1527

KENTUCKY GEOLOGICAL SURVEY

UNIVERSITY OF KENTUCKY, LEXINGTON SERIES XI, 1981

Donald C. Haney, Director and State Geologist

KOGA

PROCEEDINGS OF THE TECHNICAL SESSIONS KENTUCKY OIL AND GAS ASSOCIATION THIRTY-NINTH AND FORTIETH ANNUAL MEETINGS, 1975 AND 1976

In cooperation with Kentucky Oil & Gas Association

SPECIAL PUBLICATION 4

KENTUCKY GEOLOGICAL SURVEY
UNIVERSITY OF KENTUCKY, LEXINGTON SERIES XI, 1981
Donald C. Haney, Director and State Geologist

PROCEEDINGS OF THE TECHNICAL SESSIONS KENTUCKY OIL AND GAS ASSOCIATION THIRTY-NINTH AND FORTIETH ANNUAL MEETINGS, 1975 AND 1976

Edited by Margaret K. Luther

ISSN 0075-5613

In cooperation with Kentucky Oil & Gas Association

SPECIAL PUBLICATION 4

UNIVERSITY OF KENTUCKY

Otis A. Singletary, President
Lewis W. Cochran, Vice President for Academic Affairs
Wimberly C. Royster, Dean of Graduate School and Coordinator of Research
James Y. McDonald, Executive Director, University of Kentucky Research Foundation

KENTUCKY GEOLOGICAL SURVEY ADVISORY BOARD

David A. Zegeer, Chairman, Lexington
Phil Miles, Vice Chairman, Lexington
David E. Bayer, Lexington
John G. Donan, Sr., Madisonville
Wallace W. Hagan, Lexington
Nicholas C. Kieffer, Jr., Louisville
Harold G. Mays, Frankfort
J. Edward Parker, Lexington
W. J. Reynolds, Allen
Henry A. Spalding, Hazard
Ralph N. Thomas, Owensboro
George H. Warren, Jr., Owensboro

KENTUCKY GEOLOGICAL SURVEY

Donald C. Haney, Director and State Geologist
Preston McGrain, Assistant State Geologist, Water, Minerals, and Maps

ADMINISTRATIVE DIVISION

Personnel and Finance Section:
James Hamilton, Administrative Staff Officer II
Margaret Fernandez, Administrative Accounts Clerk

Clerical Section:
Brenda L. Hayden, Administrative Secretary
Anna L. Hopkins, Administrative Secretary
Sherry A. McKune, Administrative Secretary
Norma J. Reynolds, Administrative Secretary
Helen P. Sensabaugh, Administrative Secretary
Jean Kelly, Secretary
Juanita G. Smith, Secretary, Henderson Office

Publications Section:
Donald W. Hutcheson, Head
Margaret K. Luther, Assistant Editor
Roger B Potts, Chief Cartographic Illustrator
Lynn D. Guindon, Principal Drafting Technician
Freda M. Harris, Drafting Technician
William A. Briscoe, III, Sales Supervisor
Jonathan M. Prasse, Clerical Assistant II
Lemuel W. Waite, Stores Worker
Patrick H. McHaffie, Geologist/Geographer II

GEOLOGICAL DIVISION

Coal Section:
Lexington Office
Russell A. Brant, Head
James C. Cobb, Geologist IV
J. Hiram Smith, Geologist III
James C. Currens, Geologist III
Richard E. Sergeant, Geologist III
Donald R. Chesnut, Jr., Geologist III
Blaine Fennell, Jr., Geologist I
Wayne T. Frankie, Geologist I
Elisabeth R. Portig, Geologist I
Ernie R. Slucher, Geologist I

Henderson Office
Allen D. Williamson, Geologist IV
David A. Williams, Geologist III

Morehead Office
Kenneth L. Gill, Geologist II
Joseph P. Hamilton, Geologist I
James Rice, Geologist I
Peter Romanik, Geologist I

Industrial and Metallic Minerals Section
Preston McGrain, Head and Assistant State Geologist
Garland R. Dever, Jr., Geologist IV
Warren H. Anderson, Geologist II
Jack R. Moody, Geologist II
Robert D. Trace, Geologist III, Princeton Office
Mary E. Barron, Senior Laboratory Assistant

Oil and Gas Section:
Louis R. Ponsetto, Head
Martin C. Noger, Geologist IV
Frank H. Walker, Geologist IV
John G. Beard, Geologist IV, Henderson Office
Patrick J. Gooding, Geologist II
Brandon Nuttall, Geologist I
Lorene Teater, Records Librarian
Richard W. Taulbee, Senior Laboratory Assistant
Robert R. Daniel, Laboratory Assistant

Water Section:
John D. Kiefer, Head
Steven Cordiviola, Geologist III
Fred Lawrence, Geologist III
James Kipp, Geologist II
Margaret A. Townsend, Geologist II
Thomas E. Dugan, Geologist I
Mary K. Gilmore, Geologist I
Julian Duffy, Geologist II, Henderson Office
Robert C. Holladay, Drafting Technician
Fred G. Shaw, Core Driller IV
Edwin A. Morford, Core Driller I

SPECIAL PROJECTS DIVISION

Projects
Kentucky Department for Natural Resources and Environmental Protection—Aquifer Characterization
Steven Cordiviola, Geologist III and Principal Investigator
Margaret A. Townsend, Geologist II
Thomas E. Dugan, Geologist I
Mary K. Gilmore, Geologist I
Robert C. Holladay, Drafting Technician

Kentucky Institute for Mining and Minerals Research—Coal Reserves, Eastern Kentucky
Lexington Office
Russell A. Brant, Geologist V and Principal Investigator
J. Hiram Smith, Geologist III
Donald R. Chesnut, Jr., Geologist III
Blaine Fennell, Jr., Geologist I
Wayne T. Frankie, Geologist I
Elisabeth R. Portig, Geologist I
Ernie R. Slucher, Geologist I

Morehead Office
Kenneth L. Gill, Geologist II
Joseph P. Hamilton, Geologist I
James R. Rice, Geologist I
Peter Romanik, Geologist I

Kentucky Institute for Mining and Minerals Research—Limestone Investigations
Garland R. Dever, Jr., Geologist IV and Principal Investigator
Jack R. Moody, Geologist II

Nuclear Regulatory Commission—New Madrid Earthquake Project
Howard R. Schwalb, Principal Investigator

U. S. Geological Survey—Coal Hydrology, Eastern Kentucky
Steven Cordiviola, Geologist III and Principal Investigator
Fred Lawrence, Geologist III
James Kipp, Geologist II
Fred G. Shaw, Core Driller IV
Edwin A. Morford, Core Driller I

U. S. Geological Survey—Coal Sampling, Eastern Kentucky
James C. Currens, Geologist III and Principal Investigator

U. S. Geological Survey—Development of Earth Science Information for Planners
Richard E. Sergeant, Geologist III and Principal Investigator
Roxanne Bingemer, Geologist I, Henderson Office

CONTENTS

PROCEEDINGS FOR 1975

PROCEEDINGS FOR 1976

OIL SHALE DEVELOPMENT, WHEN?

PAUL WELLMAN
Ashland Oil Company
Ashland, Kentucky

ABSTRACT

It has been estimated that by 1985 the United States will consume 23 million barrels of oil a day, 8 million of which will be imported. This will result in a $35 billion a year trade deficit. Such a deficit cannot be tolerated by our economy over a long period of time. The alternative to imports is development of available domestic fuels—coal and oil shale.

At the present world price for oil, oil shale produces a modest return on investment. Based on a crude-oil price of $12 a barrel, a complex that produces 100,000 barrels a day would yield a total annual income of $455,164,000. This 15 percent return on investment is unacceptable for a new-industry, high-risk venture.

The major problems confronting oil-shale developers are politics, environment, financing, OPEC pricing, new discoveries, offshore discoveries, domestic conservation, and technology.

The oil shale underlying Appalachia has potential for oil-shale development. The two groups of Eastern shales of special interest are the Devonian black shales and the shale units in coal-bearing beds of the Pennsylvanian. Kentucky oil-shale deposits are concentrated in the eastern and southeastern parts of the state. Estimates of oil yields for three core holes drilled in the New Albany Shale of Kentucky are 76,000, 34,000, and 35,000 barrels per acre. These figures illustrate the huge reserves of fossil energy contained in Kentucky oil shales; certainly sometime in the future they will be developed and used by American industry.

Oil shale is misnamed; the rock which contains the carbonaceous material is not shale and the carbonaceous material is not oil, as we think of crude oil. The rock is actually marlstone and the carbonaceous material is kerogen. Kerogen differs from crude in several important ways. Crude, raw shale oil has a pour point of 80° to 95° F; it is very viscous and cannot be pumped at ambient temperatures. The nitrogen content of kerogen is high, and this affords some unique refining problems. Shale oil contains more oxygen than crude oil, and therefore contains more oxygenated compounds.

Kentucky, along with 32 other states, has oil-shale deposits which may sometime in the future support commercial development; however, it is the author's opinion that an oil-shale industry in Colorado will precede development in less desirable locations.

Before the development of the petroleum industry in the United States (about 1860), coal and shale had been used to produce crude oil, "coal oil" or kerosene, lubricating oils, and waxes. After 1860, petroleum afforded a much cheaper source of these materials, and the oil-shale industry ceased to exist in this country. Shale-oil industries existed in some foreign countries much later, particularly the oil-poor countries. A thriving industry based on oil shale was in operation in Scotland as late as 1920.

No one can say for sure when oil shale will be developed in this country. The historical literature on oil shale shows that development has been eminent since 1915 in some entrepreneurs' minds, but no industry exists today. The situation today has no precedence; actually, more incentive to develop exists now than ever before. It is the author's opinion that we desperately need to develop oil shale now.

In late 1973 and early 1974 the OPEC nations enforced an oil embargo. The result was that world oil prices increased by a factor of 4, from about $2.80-$3.00/bbl to almost $12/bbl. Naturally this has had an astounding economic impact on the oil-importing countries of the world. Inflation is the most direct result of which everyone is aware; gasoline prices have almost doubled, and as energy consumption is related to nearly every product we buy, prices for almost all products have increased. It has been estimated that the OPEC countries amassed an $80 billion trade surplus in 1974 alone, of which the United States contributed $20 billion.

The "Oil and Gas Journal" of Nov. 11, 1974, projected oil consumption in the United States at about 23 million barrels a day by 1985, of which more than 8 million barrels will be imported. At $12 barrel this represents a trade deficit of $96 million a day, or $35 billion a year. A $35 billion trade deficit for oil cannot be tolerated by our economy, or any economy, over a long period of time.

The national security of the United States is threatened by this increasing dependence on oil imports. Since 1968 this country has consumed oil at a faster rate than it has been found. The gap widens each year, and the result is that we fill the gap between supply and demand with ever-increasing imports. The alternative to imports is to use the fuels we have. These alternate fuels are coal and oil shale.

The subject of this paper will be oil shale development and the production of 100,000 barrels of shale oil a day. The processing complex would require the largest underground mine in the world. Based on 30 gallons per ton shale, the mine would be required to produce about 180,000 tons of rock a day, or enough to load 9,000 20-ton dump trucks. The mine would be almost 10 times as large as the largest underground coal mine, and it would require a whole new line of equipment to mine the 70-foot-thick Mahogany ledge. The surface equipment would be large by any standard. The crushing and screening plant to prepare the shale for retorting would be the world's largest.

If the development occurs in the Piceance Creek Basin in Colorado, which seems most likely, other problems such as the influx of people to a sparsely populated area would arise. It has been estimated that 3,000 construction workers and about 1,500 permanent operating personnel would be required. This would mean construction of housing, schools, towns, hospitals, and other facilities. Support personnel estimates have been about 5 to 7 for each permanent employee.

The investment requirement for an oil-shale complex to produce 100,000 barrels a day of a partially refined crude product is in excess of $12,000 per daily barrel of production, or more than $1.2 billion. That is about two times the book value of Ashland Oil; yet, it would not produce enough oil to supply Ashland's Catlettsburg refineries.

At the present world price for oil, oil shale is marginal; in other words, a complex built starting today would produce a very modest return on investment. Operating cost estimates indicate an operating cost of about $275 million annually, including depreciation but no return on investment.

Besides crude oil, the products from an oil-shale complex are sulfur, ammonia, and if partial refining is done, petroleum coke. The annual revenue from such an installation, based on current prices is as follows:

	Total Annual Income
Crude oil—36,500,000 bbl/yr x $12/bbl	$438,000,000
Coke—624,150 tpy x $15/ton	9,362,300
Sulfur—31,025 tpy x $25/ton	775,600
Ammonia—100,375 tpy x $70/ton	7,026,300
	$455,164,200

If the OPEC countries decided to sell oil for $7.50 a barrel—and they manipulate the world oil price—then the total revenue would be:

	Total Annual Income
Crude oil—36,500,000 bbl/yr x $7.50	$273,500,000
Coke—624,150 tpy x $15/ton	9,362,300
Sulfur—31,025 tpy x $25/ton	775,600
Ammonia—100,375 tpy x $70/ton	7,026,300
	$290,664,200

As you can readily see, almost all profit is gone in the second case, and the investors in such a situation would get a minute return on their investment.

The return on investment in the second case would be only about 1.3 percent, or so low that it would not pay the interest on the investment. The return on investment in the first case is 15 percent, which might be acceptable in a low-risk venture, but is not acceptable for a new industry, high-risk venture.

A shale-oil industry would have a great impact on the local economy, regardless of where it might be established. The obvious results would be higher employment, increased tax base, population growth, improved standard of living, and an influx of related industries.

The major problems confronting oil-shale developers today are:

1. Politics
2. Environment
3. Financing
4. OPEC Pricing
5. New Discoveries, Offshore Discoveries, Domestic Conservation
6. Technology

Mr. John M. Hopkins, acting president of the synthetic fuels division of Union Oil Company, addressing an oil-shale symposium in Denver, Colorado, in November 1974, said:

> Perhaps even more important than the impact of inflation is the problem of an unstable economic and political environment. When we activated our present accelerated program about a year ago, we confidently expected by this time the federal government would have formulated a national energy policy. We further expected that this policy would remove some of the political uncertainties affecting our industry, as well as provide stable conditions in which companies can make the major capital commitments required for projects such as oil shale development.
>
> Unfortunately, this national energy policy is still not available. The oil industry is still regulated both as to price and to market in a most uncertain way. In addition, political leaders have been threatening to impose a variety of new burdens on energy development.

An improved political climate that does not threaten new impositions each day is needed.

Oil shale, if developed soon, would be the first major industry developed under the environmental laws of recent years. Great care has been taken to assure conformance with the law in developing the resource. The State of Colorado has adopted air-quality standards more stringent than the federal standards; this is particularly true concerning particulate matter. Mr. Hopkins, at the symposium previously cited, said:

> It is difficult to understand why the State of Colorado has established ambient air standards considerably more restrictive than the federal standards. These state standards, if allowed to stand, will mean curtailment of not only the extent of shale development in Colorado, but also any other type of new business, be it new resorts, new housing, or additional energy development. If every state in the nation adopted this type of control, the nation would soon be in the throes of an economic disaster.

At this time there seems to be a reevaluation on the part of the state, and new, less stringent standards may be adopted.

Financing such a capital-intensive project is a very real problem. Development in the near future seems unlikely without government support. Companies cannot afford to finance oil-shale development alone because there is no protection against OPEC pricing, new discoveries that would depress oil prices, or a good domestic conservation program. The glut of oil on the world market today is a result of less-than-anticipated consumption.

The technological problems are also formidable. The largest retorts operated to date have been 10 feet or less in diameter. Experts believe that diameters must be 35 feet or greater to be commercial. Most oil-shale people would agree that some method to handle the viscous raw shale oil other than hydrogenation (partial refining) at the point of production is necessary for the rapid development of the industry. Otherwise, the limited amount of water available will have a depressing effect on the development of a significant industry, and will place an ultimate limit on its growth.

There is a serious energy problem in this country and it will not go away. We must develop alternate energy sources and we can do it if the proper circumstances exist. We must move now to develop these alternates.

Oil shale underlies about half of the eastern region of the United States, which is known as Appalachia. The shale is referred to as ''black shale''; it contains finely divided organic matter and will yield oil from a few to 100 gallons per ton. Where the richness is greater than 10 gallons per ton by Fischer assay, the material is termed ''oil shale.''

Whether or not the lower grade Eastern shales will be exploited commercially remains to be determined. If development does occur, much basic research and development work remains to be done.

The ore bodies are not well defined in the East, and many of the oil-shale deposits of Mississippian age are difficult to separate from impure coal of the same period. The extent of the Appalachian deposits, particularly to the east, is uncertain. The outcrops in Kentucky have generated more interest than other Eastern deposits, and would be a likely location for early development.

Some work has been done on the Eastern shales, particularly by the U. S. Bureau of Mines. According to Benson and Tsaros (1965), Eastern shales are more amenable to direct hydrogenation and it is possible that other processing advantages exist.

Two groups of Eastern shales are of special interest because of their energy potential. The first group is a sequence of Devonian and Mississippian shales that extends from Alabama to New York; it is known by various names, but chiefly as the Chattanooga, New Albany, Ohio, Marcellus, and Sunbury Shales. The second group is the widespread shale units in coal-bearing beds of Pennsylvanian age; some of the impure coals are included.

The Kentucky oil-shale deposits are concentrated in the east-southeast part of the state and are of more than passing interest. Reports prepared in the 1920's give information about the Ohio and Sunbury Shales and mention possible mining areas. Jillson (1921) stated that the Sunbury Shale ranges in thickness from 4 to 16 feet, and the Ohio Shale from 20 to 45 feet. Fischer assays that were made on samples from unspecified parts of these shales in 13 of the 20 counties where it outcrops gave an average yield of nearly 16 gallons per ton; later work by Crouse (1925) indicates a somewhat higher yield. In either case, it is doubtful that these yields would be realized for the entire thickness of the deposits. The outcrop is shown on Figure 1.

If the Kentucky shales prove to be suitable for hydrogenation, as preliminary experiments indicate (Shultz, 1965), they could yield as much gas by hydrogasification as the Colorado shales, which have twice the assay value.

Fischer assay accounts for 65 to 75 percent of the carbonaceous material in the Colorado shales, but only about one-third of the carbon content of the Eastern shales. Direct hydrogenation could be extremely important to oil-shale development in the East.

A paper by Smith and Young (1967) of the Laramie Energy Research Center Bureau of Mines compared compositions of the organic elements of New Albany Shale, Green River Formation shale, and selected coals. The comparison is shown in the following table taken from their paper:

MATERIAL	ORGANIC COMPONENT (wt. %)					
	C	H	N	S	O	C/H
New Albany Shale[1]	82.0	7.4	2.3	2.0	6.3	11.1
Green River Shale[2]	80.5	10.3	2.4	1.0	5.8	7.8
Coals[3]						
Lignite, North Dakota	64.2	5.3	0.9	0.5	29.1	12.1
Bituminous:						
High Volatile C, Penn.	76.5	5.7	1.4	3.3	13.1	13.4
High Volatile B, Ky.	78.3	5.6	1.6	4.5	10.0	14.0
High Volatile A, Penn.	82.7	5.5	1.6	1.2	9.0	15.0
Medium Volatile, W.Va.	87.9	5.2	1.2	1.0	4.7	16.9
Low Volatile, Penn.	89.2	4.6	1.4	1.3	3.5	19.4
Anthracite, Penn.	91.2	2.6	1.1	0.6	4.5	35.1

1 Average from coreholes.
2 Average from Mahogany zone.
3 Typical analysis.

Figure 1. Geologic map of Kentucky showing outcrop of Devonian oil-shale deposits.

Some conclusions may be drawn from the table. The hydrogen content of the New Albany Shale is higher than any of the coals; therefore, the carbon to hydrogen ratio is less. Also, the oxygen content of shale is much less than in the high-volatile coals to which oil shale is most analogous. The nitrogen content is higher for shale than for any of the coals. Therefore, the Eastern black shales are not impure coal, but a separate organic entity. The Eastern black shale composition lies between coal and Green River Shale. These differences probably account for the relatively poor showing of Eastern shales on retorting to produce liquid products.

A paper by Smith and Stanfield (1964) reports the yields of oil from three core holes (Fig. 2). The three cores were assayed for the entire New Albany Formation at the location of the core holes; the results of assaying the cores are shown in Figure 2.

The location and description of the wells are:

1. No. 1 Leslie Norton, drilled in Rockcastle County by Ferguson and Bosworth Oil Exploration, Carter coordinate section 18-I-63, along dirt road about 1 mile north of Ky. Highway 80, at crossing of Rockcastle River. Depth (below surface) of New Albany formation: 971.8-1,071.3 feet; thickness of formation: 99.5 feet.
2. No. 1 G.T. Morris, drilled in Pulaski County by Ferguson and Bosworth Oil Exploration, Carter coordinate section 19-H-57, on Coldweather Creek about 1,000 feet downstream from confluence of Cooper Creek. Depth of New Albany for-

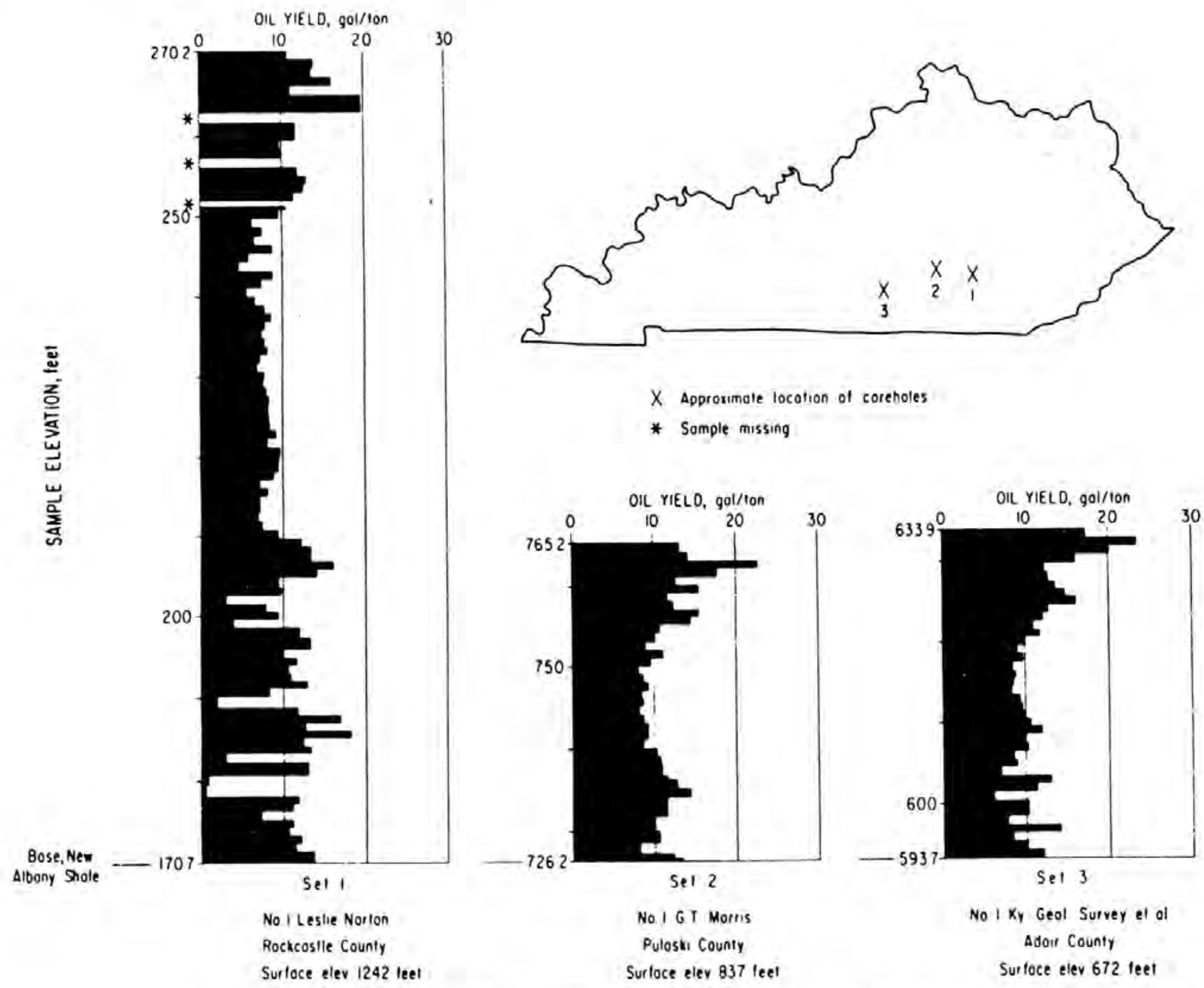


Figure 2. Oil yields of New Albany Shale from three Kentucky cores.

mation: 71.8-110.8 feet; thickness: 39 feet.

3. No. 1 Kentucky Geological Survey and others, drilled in Adair County by the Kentucky Geological Survey and the United States Geological Survey, Carter coordinate section 25-H-51, about 1.5 miles southwest of Columbia on Ky. Highways 61 and 80 at Pettys Fork Crossing. Depth of New Albany formation: 38.1-78.3 feet; thickness: 40.2 feet.

At the Laramie Energy Research Center of the Bureau of Mines (now of the Energy Research and Development Administration), the cores were divided into samples about a foot long; the cores included rocks of similar lithological character in each individual sample. Oil yields were determined by the modified Fischer retort method which is widely applied to assaying of oil shales. Oil-yield profiles determined by this method are shown in Figure 2. The maximum yields from each of the wells were 19.8, 22.6, and 23.4 gallons per ton for cores 1, 2, and 3, respectively.

A tabulation of the estimated oil yield in barrels per acre, average yield gallons per ton, and barrels per acre foot for each of the cores is as follows:

Core No.	Thickness Feet	Gallons per Ton	bbl/acre Foot	bbl/acre
1	99.5	9.75	765	76,000
2	39.0	11.36	871	34,000
3	40.2	11.48	879	35,000

Although these are impressive potential oil-yield values, the total organic matter in the rock is more impressive. Only about one-third of the total organic matter is recovered as oil.

The following table shows the tons of shale and tons of organic matter per acre.

Core No.	Shale, tons per acre	Organic Matter, tons per acre
1	328,185	37,500
2	125,000	16,560
3	129,685	17,185

These tabulations provide an idea of the huge reserves of fossil energy contained in Kentucky oil shales; certainly sometime in the future they will be developed and used by American industry.

REFERENCES

Benson, H.E., and Tsaros, C.L., Gas from coal and shale: how close: Hydrocarbon Processing and Petroleum Refiner, v. 44, p. 191-198.

Crouse, C.S., 1925, An economic study of the black Devonian shales of Kentucky: Kentucky Geological Survey, series 6, v. 21, p. 57-59.

Hopkins, J.M., 1974, Some approaches to a viable oil shale industry: A Seminar on Oil Shale Development, No. 15, 1974, Denver, Colorado.

Jillson, W.R., 1921, A preliminary report on the oil shales of Kentucky: Kentucky Geological Survey, series 6, v. 2, 37 p.

Perkins, J.H., 1972, Geology and economics of Knox Dolomite oil production in Gradyville East field, Adair County, Kentucky, *in* Hutcheson, D.W., ed., Proceedings of the Technical Sessions, Kentucky Oil and Gas Association 34th and 35th Annual Meetings, 1970 and 1971: Kentucky Geological Survey, ser. 10, Special Publication 21, p. 10-25.

Smith, J.W., and Stanfield, K.E., 1964, Oil yields of Devonian New Albany shales, Kentucky: American Association of Petroleum Geologists Bulletin, v. 48, no. 5, p. 712-714.

Smith, J.W., and Young, N.B., 1967, Organic composition of Kentucky's New Albany Shale: determination and uses: Chemical Geology, v. 2.

Shultz, E.B., Jr., 1965, Methane, ethane, and propane from American oil shales by hydrogasification: Green River Formation shale and shales of the eastern United States and New Brunswick, *in* Jones, J.R., Jr., ed., Hydrocarbons from oil shale, oil sands, and coal: Chem. Eng. Prog. Symposium series 54, v. 61, p. 48-59.

U.S. Geological Survey and U.S. Bureau of Mines, 1968, Mineral resources of the Appalachian Region: U.S. Geological Survey Professional Paper, 492 p.

TERTIARY RECOVERY AND THE MARAFLOOD™ OIL RECOVERY PROCESS

FRED H. POETTMANN
Marathon Oil Company
Findlay, Ohio

ABSTRACT

About half of the discovered oil that is unrecoverable by presently known techniques is a candidate for tertiary recovery. Secondary and tertiary oil-recovery methods involve the injection of energy through a wellbore into a formation containing oil; this drives the oil to a producing well.

A new tertiary oil-recovery process is microemulsion flooding. Surfactants are added to water in order to reduce interfacial tension. Microemulsions are added to prevent adsorption of surfactant by rocks. A properly designed slug of microemulsion completely displaces oil in the portion of the reservoir contacted, as long as the slug remains intact.

The Pennzoil Company is using the Maraflood™ process at the Bradford field in McKean County, Pennsylvania. To date, more than 153,000 barrels of oil have been produced from the project. It is estimated that ultimate recovery may be as high as 50 percent of the post-waterflood oil saturation.

The inadequate supply of domestic crude oil has put greater and greater emphasis on economical secondary and tertiary oil recovery. The demand for oil far exceeds domestic supply, and domestic production is decreasing annually. This decline will continue until the Alaska pipeline begins to deliver oil from the North Slope in late 1977 or early 1978. After about 1980, production will probably level off again. This domestic crude-oil supply crisis has come about, basically, for two reasons: (1) domestic oil is more difficult to find and costs have rapidly increased, and (2) United States domestic production capacity has decreased so that increased imports are required to meet rapidly increasing domestic demand. These reasons, coupled with the ever-stringent environmental protection requirements, have resulted in the domestic crude-oil shortage and have stimulated activity in tertiary oil recovery research. The crisis was further aggravated by the Middle East war, the Arab oil embargo, and high foreign crude-oil prices.

Tertiary oil recovery has more immediate potential, both economic and technical, than oil from oil shale or tar sands; the tertiary oil is there to be produced. Oil in place discovered in the lower 48 states totals 434 billion barrels (American Gas Association and others, 1973). Of this total, 103 billion barrels have already been produced, and the recognized, proved reserves are about 33 billion barrels. This figure includes all oil recoverable by presently known methods. The recovery efficiency is about 31.4 percent. Another 68.6 percent, or about 298 billion barrels, is unrecoverable by presently known techniques. A good portion, perhaps half, of these 298 billion barrels is a candidate for tertiary recovery. Over the past several years, oil recovery, because of improving technology, has constantly increased at an absolute rate of about 0.5 percent per year to its current level. Each 1 percent increase in oil recovery will add 2.5 to 3.0 billion barrels of oil from currently producing fields to domestic reserves.

Tertiary recovery refers to recovery of oil left after waterflooding of any other secondary operation. This is not to say that tertiary recovery processes cannot be used as secondary recovery processes after the primary energy in a reservoir has been dissipated. For this reason, ''improved fluid-injection processes'' or ''unconventional oil recovery'' might be preferable terminology. These processes are generally considerably more sophisticated than secondary processes and consequently are heavily front loaded financially; that is, the application of the processes requires large initial investments. In addition, initial production is often delayed for a number of years, thus delaying income. The risk is, therefore, greater, and considerably more care must be taken in evaluation of prospects for tertiary flooding. Hopefully, the government will maintain a favorable economic climate for tertiary recovery.

In secondary and tertiary oil recovery methods, energy is injected through a wellbore into a formation containing oil, driving the oil to a producing well. The injected energy can take the form of water, gas, surfactant solutions, hydrocarbon, and other fluids. The displacement can take place in an immiscible or miscible manner; the driving force is the pressure generated by the injected fluids. The injected fluids can also be heated or heat can be generated in place in the formation. Heat imparts more favorable physical characteristics to the oil, which facilitate the flow of the oil by reducing the oil viscosity.

A major factor affecting the displacement efficiency of the injected fluid is mobility. If the driving fluid has a higher viscosity than the oil and water being displaced, then the displacement efficiency will be high. Conversely, if the viscosities are reversed, then there will be a lower displacement efficiency and a lower volumetric displacement. Mobility control is, therefore, an important design criteria in selecting injection fluids. Each fluid bank is driven by a fluid with higher viscosity, thus maximizing displacement efficiency.

Secondary and tertiary recovery processes can be put into four categories: gas injection, water injection, heat injection, and solvent injection. Straight gas injection and water injection are relatively old, and many barrels of oil have been recovered by these processes.

Advantages of using gas and water include cost, availability, and ease of handling. Disadvantages result from their immiscibility with oil in the reservoir; this causes a high percentage of the original oil to remain in place because of capillary effects, which leads to a low unit displacement efficiency. The oil left after waterflooding can easily equal more than half of the original oil saturation before waterflooding. In the case of gas injection, recoveries are even less.

Modifications of the waterflooding process are being employed in which water-soluble polymer is added to the water to give it better mobility control; in other cases, highly alkaline chemicals such as silicates and caustic solutions are added to the water. These materials are effective in a number of ways. They react with constituents in the crude to form surface-active compounds, which, in turn, lower interfacial tension and increase oil recovery. Also, the alkaline chemicals affect the in-situ mobility of the displacing fluids in a favorable manner.

Heat injection, in the form of in-situ combustion or hot fluid injection such as steam or hot water, has been primarily applied to the heavier oils, with some success. Forward in-situ combustion is the most common of the in-situ heat-generation processes. Air is injected into the reservoir, part of the oil is oxidized, and heat is generated to aid in the recovery. Modification of the forward combustion process, such as the simultaneous injection of water with air, has advantages in certain reservoirs. Steam, both as steam drive and huff-and-puff process, is the most common thermal energy fluid injected. Steam reduces the viscosity of the crude and more oil is produced. The United States currently produced about 200,000 barrels per day by steam and hot-water injection. The limited use of these processes is a result of various disadvantages which include reservoir depth, selective rock and crude-oil characteristics, and the significant initial investment in compressors, steam generators, and fuel costs.

Solvent injection, or the injection of LPG, alcohols, and enriched gases at high pressure, has not found widespread acceptance, primarily because of mobility-control problems. These highly mobile fluids tend to finger through the formation; this results in poor displacement efficiencies. The various miscible processes use slugs, which are miscible with the reservoir oil at their leading edge. Slugs are propelled through the reservoir with a cheap scavenger fluid such as gas or water. The advantage of the high unit displacement of solvents is generally offset by the poor mobility relationship with the reservoir crude.

One of the newest tertiary oil-recovery processes that has come on the scene in the last 10 years is a form of chemical flooding, or miscible-type waterflooding, also known as micellar solution or microemulsion flooding. The oil industry has tried adding surfactant to water to reduce interfacial tension a number of times. One of the problems associated with surfactant floods has been the magnitude of adsorption of the surfactant on the reservoir rock. This problem has been reduced in microemulsion flooding.

Microemulsions are surfactant-stabilized dispersions of water and hydrocarbons. At sufficiently high concentrations, surfactant molecules form aggregates called micelles. These micelles are capable of solubilizing fluid in their cores and are called swollen micelles. Microemulsions are transparent and homogeneous and are stable to phase separation. The term "soluble oil" is also often used to describe an oil-external microemulsion.

Microemulsion flooding is a fluid-injection process in which a microemulsion is injected into the formation and is in turn displaced by a mobility buffer solution. The mobility buffer solution is in turn displaced by water; in other words, the process reverts to a waterflood. The microemulsion is the key to the process. Oil and water are displaced ahead of the microemulsion slug and a stabilized oil and water bank develops (Fig. 1).

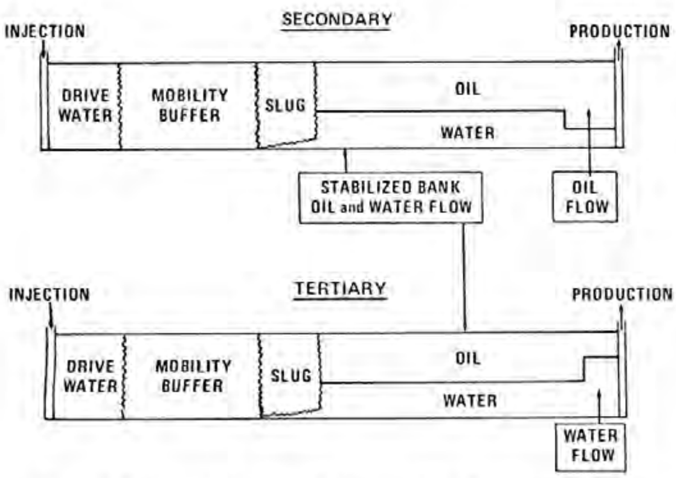


Figure 1. Schematic drawing of microemulsion flooding process.

The viability of any oil-recovery process depends, among other things, on two major factors: unit displacement efficiency and conformance. Microemulsion flooding attempts to maximize both of these efficiencies. In displacing one fluid with another, conformance is determined by the mobility of the displacing and displaced fluids. High vertical and areal sweep efficiencies result when the displacing fluid has a mobility equal to or less than the mobility of the displaced fluid. Mobility control is a very important characteristic of micellar solution flooding. It inhibits the rapid dissipation of the micellar solution slug by preventing fingering and channeling of the slug; this results in high reservoir conformance. Aqueous solutions of high-molecular-weight polymers are used as the mobility buffer. After the necessary amount of buffer is injected, the operation reverts to water injection.

Figure 2 shows in terms of crude-oil gravity the general range over which the various oil-recovery processes are applicable. Note the range covered by microemulsion flooding. Generally speaking, wherever a waterflood has been successful, microemulsion flooding may also be technically applicable.

Microemulsions are composed of hydrocarbons, water, and a surface-active agent. Other chemicals such as alcohols and salts are added to control stability, viscosity, and other characteristics. The hydrocarbons can range from LPG to crude oil. Petroleum sulfonates are used as surfactants. Figure 3 illustrates a typical range of microemulsion compositions.

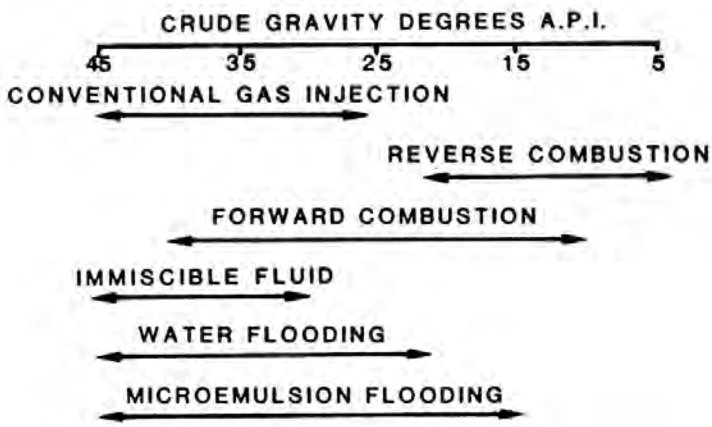


Figure 2. Graph showing range of applicability in terms of API gravity of various oil-recovery processes.

COMPONENT	VOLUME PERCENT LOW WATER OIL EXTERNAL	HIGH WATER OIL EXTERNAL	HIGH WATER WATER EXTERNAL
SURFACTANT	>5	>4	>4
HYDROCARBON	35-80	4-40	2-50
WATER	10-55	55-90	40-95
COSURFACTANT	<4	0.01-20	0.01-20
ELECTROLYTE	.001-5*	0.001-4*	0.001-4*

*WT. % BASED ON WATER.

Figure 3. Compositions of micellar solutions.

Slug sizes used in microemulsion flooding usually range from 4 to 7 percent of the reservoir pore volume. The mobility buffer solution is usually graded in concentration in order to minimize fingering, and, depending on concentration, the size of the mobility buffer may range from 50 to 100 percent of a reservoir pore volume. The mobility buffer is followed by 50 to 100 percent of a pore volume of water.

A properly designed slug of microemulsion completely displaces oil in the portion of the reservoir contacted, as long as the slug remains intact. Some brines may not be completely displaced as the slug is injected; this depends on rock type, in-place water salinity, and the slug composition.

The first pilot field test of microemulsion flooding started in 1962. Since that time some 15 to 20 tests and expanded operations have been reported. The field tests have been concentrated in the Illinois Basin and in Pennsylvania. The majority of the tests carried out to date were tertiary operations; two were secondary tests. The initial tests were conducted with relatively low water content systems, while the most recent tests are being conducted with higher water content slugs. Of the field tests initiated to date, test size has varied from 0.625 acres to 45 acres, and pattern types have varied from isolated, inverted, and regular five-spots to line-drive and developed five-spot configurations. Recently, single-well injection tests with core tests to evaluate displacement performance have been initiated.

Oil recoveries for these tests have varied from as low as 8 percent to as high as 63 percent of oil in place at the time the tests were initiated. Barrels per acre-foot recoveries on displacements have ranged from as high as 384 to as low as 86. Two large tests, one a 40-acre, line-drive test in the Robinson sand of Illinois (Bleakley, 1971; Gogarty and Davis, 1972; Oil and Gas Journal, 1974; Earlougher and others, 1974), and the other a 47-acre five-spot test in the Bradford Third sand of Pennsylvania (Danielson and others, 1974) are under way.

Slug injection started in September 1968 in the Illinois 119-R test and continued until January 1969. The amount of slug injected was about 7 percent of a reservoir pore volume, and the slug was made using lease crude oil for the first time. Thickened water made with a Dow polyacrylamide was injected in January 1969. There have been no serious operating problems. The pattern is a direct line-drive with two rows of injection wells and three rows of producers (Fig. 4). There are nine wells in each row, and the total area enclosed is 40 acres. The test objective was to determine performance of the process over a distance of 10-acre spacing. Injection and production wells are 467 feet apart, and

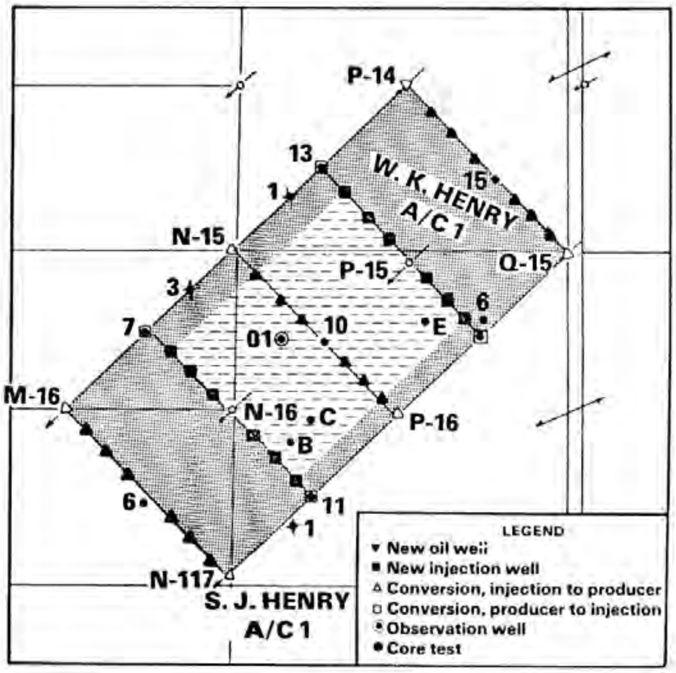


Figure 4. Map showing 119-R project test pattern.

adjacent wells are 116 feet apart. After slug injection, polyacrylamide polymer solution was injected. The initial concentration of polymer was 1200 ppm, but the concentration was continually decreased as the polymer injection increased. Water is now being injected. Core tests indicate that a substantial bank of oil was formed. Figure 5 shows the overall production history of the pattern to date. Oil production increased from 140 barrels per week to more than 1,600 barrels per week at the peak. Oil cut increased from 1.5 percent to a high of 22 percent (Fig. 6). Over 245,000 barrels of oil have been produced to date (February 1975). Recovery from the total pattern at this date is about 38 percent of the oil in place at the start of the test. In the confined area of the test the recovery at this date is 43 percent. Total recovery to date represents about 6,122 barrels per acre. This compares to a waterflood recovery of about 5,000 barrels per acre. Thus, tertiary recovery has exceeded waterflood recovery. Ultimate recovery in the confined area could approach 45 percent of the oil in place. However, it must be recognized that the flooding pattern is different.

The chemicals that are injected with the microemulsion have little effect on crude characteristics and the refining processes since most of the crude oil produced never sees the slug and is therefore no different from the

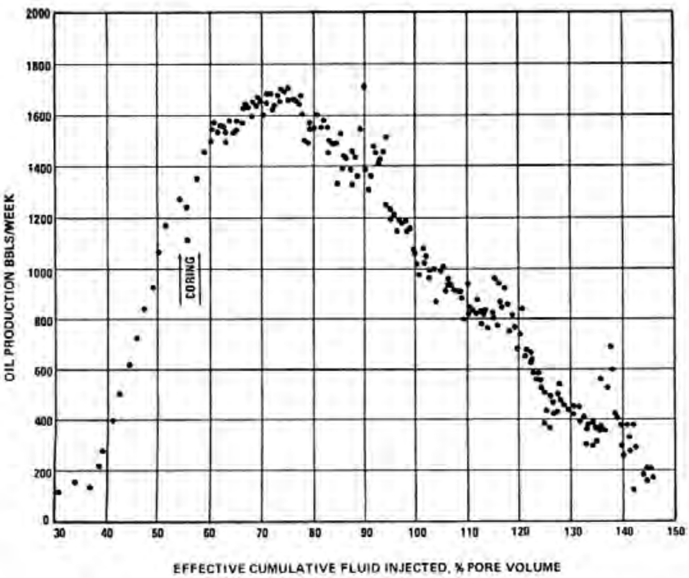


Figure 5. Graph showing production history of 119-R project.

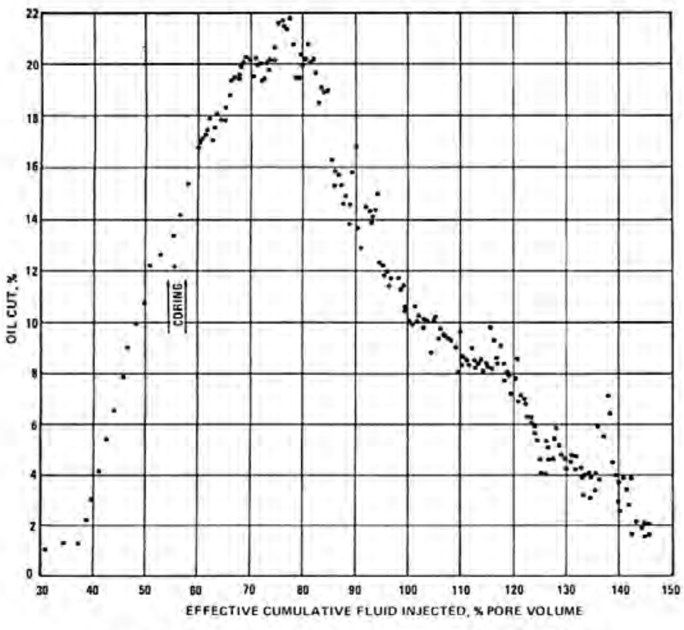


Figure 6. Graph showing oil-cut history of 119-R project.

original crude production; however, at the end of the production process, the combination of petroleum sulfonate and polymer breakthrough in the producing wells aggravates the production of crude-oil emulsions. This problem has been solved by increasing the brine or salt content of the water and adding chemicals and heat. The concentration of petroleum sulfonate in both the oil and water phases at breakthrough ranges up to 1000 ppm. Polymer, of course, shows up only in the water. Tests to date indicate that there are no serious difficulties from the sulfonate in the crude as far as refining operations are concerned.

The Bingham test in the Bradford Third sand of the Bradford field, McKean County, Pennsylvania, was initiated in March 1971 (Danielson and others, 1974). The Pennzoil Company is the operator of the test and is using the Maraflood™ process under license from the Marathon Oil Company. The test site consists of 47 acres. The old waterflood five-spot pattern in the area is being reused. Pattern spacing is about 3 acres. Figure 7 is a map of the test pattern. The producing wells are divided into two groups, Farm A and Farm B. Farm A consists of 26 acres with nine confined five spots or inside producing wells; Farm B consists of the remaining 16 producing wells surrounding Farm A. The reservoir in the test area is about 1,950 feet deep.

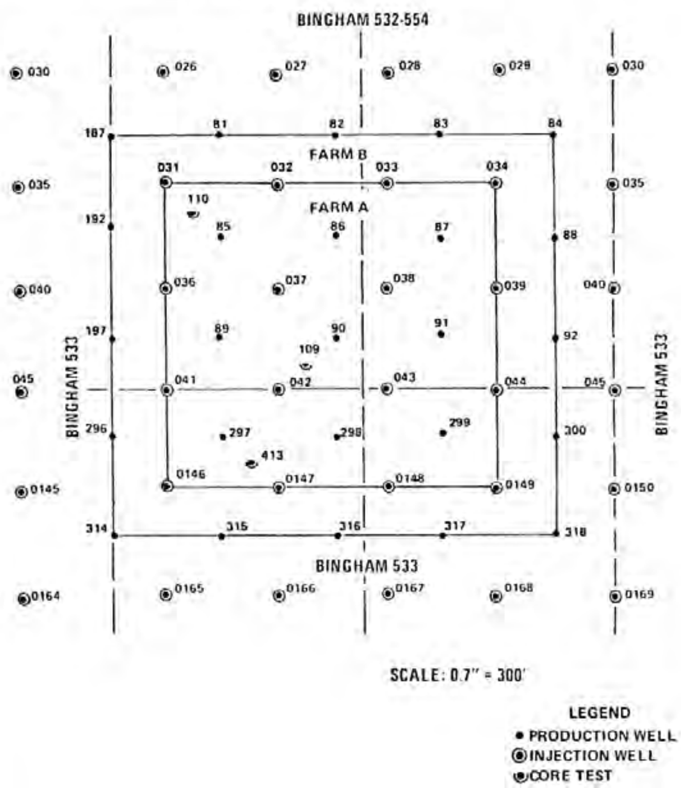


Figure 7. Map showing test pattern of Bingham expansion test.

Slug injection started in March 1971. The amount of slug injected was 5 percent of a pore volume. Following slug injection, Dow Pusher 500 polymer was injected and is still being injected. Figure 8 shows the performance of the total project to date; Figures 9 and 10

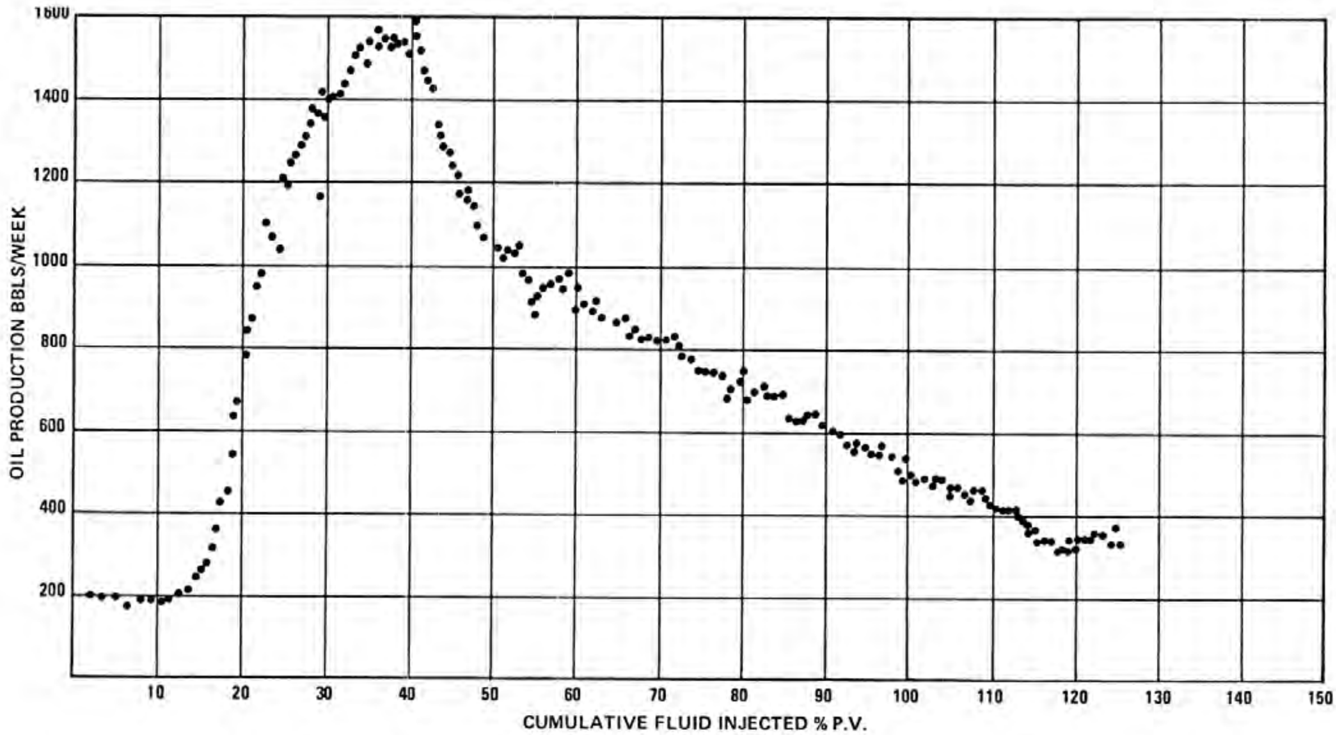


Figure 8. Graph showing cumulative production history of Bingham expansion test.

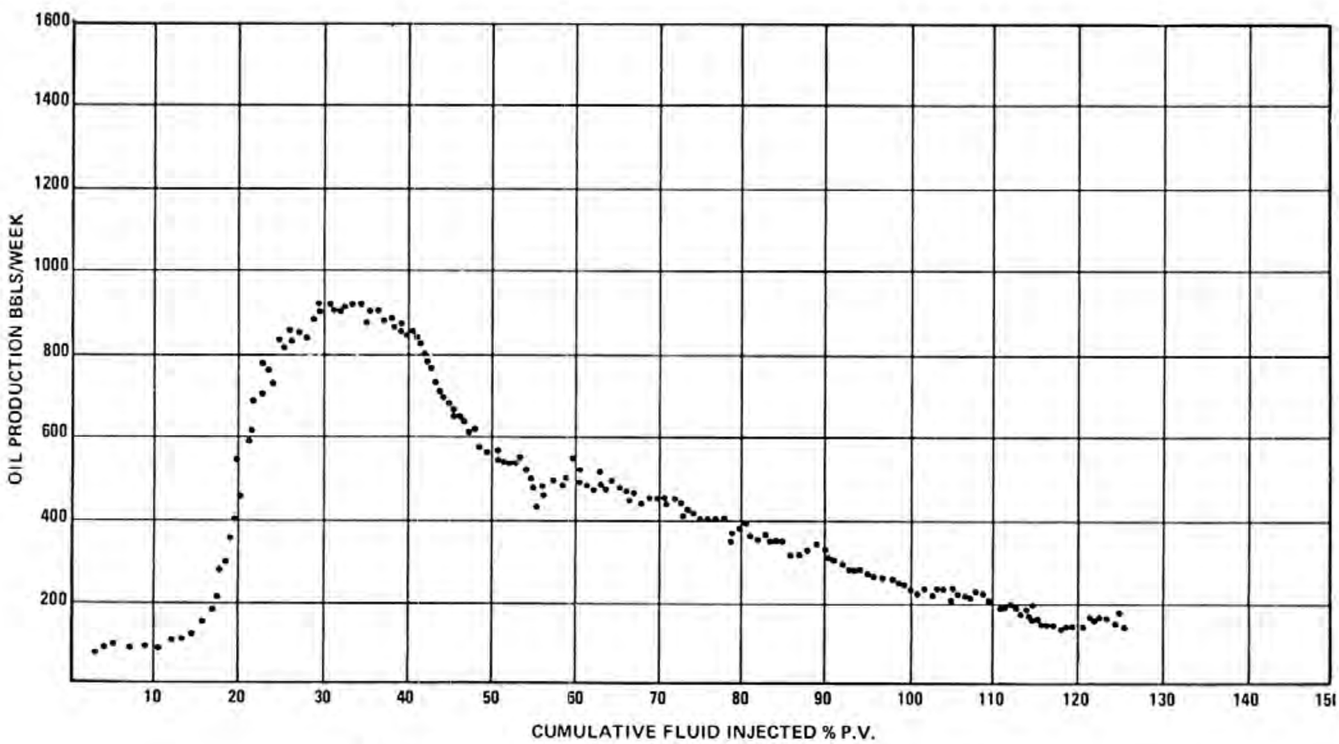


Figure 9. Graph showing production history of Farm A of Bingham expansion test.

show the performance of Farms A and B.

To date more than 153,000 barrels of oil have been produced from the project; 85,000 barrels came from Farm A and 68,000 barrels came from Farm B. Oil pro-

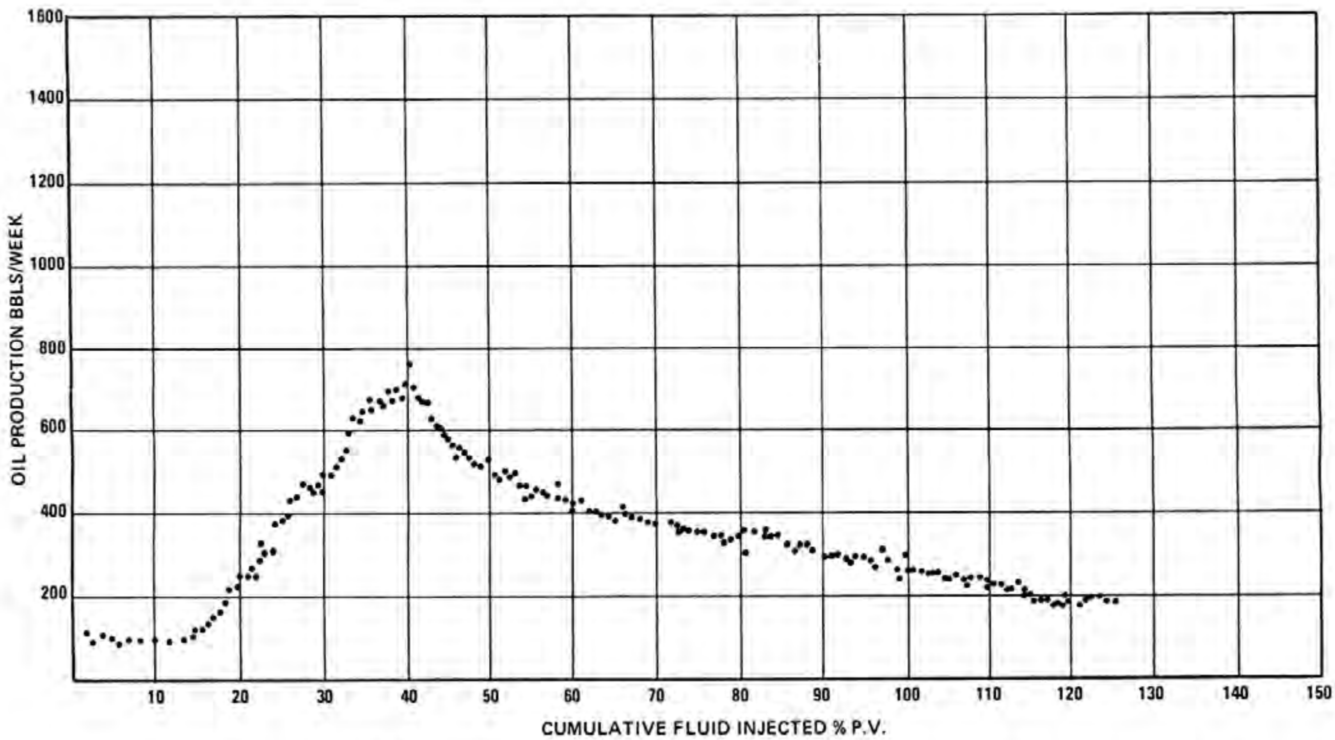


Figure 10. Graph showing production history of Farm B of Bingham expansion test.

duction increased from around 200 barrels per week to more than 1,500 barrels per week at the peak. Oil cut for the total pattern increased from 2.0 percent to a high of 13.6 percent. It is estimated that ultimate recovery may be as high as 50 percent of the post-waterflood oil saturation. No serious production problems have been encountered to date in this test. The only problem is maintaining high injectivity. The polyacrylamide polymer functions as a mobility control agent by reducing the permeability of the formation and increasing the viscosity of the buffer solution. In low permeability reservoirs, any large permeability reduction cannot be tolerated because of its effect on injectivity. An active well-stimulation program has maintained well injectivity.

As field testing has progressed in the past 10 years, a testing philosophy based on previous experience has also evolved. Initial tests were designed with fairly limited objectives. Later testing has been aimed at either testing improved fluids or answering questions about scaling or the behavior of fluids in different reservoir environments. During this period, micellar-solution technology improved substantially, yielding lower cost fluids and more efficient performance in laboratory floods. New concepts for the proper design of mobility control and type of mobility buffer were also developed. With the increase in the price of crude and improvements in process economics, we are now at the point of large-scale commercial field application. In the next few years, we should see tertiary recovery beginning to make substantial contributions.

Much of the gap between domestic production and demand can be met by the large-scale application of microemulsion flooding. However, this will require large volumes of chemicals which are not now available in the quantity needed. For example, every 100 million barrels of production developed per year (273,000 barrels a day) by microemulsion flooding would require approximately 1.7 billion pounds per year of surfactant, 18.1 million gallons per year of alcohol, and 102 million pounds per year of polymer. These are staggering numbers. Their production, however, is necessary if tertiary recovery is to make a significant contribution to the energy needs of the nation.

Marathon Oil Company has announced the first large-scale application of the Maraflood™ oil-recovery process at its fields in the Illinois Basin. The process is now being applied to a 120-acre tract in southeastern Illinois. Expansion of this first tract to several thousand acres is planned over a period of years. In order to provide the micellar solution for this project, a 5,000-barrel-per-day crude-oil surfactant slug manufacturing plant is under construction at Marathon's Robinson Refinery; that location is in the immediate vicinity of the producing properties. This facility should be completed and producing by late fall of 1975, when injection into the initial 120 acres will commence.

Marathon is planning an investment of $125 to 130 million over the next five years for commercial application of the Maraflood™ process. The program, on about 2,700 acres of leases, would aim to recover up to 45 percent of the oil in place after waterflooding. Economic feasibility will depend on trends in oil prices, costs of materials and services, and the impact of legislation affecting the oil industry.

REFERENCES

Beakley, W.B., 1971, How the Maraflood™ process performs: Oil and Gas Journal, November 29, 1971.

Danielson, H.H., Paynter, W.T., and Milton, H.W., 1974, Tertiary recovery by the Maraflood™ process in the Bradford field: Presented at the Improved Oil Recovery Symposium, April 22-24, 1974, Tulsa, Oklahoma.

Earlougher, R.C., Jr., O'Neal, J.E., and Surkalo, H., 1974, Micellar solution flooding: field test results and process improvements: Presented at Second Midwest Oil and Gas Symposium of Society of Petroleum Engineers of A.I.M.E., March 28-29, 1974, Indianapolis, Indiana.

Gogarty, W.B., and Davis, J.A., Jr., 1972, Field experience with Maraflood™ process: Presented at the Improved Oil Recovery Symposium, April 16-19, 1972, Tulsa Oklahoma.

Maraflood Pilot, 2 1/2 years later: Oil and Gas Journal, March 25, 1974.

Reserves of crude oil, natural gas liquids, and natural gas in the United States and Canada and United States productive capacity as of December 31, 1972: American Gas Association, American Petroleum Institute, Canada Petroleum Association, v. 27, 251 p.

COAL LIQUEFACTION—A SOURCE OF HYDROCARBONS

J. V. FOX
Ashland Oil, Inc.
Ashland, Kentucky

ABSTRACT

The United States and the rest of the world are becoming increasingly dependent on hydrocarbons. High consumption of hydrocarbons necessitates the discovery of new sources for hydrocarbons. Coal liquefaction is one new source. The three major liquefaction processes are pyrolysis or low-temperature carbonization, direct hydrogenation, and Fischer-Tropsch processes.

Capital requirements for liquefaction will be approximately $100,000 per daily barrel capacity. Coal requirements are roughly one ton of coal per three barrels of product. With operating costs at about $3.50 per barrel, the price of the product would have to be approximately $16 a barrel for a return on investment of 15 percent DCF. Although these costs seem high by traditional standards, the rapidly increasing price of Middle East oil makes coal liquefaction nearly economically feasible at the present time.

This day in which we now live could well be called the "Hydrocarbon Age." For the past hundred years or so, the United States and the remainder of the world have become more and more dependent upon hydrocarbons.

It is difficult to survey any activity, event, or product that is not in some way related to hydrocarbons, either as a source of energy or as a raw material. This dependence upon hydrocarbons has come about because of the traditional availability and easy access of petroleum-based hydrocarbons. In the United States alone the current consumption of hydrocarbons is on the order of 17 million barrels per day; 23 trillion scf of natural gas are also consumed each day. Today we are faced with the need to find a substitute for this traditional source of hydrocarbons for use as a chemical raw material and as an energy source. Because of this nation's abundant coal reserves, coal liquefaction seems a natural place to begin.

There are important differences between coal and petroleum. First, there is the carbon-hydrogen ratio. Typical carbon-hydrogen ratios for hydrocarbons from various sources are shown in Table 1. The carbon-hydrogen ratio for methane or natural gas, for instance, is 1 to 4 on an atomic basis. The carbon-hydrogen ratio for propane as LPG is 3 to 8. The carbon-hydrogen ratio for crude oil is approximately 1 to 2. The ratio for bituminous coal is typically 1 to 1. Generally speaking, liquefying coal means decreasing the carbon-hydrogen ratio of the hydrogen-deficient solid resource. One possible exception would be the conversion of coal to benzene, which has a carbon-hydrogen ratio of 1 to 1. Minimum hydrogen would be required if the proper process existed.

The molecular structure of petroleum products is well understood by today's technology. The molecular makeup of paraffins, aromatics, and other molecular types is well known and well defined. Likewise, instruments and technology for describing petroleum-based fractions in terms of molecular structure are well developed.

Coal molecular structures, on the other hand, are much less well defined. Several researchers are active in this area, but the complexity of the subject, plus a lack of widespread interest, has left our knowledge in this area far behind the advanced state of petroleum technology. As far as physical properties are concerned, the im-

Table 1.—Typical Carbon-Hydrogen Ratios.

Hydrocarbon	C-H Atomic Ratio
Methane	1:4
LPG (Propane)	3:8
Crude Oil	1:2
Benzene	1:1
Coal	1.1:1

portant difference is that coal is a solid and petroleum is a fluid.

The two products also have basic differences with regard to impurities. Nitrogen, sulfur, and oxygen are, of course, common to both products; however, the oxygen content of crude oil is usually quite low compared to coal, which may have an oxygen content as high as 10 percent. Probably the most important single impurity in the two products is ash. Ash is a minor part of crude oil and a very significant part of coal—as high as 10 to 20 percent. The removal of ash impurity from coal or coal products is a major problem in coal gasification; it is also a large part of the total cost of utilizing coal as a basic resource for hydrocarbons.

Given the previously discussed differences, how does one go about making oil or a substitute for petroleum from coal? There are several approaches, but basically they fall into three categories: pyrolysis or low-temperature carbonization, direct hydrogenation, and Fischer-Tropsch processes.

Processes which decrease the carbon-hydrogen ratio by removing carbon are usually referred to as pyrolysis or low-temperature carbonization. By heating coal up to a temperature of 1500° to 1600° F, one can drive off the volatile material and recover liquid in the form of a tarlike oil. This oil can then be upgraded to a syncrude. Depending upon the particular coal, yields are on the order of one barrel per ton. About 60 percent of the total coal charge winds up as char. The large amount of by-product char means that a use must also be found for the char. Char is essentially carbon and ash. This material could be used to produce gas by the steam-carbon reaction.

The best example of low-temperature carbonization is the COED process, which was developed by FMC at Princeton, New Jersey, under the auspices and sponsorship of the Office of Coal Research. It has been demonstrated in a 36-ton-per-day unit at Princeton, New Jersey. Figure 1 shows this process. This laboratory is also the site of the Cogas development program, which is presently underway. Cogas would convert the char to pipeline-quality gas. Cogas, unlike COED, is funded entirely by a consortium of industrial companies headed by FMC.

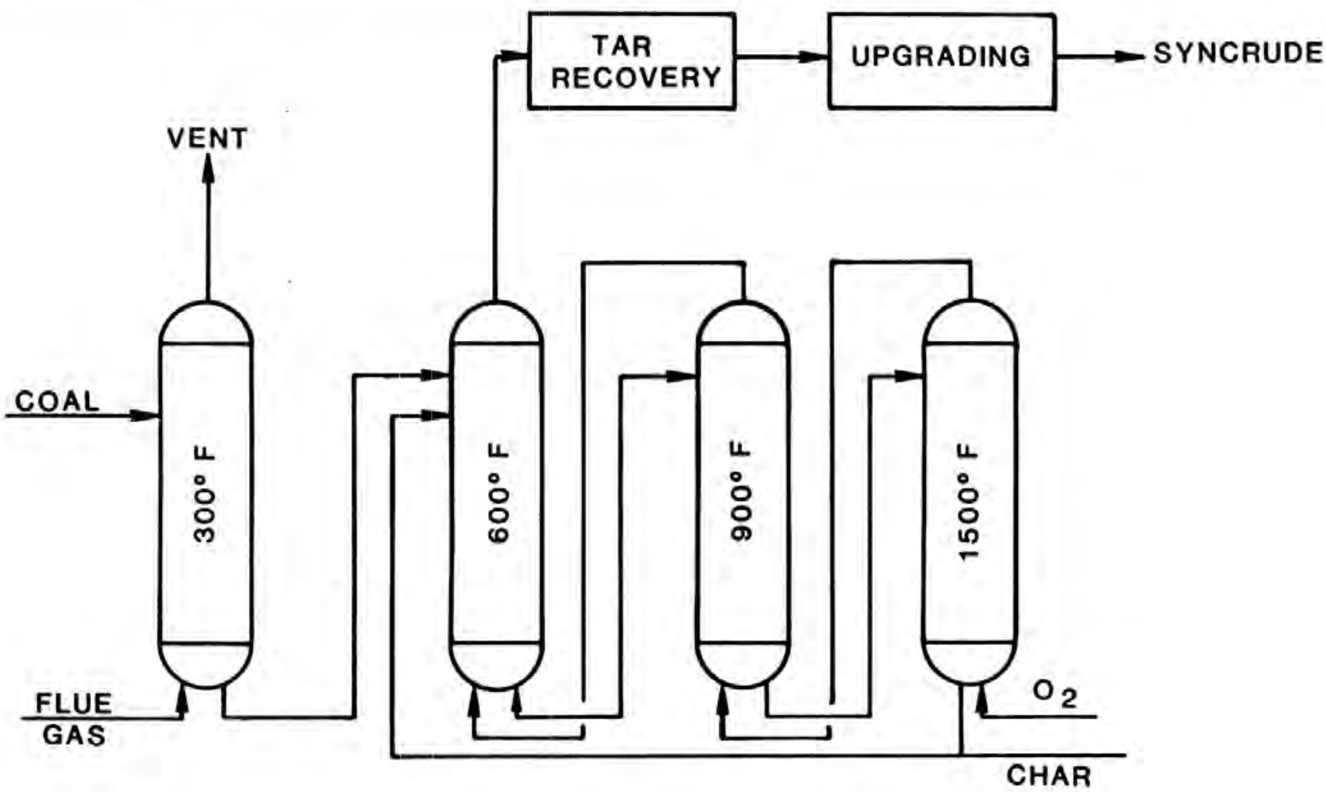


Figure 1. Schematic representation of COED-type coal carbonization.

Direct hydrogenation of coal can yield approximately 3 barrels of oil per ton of bituminous coal. Figure 2 is a schematic representation of this type of process. Requirements for producing oil from coal by direct hydrogenation are pressures as high as 3000 psi, temperature on the order of 850° F, and raw materials consisting of approximately one ton of coal per three barrels of product, 750 gallons of water per ton of coal, and 0.27 ton of oxygen per ton of coal (Table 2). This liquefaction complex will include a plant to process a portion of these materials into a hydrogen requirement of 4000 to 6000 scf per barrel of product. The oxygen is used as an oxidizer for the heat source when the coal is gasified in order to produce the hydrogen requirement. In this process, oxygen is eventually removed as carbon dioxide. The carbon that is lost in the rejection of carbon dioxide is an important by-product.

There are numerous examples of processes for the hydrogenation of coal. Some of the important ones are the Solvent Refined Coal Process (SRC), the Synthoil Process, and the H-Coal Process. Within the private sector there are several other processes which are reportedly well advanced. The H-Coal Process has probably received the most publicity of all the hydrogenation processes, particularly here in Kentucky. This is because a 500-ton-per-day unit is to be built near Catlettsburg, adjacent to the Ashland Oil Refinery complex. The H-Coal process will be discussed later in the paper.

In the solvent refining of coal, pulverized coal, a recycled stream of oil, and a hydrogen stream under pressure of 1500 psi are mixed in a reactor at a temperature of 850° F. The coal is solvated and hydrotreated to produce a very heavy, partially desulfurized liquid. Following removal from the reactor, excess hydrogen is separated for recycling, the product is filtered for removal of ash, and the oil is either recycled into the feed-preparation system or becomes product. Hydrogen uptake in this process is low, and as a result the product is, in fact, a solid up to the temperature of 300° to 400° F. Thus, in order to be a true substitute for most uses of hydrocarbons, this material must be upgraded by further hydrogenation. Solvent-refined coal as a process is being practiced today in an 8-ton-per-day unit at Wilsonville, Alabama, by the Southern Services Company under sponsorship of EPRI, and at Tacoma, Washington, at the rate of 50 to 60 tons per day by Gulf Oil under the sponsorship of the Energy Research and Development Administration.

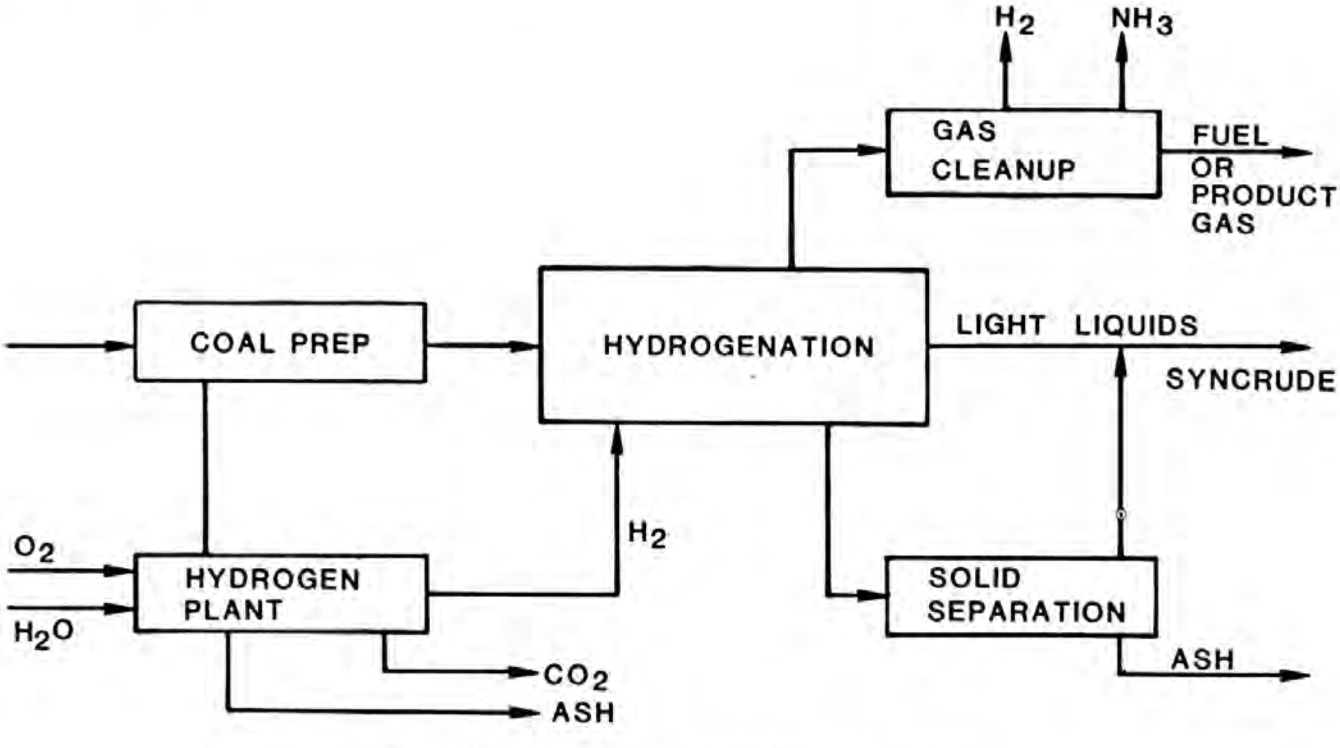


Figure 2. Schematic representation of coal hydrogenation process.

Table 2. — Resource Requirements for Coal Liquefaction.

Resource	Per Barrel Requirement
Coal	.33 Ton
Oxygen	.09 Ton
Water	250 Gallons

A second example of hydrogenation liquefaction is the Synthoil Process. The Synthoil Process was developed by the U. S. Bureau of Mines at the Bruceton Laboratories near Pittsburgh. In this process, a slurry of pulverized coal and hydrogen are passed under conditions of extremely high turbulence and high pressure drop across a reactor filled with pelletized catalyst in a manner similar to typical refinery hydrotreating, HDS, or hydrocracking system. Under conditions of approximately 850° F, and 2000 to 4000 psi pressure, coal is hydrotreated to produce a low-sulfur liquid product. The highly turbulent conditions within the reactor apparently cause the ash in the system to act as a scouring agent. This keeps carbon residue removed from the catalyst pellets and enables the process to continue for a significant period of time without complete deactivation of the catalyst. Catalyst deactivation rates are an important variable in this process. An 8-ton-per-day unit is presently being designed and will be constructed near the USBM station at Bruceton, Pennsylvania.

A third general category of technology for the production of hydrocarbons from coal the Fischer-Tropsch-type processes (Fig. 3). In a Fischer-Tropsch reaction, coal is completely destructed by the carbon-steam reaction to produce a synthesis gas of carbon monoxide and hydrogen. These two gases are subsequently reconstituted by reaction under conditions which produce primarily olefinic and polyolefinic hydrocarbons. The Fischer-Tropsch reaction, while characterized by low overall efficiency, is the most advanced of all the coal-liquefaction processes. It is the technology currently being utilized by the Sasol Company in South Africa for the production of several thousand barrels per day of hydrocarbons.

A similar process which might also be considered well developed is methanol production with coal as feedstock. While methanol is not presently being produced by coal gasification and reconstitution of the resulting synthesis gas, this technology has been developed and was utilized earlier by DuPont near Bell, West Virginia. Methanol from coal is receiving considerable publicity as a clean, versatile fuel. Methanol would be an excellent substitute as a clean fuel for many uses currently supplied by LPG and natural gas. Examples are grain drying, glassmaking, and other similar processes which require the use of a very clean fuel. In addition, methanol shows some possibility as a gasoline extender. The use of methanol as a gasoline extender in quantitites up to 10 percent has received considerable publicity. As natural gas supplies in this country continue to diminish, and the use of natural gas as a feedstock for the production of chemical-grade methanol becomes more difficult, the direct substitution of coal-based methanol seems inevitable. The economics of producing methanol from coal would be considerably enhanced by the development of a high-pressure synthesis gas producer. The technology utilized by DuPont at Bell relied upon an atmospheric-pressure coal gasification system for the production of synthesis gas. Since the production of methanol from synthesis gas occurs at pressures ranging from several hundred pounds psi to 2000 pounds psi, it would be economically beneficial to produce synthesis gas under conditions of at least 300 to 500 psi. There is considerable promise for development in this area in the near future. Thus, methanol from coal has the potential of being a significant source for a substitute for petroleum hydrocarbons in the near future.

H-Coal is a registered trademark of Hydrocarbon Research, Incorporated, of New York. The development of the H-Coal Process began several years ago at the time of the beginning of the Office of Coal Research of the Department of the Interior. Some $2 million from OCR was granted to HRI for the early development of this technology. The program has been carried forward by an all-industry group headed up originally by Atlantic-Richfield and later joined by several companies, including Ashland, Exxon, Gulf, Sunoco, Amoco, and Consolidated Coal, as well as the Electric Power Research Institute. Under the sponsorship of this industrial group, the program was demonstrated at a level of 3 tons per day. In December 1973, the Office of Coal Research again became a part of the program as plans were being made to demonstrate the process at the 500-ton-per-day level previously mentioned. Actually, the

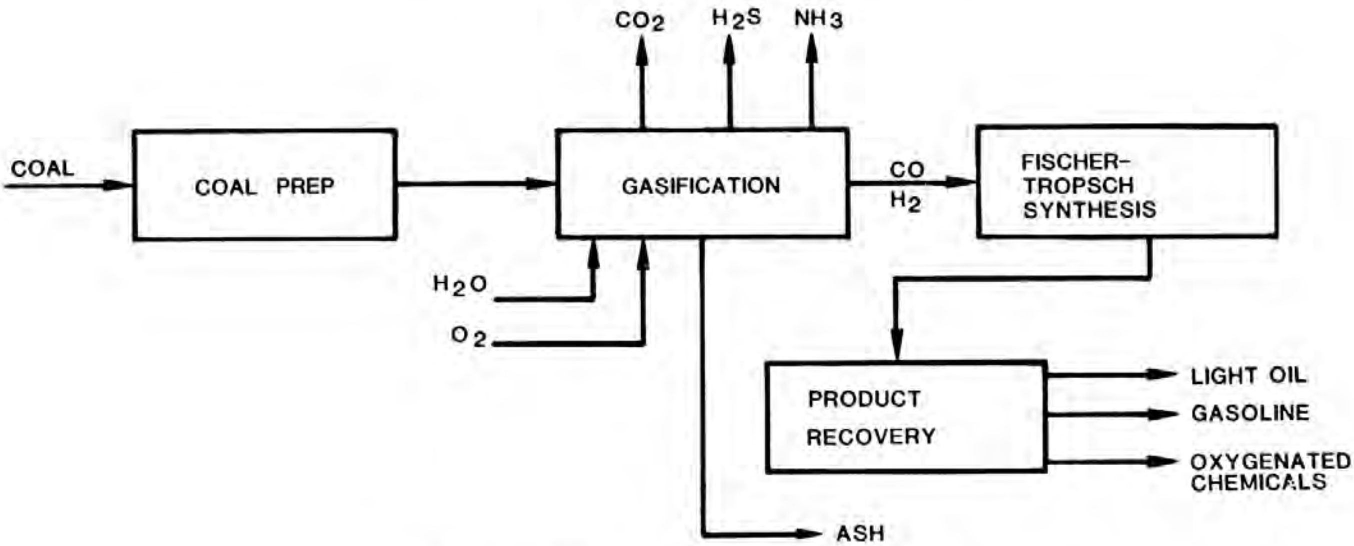


Figure 3. Schematic representation of Fischer-Tropsch process.

plant is being designed to be very versatile and will handle feed rates between 200 and just over 600 tons per day, based on midwestern bituminous coal. Funding for the project is provided by ERDA, the Commonwealth of Kentucky, Ashland, Sun, ARCO, Standard of Indiana, and the Electric Power Research Institute.

The H-Coal Process is based on HRI's ebullating-bed technology. In this technology oil, or a slurry of coal, and hydrogen are passed upward through a bed of catalyst at conditions that produce a stirring or ebullation of the reactor-catalyst bed. Under a temperature of 850° F and pressures up to 3000 psi, coal is hydrotreated for the removal of heteroatoms and the production of a synthetic oil. Subsequent downstream processing removes the ash impurity and produces recycled streams of hydrogen and slurrying oil. The versatility of the process allows the hydrogen consumption to be varied from as low as 4000 standard cubic feet per barrel of product up to 6000 standard cubic feet per barrel of product.

The unique characteristic of this process is, of course, the ebullating-bed reactor. In this reactor, with the catalyst being continually stirred or expanded, it is possible to continuously add catalyst by a lock-hopper system into the reactor, and at the same time, and in similar fashion, remove spent catalyst. Being able to perform this operation makes it possible to maintain the reactor at a constant equilibrium activity. Thus, reactor turnaround is required for maintenance purposes only, and no shutdowns for catalyst replacements are required. Also, this type of reactor system allows the processing of heavy oils and coal slurries which might otherwise be so deactivating on the catalyst system that they would be economically or practically infeasible in a fixed-bed system. The status of the current program is that HRI has a contract for the first phase of this pilot plant program. Phase I consists of detailed construction engineering of the plant in HRI's Miami offices; additional research is being conducted at their Trenton laboratories in New Jersey; environmental assessment is being made by the Environmental Research and Development Administration, and the Technical Management Program for the actual operation of the plant is being developed by HRI's New York office. Following Phase I, Phase II, the actual construction of the plant, will be conducted. Phase III is the actual operational phase of the program, and it will be conducted by Ashland Oil. It is anticipated that operation of this plant will begin in 1978.

Capital requirements for liquefaction will be on the order of $10,000 per daily barrel capacity. Coal requirements,as discussed above, will be based on one ton of coal for each three barrels of product. Operating costs other than coal will be approximately $3.50 per barrel. Thus, for a return on investment of 15 percent DCF, the price of the product would be approximately $16.00 a barrel, with coal at $15.00 per ton (Table 3). These costs are high by traditional standards. However, if the continually escalating price of oil from the Middle East, and the effect of this price of oil on our national econ-

Table 3. — Syncrude Costs.

Cost Component	Dollars/Barrel
Capital	7.50
Operating	3.50
Coal ($15.00/Ton)	5.00
TOTAL	16.00

omy and our national security is considered, we see that coal liquefaction as a substitute for petroleum or at least an extender of our petroleum reserves is nearly economically feasible at the present time. With our ever-increasing demand for hydrocarbons and our ever-decreasing supplies from domestic sources, this nation must look to alternate sources such as our large coal reserves for conversion to clean gas and liquid fuels and raw materials for our chemical industry.

RADIOACTIVE-LOGGING SURVEY OF THE PICKETT CHAPEL-EXIE SOUTH FIELD, ADAIR AND GREEN COUNTIES, KENTUCKY

SAM NORRIS
Kentucky Department of Mines and Minerals
Glasgow, Kentucky

ABSTRACT

Radioactive-logging surveys (mainly gamma ray-density) conducted in the Pickett Chapel-Exie South field indicate an excellent correlation marker in the Lower Black River Formation (Murfreesboro) of Early Ordovician age. Four correlation markers, identified by radioactive-logging surveys, are used as markers to divide the upper Knox dolomite section into four main productive porosity zones.

INTRODUCTION

The Pickett Chapel-Exie South field was discovered in December 1974. It is the fourth and latest Knox discovery in southern Kentucky since the discovery of the Gradyville East field. Previous Knox production in Adair County includes Gradyville East, discovered in July 1969, Gradyville North, discovered in 1970, and Maple Grove School, discovered in 1971 (Fig. 1).

The Pickett Chapel-Exie South field is located in Carter coordinate sections H-48 and H-49 of southwestern Adair and southeastern Green Counties. The discovery well, C. R. Hutcherson No. 1 Buel Rogers, was completed in December 1974, with an initial production of 40 barrels of oil per day without treatment from the Knox dolomite.

Knox production from this field and the other Adair County fields appears to be directly related to their location on ancestral anticlinal structures on which porous, topographic features were carved by erosion.

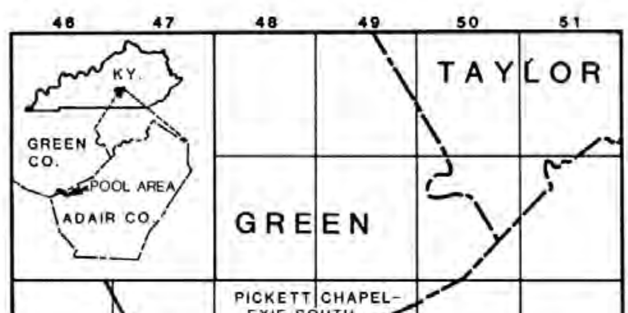


Figure 1. Map showing Knox production in Adair County, 1969 to 1974.

STRATIGRAPHY

Rocks of Mississippian age are exposed at the surface in the vicinity of Pickett Chapel-Exie South. The St. Louis Limestone forms the hills; in the absence of the St. Louis, the underlying Salem-Warsaw Formations form the hills. The Lower Mississippian Fort Payne Formation crops out along the stream valleys.

In the subsurface, the Mississippian Fort Payne rests conformably on the Chattanooga Shale of Devonian age. The Chattanooga is a rich, black, bituminous shale ranging in thickness from 35 to 40 feet in the vicinity of the Pickett Chapel-Exie South field.

Approximately 1,300 to 1,400 feet of Ordovician limestone lies unconformably beneath the Chattanooga Shale, with some interbedded shale, siltstone, and dolomite. The first 700 feet in this sequence consists of the Upper Ordovician Richmond-Maysville Group and the Lexington Limestone. The Lexington Limestone conformably overlies between 600 and 700 feet of the Black River Formation of Early Ordovician age.

Near the top of the Black River section, several thin bentonites occur. The most persistent bentonite occurring within the top 20 feet of the Tyrone is termed "Pencil Cave" by the driller. Although the "Pencil Cave" is only a few feet thick, it serves as an excellent correlation marker on the radioactive and driller's logs.

The Black River Formation is a sequence of vaughanitic to lithographic limestone with constant facies (Freeman, 1953). One interval occurring in the lower Black River Formation serves as an excellent correlation marker on the radioactive log. This horizon is referred to as the "Gilbert marker," after James L. Gilbert of Tri-State Logging Company, Inc.

The "Gilbert marker" occurs approximately 500 to 525 feet below the "Pencil Cave" and in the samples consists of an upper and lower bed of tan, lithographic limestone, 8 to 10 feet thick, separated by approximately 8 feet of gray, calcareous claystone. The "Gilbert marker" varies in thickness from 25 to 30 feet.

The Lower Ordovician rests unconformably on the Knox dolomite of Cambrian age. The erosional surface of the Knox is irregular. The basal portion of the Lower Ordovician section, which includes the lower Black River and Wells Creek Formations, is absent; this is explained by nondeposition. Figure 2 is a generalized stratigraphic section showing the units present in the Pickett Chapel-Exie South field.

STRUCTURE

The Pickett Chapel-Exie South field is located on the west flank of the Cincinnati Arch. Most of the production occurs on the crest and flanks of a northwest-plunging anticline; the anticline is contoured on the base of the Chattanooga Shale (Fig. 3). In Carter coordinate section 11-H-48, the anticline dips at a rate of 50 feet per mile. Structural contours on the "Pencil Cave" (Fig. 4), the base of the "Gilbert marker" (Fig. 5), and on top of the Knox A_1 zone (Fig. 6) indicate a similar anticlinal axis.

GEOLOGIC HISTORY

The Knox dolomite was deposited in relatively shallow seas near peneplaned lowlands. During deposition of the Knox, widespread volcanic ash was deposited periodically as thin interbeds of bentonitic siltstone.

Most of the permeability and porosity in the Knox is considered to be secondary and the result of leaching and erosion by circulating ground water. The cherty zones in the upper portion of the Knox possibly resulted from secondary deposition or replacement of the carbonates by silica that was transported by circulating ground water.

At the close of Knox time, the Cambrian seas retreated and erosion of the Knox surface was widespread. Erosional remnants of Knox dolomite in the form of knobs and ridges protruded above the encroaching Early Ordovician seas. The Wells Creek and basal Black River Formations were not deposited on these remnants. The Wells Creek Formation appears to be restricted to depressed low areas and on flanks of Knox remnants.

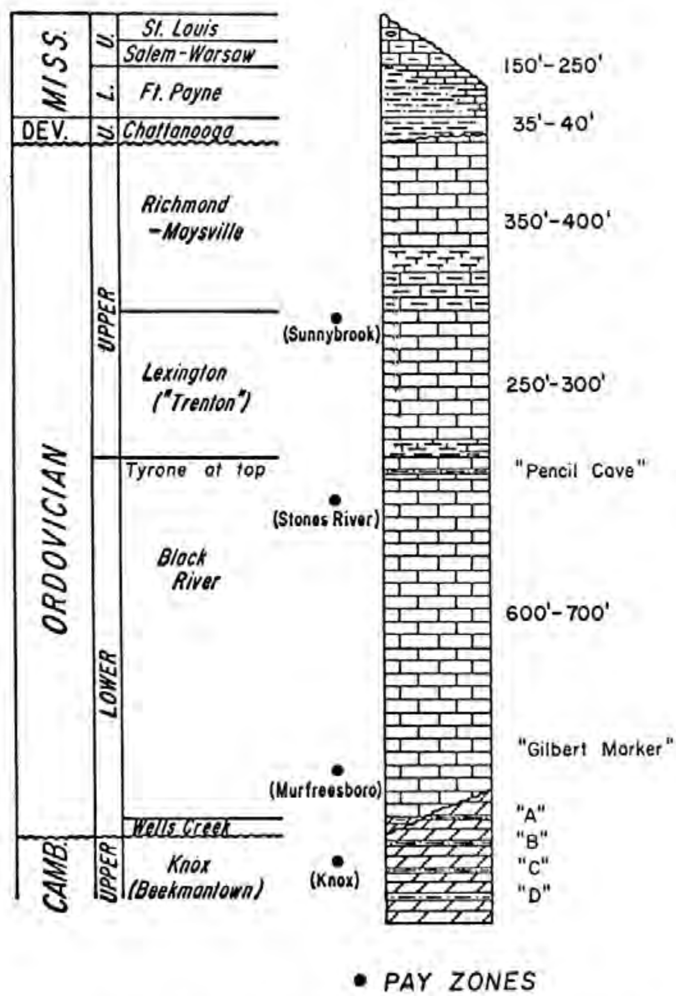


Figure 2. Generalized stratigraphic section of Pickett Chapel-Exie South field.

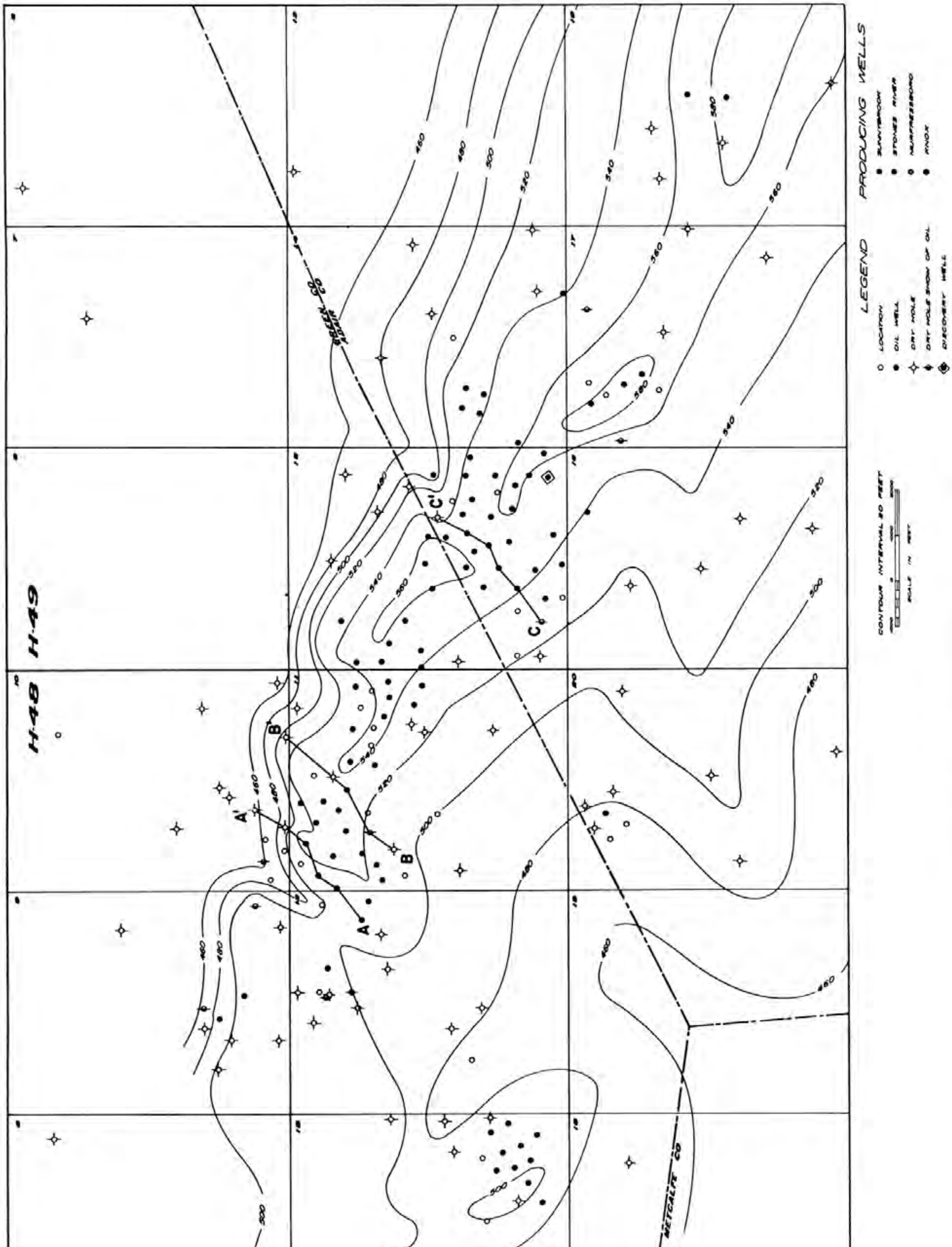


Figure 3. Map showing structure at base of Chattanooga Shale.

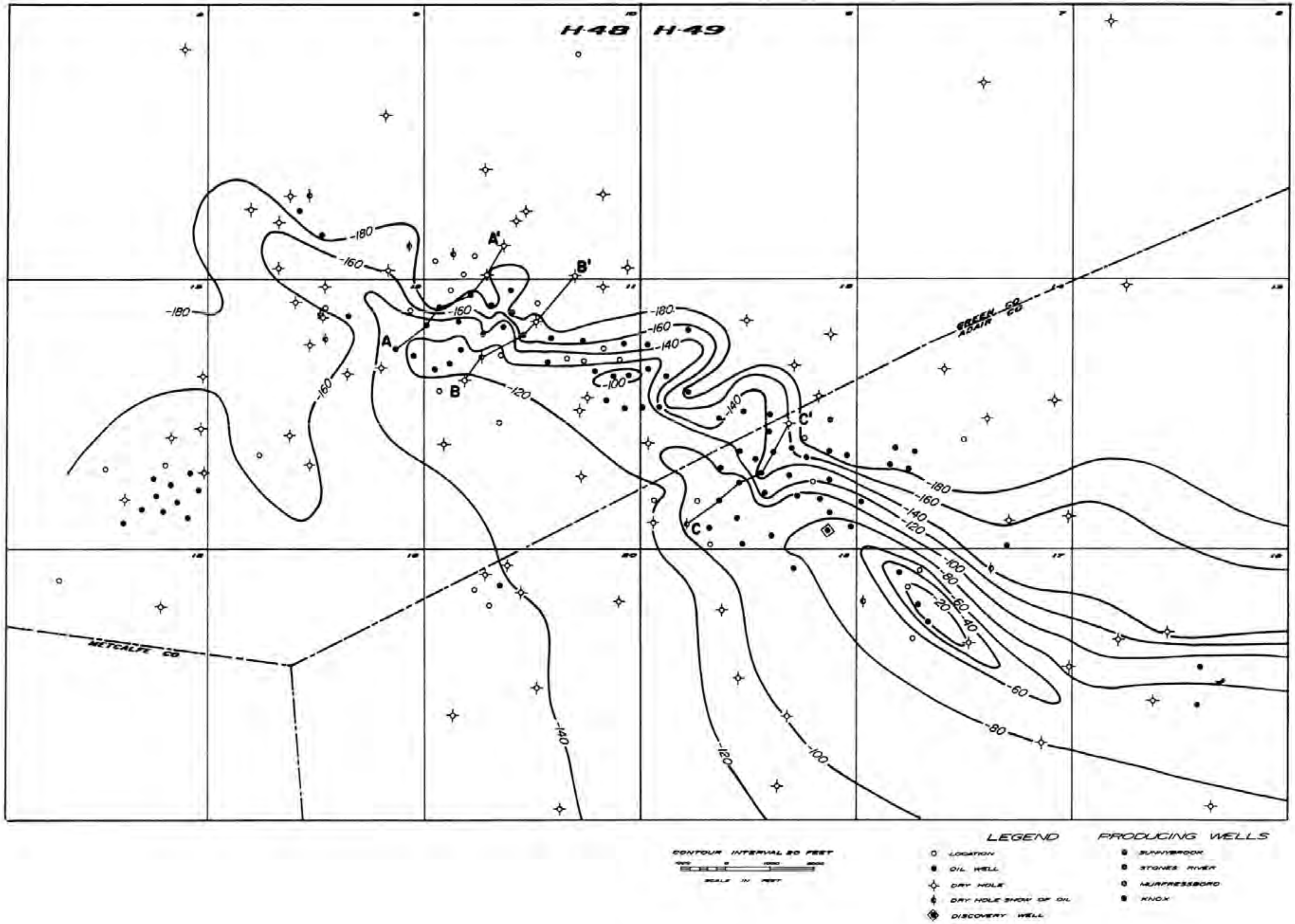


Figure 4. Map showing structure at top of Pencil Cave.

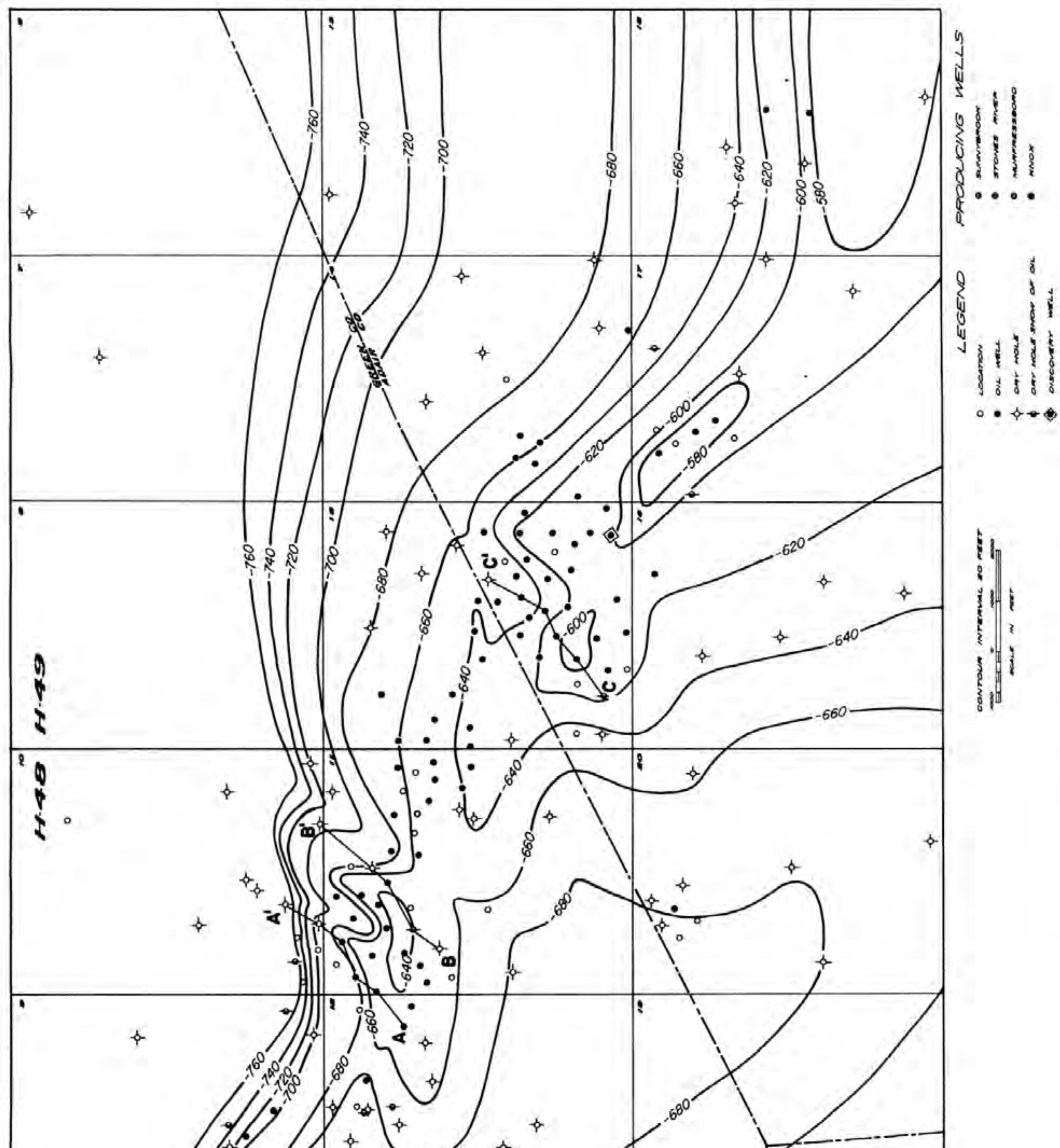


Figure 5. Map showing structure at base of Gilbert marker.

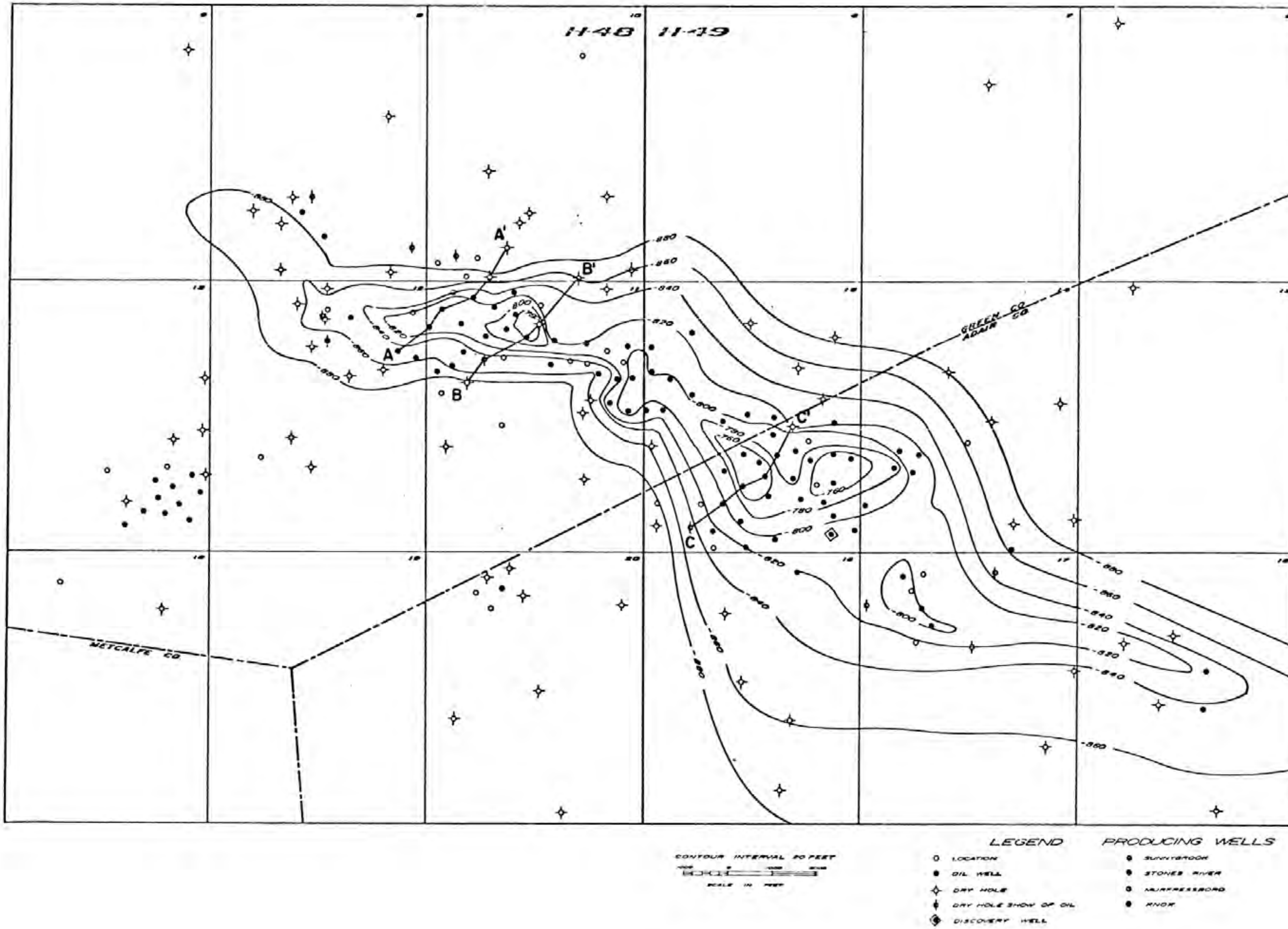


Figure 6. Map showing structure at top of Knox A_1 zone.

Structural movement in this area occurred after deposition of the Knox, following deposition of the Black River Formation and prior to deposition of the Chattanooga Shale, and after deposition of the Chattanooga Shale. In this area all three structural movements appear to follow the same alignment.

RESERVOIR CHARACTERISTICS

A few wells in the Pickett Chapel-Exie South field produce entirely from porosity zones in the Ordovician section above the Knox. Although the production is stratigraphically controlled, information regarding the characteristics of these reservoirs is extremely sparse.

The primary reservoir in this field is the Knox dolomite. In the samples the Knox is a tan to light-brown, some tan to gray, fine-grained to finely crystalline, and cherty dolomite; it is interbedded with occasional thin layers or laminations (1 to 3 feet thick) of alternating pale-green and greenish-gray bentonitic and dolomitic siltstone.

The radioactive siltstone layers used as markers to divide the upper Knox dolomite section are labeled "A" through "D" shale markers, in descending order. The "C" siltstone layer is termed the "C" Twin shale marker; it consists of two thin siltstones separated by 2 to 3 feet of dolomite. It forms a distinctive unit marker of 6 to 8 feet on the radioactive (gamma ray-density) log (Fig. 7).

Four main productive porosity zones or reservoirs are identified in the upper Knox dolomite section. They are the A_2, A_1, B, and C zones (Fig. 7). Although all four porosity zones have been productive in different portions of the field, the lower B and C zones usually contain salt water unless they are encountered at relatively high structural positions. Probably the most productive Knox interval is the A_1 zone; however, the A_1 and overlying A_2 zones may not be productive in an off-set well (Figs. 8 and 9). The B porosity zone is productive in the southeastern portion of the field (Fig. 10). Of the four porosity zones, the C zone appears to have the most persistant widespread porosity.

These porous zones correspond to those recognized by Perkins (1970) in his study of the Gradyville East field. In addition to the A_1 and A_2 zones, Perkins identi-

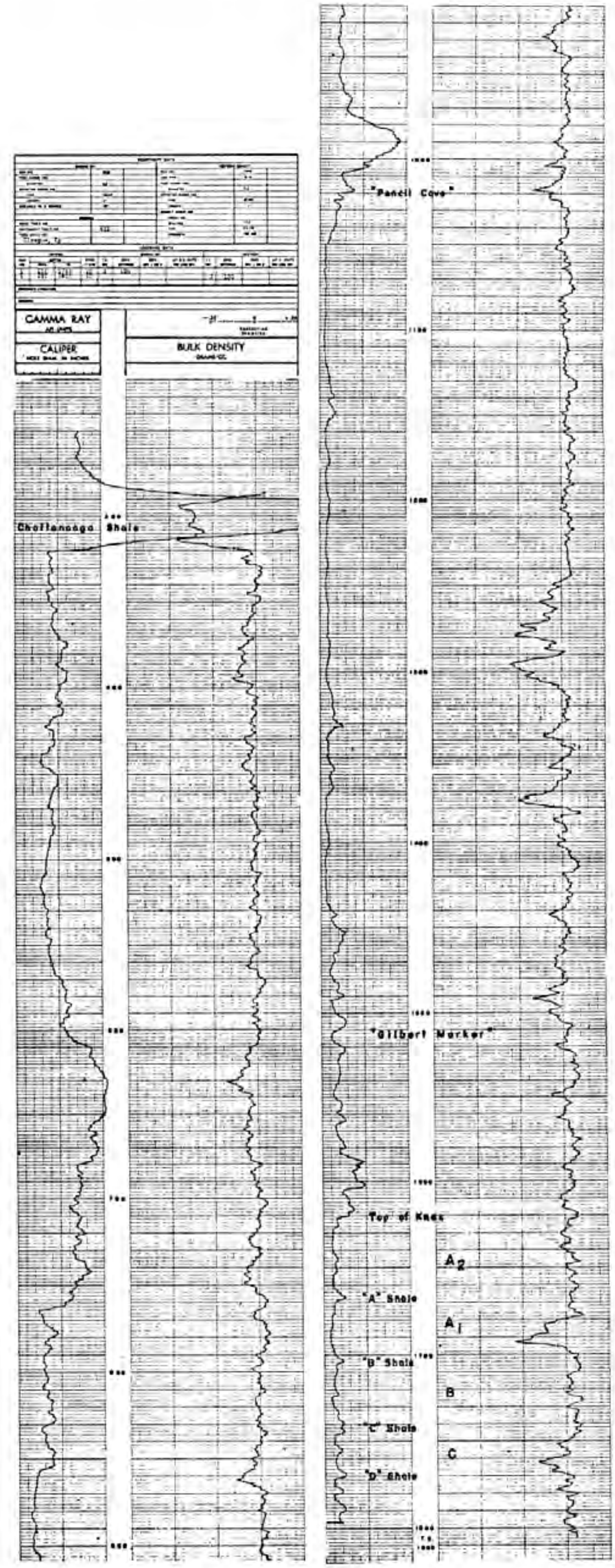


Figure 7. Gamma ray-density log from upper Knox Dolomite showing markers and porosity zones.

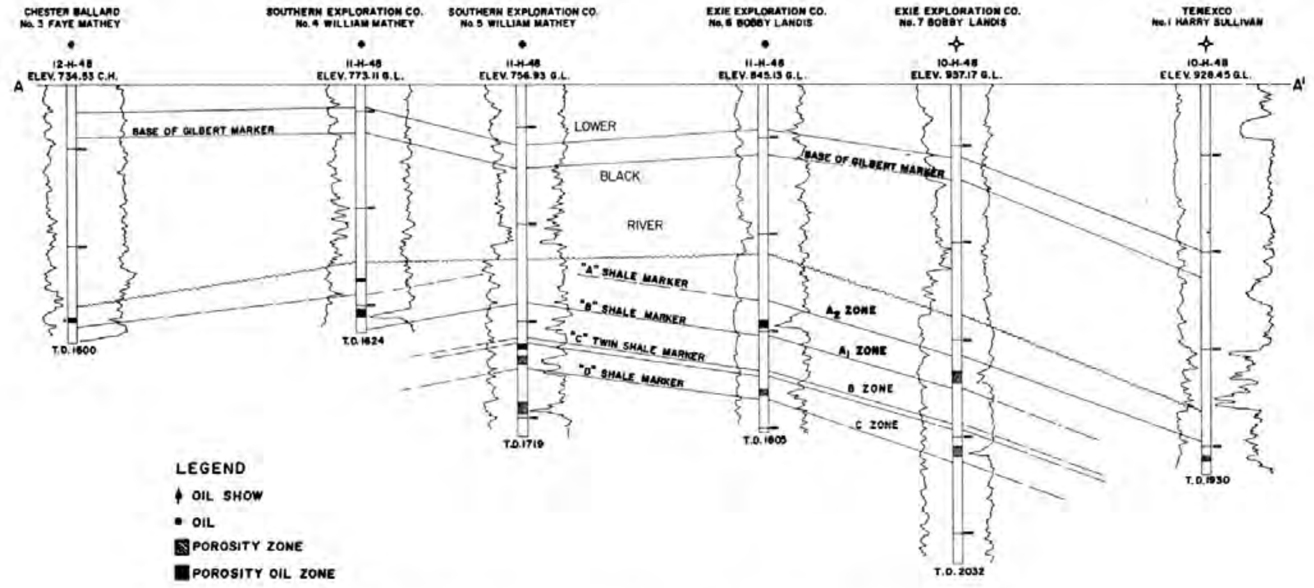


Figure 8. Structural cross section A-A′ of upper Knox Dolomite.

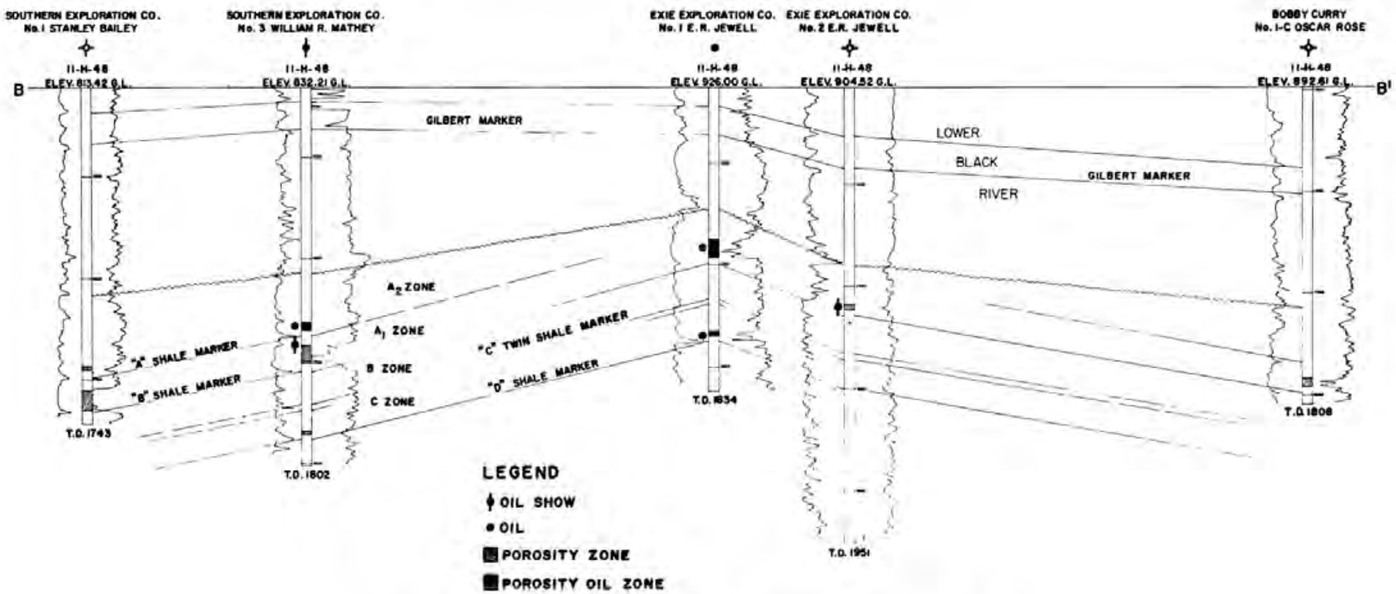


Figure 9. Structural cross section B-B′ of upper Knox Dolomite.

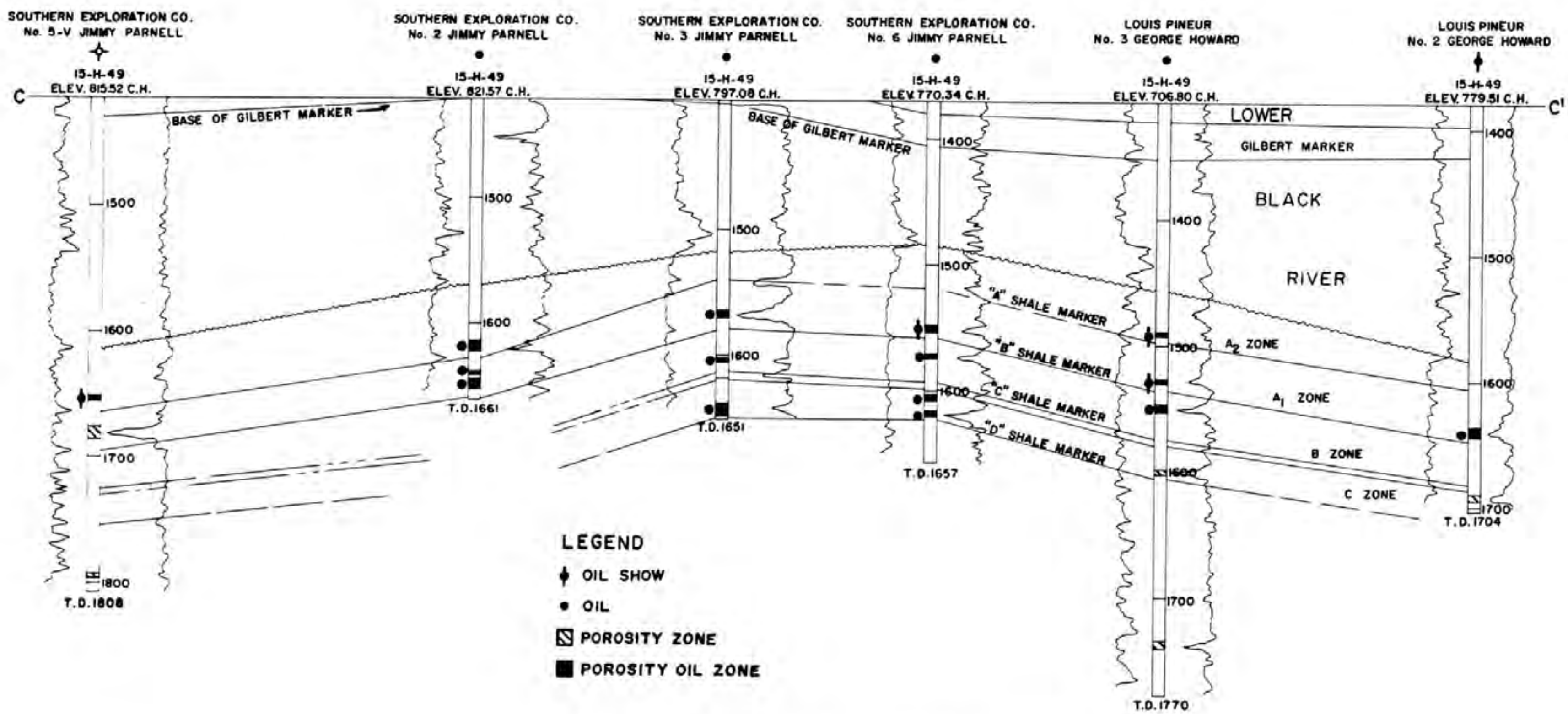


Figure 10. Structural cross section C-C′ of upper Knox Dolomite.

fied an A_3 interval which is not present in the Picket Chapel-Exie South field; this is because of post-Knox erosion. The C zone, which contained salt water in the Gradyville East field, was recognized by Perkins as having good productive potential due to its "persistent and widespread porosity."

PRODUCTION

From December 1974, to March 1, 1976, 104 wells were drilled in the field; 54 were productive and 50 were dry and abandoned. Of the producing oil wells, 51 are producing from the Knox dolomite; this includes 12 wells dually completed in the Murfreesboro (lower Black River) and Knox. Three additional wells produce from shallower reservoirs in the Ordovician; one well is completed in the Stones River, and two other wells are producing from the Sunnybrook (Lexington) section.

Production for the field during the first 14 months from 54 wells totaled 116,056 barrels of oil from all reservoirs, the Knox dolomite being the predominant producer (Fig. 11). The 54 producing wells have averaged 2,149 barrels of oil per well. Calculating drilling and completion costs at an average of $25,000 per well, these producing wells, discounting lease costs, are very close to pay out, based on the field price for crude oil of $10.53 per barrel as of March 1, 1976.

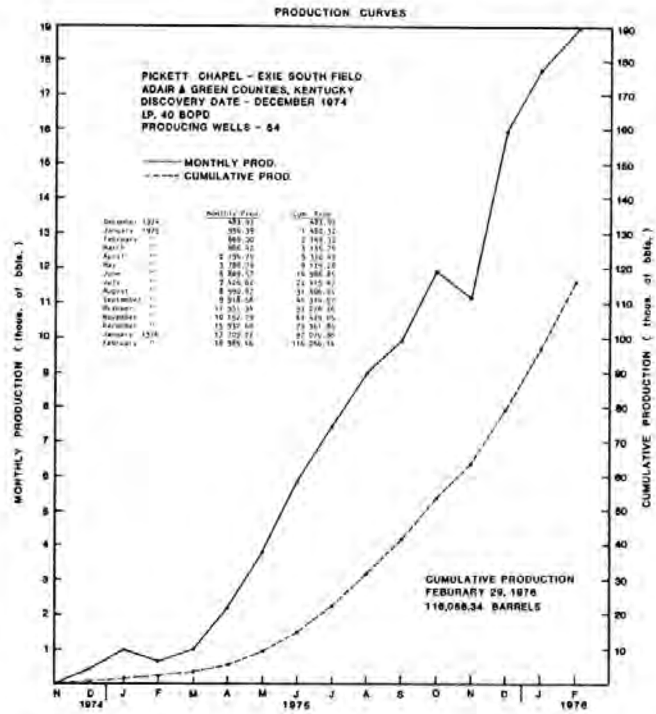


Figure 11. Graph showing first 14 months' production of Pickett Chapel-Exie South field.

COMPLETION

Due to the erratic nature of the upper porosity zones of the Knox, it is recommended that initial development wells be drilled on five-acre spacing to a depth sufficient to penetrate the Knox C zone. This spacing should provide for more accurate log correlation and structural control and should be continued unless additional reservoir evaluation indicates a wider spacing pattern.

"Open hole" is the method of completion for all wells drilled in the field. Cable-tool wells cement the bentonite zones or "Pencil Cave" after the bentonites have become swollen and have fallen into the bore. The cement is then drilled out; this substitutes for setting a liner through the bentonite horizons. The air-rotary wells drill through the bentonite zones; unless a large fill-up of salt water is encountered over the bentonite zones, the bentonites do not present a problem of caving in. Any air-rotary test that penetrates porosity in the Knox dolomite should be logged immediately after pulling the drill pipe to avoid caving and fill-up of the lower portion of the well bore by the bentonite zones.

Approximately 75 percent of the wells drilled in the vicinity of the field were logged by mechanical methods. Radioactive-logging surveys (mainly gamma ray-density) were conducted in 114 wells; however, approximately 45 percent of these wells did not penetrate the A_1 porosity zone, and consequently the logs obtained were not adequate for definite correlation of zones within the Knox.

SUMMARY

The deeper Knox structures may not always coincide with those of the shallow Chattanooga Shale; however, in the Pickett Chapel-Exie South field there are similar structural relations (anticlinal axis) between the shallow and deeper formations.

Any Knox test should be drilled through the C zone in order to test all potential porosity zones that may be preserved in the upper Knox. In portions of the Pickett Chapel-Exie South field, expecially on the flanks of the anticline, it may be necessary to drill 150 to 180 feet into the Knox to penetrate the C zone (Figs. 8, 9, and 10).

Accurate well elevations and complete, total depth-to-surface radioactive-log surveys of all wells are necessary to properly correlate the producing zones. Information obtained from dry holes may lead to discoveries in adjacent areas when properly evaluated.

The gamma ray-density radioactive log is adequate for definite correlation of zones within the Knox and the overlying formations.

A number of areas in southern Kentucky merit exploration of the Knox dolomite. Some of these areas are adjacent to wells which encountered shows of oil and gas in the Knox. Other potential areas are located on structural highs contoured on the shallow Chattanooga Shale.

ACKNOWLEDGMENTS

A number of companies and individuals furnished well data used in this paper. South Kentucky Purchasing Company, Inc., provided production data for the field, from which production curves were prepared. James L. Gilbert of Tri-State Logging Company, Inc., supplied copies of radioactive well-log surveys on which operator's releases had been obtained. David Shockley of Glasgow, Kentucky, drafted most of the illustrations, with the assistance of Roger Potts of the Kentucky Geological Survey. The author appreciates the cooperation of all individuals and companies that have assisted in the preparation of this paper.

SELECTED REFERENCES

Cattermole, J.M., 1965, Geology of the East Fork quadrangle, Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-413.

Freeman, L.B., 1953, Regional subsurface stratigraphy of the Cambrian and Ordovician in Kentucky and vicinity: Kentucky Geological Survey, series 9, Bulletin 12, 352 p.

Helton, W.L., 1963, Oil, gas and structure map, Adair County, Kentucky: Kentucky Geological Survey, series 10, scale 1:48,000.

Moore, S.L., 1968, Geology of the Exie quadrangle, Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-752.

Perkins, J.H., 1970, Geology and economics of Knox dolomite oil production in Gradyville East field, Adair County, Kentucky, in Hutcheson, D.W., ed., Proceedings of the technical sessions, Kentucky Oil and Gas Association 34th and 35th annual meetings, 1970 and 1971: Kentucky Geological Survey, series 10, Special Publication 21, p. 10-26.

Taylor, A.R., 1963, Geology of the Gradyville quadrangle, Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-233.

Taylor, A.R., 1965, Geology of the Gresham quadrangle, Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-421.

MASSIVE HYDRAULIC FRACTURING— FROM PLANNING TO PERFORMANCE

W. T. MALONE, E. J. STAHL, JR., AND G. R. COULTER
Halliburton Services
Duncan, Oklahoma

ABSTRACT

Research on improved recovery methods has shown that massive hydraulic fracturing (MHF) is one means of solving the increased world demand for petroleum products. The technique has been proven to be the most successful well-stimulation tool currently available to the industry. Research on MHF includes development of techniques to prevent clay damage and development of criteria of fluids acceptable for this stimulation technique.

MHF involves placing extremely large volumes of fluid and propping agent in a fracture. As a result, research was required to develop the equipment necessary to adequately handle these materials. This involved handling systems for large volumes of fluid and proppant. A means of storing and rapidly moving proppant from storage to the blending equipment was developed. Pumping equipment capable of reliably pumping under pressure for periods in excess of 12 to 14 hours continuously and communications equipment to supervise and control the entire operation was necessary. Proper planning for a job of this magnitude is essential to the success of the treatment.

INTRODUCTION

Hydraulic fracturing, developed on a commercial scale in 1949, has been the most successful stimulation tool available to the petroleum industry since that time. It has been employed primarily to increase production from oil- or gas-bearing formations. Many formations are now producing economically that could not have been produced without hydraulic fracturing.

Due to the increased world demand for petroleum products, there has been a tremendous increase in efforts to recover oil and gas from formations which were previously thought to be uneconomical. Hydraulic fracturing as a stimulaton tool is a large part of this effort, and for this reason many new techniques have been developed which improve the success of hydraulic fracturing. Massive hydraulic fracturing (Natural Gas Technology Task Force, 1973) is one of the newer techniques.

Massive hydraulic fracturing (MHF) is a somewhat loosely defined term for the large-volume treatments being conducted in low-permeability gas sands (Fig. 1). Massive hydraulic fracturing has been defined as a fracture treatment resulting in a fracture having a conductive length of at least 1,000 feet in each direction from the wellbore.

OBJECTIVES IN HYDRAULIC FRACTURING

Hydraulic fracturing is used primarily to bypass formation damage or to stimulate the zone of interest or both. In either case, the objective is to generate a fracture system which has the desired geometry and sufficient fracture-flow capacity to increase the flow of fluid from the formation to the wellbore.

For stimulation, the effective wellbore radius is increased to give a higher production rate. The following equation (Darcy's Law for radial gas flow) determines the expected production rate prior to stimulation.

A massive hydraulic fracturing treatment does not physically enlarge the wellbore, but since a fracture is initiated at the wellbore and extends from the wellbore outward, the result is an increase in the effective wellbore radius. For example, by increasing the effective wellbore radius from 0.33 feet (0.1 m) to 250 feet (76.2 m), the production rate, Q, could be increased by a factor of approximately 3.5 for a drainage radius of 2,640 feet (804.6 m). Work by Prats (1961) indicates that effective wellbore radius is approximately equal to one-quarter the total fracture length generated by the treatment, if the fracture is vertical and has infinite conductivity. Thus, for stimulation it would be desirable to obtain a long, highly conductive fracture system through the use of massive hydraulic fracturing treatments.

Massive hydraulic fracturing has been shown to be the only effective operational means of increasing production rates and recoverable reserves from extremely low permeability formations (0.01 to 0.1 md). This technique, however, must be applied in appropriate areas and with careful planning prior to the job (Fast and others, 1975). An example of this work is the stimulation of the Muddy "J" Formation in the Wattenberg field in Colorado. In this and other studies (Elkins, 1973; Randolph, 1974) massive hydraulic fracturing creates vertical fractures which extend in opposite directions from the wellbore for 1,500 to 2,000 feet. These fractures are placed in formations which generally exhibit effective permeabilities of less than 0.1 md; in some cases, permeability is as low as 0.001 md. In many cases, these conditions are also associated with formation thicknesses of 2,000 to 4,000 feet of gross interval (Randolph, 1974). Several vertical fractures may be required, therefore, to cover the entire section.

CONSIDERATIONS PRIOR TO MASSIVE HYDRAULIC FRACTURING

Several factors should be considered prior to conducting a massive hydraulic fracturing treatment. Some

Figure 1. Aerial view of massive hydraulic fracturing treatment plant.

of these are: (1) possibility of wellbore damage, (2) formation flow capacity ($k_i h_i$), (3) existing reserves and/or depletion (reservoir pressure), (4) formation interval or thickness to be stimulated in relation to well completion practices, (5) location size and terrain, (6) availability of fluids and surface storage facilities, (7) fracture geometry (propped length and height), (8) fracture flow capacity ($k_f w_f$), (9) theoretical production increase, and (10) economics.

Productivity of the well may be reduced due to formation damage around the wellbore. Damage may exist because of naturally-occurring clays, and 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 type and size of treatment required to remove or bypass the restriction to production. Extent of wellbore damage may be determined by production tests, pressure testing, and production history.

Formation flow capacity ($k_i h_i$) is an important formation characteristic when considering 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. If evaluation indicates low formation flow capacity, a deep penetrating hydraulic fracture may be required to bring the well up to an economical production rate regardless of wellbore damage.

One of the most important considerations prior to conducting a hydraulic fracturing treatment is the amount of hydrocarbon reserves and extent of depletion. This information may come from initial estimates of producible reserves and cumulative production information to date. Original 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 water drive, existing reservoir pressure may not be indicative of hydrocarbon depletion.

Planning for a massive hydraulic fracturing treatment should begin before well-completion specifications are finalized. If the intervals to be fractured are in excess of 50 to 100 feet in thickness, then increased injection rates may be required to create sufficient vertical fracture height to cover the zone. This increased rate also allows the large volumes of fluid required to create the long propped fracture lengths to be placed in a reasonable amount of time. Thus, casing or tubing sizes, and strengths to withstand rates and anticipated surface pressures during fracturing should be specified in the completion program.

The volume and type of fluid, and quantities of proppant required to conduct these treatments necessitate special consideration of location size and terrain. Early treatments utilized 50,000 to 150,000 gallons of fluid. However, treatments today routinely use 300,000 to 500,000 gallons of fluid, with even larger jobs in the planning stages (Fast and others, 1975). Quantities of propping agents associated with these volumes have reached 1.4 million pounds; plans are for using up to two million pounds in the near future. Thus, the layout of a location of sufficient size to handle these materials is a major factor to consider.

Proper storage of large quantities of proppant requires careful consideration of the footing or foundations for the bulk-storage facilities to support this weight. Location and space for these facilities in relation to the blending equipment is also important since proppant is transferred at rates of 2,000 to 10,000 pounds per minute during treatment.

If fluids to be used in the stimulation treatment are composed of flammable products, then safety requires that these fluids be stored at distances of at least 75 to 150 feet from blending and pumping equipment. Also, slope of the terrain is important, should a leak develop in tanks or manifolding equipment. It is also desirable, where possible, to place these fluids on the downwind side from pumping equipment due to fumes which may be associated with some fluids.

Selection of the fluid should be based on tests utilizing formation core. However, it may be necessary to consider more than one fluid, depending on certain variables.

If the hydrocarbon selected as all or part of the base fluid is available only in a limited supply, the cost of the treatment may be significantly increased. This is further complicated if the number of rental storage tanks are limited. Thus, it is necessary to contract for the tanks well before the job to insure that they are all available and on location. This lead time may be further extended if the hydrocarbon must be trucked to the location and accumulated over several weeks in order to insure a sufficient quantity for the treatment.

If an aqueous-base fluid is used, the same considerations should be made in relation to tanks, unless all or part of the fluid could be held in pits. Again, pits and equipment to transfer water from the pits to tanks or blending equipment require space and planning. The overall job logistics are definitely a consideration.

Geometry of the fracture system is important to the overall results of the stimulation treatment. Design of the treatment will vary depending on the expected fracture geometry. Hydraulic fracturing theory predicts that the induced fracture will be oriented perpendicular to the least principal stress existing in the formation. The fracture may be vertical, horizontal, or at an angle with respect to the wellbore (Fig. 2). Evidence indicates hydraulic fractures are primarily oriented vertically, particularly at the depths drilled today. Theory and laboratory work indicate that vertical fractures extend 180 degrees in two opposite directions from the wellbore.

It is important that the fracture system extends vertically through the zones of interest; the vertical fracture height must be sufficient for optimum stimulation. This generated fracture height will influence, to a large degree, the lateral penetration of the fracture into the reservoir away from the wellbore. Penetration or fracture length is important to stimulation, as has been shown by the effective wellbore radius approach. However, this approach assumes that

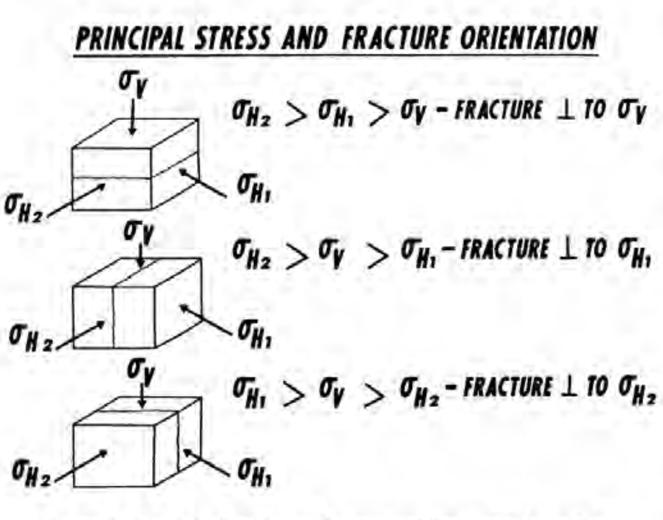


Figure 2. Principal directions of stress and fracture orientation.

the fracture system has infinite flow capacity; the fracture system will normally have a finite flow capacity. Ideally, the induced fracture will not close following the release of hydraulic pressure, which results 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 (1970), where wells fractured with no propping agent showed a sharper decline than wells fractured using a propping agent.

In most cases, a proppant such as sand or high-strength glass beads is used to obtain the final fracture flow capacity ($k_f w_f$). There are many options available as to type, size, and amount of proppant.

Parameters affecting production increase following a stimulation treatment are discussed by McGuire and Sikora (1960) and Tinsley and others (1969). Tinsley indicates that the conductive fracture height to net formation height ratio (h_f/h_i), the fracture flow capacity to formation permeability ratio ($k_f w_f/k_i$), and the conductive fracture length to drainage radius ratio (L/r_e) are the most significant factors in the production increase resulting from a hydraulic fracturing treatment. Figure 3 is an example production increase curve which shows that the expected production increase is a function of the relative capacity A ($k_f w_f/k_i$ and the L/r_e relationship. Thus, as the fracture flow capacity ($k_f w_f$) increases with respect to the formation permeability (k_i), the relative capacity increases. For a low relative capacity value, the effect of fracture length on production increase is insignificant. 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. For a massive hydraulic fracturing treatment, if the fracture flow capacity generated by the proppant in the treatment is 500 to 1000 md-ft ($k_f w_f$) and the formation permeability (k_i) is 0.01 md, then the ratio $k_f w_f/k_i$ is 50,000 to 100,000. With values of this magnitude, it is readily apparent that the effect of propped fracture length is most important in a low permeability formation.

Using these types of equations, the expected results of a MHF treatment may be evaluated. This approach lends itself to optimization of the type of treatment required to attain the necessary propped length, flow capacity, etc., based on cost. The cost of the stimulation treatment and expected gain in the production following the stimulation may be used in the evaluation of the economics of the treatment.

CONSIDERATIONS IN DESIGNING MASSIVE HYDRAULIC FRACTURING TREATMENTS

Many factors should be considered when designing a fracturing treatment of this size. Some of the formation characteristics which are important to the design are permeability, porosity, reservoir pressure, rock hardness, acid solubility, and fluid sensitivity. Production-increase theory indicates that extremely long, conductive fractures are necessary in low-permeability formations for adequate gas production rates. Thus, it is also important to consider the temperature stability of the fluid used to place the proppant in the fracture.

The formation permeability will dictate the amount of flow capacity needed in the fracture for stimulation. In addition, fluid loss to the formation during the treatment is a function of the formation permeability. If the permeability is high, fluid-loss additives may be needed to assist in the control of this loss. Loss of the 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,

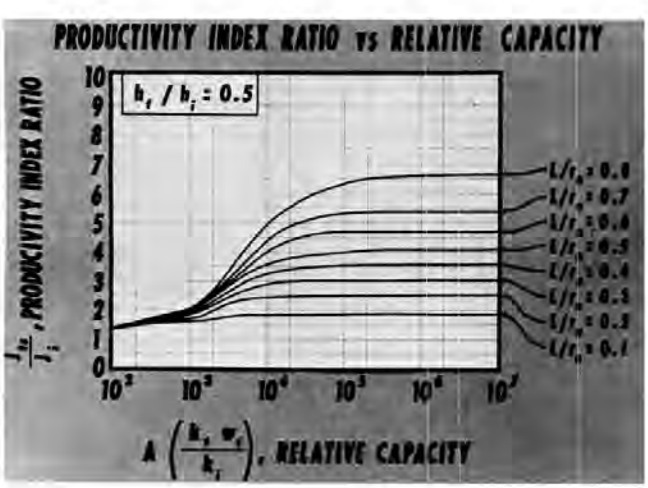


Figure 3. Example production increase curve.

increasing the pore-space fluid saturation along the fracture face reduces the effective permeability to gas. 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 pressure to recover this lost fluid. It should also be recognized that even in low permeability zones, if natural fractures are present, leak off may be high, which results in less fracture volume than desired. In this case, additives or techniques should be used to overcome this high leak-off potential.

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

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.

When 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; in a soft, poorly consolidated rock, the proppant may embed into the formation. In either case, the result would be a reduction in fracture flow capacity. Other rock properties, such as elasticity and Poisson's Ratio, should also be considered, since they affect geometry of the fracture.

In formations such as sandstone with calcareous cement, an acid-base fracturing fluid may be detrimental; it could cause the release of fines since the acid would preferentially react with the calcareous material.

For the last few years, approximately 75 to 80 percent of all hydraulic fracturing treatments employing propping agents have been conducted with water-base fluids. There are several advantages of 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, which reduces pipe-friction pressures during injection, and controls fluid loss to the formation, among other benefits. However, one of the disadvantages of a water-base fracturing fluid is its potentially detrimental effect on the formation due to the 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 core 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 and immersion tests, in which pieces of the formation are subjected to various fluids to determine the quantity of fines released. Also, flow tests are conducted by flowing various fluids through core samples to evaluate the detrimental effects of the fluid flowing into the formation.

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.

The fluid required to carry propping agent great distances from the wellbore must be selected. One of the requirements of the fluid is that it remain stable for long periods of time (4 to 12 hours) at elevated temperatures (Randolph, 1974). The fluid must be tailored to give the time and temperature stability required, and viscosity must be reduced later for fluid recovery. The fluids most successfully employed in MHF work are the cross-linked guar gum and guar gum derivative gel systems and the emulsion system. In addition to the gel stability and breaking characteristics, these fluids have many other desired fracturing-fluid properties.

In 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 large treatments. The type and size of sand 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 to 20 mesh throughout the treatment. The purpose of this size variation is to achieve the desired proppant distribution (Randolph, 1974). 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 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 in the latter part of the job, as fluid temperature thinning decreases, larger proppant sizes are normally used.

After the base fluid and means of obtaining flow capacity have been 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. In most cases, a number of potential treatments are calculated in which injection rates, fluid viscosities, fluid volumes, and other factors are varied. For each set of variables, the production increase is normally calculated so that the potential treatments may be compared. The cost of each of these treatments may also be compared so that the economics can be evaluated.

Current demands for natural gas are encouraging exploration and completion of extremely low permeability gas wells. Some of these have been successfully stimulated with large-volume hydraulic fracturing treatments, while a few have been somewhat less successful. One of the factors that should be considered in stimulating tight gas zones by hydraulic fracturing is fluid retention. With 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 gas permeability results. This fluid retention can be aggravated by a number of factors, including high surface-tension fluids, and reaction of the fluid or chemicals in the fluid with minerals surrounding the pore space. 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 initiate fluid flow. 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 conducted with various fluids to determine the relative compatibility of various fluids with the rock from a regained gas permeability effect (Fig. 4).

Information gained from petrographic and scanning electron microscope studies of low permeability sandstones indicates that improved clay-control materials may be necessary to make the fracturing fluid compatible with the formation. Clay control using an aqueous base fluid has been based on the concept of ion exchange. With this concept, a more stabilizing cation replaces the existing cation, resulting in clay control. Hower and Black (1965) report that the potassium ion is a very efficient clay-control cation. However, considering the large quantities and types of clays associated with the formation pore space in some low permeability sands, more than cation exchange is required to protect the swelling clays. Many clay platelets are observed which are composed of swelling clays (including montmorillonite and mixed-layer clays) and nonswelling clays (including illite, kaolinite, and chlorite). With a large quantity and variety of clays, a newer technique utilizes a blanketing effect with polymers to protect the clays from swelling and migrating. Chemicals which achieve this effect are hydroxy aluminum (Reed, 1972), zirconyl chloride (Veley, 1969), and multicharged organic polymers. Each of these chemicals can 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, and other factors.

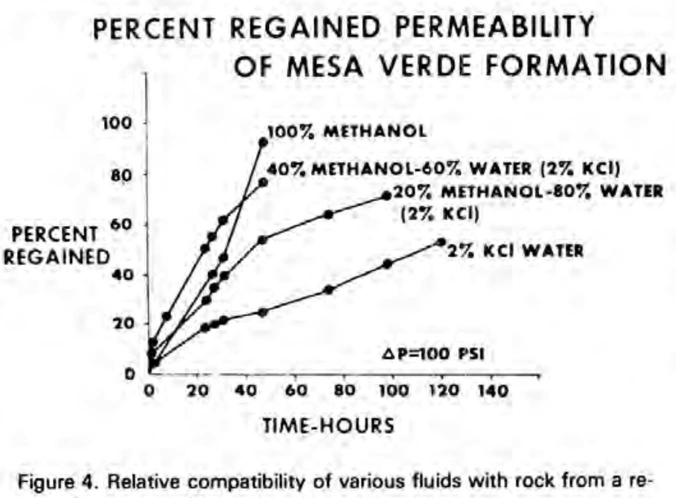


Figure 4. Relative compatibility of various fluids with rock from a regained gas permeability effect.

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 sites 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 include the organic polymers used to increase the viscosity of the base fluid and surfactants used to lower the surface tension of the fracturing fluid. The end result of 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 lower viscosity fluids.

Figure 5 shows that lower viscosity fluids allow proppant to settle, which builds up a proppant bed. The fluid which loses the proppant proceeds out into the reservoir; this creates additional fracture length. Theoretical results of most low viscosity fluid fracturing treatments are a propped length which is normally considerably shorter than the created length. In addition, 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 results in a proppant distribution as shown in Figure 6. With this type fluid, the proppant may be carried a greater distance from the wellbore and completely cover the entire vertical fracture height.

With massive hydraulic fracturing treatment fluid volumes continually increasing, there is more concern about the cost per gallon of the fluid. Treatment volumes of 300,000 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 emulsion system (Sinclair and others, 1974) is 50 to 80 percent an internal phase consisting of a liquid hydrocarbon such as diesel, kerosene, or crude oil, and 20 to 50 percent 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 on 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 that is relatively inexpensive, depending on the cost of the hydrocarbon phase. This fluid has been used very effectively in several areas, most notably in the Rocky Mountain area (Fast and others, 1975).

In an attempt to improve on some undesirable properties of some fracturing fluids such as fluid retention in low permeability gas wells, foams were developed for use as fracturing fluids. Reported properties of foam include excellent proppant transport, low fluid loss to the formation, and rapid cleanup. Foam fracturing fluids have been used in several areas in the United States and Canada. Many of these treatments are currently being evaluated, and it may be some time before wells can be accurately field evaluated from a performance standpoint.

SUMMARY

Massive hydraulic fracturing treatment is the utilization of fluid and proppant quantities on a scale considerably larger than previous fracturing treatments. It is also the accumulation and coordination of large amounts of blending, pumping, metering, and transfer equipment together with fluid and proppant storage facilities, all of which must be organized and supervised by trained personnel.

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

CONCLUSIONS

Massive hydraulic fracturing has:

1. Been reported to be an effective means of increasing production rates and recoverable reserves when applied in the proper areas;
2. Provided a means of stimulating formations which previously have not been stimulated economically;
3. Shown the necessity for substantial pre-planning in completing the well and mobilizing for the job; and
4. Provided advanced equipment to the industry

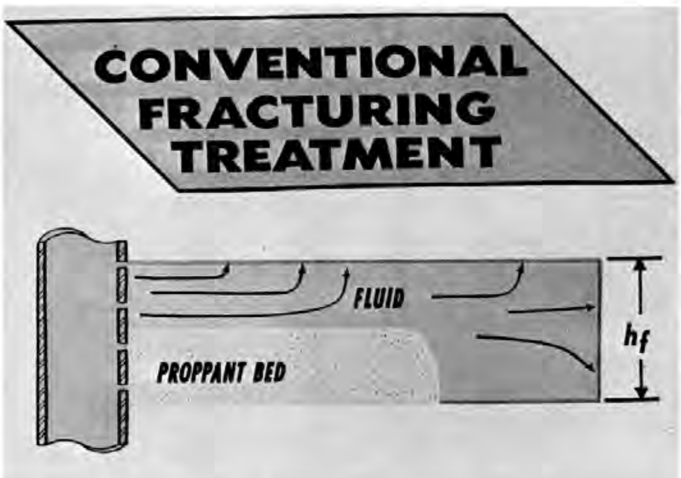


Figure 5. Proppant distribution in a conventional, low fluid viscosity fracturing treatment.

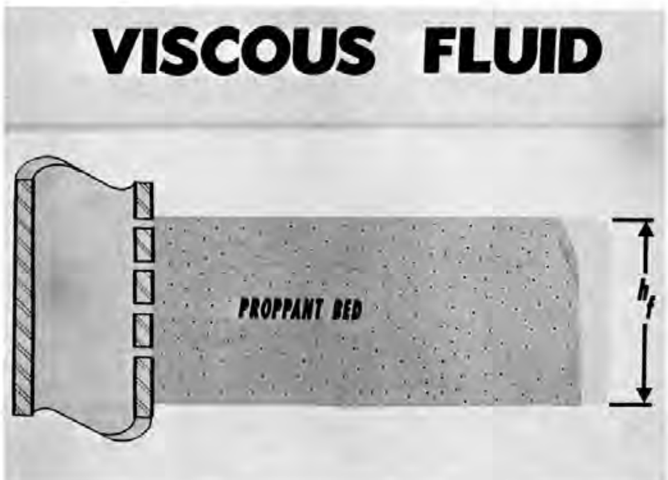


Figure 6. Proppant distribution in an extremely high viscosity fluid fracturing treatment.

for reliably handling fluids and solids on a scale this size.

ACKNOWLEDGMENT

The authors wish to express their appreciation to Halliburton Services for the opportunity to prepare and present this paper.

REFERENCES

Black, H.N., and Hower, W.F., 1965, Advantageous use of potassium chloride water for fracturing water sensitive formation: American Petroleum Institute Meeting, Wichita, Kansas, Paper No. 851-39-F.

Elkins, L.E., 1973, Alternate methods for stimulation: American Nuclear Society Meeting, San Francisco, California, Proceedings.

Fast, C.R., Holman, G.B., and Covlin, R.J., 1975, A study of the application of MHF to the Tight Muddy "J" Formation, Watlenburg field, Adams and Weld Counties, Colorado: Society of Petroleum Engineers-American Institute of Mining Engineers Fall Meeting, 50th, Dallas, Texas, Society of Petroleum Engineers Paper 5624.

Howard, G.C., and Fast, C.R., 1970, Hydraulic fracturing: Society of Petroleum Engineers: American Institute of Mining Engineers Monograph, v. 2, p. 59-60.

McGuire, W.J., and Sikora, V.J., 1960, The effects of vertical fractures on well productivity: American Institute of Mining Engineers Transactions, v. 219, p. 401-403.

Natural Gas Technology Task Force, 1973, Report for the Technical Advisory Committee of the National Gas Survey by the Federal Power Commission: Federal Power Commission, National Gas Survey Report, v. 2, in press.

Prats, M., 1961, Effect of vertical fractures on reservoir behavior—incompressible fluid case: Society of Petroleum Engineers Journal, p. 105-118.

Randolph, P.L., 1974, Massive stimulation effect may double U.S. gas supply: World Oil, parts 1-4.

Reed, M.G., 1972, Stabilization of formation clays with hydroxy aluminum solutions: Journal of Petroleum Technology.

Sinclair, A.R., Terry, W.M., and Kiel, O.M., 1974, Polymer emulsion fracturing: Journal of Petroleum Technology, p. 731.

Tinsley, J.M., Williams, J.R., Jr., Tiner, R.L., and Malone, W.T., 1969, Vertical fracture heights—its effect on steady-state production increase: Journal of Petroleum Technology, p. 633.

Veley, C., 1969, How hydrolyzable metal ions react with clays to control formation water sensitivity: Journal of Petroleum Technology, p. 1111-1117.

A GEOPHYSICAL AND TECTONIC STUDY OF EAST-CENTRAL KENTUCKY WITH EMPHASIS ON THE ROME TROUGH

G. R. KELLER, M. L. AMMERMAN, AND A. E. BLAND
University of Kentucky
Lexington, Kentucky

ABSTRACT

Recent geophysical and tectonic studies in the east-central Kentucky region suggest that this area has experienced a varied and complex geologic history. Surficial faults exposed today reflect renewed movement along old zones of weakness. These zones were created by Keweenawan rifting, as evidenced by the presence of the East Continent gravity high or by faulting related to the formation of the Rome Trough. The Rome Trough is a complex feature whose northern boundary is a series of interrelated faults and whose southern boundary is marked by several basement uplifts in southeastern Kentucky.

INTRODUCTION

East-central Kentucky is an area whose tectonic history is quite complex. A better understanding of the history of this area is important because of the substantial hydrocarbon deposits present. Over the past three years, the geophysics group at the University of Kentucky has been conducting studies in this area. The goal of these studies has been to delineate the major tectonic units present and determine their history and interrelationships. The purpose of this paper is to summarize the results of these studies to date. Some aspects of these results have been reported in greater detail by Keller and others (1975, and in preparation), Ammerman and Keller (1976, and in preparation), and Black and others (1976, in preparation).

The Bouguer gravity map shown in Figure 1 is the primary product of this project. This map incorporates over 4,000 gravity readings which were spaced at approximately 2-mile intervals in the shaded areas shown in Figure 2. Principal facts for the gravity readings and more detailed maps (2-milligal contour interval) are on open file at the Kentucky Geological Survey. In addition, a detailed tectonic, gravity, and aeromagnetic study of the area outlined in Figure 2 has been recently completed by Black and others (1976). Several major fault systems converge in this area, and data from this area have been particularly useful in elucidating structural relations and have demonstrated the value of the integration of geological and geophysical data. In the studies discussed below, the integration of geological and geophysical data has been stressed.

EVIDENCE FOR KEWEENAWAN RIFTING AND GRENVILLE METAMORPHISM

The most obvious gravity anomaly present in Figure 1 is the East Continent gravity high (Keller and others, 1975). This gravity maximum, which extends from Alabama into the Great Lakes region, has a relief of over 80 mgal and is one of the largest anomalies in the eastern midcontinent region. As noted by Keller and others (1975), this feature is also associated with a zone of complex, high-amplitude magnetic anomalies, volcanic basement rocks (Fig. 3), and large, flanking gravity lows. In every respect, this anomaly is analogous to the Midcontinent gravity high which extends from Minnesota to Kansas. The widely accepted interpretation of the Midcontinent gravity high is that it represents a Keweenawan-age (1.3- to 1.0-billion-year age) rift zone that was aborted before it actually split the continent (King and Zietz, 1971; Ocola and Meyer, 1973; Chase and Gilmer, 1973; Hinze and others, 1975).

The computer-generated earth model (Fig. 4) along gravity profile A-A' (Fig. 2) demonstrates that this anomaly can also be readily interpreted as such a rift zone. The hypothesis of a major rift in the area of the East Continent gravity high is further substantiated by the petrologic character of basement rocks encountered in the region. In Ohio, Kentucky, and Indiana, mafic and felsic volcanics, amphibolites, and mafic-two pyroxene-granulites are encountered in the vicinity of gravity highs, while granites, granite gneisses, metasediments, and felsic volcanics are encountered in the vicinity of the gravity lows (Fig. 3). The mafic volcanics and clastics have been described as similar in character to the Keweenawan rocks from the Lake Superior region by Bass (1970, written commun.). The

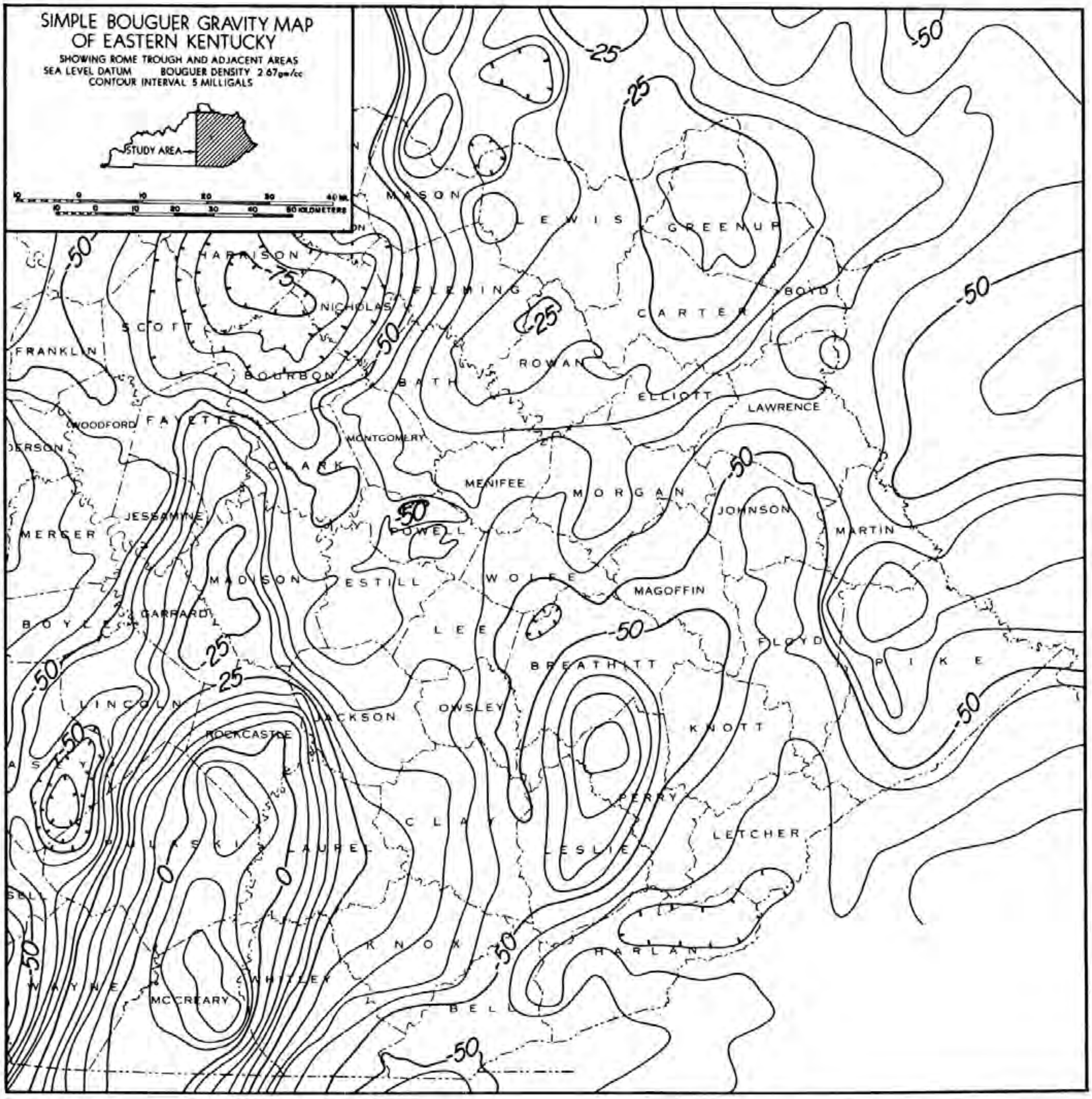


Figure 1. Simple Bouguer gravity map of eastern Kentucky (from Ammerman and Keller, 1976).

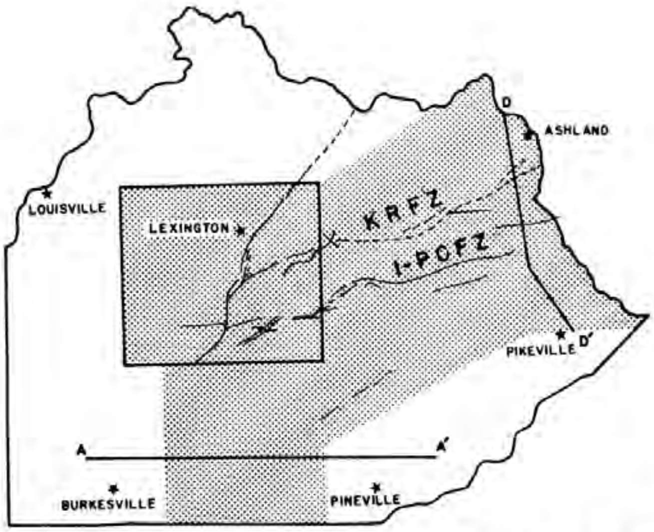


Figure 2. Index map of study area. Gravity data available at two-mile spacing in shaded region. Study area of Black and others (1976) is outlined. Gravity profiles are A-A' and D-D'. KRFZ = Kentucky River fault zone; I-PCFZ = Irvine-Paint Creek fault zone.

volcanics and shallow intrusives encountered in the vicinity of the East Continent gravity high constitute a bimodal basalt (gabbro)-rhyolite trachyte (syenite, granite) suite with peralkaline characteristics, as evidenced by the presence of riebeckite in several of the *felsic* members of the suite. The bimodal character and peralkaline nature of rifting volcanics have been noted in the Ethiopian Rift, Rhine Graben, and East African Rift by LeBas (1971) and Mohr (1971).

Whole-rock radiometric ages of basement lithologies in Ohio and Tennessee (Wasserberg and others, 1962; Lidiak and others, 1966; Muehlburger and others, 1967) indicate that the volcanic and intrusive equivalents associated with the East Continent gravity high were emplaced between 1.3 and 1.0 billion years ago, which coincides with the approximate time of emplacement of Keweenawan rifting volcanics in the Lake Superior Region (Silver and Green, 1972). Mineral ages in this area indicate that there was a thermal disturbance 1,000 to 850 million years ago (Lidiak and others, 1966; Denison and Hetherington, 1976, personal commun.; Silberman, 1976, personal commun.) associated with Grenville metamorphism. In central Kentucky volcanic basement rocks in areas near the East Continent gravity high appear to be unmetamorphosed. However, immediately to the northeast, the metamorphic grade abruptly changes to upper amphibolite-granulite. Therefore, the Grenville Front in Kentucky (Fig. 3) appears to trend north-northeast, crosscutting the East Continent gravity high at a low angle; Grenville metamorphism converted mafic volcanics east of the front to amphilolites and mafic-two pyroxene-granulites (Bass, 1970, written commun.). The Grenville Front must therefore postdate the emplacement of the rifting volcanics associated with the East Continent gravity high.

A GEOPHYSICAL AND TECTONIC STUDY OF THE ROME TROUGH

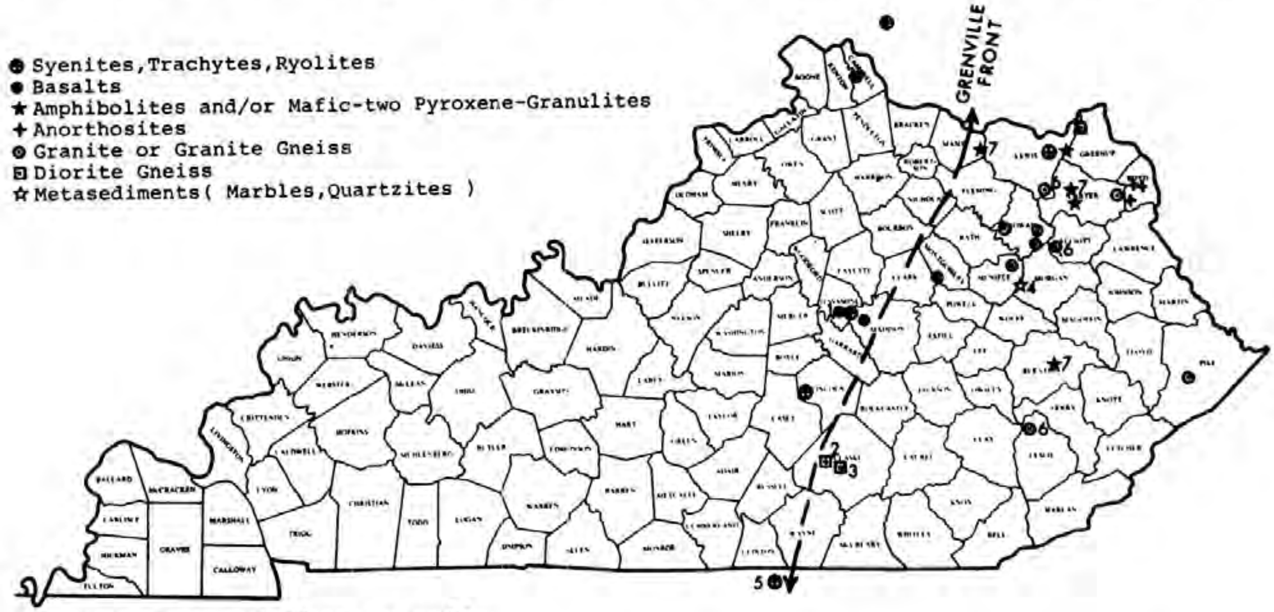
From the standpoint of hydrocarbon deposits, the Rome Trough (Woodward, 1961; McGuire and Howell, 1963) is a very important feature, but presently its areal extent is poorly known. The gravity anomalies associated with this trough (Fig. 1) are subtle compared to the East Continent gravity high, but in a study integrating subsurface geological data with geophysical data, Ammerman and Keller (1976, and in preparation) have outlined both this and adjoining features. The features, which can be delineated by gravity data, and the limited aeromagnetic data available are shown in Figure 5.

A computer-generated earth model along a gravity profile (D-D', Fig. 1) across the Rome Trough is shown in Figure 6. To construct this earth model, deep wells were used as tie points and densities were calculated using formation density logs. The stratigraphic section was found to be readily divisible into four units which showed consistent densities. The negative gravity anomaly associated with the Rome Trough is due primarily to thickening of pre-Knox rocks with a density of 2.51 gm/cc, which, by volume make up most of the Rome Formation (Fig. 6). The Kentucky River fault zone, which forms the northern boundary of the Rome Trough, crosses the profile approximately 40 km from the north end; the presence of the intrabasement body located just north of this fault is substantiated by both drilling (Silberman, 1976, personal commun.) and magnetic data.

The Rome Trough deepens gradually to the south; its deepest portion is bounded on the north by the Irvine-Paint Creek fault zone (Fig. 5). Although its southern boundary is complex, faulting plays a significant role. For example, the Pike County uplift, which bounds the trough on the south, probably has a faulted northern limb. This uplift is separated from another uplift in Perry County by the Floyd County channel (Fig. 5). Although complicated by the presence of the East Continent gravity high, there appears to be yet another uplift in the Owsley County area which acts as the western boundary of the deeper portions of the Rome Trough. Further north, this uplift may separate small basins in Estill, Clark, and Powell Counties from the main body of the Rome Trough.

As a regional tectonic feature, the Rome Trough extends westward to the western boundary of the East Continent gravity high. The study of Black and others (1976) demonstrates that the faulting associated with the Kentucky River and Irvine-Paint Creek fault zones does not extend west of the East Continent gravity high and there is no significant strike-slip movement. The gravity data and limited aeromagnetic data available (Zietz and others, 1968) suggest that this is also the case for subsurface fault systems associated with the Rome Trough further to the south in Kentucky (Harris, 1975). The Rome Trough shallows and narrows to the southwest (Harris, 1975), but its exact boundaries in this area are obscured by the East Continent gravity high.

The Rome Trough is a complex feature, but it seems clear that extensional tectonics have played a major role



1. Texaco No. 1 Sherrer well.

2. Rb/Sr feldspar age on microsyenite dike 975 $\pm$ 85 m.y. (Hetherington and Denison, 1976, personal commun.).

3. Rb/Sr biotite age 950 $\pm$ 40 m.y. (Hetherington and Denison, 1976, personal commun.).

4. K/Ar biotite age 917 $\pm$ 31 m.y. and 894 $\pm$ 30 m.y. (Silberman, 1976, personal commun.).

5. Riebeckite-bearing quartz syenite (Denison, 1976, personal commun.).

6. Acidic paragneiss and orthogneiss (Bass, 1970, personal commun.).

7. Interlayered amphibolite and mafic-two pyroxene-granulite and acidic paragneiss and orthogneiss (Bass, 1970, personal commun.).

Figure 3. Map showing basement lithologies in eastern Kentucky.

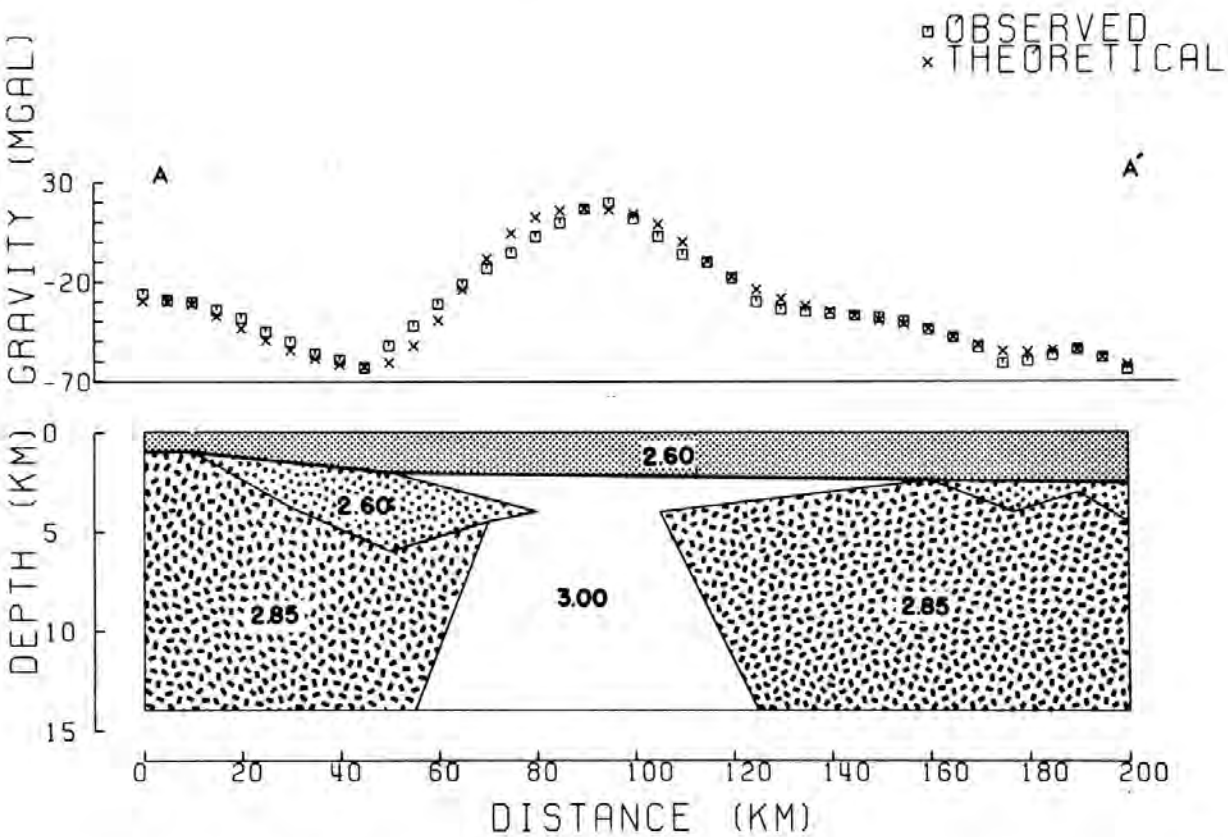


Figure 4. Computer-generated earth model for gravity profile A-A'. Numbers within bodies indicate densities in gm/cc. (From Keller and others, 1976.)

in its formation. The formulation of a tectonic model to explain the origin of the Rome Trough is presently hindered by uncertainties in our understanding of events in the Appalachians. An attractive tectonic model is that the Rome Trough formed as a failed arm or aulocogen (Burke and Dewey, 1973) at the same time a Precambrian continent was rifted to form the Proto-Atlantic (Wilson, 1966). However, our present knowledge of the timing of events in the Appalachians suggests that the Rome Trough is too young to be such a feature. If this is the case, then the Rome Trough may be related to the closing of the Proto-Atlantic and be analogous in part to a feature such as the Basin and Range Province.

SUMMARY AND CONCLUSIONS

There is certainly a great deal yet to be learned about east-central Kentucky, but it is now possible to construct a tectonic history of the area that can be refined and modified by future studies. The first known event in this history is Keweenawan rifting, evidenced by the East Continent gravity high and volcanic basement rocks. It is possible that the 38th parallel lineament (Heyl, 1972) is due to an even older event that is reflected by a zone of weakness along the 38th parallel. However, the data presented by Black and others (1976)and Ammerman and Keller (1976, and in preparation) strongly suggest that large-scale strikeslip movements have not occurred along this lineament for over a billion years.

The Grenville Front formed 850 to 1,000 million years ago. In Kentucky, the front reflects a metamorphic event rather than a tectonic event. The tectonic activity responsible for this metamorphism must have occurred east of Kentucky, perhaps along an ancient continental margin.

The next tectonic event was the formation of the Rome Trough. The major faulting associated with this event is Cambrian in age (Webb, 1975), although later movements have occurred (Webb, 1969; Silberman, 1972). These later movements, which are reflected as presently exposed fault zones, did not take place along all the faults associated with the Rome Trough. In fact,

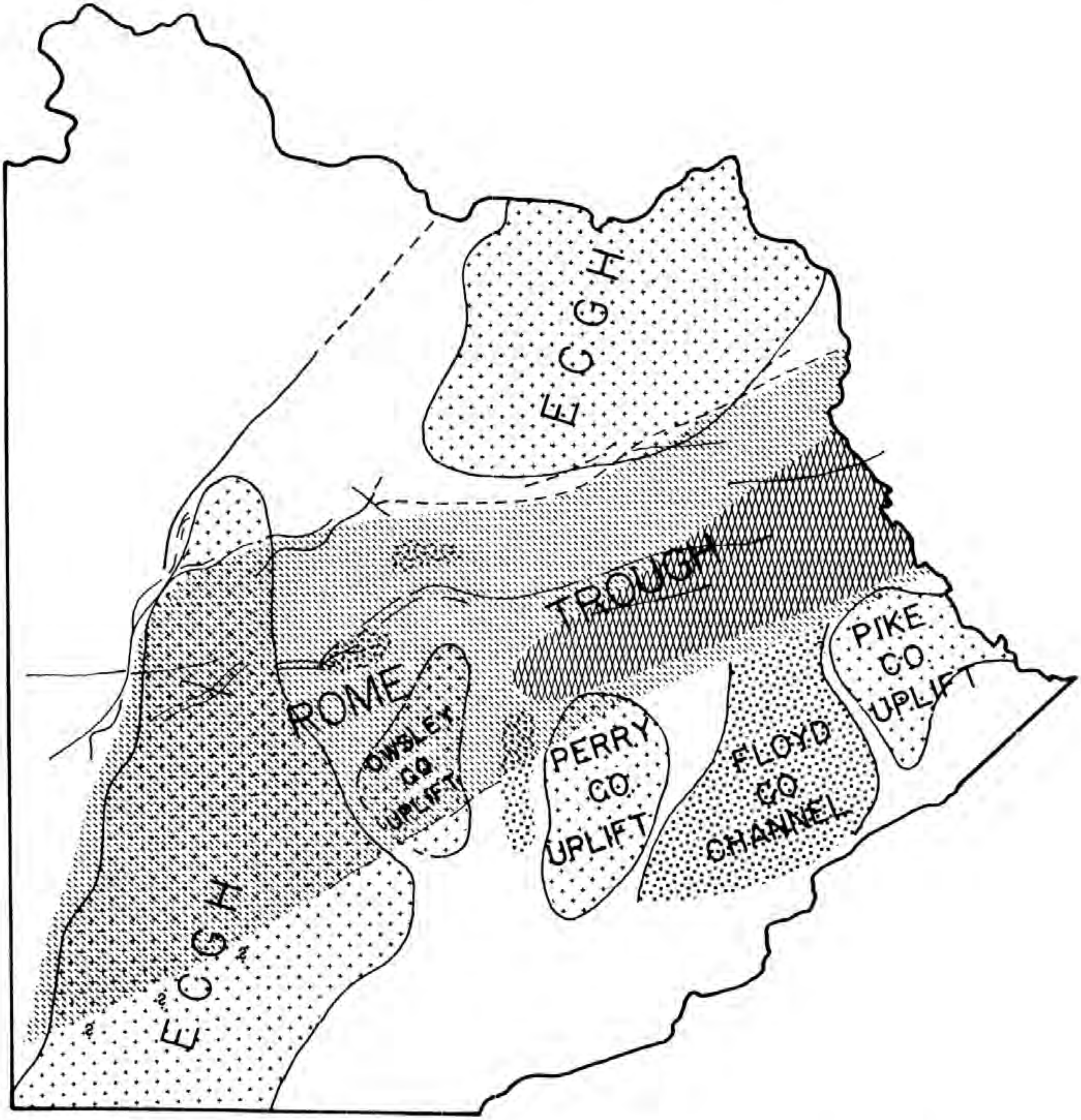


Figure 5. Map of eastern Kentucky showing major tectonic features. ECGH = East Continent Gravity High.

in central Kentucky, they occurred only along the western boundary faults of the Keweenawan rift zone. Thus, it seems most appropriate to consider these movements as renewed faulting along old zones of weakness that were probably due to tectonic forces generated in the Appalachians. The formation of the Rome Trough should be considered a distinct Cambrian event.

The tectonic history outlined above will almost certainly be modified in the future, but it serves the major purpose of demonstrating that east-central Kentucky has experienced a varied and complex geologic past. If the full economic potential of this area is to be realized, this past history must be adequately understood.

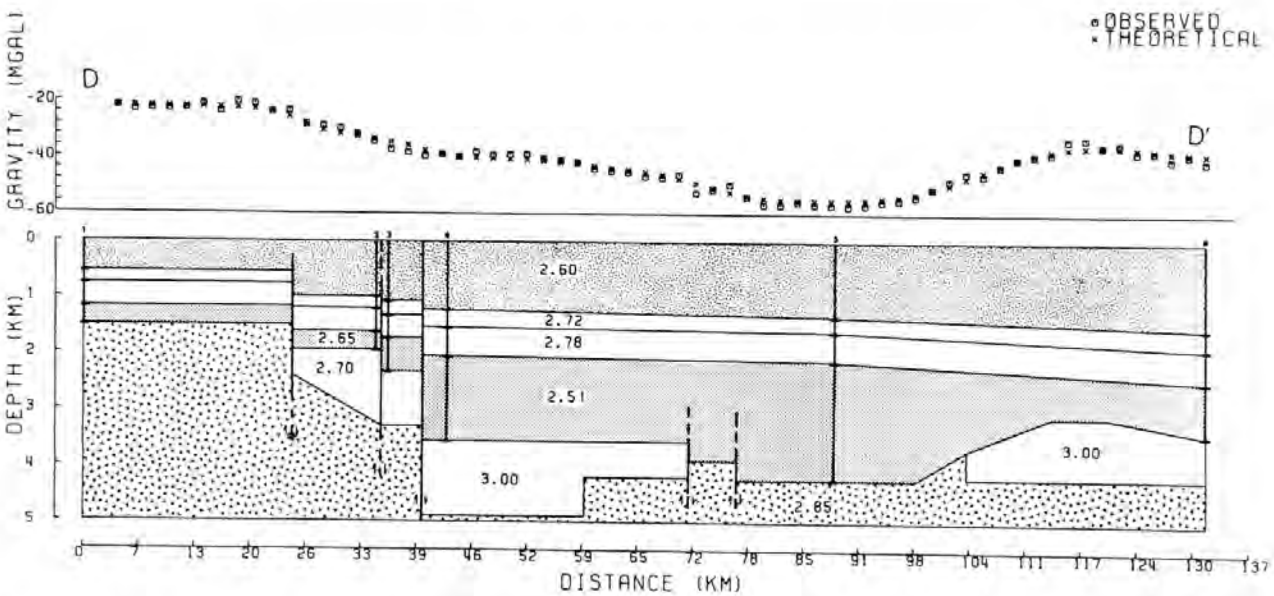


Figure 6. Computer-generated earth model for gravity profile D-D'. Numbers within bodies indicate densities in gm/cc. Numbers along surface indicate deep wells used as control. (From Ammerman and Keller, 1976.)

ACKNOWLEDGMENTS

The authors would like to thank M.N. Bass, D.F.B. Black, R.E. Denison, L.D. Harris, E.A. Hetherington, R.W. Johnson, J.D. Silberman, and E.N. Wilson for providing unpublished data and helpful comments. This work was supported in part by the U.S. Geological Survey and the Kentucky Geological Survey.

REFERENCES

Ammerman, M.L., and Keller, G.R., 1976, A gravity and tectonic study of the Rome Trough (abs.): Geological Society of America Abstracts with Programs, v. 8, no. 2, p. 124.

Black, D.F.B., Keller, G.R., and Johnson, R.W., 1976, An integrated geological and geophysical study of a part of central Kentucky: regional tectonic implications (abs.): Geological Society of America Abstracts with Programs, v. 8, no. 2, p. 135.

Burke, K., and Dewey, J.F., 1973, Plume-generated triple junctions: key indicators in applying plate tectonics to old rocks: Journal of Geology, v. 81, p. 406-433.

Chase, C.G., and Gilmer, T.H., 1973, Precambrian plate tectonics: the Midcontinent gravity high: Earth and Planetary Science Letters, v. 21, p. 70-78.

Harris, L.D., 1975, Oil and gas data from the Lower Ordovician and Cambrian rocks of the Appalachian Basin: U.S. Geological Survey Miscellaneous Geologic Investigation Map I-917D, Scale 1:2,500,000.

Heyl, A.V., 1972, The 38th parallel lineament and its relationship to ore deposits: Economic Geology, v. 67, p. 879-894.

Hinze, W.J., Kellogg, R.L., and O'Hara, N.W., 1975, Geophysical studies of basement geology of southern peninsula of Michigan: American Association of Petroleum Geologists Bulletin, v. 59, p. 1562-1584.

Keller, G.R., Bryan, B.K., Bland, A.E., and Greenberg, J.K., 1975, Possible Precambrian rifting in the southeast United States (abs.): Transactions American Geophysical Union, v. 56, p. 602.

King, E.R., and Zietz, I., 1971, Aeromagnetic study of the midcontinent gravity high of central United States: Geological Society of America Bulletin, v. 82, p. 2187-2208.

LeBas, M.J., 1971, Per-alkaline volcanism, crustal swelling, and rifting: Nature Physical Science, v. 230, p. 85-86.

Lidiak, E.G., Marvin, R.F., Thomas, H.H., and Bass, M.N., 1966, Geochronology of the midcontinent region, U.S., part 4: eastern area: Journal of Geophysical Research, v. 71, no. 22, p. 5427-5438.

McGuire, W.H., and Howell, P., 1963, Oil and gas possibilities of the Cambrian and Lower Ordovician in Kentucky: Lexington, Ky., Spindletop Research Center, 216 p.

Mohr, P.A., 1971, Ethiopian rift and plateau: some volcanic petrochemical differences: Journal of Geophysical Research, v. 76, no. 8, p. 1967-1984.

Muehlberger, W.R., Denison, R.E., and Lidiak, E.G., 1967, Basement rocks in continental interior of United States: American Association of Petroleum Geologists Bulletin, v. 51, p. 2351-2380.

Ocola, L.D., and Meyer, R.P., 1973, Central North American rift system: 1. Structure of the axial zone from seismic and gravimetric data: Journal of Geophysical Research, v. 78, no.

23, p. 5173-5194.

Silberman, J.D., 1972, Cambro-Ordovician structural and stratigraphic relationships of a portion of the Rome Trough, *in* Hutcheson, D.W., ed., Proceedings of the technical sessions, Kentucky Oil and Gas Association 34the and 35th annual meetings, 1970 and 1971: Kentucky Geological Survey, Series 10, Special Publication 21, p. 35-45.

Silver, L.T., and Green, J.C., 1972, Time constants for Keweenawan igneous activity (abs.): Geological Society of America Abstracts with Programs, v. 4, no. 7, p. 665.

Wasserburg, G.J., Wetherill, G.W., Silver, L.T., and Flawn, P.T., 1962, A study of the ages of the Precambrian in Texas: Journal of Geophysical Research, v. 67, no. 10, p. 4021-4047.

Webb, E.J., 1969, Geologic history of the Cambrian System in the Appalachian Basin *in* Rose, W.D., ed., Proceedings of the technical sessions, Kentucky Oil and Gas Association 33rd annual meeting, June 5-6, 1969: Kentucky Geological Survey, Series 10, Special Publication 18, p. 7-15.

Webb, E.J., 1975, Cambrian potential in the central Appalachian Plateau: presented at the Kentucky Oil and Gas Association 39th annual meeting.

Wilson, J.T., 1966, Did the Atlantic close and then re-open?: Nature, v. 211, no. 5050, p. 676-681.

Woodward, H.P., 1961, Preliminary subsurface study of southeastern Appalachian Interior Plateau: American Association of Petroleum Geologists Bulletin, v. 45, no. 10, p. 1634-1655.

Zietz, I., Stockard, H.P., and Kirby, J.R., 1968, Transcontinental geophysical survey (35°-39°N) magnetic and bathymetric map from 74° to 87°W longitude: U.S. Geological Survey Miscellaneous Geologic Investigation Map I-535-A, scale 1:1,000,000.

SILURIAN REEFS IN SOUTHWESTERN INDIANA AND THEIR RELATION TO PETROLEUM ACCUMULATION

LEROY E. BECKER and STANLEY J. KELLER
Indiana Geological Survey
Bloomington, Indiana

ABSTRACT

Reefs and reef structures are found across most of Indiana (Ault and others, in preparation), but pinnacle reefs have been recognized only in the Illinois Basin portion of Indiana. The distribution and stratigraphic setting of reef structures in the Illinois Basin of southwestern Indiana and the structural highs associated with them are outlined. Petroleum occurs in the highs overlying the reefs; favorable areas for additional reefs are included.

INTRODUCTION

To date, oil has never been produced in Indiana from Silurian reefs themselves, but oil production from structural highs associated with Silurian reefs dates back to the discovery of the Terre Haute field in Vigo County in 1889. The production at Terre Haute was from Devonian rocks, and at that time it was not known that the structural high that entrapped the oil was a reflection of an underlying Silurian reef. After the Terre Haute discovery, only three commercial pools related to reefs were discovered until the late 1940's and early 1950's, when reef exploration reached its peak.

Exploration for natural gas storage fields resulted in the discovery of the Plummer field in Greene County in 1969 (Noel, in preparation). The primary production at Plummer is from the Salem Limestone, and some production comes from the Ste. Genevieve Limestone and Devonian carbonate rocks. Since the Plummer discovery in 1969, additional reefs have been found in Greene, Daviess, Owen, and Clay Counties.

SILURIAN REEFS IN INDIANA

Geologic literature provides many different meanings for the term "reef." As commonly used by petroleum geologists, it means an irregularly layered or mound-like carbonate rock body built by sedentary marine organisms such as corals, usually enclosed in rock of different lithology. Isolated reef growths that stand several hundred feet high and cover less than one square mile are referred to as pinnacle reefs.

A typical pinnacle reef in the Indiana subsurface is lithologically different from the horizontally bedded rocks that enclose it. The reef body is composed principally of pure carbonate rock, limestone, or dolomite, and chert is generally absent from the reef rock. The reef core is massive and generally lacks stratification. The material surrounding reefs is referred to as country rock or inter-reef deposits and generally exhibits well defined stratification.

Some of the earliest and most comprehensive studies of Silurian reefs in Indiana were by Cumings and Shrock in 1927 and 1928. Their studies presented evidence showing that dome-like structures in the upper Wabash Valley of north-central Indiana were fossil coral reefs.

In 1949 H.A. Lowenstam published a paper on Niagaran reefs in Illinois and their relation to oil accumulation. He developed a regional map which included Indiana that showed the distribution of Silurian rocks and known reefs. He identified from subsurface data a cluster of reefs in Sullivan and Vigo Counties and a belt of reefs in the Silurian outcrop area.

OUTCROP AND THICKNESS OF SILURIAN ROCKS

Silurian and older rocks crop out in a broad belt from southeastern to northwestern Indiana. In the subsurface the Silurian section thickens westward. The greatest thickness of Silurian rocks in southwestern Indiana extends in a belt from Spencer County northwestward through Dubois and Daviess Counties and western Greene County to Sullivan County (Fig. 1). Silurian rocks thin both eastward and westward from this thick band. The maximum regional thickness of the Silurian System in this belt is about 700 feet. Within this section there are isolated small dome-like areas where the Silurian thickness may reach 900 feet. These areas are referred to as pinnacle reefs.

All commercially significant oil or gas production that can be structurally related to pinnacle reefs lies in this belt in which the Silurian is more than 400 feet thick (Fig. 1). Fifty-five reefs associated with oil or gas production or gas storage have been identified, and many other reefs that are not productive have been found. Most of the identified reefs are in northern Sullivan County, southern Vigo County, western Clay County, western Greene County, and northern Daviess County (Carpenter and Sullivan, 1976).

Where Silurian rocks are less than 400 feet thick, reef-related commercial production has not been found. But in areas where the Silurian is 150 to 400 feet thick, some reefs of relatively low relief have been recognized.

The Silurian System in southeastern Indiana thickens from its outcrop area southwestward toward the deep part of the Illinois Basin (Fig. 2). In general, Silurian rocks thicken from about 100 feet at the outcrop to more than 700 feet in southeastern Daviess County and then thin abruptly downdip to less than 300 feet (Fig. 1). This thick Silurian carbonate belt has been named the Terre Haute bank by Droste and Shaver (1975, p. 395). The thinning of the Silurian section west of the Terre Haute bank indicates an increased rate of subsidence and a slow rate of sedimentation west of the bank.

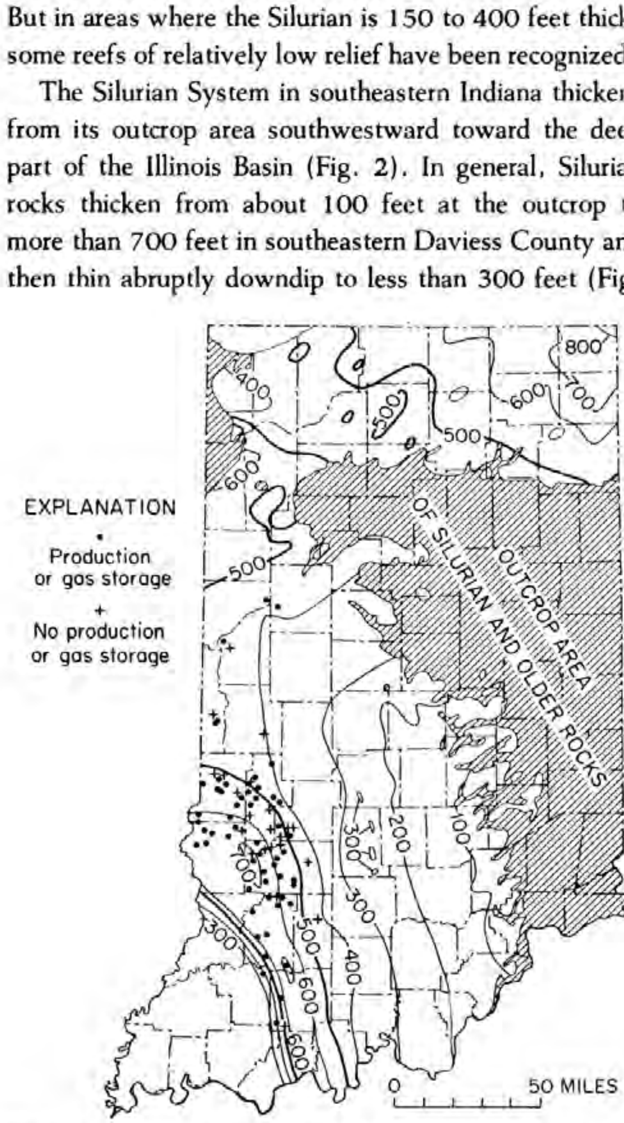


Figure 1. Isopach map showing outcrop of Silurian System and location of reefs in southwestern Indiana that have induced structure in younger rocks. The part of the Bailey Limestone that is probably Silurian in age is not shown.

In addition to the Middle Devonian carbonates, as much as 1,000 feet of Lower Devonian cherty carbonates accumulated in the part of the Illinois Basin that lies west of the Terre Haute bank (Becker, 1974, p. 25).

Pre-reef Silurian deposits are uniform in thickness, but the overlying Silurian section shows a considerable increase in thickness. Good reef development occurred where the Silurian section is thickest. Tall reefs in the thick Silurian section were not subjected to pre-Devonian erosion, but the updip reefs were partially truncated (Fig. 3.).

Reef-type Silurian rock occurs west of the Terre Haute bank. Reefs stood high enough to project into the Lower Devonian rocks and,in some places through the Lower Devonian section (Fig. 3). A similar situation is found on the west side of the basin in Illinois, where Silurian reefs stood high enough to project through the Lower Devonian rocks.

ENTRAPMENT AND OIL PRODUCTION

The doming of strata above a pinnacle reef resulted from differential compaction between the reef and the sediments adjacent to it. The reefs were rigid and permitted very little additional compaction from the weight of the overlying sediments. In contrast, the sediments surrounding the reef were soft and were subjected to a considerable amount of compaction. This differential compaction process appears to have been continous throughout post-Silurian time.

Although structural closure, or doming, is apparent in all strata overlying a reef, the amount of structural closure is greatest for the beds immediately above a reef. In the commercially significant reef belt of southwestern Indiana, reef-induced structure of 150 feet on Devonian strata gradually diminishes upward and is about 60 feet in the Pennsylvanian rocks of Coal V (Fig. 4).

In some areas, including Michigan and Illinois, petroleum is produced directly from the reef body. In Indiana, all commercial accumulation of petroleum in as-

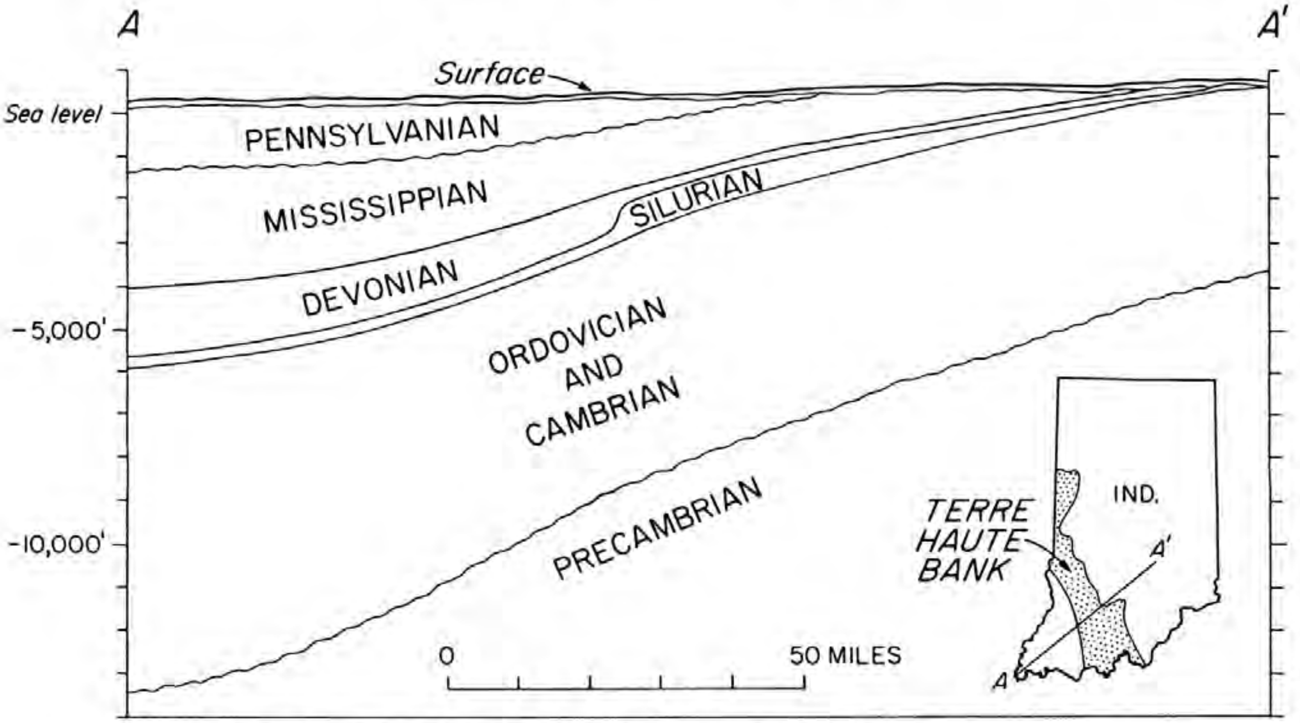


Figure 2. Cross section of Paleozoic rocks. Bailey Limestone is included in the Devonian section.

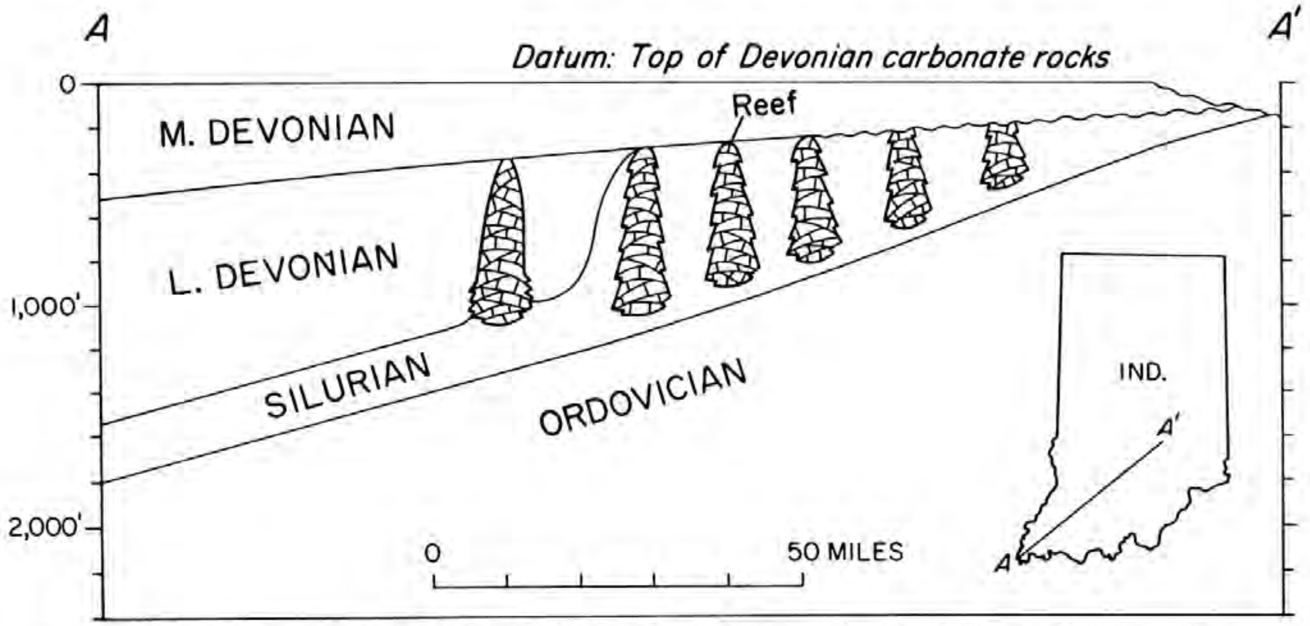


Figure 3. Cross section of Paleozoic rocks showing Silurian reefs. Bailey Limestone is included in the Lower Devonian section.

sociation with Silurian reefs is in rocks overlying the reefs. Oil or gas have been found in the domed beds above the reef in the Devonian limestone section, the Salem Limestone, and the Ste. Genevieve-Aux Vases interval. Oil production has been obtained from reef-related structures in 37 fields, from Devonian limestone in 20 fields, from Mississippian reservoirs in 10 fields, and from both Devonian and Mississippian rocks in seven fields.

There are indications that Silurian reef cores should be

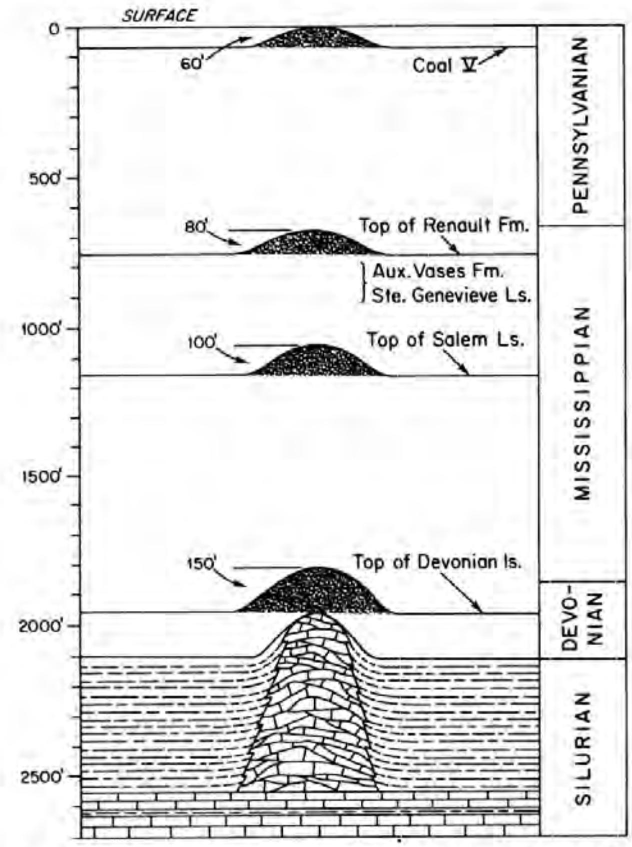


Figure 4. Schematic drawing showing doming of strata above reef.

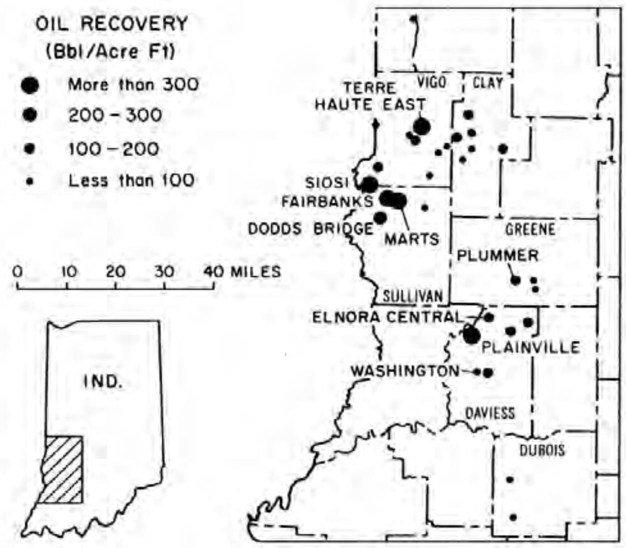


Figure 5. Oil recovery from fields associated with reef structures.

more thoroughly investigated even though no commercial production has been found within them in Indiana. At Shelburn Consolidated field in Sullivan County, the upper part of a Silurian reef was cored, and the core analysis indicated low oil saturation in a 2-foot interval. Shows of oil or gas have also been reported from the Howesville, Dixon, and Switz City gas storage projects. At the Wilfred field, circulation was lost in the reef core during drilling, thereby indicating porosity. West of the Terre Haute bank the less permeable Lower Devonian rocks may provide a seal that Middle Devonian rocks thus far have not.

OIL RECOVERY

Oil accumulations in Devonian limestone above Silurian reefs are significant. Four fields, Siosi, Fairbanks, Marts, and Terre Haute East (Fig. 5) in Vigo and Sullivan Counties, compare favorably with any group of oil fields in Indiana. Ultimate recovery from them will be more than 11 million barrels—two and three-quarter million barrels per field on the average. Oil recovery from these four fields will average more than 300 barrels per acre-foot (Fig. 5). The four fields are bounded by a group of Devonian reservoir fields based on Silurian reef structures. One field, Dodds Bridge (Fig. 5), has recovered between 200 and 300 barrels per acre-foot, and there are five fields in which recovery has been between 100 and 200 barrels per acre-foot. Other fields will yield less than 100 barrels per acre-foot. In Greene and Owen Counties, southeast of the Devonian oil fields, gas has been found in the Devonian limestone above Silurian reefs. The gas accumulations in these fields were not sufficient in volume to be commercial, but seven of the Greene County fields have been developed for gas storage by Citizens Gas and Coke Utility.

Reef-induced structures in Greene, Daviess, and Dubois Counties hold important oil accumulations in Mississippian Salem and Ste. Genevieve limestones and Aux Vases dolomite. Most reef-related Mississippian reservoirs found in these counties prior to the discovery of the Plummer field are commercial, but Plainville (Fig. 6), with oil reservoirs at a depth of 700 to 750 feet, has a recovery factor greater than 300 barrels per acre-foot and is much better than the others (Fig. 5). Ultimate recovery from it will be as much as 3.7 million barrels.

Cumulative oil production in Indiana at the end of 1975 amounted to almost 450 million barrels. Production attributed to reef-related fields amounted to 28 million barrels, or 6 percent of the cumulative production. Of the 28 million barrels, 19 million barrels (68 percent) are from Devonian rocks and 9 million barrels (32 percent) are from Mississippian reservoirs (Fig. 6).

In the 37 reef-related fields of southwestern Indiana, it is estimated that the ultimate recovery will be 31.3 million barrels, or about 22 percent of the original oil in place. Reef-related fields have produced 28 million barrels to date, which is about 89 percent of the recoverable oil; the remaining reserves are estimated at 3.3 million barrels, or 11 percent of the total recoverable oil (Fig. 6).

WATERFLOODING

Waterflooding operations have been carried on in six reef fields, but production statistics are available for only two fields, Plainville and Washington. In Plainville, the Aux Vases and Ste. Genevieve reservoirs are being flooded, and secondary oil amounts to 45 percent of the field cumulative production. In Washington, the Salem Limestone is being flooded, and secondary oil amounts to 25 percent of the field cumulative production (Carpenter and Keller, in preparation). A new flood operation was installed in the Elnora Central field during 1975, but secondary production figures are not available at this time.

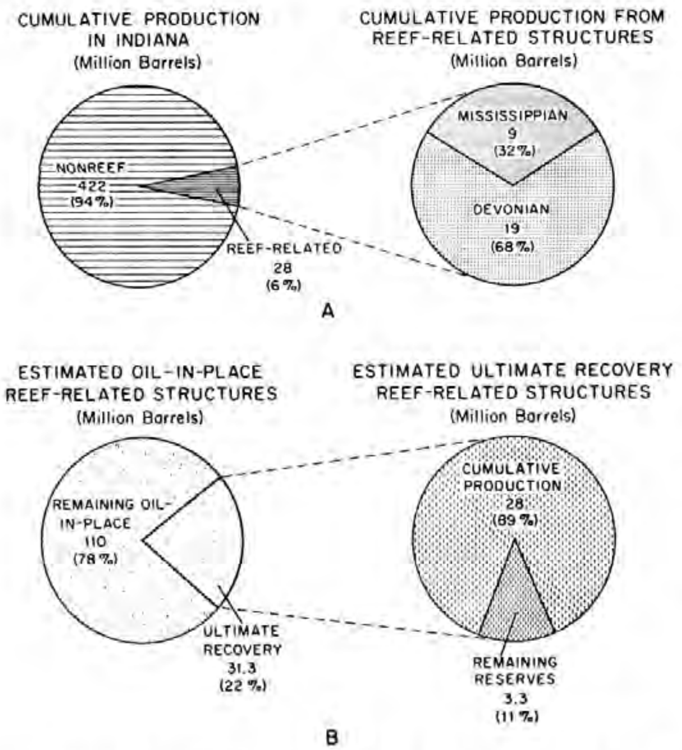


Figure 6. Graphs showing (A) cumulative oil production from Indiana and reef-related structures, and (B) estimated oil in place and estimated oil recovery from reef-related structures.

UNDERGROUND STORAGE OF NATURAL GAS

Fourteen underground natural gas storage fields in Greene, Sullivan, Vigo, Vermillion, Clay, Warren, and Tippecanoe Counties are associated with Silurian reefs. Practically all the underground storage is in Middle Devonian carbonate reservoirs. The gas storage fields have a reservoir capacity of 42 billion cubic feet and a work capacity of 11 billion cubic feet. Other known reefs in west-central Indiana are overlain by porous Middle Devonian carbonates that offer future possibilities for underground storage of natural gas.

SUMMARY

Additional petroleum exploration is merited in a large area of southwestern Indiana where petroleum accumulations will probably be found in association with Silurian pinnacle reefs. The strata in which accumulations may be found are the Mississippian Ste. Genevieve Limestone, Aux Vases Formation, and Salem Limestone, and the Middle Devonian carbonate section. Not to be overlooked are the Silurian reef bodies themselves.

The most promising area for future exploration is a large part of the particularly thick Silurian section that extends from Spencer County northwestward through Dubois, Daviess, Greene, and Sullivan Counties. However, reef complexes may be found basinward from the principal Silurian bank and, therefore, within the area where Lower Devonian rocks are present.

All of these Silurian pinnacle reefs are reflected in shallow strata by structural closure, and a good method of exploration is shallow test drilling.

SELECTED REFERENCES

Ault, C., and others, In Press, Map of Indiana showing thickness of Silurian rocks and locations of reefs and reef structures: Indiana Geological Survey Miscellaneous Map.

Becker, L.E., 1974, Silurian and Devonian rocks in Indiana southwest of the Cincinnati Arch: Indiana Geological Survey Bulletin 50, 83 p.

Carpenter, G.L., Dawson, T.A., and Keller, S.J., 1975, Petroleum industry in Indiana: Indiana Geological Survey Bulletin 42-N, 57 p.

Carpenter, G.L., and Keller, S.J., In Press, Oil development and production in Indiana during 1975: Indiana Geological Survey Mineral Economics Series 22.

Carpenter, G.L., and Sullivan, D.M., 1976, Map showing oil, gas, and gas storage fields in Indiana: Indiana Geological Survey Miscellaneous Map No. 21.

Cumings, E.R., and Shrock, R.R., 1927, The Silurian coral reefs of northern Indiana and their associated strata: Indiana Academy of Science Proceedings, v. 36, p. 71-85.

Cumings, E.R., and Shrock, R.R., 1928a, Niagaran coral reefs of Indiana and adjacent states and their stratigraphic relations: Geological Society of America Bulletin, v. 39, p. 579-620.

Cumings, E.R., and Shrock, R.R., 1928b, The geology of the Silurian rocks of northern Indiana: Indiana Department of Conservation Publication 75, 226 p.

Droste, J.B., and Shaver, R.H., 1975, Jeffersonville Limestone (Middle Devonian) of Indiana: stratigraphy, sedimentation, and relation to Silurian reef-bearing rocks: American Association of Petroleum Geologists Bulletin, v. 59, p. 393-412.

Lowenstam, H.A., 1949, Niagaran reefs in Illinois and their relation to oil accumulation: Illinois Geological Survey Report of Investigations 145, 36 p.

Noel, J.A., In Press, The Plummer field, Greene County, Indiana: Indiana Geological Survey Special Report.

KENTUCKY OIL AND GAS ASSOCIATION