approximately given by the porosity of the medium

In the event that the small channels are filled with fluid, the above equation no longer holds, but rather

$$D = \varepsilon \, R_F \, D_\ell$$

where D_ℓ is the diffusion constant of the hydrocarbon through the fluid filling the channels and R_F and ε have the same meaning as before.

As a conclusion to this section, it should be noted that the distinction between λ_g and λ_w implies a fundamental difference in the properties of large versus small channels that may be correlated with the fracture system versus bulk rock properties distinction made in the Introduction. Knudsen flow, rather than Poseuille flow, occurs in small channels. Further, the adsorptive properties of the walls play an increasingly important role in small channels because the ratio of channel wall area (available for adsorption) becomes large relative to channel volume.

EXPERIMENTAL

Sample History and Well Log Parameters

The samples used in this work were from cores obtained from the R. D. Brown Well, Belmont County, Ohio, and were furnished by Columbia Gas System Service Corporation. Also furnished were well logs of this well. The cores were from three different depths: core 1 from 5568 feet, core 2 from 4403 feet and core 3 from 2425 feet.

The following "well" characteristics were obtained from the logs:

Core #3, 2425 feet: At this depth the wide-wall neutron porosity log showed approximately 12.5% porosity and the accompanying

EXPERIMENTAL (con't)

Sample History and Well Log Parameters (con't)

gamma ray trace showed moderate shale structures of approximately 140 API units. The compensated neutron porosity log showed a porosity of about 25% and a gamma ray reading again of approximately 140 API units. The formation density log at this depth showed 0% porosity,

Core #2, 4403 feet: At this depth the sidewall neutron porosity log showed 12% porosity and the accompanying gamma ray trace indicated shale structure equivalent to 160 API units. The compensated neutron porosity log showed a porosity of 25% with a gamma reading of approximately 160 API units. The formation density log showed 0% porosity.

Core #1, 5568 feet: At this depth the sidewall neutron porosity log showed about 15% porosity and the accompanying gamma ray log a reading of 180 API units. The compensated neutron porosity log showed a porosity of 24% with a gamma reading of 170 API units. The formation density log showed a porosity of 9%.

The well log data from these depths suggest a few trends through the formation. Both the sidewall well porosity and formation density logs indicated an increase in porosity as one goes from core 3 to core 1. The gamma ray reading indicates an increase in the amount of shale as the depth increases from core 3 to core 1. It should be realized that because of the heterogenity of rock formation trends s ich as these are not perfectly continuous and, for some regions, can even be reversed.

Age of Core Sample

One of the factors that should be kept in mind in evaluating these results is the age of the samples (i.e., the length of time since they were removed from the bore hole). A year had passes since the coring was finished and the degassing experiment begun. During this time the amount of natural degassing which the cores could have experienced is not known, but it could have been considerable, The effect this would have on the degassing results of the experiment are, of course, obvious. The effects of

Age of Core Samples (con't)

this exposure to air are probably not significant for the structure analysis.

Degassing Studies

The apparatus used was essentially a rebuilt version of the BET apparatus described earlier.[6] Slight modifications consisted of replacing the mercury-operated, glass-plunger valve with an ordinary O-ring valve. In addition, the sublimation furnace was replaced with a fluidized bath capable of temperatures up to $600^{o}C$ with somewhat improved temperature uniformity.

For a run, a sample of shale was broken from the core, crushed, and several grams introduced into a flat-bottomed sample cell. The cell is Erlenmeyer-like in design, some three cm across at the base, but necking down to an opening made of wide base capillary tubing. The advantage of this improved design is several fold. First, the wide base of this design decreases the chance of degassing blowing powdered shale into the rest of the system. As the cell was sealed directly to the system by connecting the capillary tubing of the cell to that of the system, changes in volume occurring as a result of the glassblowing were kept small. In addition, the volume of the cell could be accurately measured and density measurements of the shale made in situ after disconnecting the cell from the run. Finally, the thermal gradient between the oven at $723^{o}K$ and the rest of the apparatus at $300^{o}K$ was restricted entirely to a negligible volume of capillary tubing. A sample of shale was introduced into the tared flask which was then reweighed and attached to the system. The system, capable of reaching 10^{-4} torr without sample, was then pumped down for a period of about 5-10 minutes. Under these circumstances, air from shale desorbtion, or from the dead volume of the apparatus, makes a negligible contribution to degassing. At this point the valves were closed, the fluidized bath raised around the sample cell and the clock started. The pressure was allowed to rise to 10 cm Hg and then the volume of the gas buret adjusted manually to maintain

EXPERIMENTAL - (con't)

Degassing Studies (con't)

constant pressure. Time measurements were taken as the various calibrations of the gas buret were reached. Kinetic measurements during a run were, thus, divisible into three regions--a constant volume region at short times wherein the pressure increased from 0 to 10 cm, a constant pressure region wherein the volume of the system increased from about 13 ml to 143 ml (the lowest mark on the gas buret) and, finally, a constant volume region (143 ml) with pressures rising to the order of one atmosphere over a period of about 12-18 hours. At this point gas was vented to the Toepler pump and the pressure adjusted for contamination-free transfer to a syringe for G. C. analysis. After a run, the cell was removed from the system, weighed, filled with water to the volume mark, evacuated several times to release entrapped air, weighed in order to ascertain shale density and system dead volume in presence of shale, the shale and water removed, and the cell weighed (re-tared) in order to obtain the weight loss of the shale upon heating.

Small amounts of non-gaseous substances were evolved from the shale that condensed within the system. Their physical appearance suggested sulfur and water and/or light oil. The amounts of these substances was small enough to be ignored. However, it was also apparent that degassed H_2S was slightly tarnishing the mercury. This was judged to be negligible; but, in view of the possible importance of the discovery of H_2 (see results section), it was important to absolutely eliminate the mercury tarnishing reaction (with H_2S) as a source of hydrogen gas. To reach this end, and to obtain some idea of how gas composition changes with time of degassing, a second all-gas apparatus was built, so the possibility of H_2 forming from mercury contamination could be eliminated. The sample was introduced into the cell which was then evacuated, sealed under vacuum by glassblowing, immersed in the fluidized bath, and gas samples taken off after the pressure built up to atmospheric by inserting a 4 ml syringe through a rubber septum

EXPERIMENTAL (con't)

Degassing Studies (con't)

mounted on the tube. These samples were then stored in evacuated 2 ml serum vials until G. C. analysis could be effected. This procedure allowed us to monitor compositional changes as a function of time in addition to the primary function of verifying the presence of hydrogen gas from the shale.

Differential Thermal Analysis--Experimental

Thermograms were obtained by use of a DuPont Model 900 Thermal Analyzer fitted with a differential scanning calorimeter cell. The heating rate was 10^{o} C/minute for most of the samples, although some data were taken with a heating rate of 20^{o} C/minute. The thermograms were taken from ambient temperature (19-26^{o}C) to about 500^{o}C in a heating mode followed by cooling back to ambient. The reference material was glass beads. The samples were finely ground by use of a ball mill.

Structure Analysis--X-ray Diffraction

Shales are made up largely of clay minerals which, in turn, are made up of various arrangements of alternating layers of tetrahedral silicates and octahedrally coordinated metal ions such as Al^{+3}, Mg^{+2}, Fe^{+3}, etc. The particle size of minerals is so consistently small that the word clay has in some cases been used to mean any mineral occurring in very small particles. In this paper, the term clay is used in the former sense.

Since there are many active sites between the layers in a clay mineral and since it is thought that transport of material would be much easier in a direction parallel to the layers, special attempts were made to analyze the clay content of the shales. Preliminary x-ray analysis of powdered samples showed a great deal of quartz present. In fact, so much quartz was present that the x-ray diffraction from the quartz tended to mask the diffraction from the clay minerals. This prompted efforts to remove quartz and other non-clay minerals from the sample.

1. Separation of Clay Minerals.--Attempts to disaggregate the clay minerals from

Structure Analysis--X-ray Diffraction (con't)

carefully crushed samples (l-2 millimeters) by use of an ultrasonic bath with water on a medium proved unsuccessful. This was presumably because of the low power of ultrasonic baths at our disposal compared to the higher powered ultrasonic probes normally used for the disaggregation of clay minerals.

A technique that proved to be effective for the removal o- quartz from our samples utilized a ball mill as follows: Core samples, after being washed with deionized or distilled water to remove possible traces of drilling muds on the outside, were crushed into pieces approximately 2 cm in diameter. The samples were then put into a ball mill (spec mixer/mill) and milled for 10 minutes. At this point the sample consisted of some hard nuggets the size of small shot and a fine powder. A slurry was prepared of the fine powder portion using enough water to make a fine flowing suspension. This suspension was pipetted onto a ceramic slide and left to evaporate. Since ceramic slides absorb water, the slide was heated in a drying oven at 95^{o} for fifteen minutes to make sure that evaporation was complete. Samples from cores #2 and #3 prepared by this technique were found by x-ray analysis to be virtually free of all quartz. Core #1 was interesting in that even though the sample had the same appearance after being milled (i.e. hard nuggets and fine powder), much of the quartz from the core was found in the powdered part of the sample. This difference in the distribution of quartz has as yet not been accounted for, nor has the composition of the hard nuggets or their distribution been investigated.

2. Preparation of Oriented Samples.--
Since orientation of the clay minerals in the shale could effect the ease with which gas could be given up or the ease with which it could pase to the bore hole, the possibility of such orientation was investigated. If the clay minerals were randomly arranged in the shales, then the x-ray diffractogram would be the same regardless of the original orientation of the sample. To determine the existence

EXPERIMENTAL (con't)

Structure Analysis--X-ray Diffraction (con't)

of possible orientation, samples were cut perpendicular and parallel to core axis. The core axis appeared to be approximately perpendicular to the bedding planes of the shale. The samples were cut on a rock saw to approximate the size of petrographic glass slide. These pieces were glued onto a slide using a technique common for mounting thin sections. Once the sample was mounted on the slide it was then cut using a thin section saw and ground flat to a thickness of about 1 mm using lapidary equipment. Samples prepared in this manner give x-ray diffractograms equivalent to x-rays being incident on the sample as shown by the arrows in figure 1. The directions of the arrows in figure 1 are mutually perpendicular.

3. Preparation of Degassed Samples.--Samples which had been degassed were, in general, treated the same as samples which were just crushed and mounted, with the exception of one additional step, Because calculations involving the volume of the cell required the addition of water to the cell, the degassed samples had to be dried before the slide could be prepared. The excess water was removed from the degassed shale by centrifuging in a Sorus Centrifuge at 6,100 g for 30 minutes. This separated all of the particles from the water.

4. X-ray Data and Mineral Identification.--The x-ray data were taken on a GEXRD-6 diffractometer with filtered Cu K_2 radiation. The scan rate was 2^{o}/min. Mineral identification was determined from the presence of unique x-ray lines.

Shale Gas Analysis

The analysis of the gas from shales was carried out by use of gas chromatography techniques. The gas composition for each sample was computed from combined data from two chromatographic separations. The details of the separations are as follows:

	Separation I	Separation II
Column Material	54 Molecular Sieve (120-170 Mesh)	20% Dow Corning Silicone Grease/Chromosorb W (60-80 Mesh)
Column Length	1.5 m	1.5 m
Column Diameter	1/4"	1.4"
Column Temperature	100°C	ambient--25°C
Carrier Gas	Ar	He
Flow Rate	100 ml/min	300 ml/min
Detector	Thermal Conductivity	Thermal Conductivity
Retention Time for He	0.6 min	---
H_2	0.7 min	0.18 min
O_2	1.1 min	0.18 min
N_2	1.6 min	0.18 min
CO_2	retained	0.20 min
H_2S	retained	0.25 min
CH_4	2.5 min	0.18 min
C_2H_6	retained	0.23 min
C_3H_8	retained	0.29 min

As the retention time data indicate, the molecular sieve column resolves hydrogen, nelium, oxygen, nitrogen, and methane, while retaining the other gases. The silicon grease column does not resolve hydrogen, oxygen, nitrogen, and methane (the "air peak"), but resolves the remaining gases.

The response of the detectors to each of the individual gases was determined. The absolute detector response was found to be quite sensitive to flow rate and diffifult to reproduce. The relative responses, however, were reproducible. The detector response for each gas resolved for column I was then determined relative to nitrogen

Shale Gas Analysis (con't)

and for column II relative to air. Both columns were constructed of copper; however, no hydrogen was detected in the molecular sieve column upon injection of H_2S. Hence, the possibility of hydrogen arising as an artifact from this source was eliminated.

The signal from each of the detectors is fed through an appropriate interface into a NOVA 1220 Computer. The computer is programmed to accept the detector data at a selected sampling rate, and to display the data on a CRT. A peak finding routine processes the data in real time to obtain retention times and peak areas. The data are stored for possible future processing. In the case of overlapping peaks, the overlapping area is divided equally among the two peaks.

Analyses were performed by first injecting a known amount of air (a 0.20 ml sample size in most cases) into each column to calibrate the detector response. A sample of the gas to be analyzed was then injected into each column. The analysis of the gas was then computed from the data of separation II by using the data from separation I to apportion the area of the "air peak" in separation II among the four gases, hydrogen, oxygen, nitrogen and methane. The total amount of gas found per ml injected, as well as percentage composition, were calculated from the data by a computer routine. The typical difference in the amount of gas detected and that injectes was about 2%, indicating excellent consistency of results.

B.E.T. Surface Area

Layered and other materials with void spaces large in comparison to molecular dimensions often strongly absorb a variety of materials. The shape of the resulting isotherms permits interpretation in terms of a surface area available for adsorbtion. In particular, the amount of gas adsorbed can be followed as a function of gas pressure either by the changing weight of the sample or by pressure volume relationships and the results can be interpreted in terms of a surface area by means of the B.E.T.

EXPERIMENTAL (con't)

B.E.T. Surface Area (con't)

equation (11)

$$\frac{x}{n(1-x)} = \frac{1}{n_m c} + \frac{(C-1)\,x}{n_m c}$$

where:

- x = ratio of pressure to pressure at the condensation point
- n = number of moles adsorbed
- n_m = number of moles corresponding to a monolayer on the surface
- C = constant related to the heat of adsorbtion

The parameter n_m is found by graphical or least squares analysis. Our results were made on degassed samples of shale, using nitrogen as the adsorbate at liquid nitrogen temperatures.

Diffusion Constants

The diffusion constant for nitrogen in shale was measured by following the uptake of nitrogen by ground and sized (sieved) samples of shale. A modification of equations discussed by Crank (10) results that

$$\frac{P_0 - P(t)}{P_0 - P_\infty} = \frac{P_0}{P}\left(\frac{6}{\pi^{1/2}}\,\frac{D^{1/2}}{a}\right) t^{1/2}$$

where:

- P_0 = pressure at t=o
- P_∞ = pressure at $t=\infty$
- P(t)= pressure at intermediate times
- t = time
- a = particle radius

Thus, given a graph of P vs $t^{1/2}$ D can be obtained for a sample of uniform size. A sample of core #1 sieved to 276-350 u was degassed at $200^{o}C$ in vacuum and then the pressure step measurements effected with N_2 at liq N_2 temperatures. The procedure is similar to that used by Walker for (12) studying diffusion through coal.

RESULTS

Results can be divided into four categories, Equilibrium, X-ray Structure Analysis, Differential Thermal Analysis, and Kinetic.

1. Equilibrium Studies-- Amount and Composition versus Sample

Table I shows a comparison of gas analysis from the three samples along with relevant well log parameters. The gas amounts and compositions refer to the average gas evolved over 18 hours at $450^{o} \pm 10^{o}C$. Four repeat runs on Sample I suggest an analysis

RESULTS (con't)

1. Equilibrium Studies--Amount and Composition versus Sample (con't)

accuracy of $\pm$ 25%. Several features should be noted. First, hydrogen is degassed in significant amounts in all three samples. As the only non condensable gas present it would appear that the shale, under correct treatment is a hydrogen source. Second, significant amounts of H_2S are evolved at the high retorting temperatures involved. This is in contrast to low

Table I

	Sample I	Sample II	Sample III
depth	5568'	4403'	2425'
total gas (milli moles/g)	.41	.2	.05
% H_2	20.9	6.3	6.3
% CH_4	8.0	10.5	3.1
% Ethane	1.5	3.2	0
Propane	2.1	3.3	0
H_2S	36.5	53.7	3.0
% CO_2	31.0	23.2	87.3
Calorific value/gram shale	36.1 cal/g	23.4	.66
Sidewall Neutron Porosity	15%	12%	12.5%
Compensated Neutron Porosity	24%	25%	25%
Formation Density Porosity	9%	0%	0%
Gamma Ray Log (API units)	180	160	140
Pseudo 1st Order Rate Constants	0.013	0.024	0.040

temperature degassing wherein H_2S (and apparently H_2) is notably absent.[2]* Third, the gas produced is not simply correlated to any of the Well log parameters

* (2) Brooks, Kenneth, Private Communication, Columbia Gas Development Corporation

RESULTS (con't)

1. Equilibrium Studies--
Amount and Composition versus Sample
(con't)

with the possible exception of the Gamma ray log..

Table II summarizes the comparative behavior of Sample I at two temperatures, $450^{o}C$ and $330^{o}C$. The increased percentage of hydrogen evolved is surprising, as well as the dramatic decrease in evolved gas.

Table II

	SAMPLE I	
	$450^{o}C$	$330^{o}C$
# millimoles gas/g shale	.41	.037
% H_2	20.9	41.5
% ethane	8.0	1.2
% propane	2.1	2.5
% CO_2	31.0	32.6
% H_2S	36.5	21.8
Calorific value per g of shale	36.1	2.59

2. Results of X-ray Analysis

The results obtained from X-ray crystallographic analysis are as follows:

A. Mineral composition: Minerals present in samples which had been prepared by grinding the entire sample to a powder from which a paste was made and applied to a slide are:

Core 1	Core 2	Core 3
Quartz	Quartz	Quartz
Pyrite	Pyrite	Illite
Illite	Illite	Kaolinite
Kaolinite	Kaolinite	Chlorite
Chlorite	Chlorite	Oligoclase*
Oligoclase*		

*trace amounts

2. Results of X-ray Analysis - (con't)

Minerals present in samples prepared from the powdered portion of a partially crushed core sample (see point 2. Preparation of Oriented Samples under Structure Analysis--X-ray Diffraction in the Experimental section) were as follows:

Core 1	Core 2	Core 3
Quartz	Pyrite	Illite
Pyrite	Illite	Kaolinite
Illite	Kaolinite	Chlorite
Kaolinite	Chlorite	
Chlorite		

Several things should be pointed out concerning these results. First, it should be noted that pyrite was not in evidence in Core 3. It is probably more than coincidence that the amount of H_2S produced on degassing at high temperature is very low for Core 3 samples compared to the amount produced for Core 1 and 2 samples. Secondly, it should be pointed out that according to the intensity of the diffracted X-rays, the amount of quartz present in the sample was quite large. In fact, the reflections from the quartz peak were so large that they tended to mask the reflection of the clay minerals. This fact motivated the experiment to remove quartz. The fact that the quartz in Cores 2 and 3 was present mostly as part of large hard nodules which resisted powdering in the mill while much of the quartz in Core 1 appeared to be mixed in with the clay minerals as finely divided crystals, indicates a difference in the rock matrix of the core.

B. Orientation of the clay minerals:

Portions of the core which were cut perpendicular to the direction of the bore hole gave completely different diffraction patterns from those cut aprallel to the direction of the bore hole, but which were 90^o to each other, gave exactly the same diffraction pattern. This indicates that there is some order between clay minerals with respect to the direction of layering.

2. Results of X-ray Analysis (con't)

That is, most of the clay mineral crystals lie so that there is the same ordering of atoms as you proceed down through the shale material. However, at any one level there is no particular order between crystals as one proceeds in any given direction along that layer.

C. Degassed and heated samples: Samples which had been heated in the degassing process showed essentially the same diffraction pattern as unheated samples with one notable exception. Pyrite was not present in the diffraction pattern after heating.

D. Experiments to determine the relationship between pyrite disappearance and the production of H_2S: Of interest to those involved in this work was the apparent correlation between the presence of pyrite as seen by X-ray analysis and the percent H_2S obtained upon degassing. That is, Cores 1 and 2, which gave clear indication of pyrite in the X-ray diffractograms, contained 36.5% and 53.7% H_2S respectively, and Core 3, which gave no discernable X-ray evidence for pyrite, produced only 3.0% H_2S on degassing. Of course, for pyrite FeS_2 to form H_2S hydrogen atoms must be available from some source. It seemed reasonable concerning the hydrated nature of clay minerals that H_2O could be that source. Therefore, a mixture of H_2O and FeS_2 was heated. No H_2S was formed. It was then thought that perhaps the clay mineral was acting as a catalyst and so a mixture of FeS_2 and illite, a hydrated clay mineral was heated. Again, no trace of H_2S was found.

It would appear that the question of whether the source of the H_2S is organic or inorganic in origin deserves further study.

3. Differential Thermal Analysis--Results and Discussion

Thermograms were obtained for the shale from the three different parts of the well for a variety of sample conditions. Thermograms for the shales indicate an endothermic process occurring at low temperature (largest magnitude of ΔT occurring from 80° C to $113^{\circ}C$ depending on the sample) and a higher temperature exothermic process beginning in the range from $300^{o}C$ to 350^{o} C. The position and magnitude of both effects varied considerably from samples and were difficult to quantitatively reproduce.

The endothermic process is postulated to be the desorption of adsorbed water. This is consistent with our observation that the magnitude of the process is quite small for freshly ground samples, but grows in size upon exposure of the ground sample to air. Samples stored in dry nitrogen also show a very small endothermic process.

The exothermic process varies considerably in temperature limits and magnitude depending on sample conditions; and, data taken in air with the sample uncovered revealed the largest exotherms. The process is interpreted to be combustion of volatile organics and other combustible gases from the shales. This is consistent with the results of the thermogravimetric analysis (TGA) of Appalachian shale reported by Yen (Quarterly Report of BR-48-12 for Period ending June 30, 1975). Yen reports two maxima in the rate of weight loss, one at $470^{o}C$ and one at $535^{o}C$. With the aid of gas analysis he assigns the $470^{o}C$ transition to organic decomposition and the 535^{o} transition to pyrite decomposition.

Two generalizations of considerable interest for the exothermic process were supported by out DTA data. The first generalization is that the magnitude of the exothermic process for freshly ground samples of the three different shales correlated qualitatively with the total gas content as shown by the B.E.T. experiments. This means that DTA analyses may possibly be a rapid and convenient method of obtaining a quantitative measure of the energy available from the combustible material in a shale sample. Obviously, quantitative work in this area in needed.

The second generalization of interest is that the magnitude of the exotherm for a particular finely ground shale decreases

3. Differential Thermal Analysis--Results and Discussion (con't)

with the amount of exposure to moist air while, as discussed above, the magnitude of the endotherm increases. A possible interpretation of this observation is that adsorbed water is displacing combustible gases on the shale.

Several of the samples showed two distinct maxima in the exotherm region, one at about 425^o and one at 475^o. A sample of standard illite (illite #35, Fithian, Illinois) revealed an exothermic process with similar maxima. This sample, upon treatment with 30% hydrogen peroxide, bubbled profusely, suggesting contamination by organic material. A DTA analysis of the standard after this treatment revealed that the exotherm was considerably reduced in magnitude. This suggests the exotherm for our illite sample to be related to combustible material present in the mineral. Since illite is a major component of our shale samples (as indicated by the X-ray analyses), it is conceivable that it is the active clay mineral for trapping the organic material in shale.

4. Kinetic Results

With respect to our kinetic results, we found that overall degassing rates (i.e. total moles) could be expressed in terms of an expoential, $n = n_t(1 - e^{-kt})$, where n_t and k are parameters relating to the total material degassed and the rate of degassing respectively. The pseudo first order dependence clearly breaks down when applied to single components because each component degasses at a different rate, resulting in compositional variation with time; but, nevertheless, the overall degassing rate is almost linear if $n_t - n$ is plotted against t. Table I (p.252) includes the slopes of such plots. In the case of curvature, the slope taken was the (extrapolated) initial slope. The reverse correlation between k's and total gas adsorbed should be noted.

The rate of degassing was highly temperature dependent, decreasing the temperature from 450^oC with Sample I using the all-glass (no mercury or other metal) apparatus

RESULTS (con't)

4. Kinetic Results (con 't)

discussed earlier. Table III shows the results.

Two points should be noted. First, each gas seems to have a time of maximum (%) evolution. For example, H_2 reaches 58% of

Table III

Time (min)	$\%H_2$	$\%CH_4$	%Ethane	%Propane	$\%CO_2$	$\%H_2S$
16	24	3.7	3.2	3.6	51	13
44	58	4.8	3.3	3.3	19	12
159	33	5.4	1.9	1.6	40	18
219	16	4.0	0	.9	56	23
295	14	4.4	0	.9	69	13

the gas at 44 minutes. It is particularly significant that H_2 reaches these levels in an apparatus where the possible formation of H_2 by tarnishing of metals is eliminated.

5. B.E.T. Results

The plotted data is shown in Figure 1. A weighted least squares computer program determined that .805 milli moles of N_2g shale corresponded to a monolayer thus implying a surface area of 78.6 m^2/g (assuming 16.3 $\AA^2$/nitrogen molecule). This value is within the range to be expected for clay minerals. This corresponds to a (monolayer) reservoir capacity of 46.5 ml gas STP per ml shale rock, thus, attesting to the efficiency of the rock as a reservoir.

6. Diffusion Constants

The plotted data are shown in Figure 2. The best straight line corresponds to a diffusion constant of 1×10^{-7}. It should be noted that while shale is of low permeability, it is not zero permeability; thus, the reservoir capacity of the rock is accessable to nearby macroscopic voids, channels and fractures.

CONCLUSION

Our results clearly demonstrate that not only is "bulk" shale permeable to material being degassed, but also it can behave as an adsorbent with material diffusing into the shale as demonstrated by the N_2 adsorbtion results. Our degassing results, in general, demonstrate that "bulk" shale is itself capable of acting as a reservoir for hydrocarbon gases. The large gas volumes evolved originally occupied a much reduced volume in the shale matrix by virtue of its being adsorbed within the spacings of the clay minerals.

Flow of a substance occurs in the direction of decreasing chemical potential of that substance; in fact, the negative of the gradient of chemical potential is the driving potential for flow to occur. The usual practice is to assume that the flux is directly proportional to the gradient of chemical potential; as a matter of fact, this phenomological approach enjoys a great deal of empirical success. Thus, the chemical potential is a monotonically decreasing function as one follows flow streamlines from the reservoir through the rock matrix to the fracture system and, hence, to the well bore and the surface. However, the drop in chemical potential is not uniform but, rather, is expected to be concentrated within regions of low permeability. In a great number of cases dealing with non-equilibrium problems, the full mathematical complexity can be avoided by the approximation that the full available drop in chemical potential occurs in one region. For the case at hand the appropriate region is the diffusion out of the reservoir are to (but not including) the beginning of the macroscopic fracture system. Our measurements of $D \approx 10^{-7}\ cm^2/sec$ for this region is much lower than the permeabilities associated with rock fractures and, thus, lends support to the hypothesis that the rate determining step is diffusion out of the rock matrix.

Figure 3 shows the model for a well that thus materializes. The well bore accesses a system of natural joints and fractures via a set of artificial fractures. These fractures access the gas reservoir which

CONCLUSION (con't)

consists of natural gas components adsorbed within the rock matrix. This reservoir is depleted by diffusion through the rock to the fracture system creating a depletion zone (shown by cross hatching) that spreads out from the fracture faces. The extent of this depletion zone, d, is given by

$$d = \sqrt{Dt}$$

and corresponds to 1.7 cm the first year, 2.5 cm the second, 3.4 cm the fourth, etc. The total amount of material degassed can easily be shown to be (10)

$$M_\tau = 2\, C_oA \left(\frac{Dt}{\pi}\right)^{1/2}$$

where:

- C_o = the initial hydrocarbon content
- A = the total rock face area
- t = time (t=0 at the moment first flow starts)

The rate of production is

$$\frac{dM_\tau}{dt} = C_o A \left(\frac{D}{\pi}\right)^{1/2} t^{-1/2}$$

This one parameter equation, in fact, fits some published well production data quite well. In particular, a least squares value of $C_oA\,(D/\pi)^{1/2}$ = 268 (MCF/da) $yr^{1/2}$ or 2.2 x 10^7 moles/se& obtained from well data published by Bagnall and Ryan is shown in Figure 3, along with replotted data points. The fit closely fits the data to the order of "random" year to year variations.

It is worthwhile to note that D and C_o are parameters associated with the bulk rock, while A is associated with the system of fractures through the rock. Thus, D and C_o can be obtained from core samples, and the constant determined from production data to obtain the total surface area of rock processed by the fracture system. For the case at hand, assuming 2% gas concentration and $D=10^{-7}$, the area is 3 x 10^8 square meters.

As a final point it should be noted that the best fit is obtained for the most productive of the wells; the wells with lower production rates have production curves that are too flat to fit an inverse $t^{1/2}$ law accurately. As a general rule flat degassing curves will occur when a constriction at the exit of a reservoir causes it to draw down slowly. Thus, it is not unreasonable that wells with low productivity

CONCLUSION (con't)

should also have flat production curves. We are proceeding with work on this point presently at the Juniata College Laboratories and expect to have an additional report in the near future.

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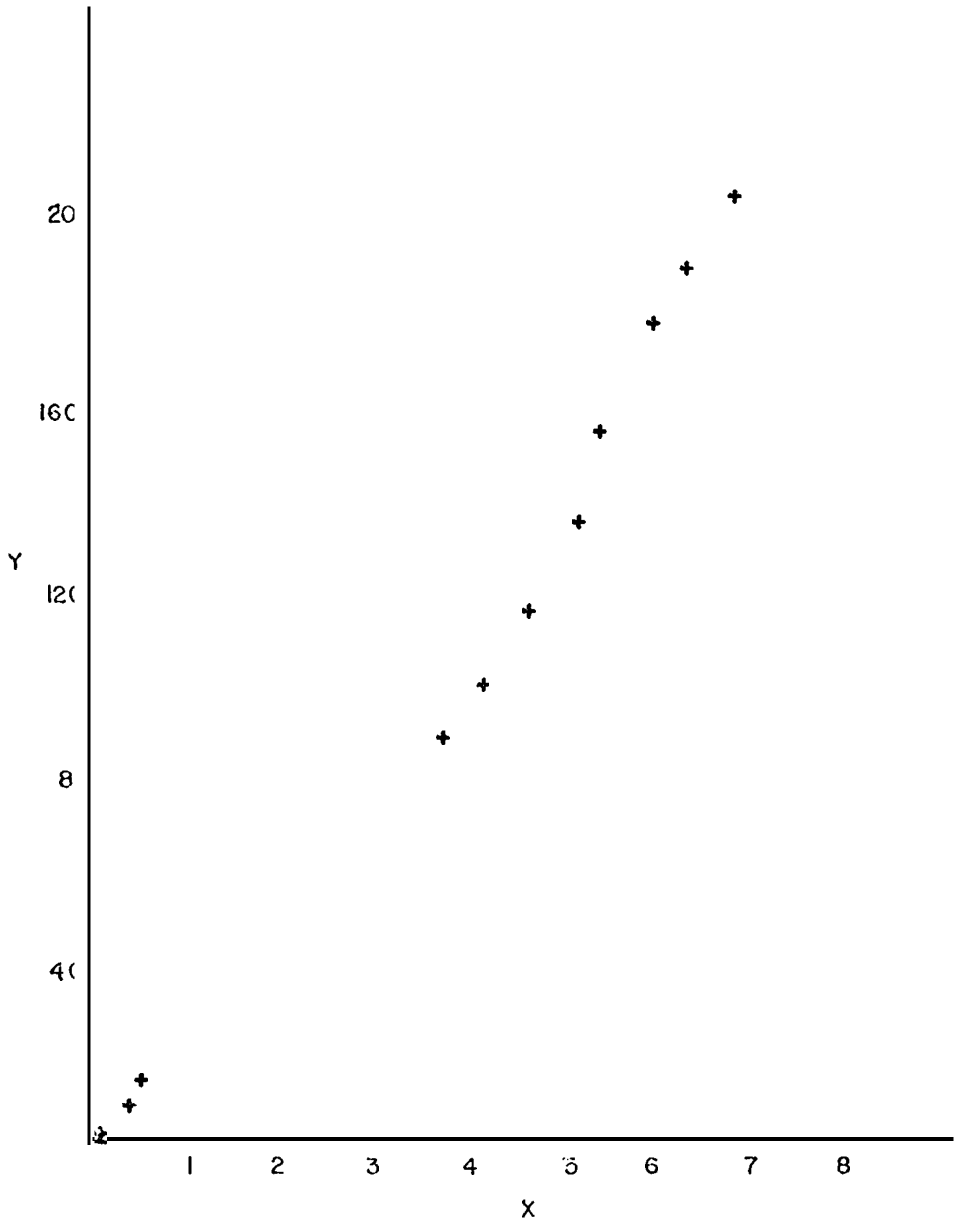

FIGURE 1. A PLOT OF $y = \frac{X}{(1-X)\,n}$ VERSUS X. SLOPE AND INTERCEPT GIVE THE AMOUNT OF GAS REQUIRED TO COVER AVAILABLE SURFACE WITH A MONOLAYER OF NITROGEN.

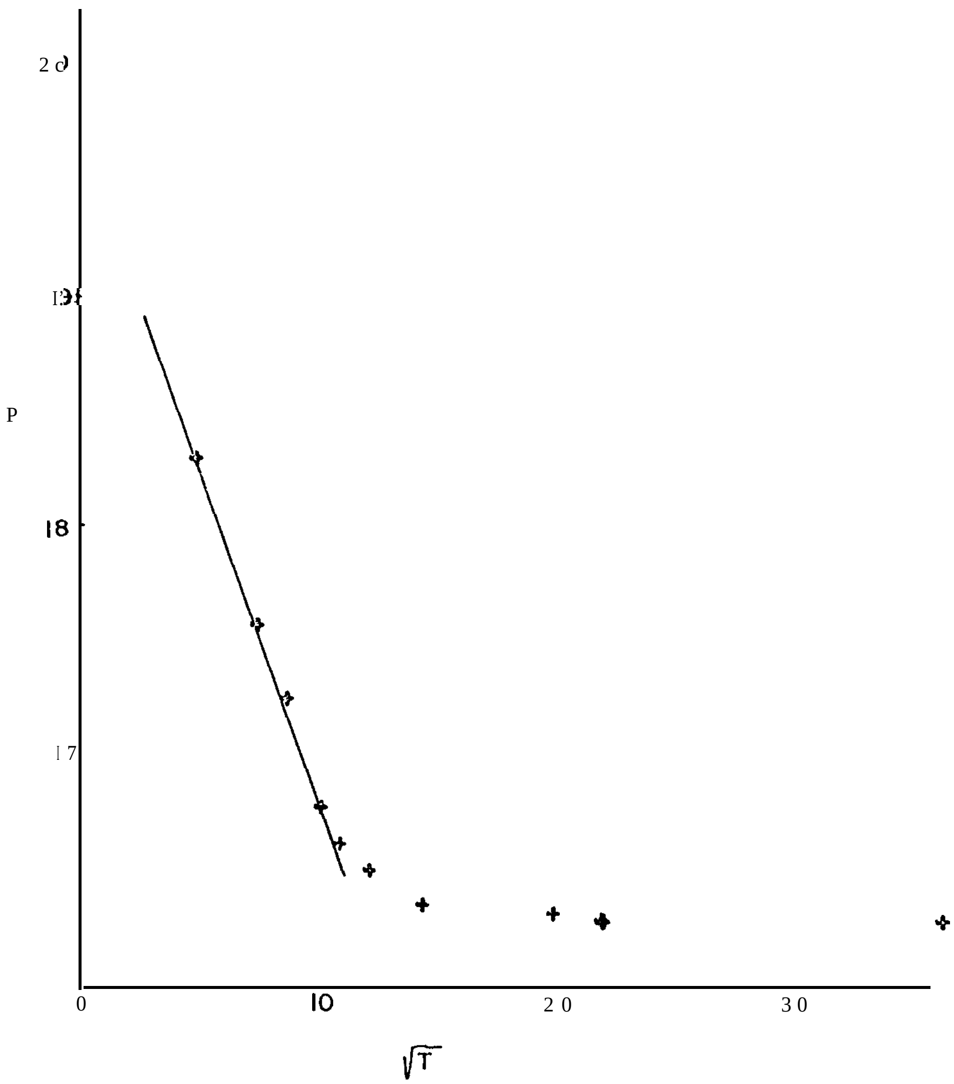

FIGURE 2. A PLOT OF P vs $t^{1/2}$ AT CONSTANT V UPON A DISCONTINUOUS CHANGE OF P to P_O at t = 0.

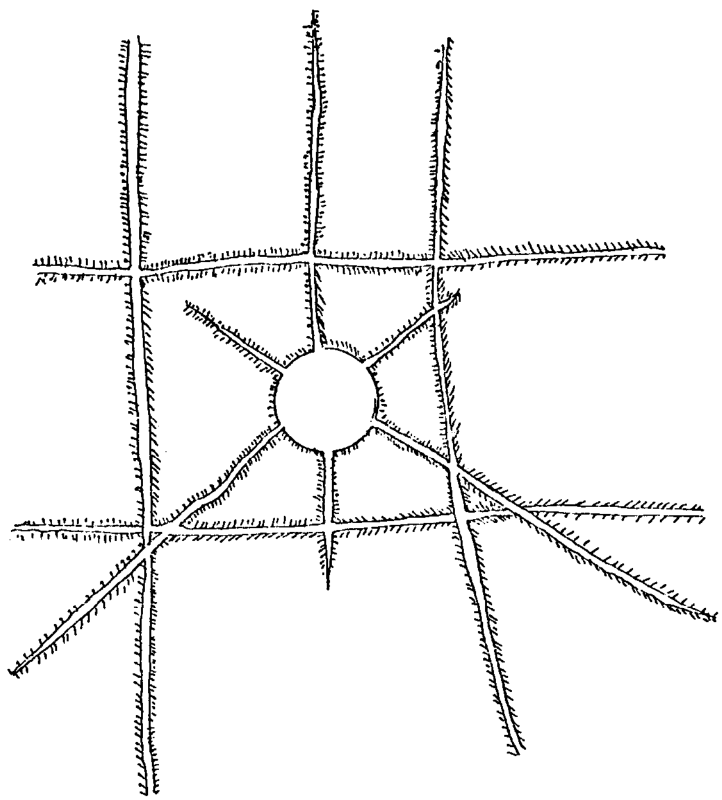

FIGURE 3. A SCHEMATIC OF A WELL BORE WITH ARTIFICIAL FRACTURES WHICH INTERSECT NATURAL FRACTURES. GAS MOLECULES INITIALLY ADSORBED WITHIN THE LAYERED CLAY STRUCTURE MOVE, UNDER THE INFLUENCE OF GRADIENT OF CHEMICAL POTENTIAL, INTO THE FRACTURE SYSTEM AND, HENCE, TO THE SURFACE VIA THE WELL BORE, LEAVING A VOLUME OF ROCK ADJACENT TO THE FRACTURES WHICH IS DEPLETED OF ITS ORIGINAL GAS CONTENT. THIS DEPLETED VOLUME GROWS WITH TIME AS THE WELL CONTINUES TO PRODUCE. WELL PRODUCTION DECREASES PRIMARILY BECAUSE THE CHEMICAL POTENTIAL GRADIENT WITHIN THE ROCK DECREASES (AS THE DISTANCE THAT THE AVERAGE DEGASSING MOLECULE INCREASES) WITH TIME.

HOW TO STUDY SHALES: SOME POSSIBLE SOURCES

An Annotated Bibliography Prepared By

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1. Davis, John C. Petrology of Cretaceous Mowry Shale in Wyoming. Am. Assoc. Petrol. Geol. Bull., v. 54, 1970, pp. 487-502.

   Mineral distribution patterns and other evidence suggest that this widespread shale is a transgressive deposit. One of the very few regional studies of shales. Many maps. A possible model study?

2. Dunoyer de Segonzac, G. The Transformation of Clay Minerals During Diagensis and Low Grade Metamorphism: A Review. Sedimentology, v. 15, 1970, pp. 281-346.

   A long review of the changes in clay minerals during burial which is by far the best introduction to this subject. Reactions involving smectite and illite are fairly well understood, but much more work on chlorite is needed.

3. Edzwald, J. K. and C. R. O'Melia. Clay Distributions in Recent Estuarine Sediments. Clay and Clay Minerals, v. 23, 1975, pp. 39-44.

   Can clay minerals differentially flocculate in a salinity gradient? Field studies showed kaolinite landward of

illite as predicted by laboratory work. Possible paleo-salinity indicator if used in a careful mapping study. Compare with Parham's (1966) review of lateral variations observed in ancient sediments.

4. Folk, Robert L. Petrography and Origin of the Tuscarora, Rose Hill, and Keefer Formations, Lower and Middle Silurian of Eastern West Virginia. J. Sediment. Petrology, v. 30, 1960, pp. 1-59.

This classic paper by a famous petrographer has some excellent thin section descriptions of Silurian shales, descriptions that can be usefully copied.

5. Gibbs, Ronald J. The Bottom Sediments of the Amazon Shelf and Tropical Atlantic Ocean. Marine Geol., v. 14, 1973, pp. 39-45.

One of the very few regional studies--this one about an elongate, muddy shelf almost 2000 km long--of variation in composition and grain size of a modern mud. See also Heath, et al. (1974).

6. Gill, James r., Cobban, William A., and Leonard G. Schultz. Stratigraphy and Composition of the Sharon Springs Member of the Pierre Shale in Western Kansas. U. S. Geol. Surv. Prof. Paper 728, 1972, 50 p.

A widespread shale that is very "layer cake" with a persistant three-fold internal stratigraphy, the middle one being organic rich. These units can be recognized on wire line logs. Interesting diagrams about rates of sedimentation and facies migration based on ammonite

zones, pp. 15-20, plus some schematic maps. Also some clay mineralogy and a goodly amount of trace element study. Fig. 23 is interesting. Compare with Chattanooga.

7. Griffin, J. J., Windom, J. and E. D. Goldberg. The Distribution of Clay Minerals in the World Ocean. Deep Sea Research, v. 15, 1968, pp. 433-459.

One of the most definitive papers ever written on the origin of clay minerals. This paper is based on geology's oldest technique--systematic mapping--which shows that climate plays a significant role in clay mineral composition at low latitudes, but not at high latitudes. This and other evidence indicate that the vast majority of clay in the recent sediments of the world ocean are detrital.

8. Hattin, Donald E. Strtigraphy of the Carlisle Shale (Upper Cretaceous) in Kansas. Kansas State Geol. Surv. Bull., v. 56, 1962, 155 p.

Comprehensive stratigraphy plus reconstruction of depositional environment and paleogeography. The Carlisle and its equivalents (Colorado, Cody, Benton and Mancos) are believed to represent the regressive half of the first major late Cretaceous cycle in the Western Interior region. Useful as a model.

9. Hattin, Donald E. Stratigraphy of the Graneros Shale (Upper Cretaceous) in Central Kansas. Kansas State Geol. Surv. Bull., v. 178, 1965, 83 p.

A careful, fully integrated and comprehensive stratigraphic study of a thin (70 m), but very widespread, shale extending from Arizona to southern Canada and beyond. Discussion of its paleontoloty, tracks and trails, petrology, paleoecology and provenance plus paleogeography all nicely summarized in ten conclusions. More shales need to be studied in this manner. Compare with Davis (1970), Pelzer (1966) and Gill, et al. (1972).

10. Heling, D. Micro-Fabrics of Shales and Their Rearrangement by Compaction. Sedimentology, v. 15, 1970, pp. 247-260.

The best paper to date on shale fabric. Grain-size distribution, total porosity, pore-size distribution (by mercury porosimetry) and specific surface area (by BET sorptometry) were measured. Down to 1000 m, these properties are controlled only by compaction, but below this zone, recrystallization effects become important.

11. Hesse, Reinhard. Turbiditic and Non-Turbiditic Mudstone of Cretaceous Flysch Sections of the East Alps and Other Basins. Sedimentology, v. 22, 1975, pp. 387-416.

Comprehensive criteria in Table 3 to differentiate between turbidite and non-turbidite mudstones in Mesozoic and Cenozoic turbidite basins. Significant because many thick basinal shales are associated with distal turbidites. To what extent can these and related criteria be applied to differentiate subenvironments of mudstones in non-turbidite basins?

12. Jones, M. L. and J. M. Dennison. Oriented Fossils as Paleocurrent Indicators in Paleozoic Lutites of Southern Appalachians. Jour. Sed. Petrol., v. 40, 1970, pp. 642-649.

Paleocurrent study of a shale. First advocated by Ruedemann in the 1890's, this technique has very rarely been used in the regional analysis of a shale sequence.

13. Lewis, T. L. and J. F. Schwietering. Distribution of the Cleveland Black Shale in Ohio. Geol. Soc. Amer. Bull., v. 82, 1971, pp. 3477-3483.

Study of a single unit within a thick shale sequence. Isopach maps show marked pinching and swelling along strike that may be related to positions of turbidite fans to the east, coming from the Catskill Delta.

14. Parham, W. E. Lateral Variations of Clay Mineral Assemblages in Modern and Ancient Sediments in K. Gekker and A. Weiss, eds., Proc. Int. Clay Conf., v. 1, 1966, pp. 135-145.

An unusual and interesting paper that compiles much literature about a neglected subject. Author's illustrations effectively tell his story, that kwolinite is most abundant near shoreline. Many more studies like this needed for mudstones and shales.

15. Pelzer, E. E. Mineralogy, Geochemistry and Stratigraphy of the Besa River Shale, British Columbia. Canadian Petrol Geol. Bull., v. 14, 1966, pp. 135-145.

A thick, 320 to 2400 m, shelf-to-basin section of a Devonian-

Mississippian black shale is examined with the X-ray and resulting mineralogical variations related to provenance. Maps and cross-sections also used to infer such an origin. See also Conant and Swanson (1961).

16. Perry, E. and J. Hower. Burial Diagenesis in Gulf Coast Pelitic Sediments. Clay and Clay Minerals, v. 18, 1970, pp. 165-177.

Vertical profiles from deep-wells in the Gulf Coast show that the major diagenetic change in clay minerals is the conversion of mixed layer illite/smectite to illite accompanied by incorporation of K^+. A major landmark in the diagenetic, burial history of clay minerals comparable to studies of clay mineral distribution in the modern muds of the world ocean by Griffin, et al. (1968) and Rateev, et al. (1969).

17. Projeto Xistoguimica. Bibliografia do Xisto/Oil-Shale Bibliography. Rio de Janeiro, Academia Brasileira de Ciencias, Instituto Brasilero de Bibliografia e Documentacao, Publicacao Especial Xistoquimica, v. 16, 1971, various paging.

5232 references from throughout the world mostly, but not not totally, about oil shales. Key word and other indices. To obtain this write to:

Academia Brasileira de Ciencias
Bibliografia do Xisto
Rua Anfilofio de Carvalho 29 3º andar
Caixa Postal 229 ZC-OD
20000 Rio de Janeiro, R. J., Brazil

18. Pryor, Wayne A. Biogenic Sedimentation and Alteration of Argillaceous Sediments in Shallow Marine Environments. Geol. Soc. Amer. Bull., v. 86, 1975, pp. 1244-1254.

An interesting and unusual paper that calls attention to the possible general importance of organisms as producers of pelletal muds and their contribution to glauconite. How often do clay mineralogists consider penecontemporaneous clay mineral alteration by the lower intestine?

19. Spencer, A. m., ed. Mesozoic-Cenzoic Orogenic Belts. Edinburgh and London, Scottish Acad. Press and Geol. Soc. Sp. Pub. 4, 1974, 809 p.

Looking for a source book to guide you to thick Mesozoic and Cenozoic geosynclinal shales? This massive, systematically edited volume is it with Figures 12, 13, 14, and 15 providing a summary of shale occurrence, as well as the many detailed tables of the 45 orogenic belts described in the text. Remarkable collection of data.

The entries above include only a tiny fraction of over 500 references to shale and mudstone papers that we have recently collected as part of our project on shales. There is a vast and very diverse literature on this subject and we hope to have a good bit of it digested by late this year. We welcome suggestions, and thank the many who have already kindly helped us.