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Gas Exploration in the Devonian Shales of Kentucky

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Front cover—Geophysical logs of a fractured gas reservoir in the New Albany Shale in western Kentucky.

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ABSTRACT

Devonian black shales constitute a major economic resource in Kentucky. These shales, known variously as the Ohio, Chattanooga, and New Albany Shales, are between 50 and 1,700 feet thick and occur both in outcrop and in the subsurface, buried as deep as 4,200 feet below sea level.

Total gas in place for the Devonian shales in Kentucky is estimated to be between 63 and 112 trillion cubic feet; between 2 and 28 percent is recoverable. Known shale gas accumulations include the giant Big Sandy Field of eastern Kentucky and adjacent West Virginia, as well as a number of smaller fields in eastern and western Kentucky.

Geochemical evidence shows that Devonian shales have acted as effective source rocks for the bulk of the oil in both the Illinois and Appalachian Basins. This finding is consistent with a vitrinite reflectance map of the Devonian shales of Kentucky, which shows that much of the New Albany Shale and the Ohio Shale has reached a level of thermal maturity adequate for abundant oil generation. Devonian shale gas is thermogenic, and associated with the widespread generation of oil. The predominance of gas production from fractured Devonian shales is attributed to evaporational fractionation during hydrocarbon migration through the organic-rich, low permeability reservoirs.

Natural fractures of different types are essential for effective gas production from Devonian shales. One common fracture type is closely associated with fault zones. Such fractured reservoirs may be poorly sealed, and productive only at the relatively low rates of migrating gas. Another common fracture type is closely associated with low-amplitude flexures. These fractured reservoirs should be well sealed, and productive at relatively high rates. Devonian shale reservoirs are commonly underpressured, but have a geological history of overpressuring that has been important in facilitating fracturing. Horizontal extension fractures in the Ohio Shale of the Big Sandy Field indicate a past episode of overpressuring that exceeded the lithostatic pressure gradient. Current underpressuring of Devonian shale reservoirs is probably caused by cooling resulting from uplift and erosion since the period of maximum burial in the Mesozoic. Calculation of paleoreservoir pressure using published values of eroded overburden and aquathermal pressure gradient suggests that reservoir pressure in the Devonian shales of the Big Sandy Field exceeded the lithostatic pressure gradient, locally resulting in horizontal extension fractures observed in core.

Regions of maximum potential for Devonian shale gas production can be identified interior to the Rome Trough in eastern Kentucky, and interior to the Moorman Syncline in western Kentucky. In these regions, the lack of surface faulting increases the potential for maintaining a good seal to the Devonian shale gas accumulations. Thermal maturity in these regions is adequate for the generation of oil and associated gas, with accompanying overpressuring. The degree of gas generation and overpressuring would have increased to the southeast in the Rome Trough, and to the west in the Moorman Syncline. Intensive drilling in the deep Rome Trough has resulted in the development of the Big Sandy Field. In contrast, the deep Moorman Syncline is virtually unexplored. In addition to avoiding surface faulting and seeking out maximum thermal maturity, effective exploration in the deep Moorman Syncline must locate those specific flexures that would have resulted in extensive reservoir fracturing in the overpressured Devonian shales.

DEVONIAN SHALES OF KENTUCKY

Introduction

Black shales of Devonian age constitute a major economic resource in Kentucky and are of great geological significance. Most of the natural gas reserves of Kentucky are contained in fractured reservoirs in the Devonian shales, which account for a large share of gas wells drilled in the State (Yost, 1986; Nuttall, 1992). In addition, the Devonian shales are rich in oil and are regarded as a large and significant potential resource for oil mining in the area of their outcrop (Barron and others, 1987). Indirectly, the Devonian shales are also of great economic significance in that they are the source rocks of the great majority of oil produced in both the Appalachian and Illinois Basins (Cole and others, 1987; Hatch and others, 1991). Finally, the shales are of major geological importance because they constitute the distal margin of the great Catskill Delta to the east and therefore provide a direct record of the prodeltaic environment during Acadian orogenic events in Devonian time (Woodrow and others, 1988; Hamilton-Smith, 1993).

Stratigraphy

In Kentucky, the Devonian shales are known variously as the Ohio Shale, Chattanooga Shale, and New Albany Shale. The distribution of these Devonian shale units in Kentucky is shown in Figure 1, and their stratigraphic correlation is shown in Figure 2. In eastern Kentucky the Devonian shale sequence consists mainly of the Late Devonian Ohio Shale, but also includes the underlying upper Olentangy Shale and Rhinestreet Shale, as well as the overlying Bedford Shale and Sunbury Shale, which are of earliest Mississippian age. The Ohio Shale includes both the Huron Shale and the Cleveland Shale (Ettensohn and others, 1988; Hamilton-Smith, 1988). In western Kentucky, the Devonian shale consists of the new Albany Shale of Middle Devonian to earliest Mississippian age (Campbell, 1946; Devera and Hasenmueller, 1991). In south-central Kentucky, the Devonian shale consists of the Late Devonian Chattanooga Shale (Conant and Swanson, 1961).

The Devonian shale sequence of Kentucky consists of dark-gray or brown to black shale interbedded with subordinate amounts of green-gray shale. In western Kentucky, the basal unit of the New Albany Shale, the Blocher Member, also contains thin beds of argillaceous dolomite (Beard, 1980). The thickness of the shale varies from a maximum of over 1,700 feet in easternmost Kentucky (Dillman and Ettensohn, 1980; Chesnut, 1993), to 50 feet or less over the axis of the Cincinnati Arch, to over 450 feet in northern Crittenden County in western Kentucky (Schwalb and Potter, 1978). The Devonian shale is exposed in outcrops in central Kentucky around the margin of the Jessamine Dome, and at various localities to the south along the crest of the Cincinnati Arch (McDowell and others, 1981). It is buried to a maximum depth of 4,200 feet below sea level in Union County in western Kentucky, and 2,700 feet below sea level in easternmost Kentucky (Potter and others, 1982).

Organic Content

Of the 371 core and cutting samples of the New Albany Shale in the Illinois Basin analyzed by Barrows and Cluff (1984), 86 percent had total organic carbon contents above 1 percent, with a maximum of 15.6 percent. Organic matter in the green-gray shales is relatively sparse, and consists mainly of the humic maceral groups vitrinite and inertinite, with small unconnected stringers of amorphous organic matter. This material corresponds to the Type III kerogen of Tissot and Welte (1978). In contrast, only 5 to 10 percent of the organic concentrates of the organic-rich black and dark brown shales are recognizable macerals, mainly alginite *(Tasmanites),* with lesser amounts of vitrinite and inertinite macerals. The bulk of the organic matter in the black shales is amorphous and of uncertain origin.

Analyses of the Ohio Shale of the Appalachian Basin show a similar organic composition to that of the New Albany Shale. Zielinski and McIver (1982) examined over 2,000 shale samples and found a range of organic carbon content from 0.1 to 27 percent, with an average value of 2.13 percent. Curtis (1988b) found total organic carbon concentrations between 3 and 6 percent for the black Lower Huron Shale Member of the Ohio Shale. By examining organic biofacies, Zielinski and McIver (1982) showed that organic material of terrestrial origins, equivalent to Type III kerogen, was more abundant in the green-gray shale and increased in relative abundance toward the Catskill Delta in the east. The eastward increase in the terrestrial component was also indicated by carbon isotope analyses reported by Maynard (1981).

Data relevant to the organic composition of the Chattanooga Shale are relatively scarce, as this shale has never been considered a major hydrocarbon resource. In their analysis of the EGSP TENN-9 core of the Chattanooga Shale from Grainger County, Tennessee, Zielinski and McIver (1982) found a range of organic carbon content from 0.1 to greater than 6 percent. Maynard (1981) reported a range of organic carbon content between 1 and 5 percent for various zones of the Chatta-

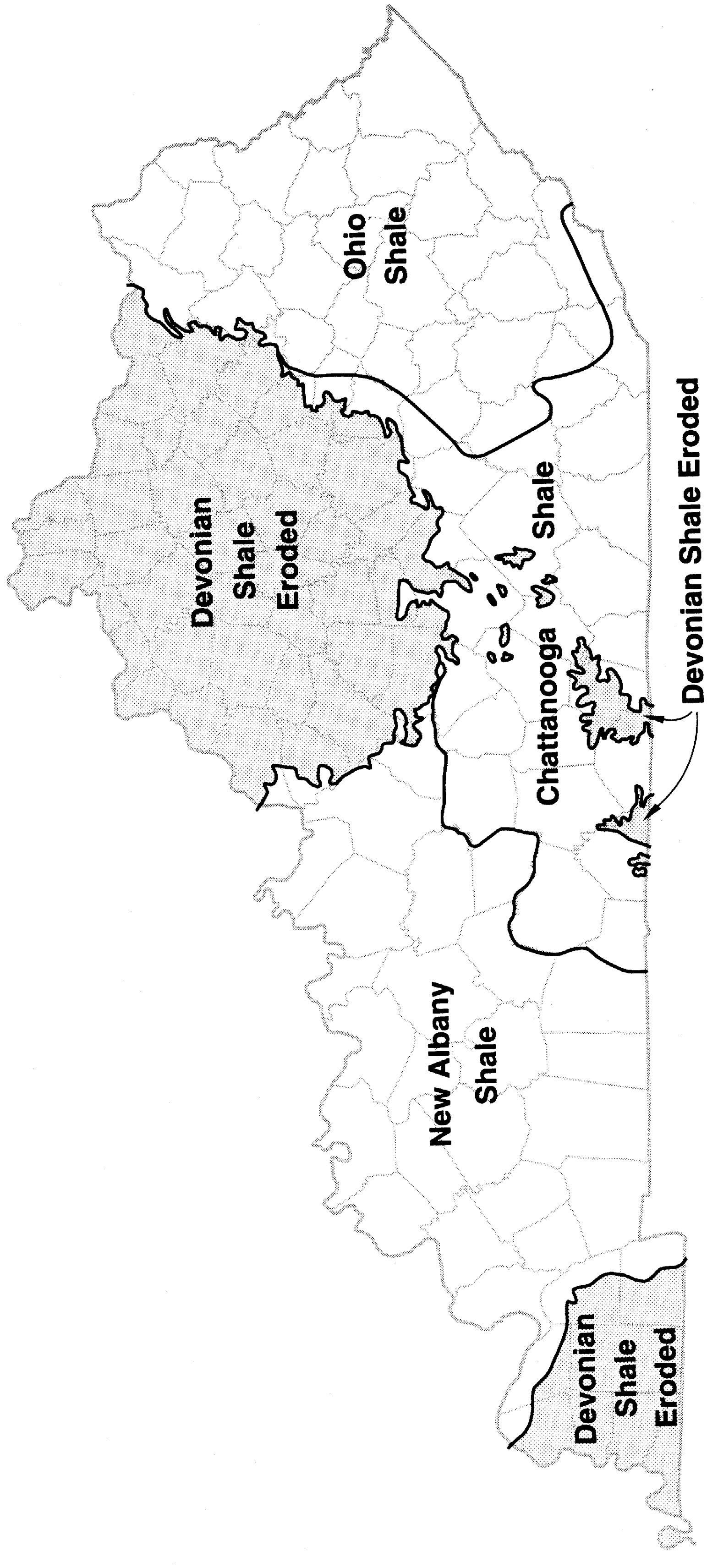

Figure 1. Distribution and nomenclature of Devonian shales of Kentucky. outcrop margins from McDowell and others (1981). Subcrop margin from Schwalb and Potter (1978). Formation boundaries from de Witt (1981).

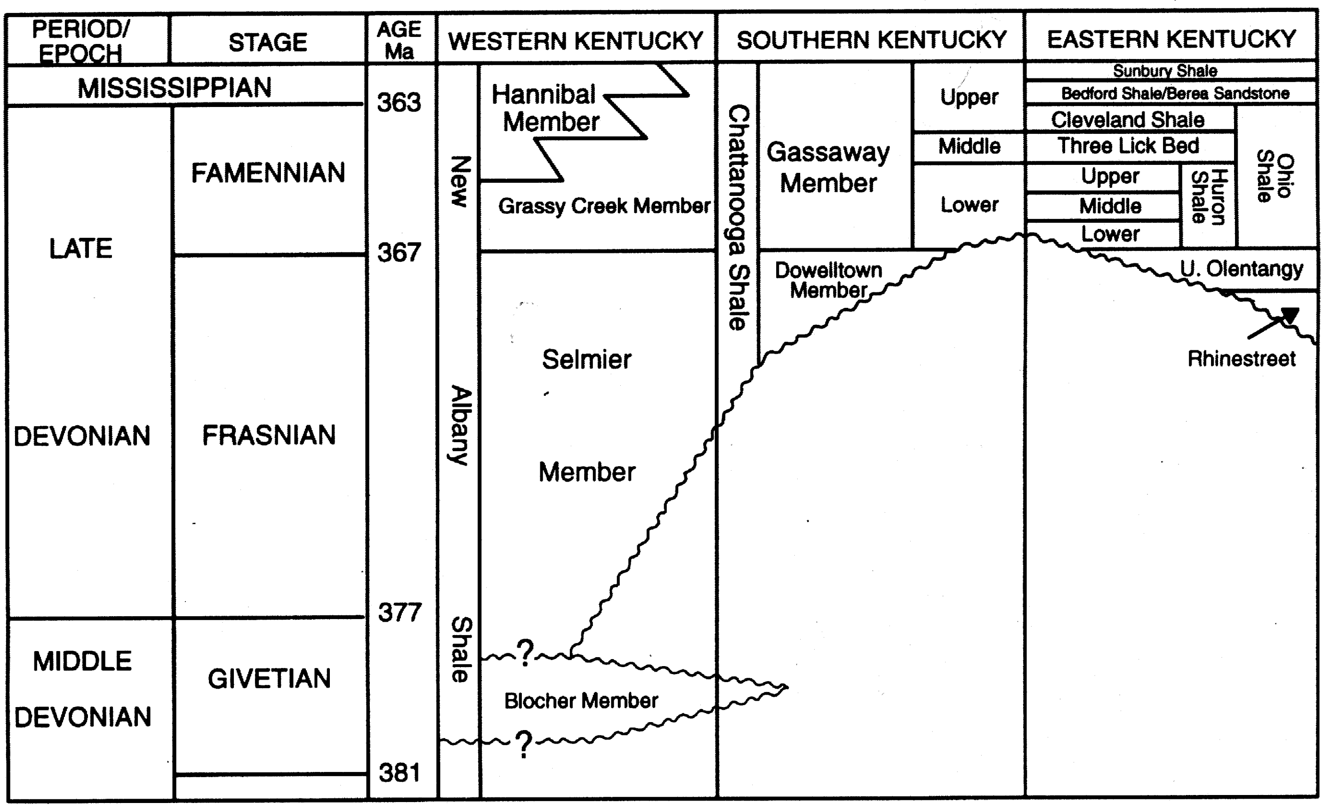

Figure 2. Stratigraphic correlation of Devonian shales of Kentucky. Time scale from Harland and others (1990). Western Kentucky section after Hasenmueller and others (in press). Eastern Kentucky section after Frankie and others (1986a–c) and Moody and others (1987a–b), as modified by Hamilton-Smith (1993). Southern Kentucky section modified after Kepferle and Roen (1981).

nooga Shale in three cores from westernmost Virginia and adjacent Kentucky. Analyses of the Chattanooga Shale from northern Alabama and southern Tennessee indicated an average organic carbon content of 17 percent (Rheams and others, 1982). By examining organic biofacies, Zielinski and McIver (1982) showed that between 10 and 70 percent of the organic material in the Chattanooga Shale was coaly or woody—of terrestrial origin. Maynard (1981) suggested that the proportion of terrestrial material in the Chattanooga Shale was relatively smaller than in the Ohio Shale.

Depositional Environment

Several aspects of the depositional environment of the Devonian shales remain uncertain, despite the attention of numerous researchers over many years. The abundance of organic material in the Devonian shales of Kentucky is commonly attributed to preservation by deposition in an anaerobic environment produced by the depth-related stratification of basin water (Demaison and Moore, 1980; Ettensohn and others, 1988). However, carbon-sulfur-iron relationships suggest that some of the black shales of the New Albany Shale were deposited under oxygenated conditions, probably as a consequence of high organic productivity (Beier and Hayes, 1989). Recent review of modern organic-rich marine sediments also suggest that high organic productivity may be generally more important than anoxia of bottom waters in the accumulation of organic-rich facies (Pederson and Calvert, 1990, 1991; Middelburg and others, 1991). This recent emphasis on high organic productivity is reminiscent of the interpretations of earlier workers in the Devonian shales, who suggested significant organic input from major blooms of the algae *Tasmanites* (Lineback, 1968; Zielinski and McIver, 1982). Physical sedimentology may also be important to the accumulation of black shales. Huc (1988) concluded that maximum concentrations or organic carbon in the Black Sea were only indirectly related to either anoxia or productivity, and were controlled primarily by the hydrodynamic properties of the organic particles.

Water depth is another uncertain aspect of the depositional environment of the Devonian shales. The New Albany Shale and the Ohio Shale have generally been considered to have been deposited in water locally deeper than 700 feet (Cluff, 1980; Ettensohn and Barron, 1981), while the Chattanooga Shale has been interpreted as originating in shallow water from a few feet to less than 100 feet deep (Glover, 1959; Conant and Swanson, 1961). McCollum (1988) has also suggested a shallow-water depositional environment for the Middle Devonian black shales of western New York. Lineback (1968, p. 1302) concluded that "depth does not seem to be a very important factor in the deposition of black shale," and suggested that the "New Albany and its equivalents could have been deposited in shallow water at some places and in deep water at other places."

SHALE GAS RESOURCES

Estimated Gas in Place and Recovery

The Devonian shales of the Illinois and Appalachian Basins contain a major natural gas resource, although various calculations show little quantitative agreement. Gas-in-place values calculated for the Appalachian Basin during the U.S. Department of Energy (DOE) Eastern Gas Shales Program varied between 900 and 2,580 trillion cubic feet (tcf) (Zielinski and McIver, 1982). In their summary of the DOE work, Kuuskraa and others (1985) reported a total gas-in-place figure for the Devonian shales of eastern Kentucky of 82 tcf, including 40 tcf in the established producing fields. In later work for the Gas Research Institute, Curtis (1988b) calculated gas in place for only the Lower Huron Shale Member of the Ohio Shale and the Rhinestreet Shale in eastern Kentucky to be 33 tcf.

Kuuskraa and others (1985) and Yost (1986) estimated that between 9 and 23 tcf of shale gas would be recoverable in eastern Kentucky, depending on the degree of new drilling and methods of well stimulation used. These estimates were based on local recovery efficiencies between 3 and 84 percent, depending on the specific area and formation depth (Kuuskraa and others, 1985), In contrast, calculations reported by Avila (1976) suggest significantly lower recovery efficiencies for the shales of eastern Kentucky, between 2 and 10 percent.

The gas content of the New Albany Shale of the Illinois Basin was estimated by the National Petroleum Council to be 86 tcf, with some 30 tcf gas in place in western Kentucky (Devonian Shale Task Group, 1979). This estimate was based on the calculation of the gross shale volume and an average gas content of 0.62 standard cubic feet of gas per cubic foot of shale. This average gas content was based on studies of gas released from core from six wells in the Illinois Basin. Only one of these wells was in western Kentucky, the Orbin Clark 1 well in Christian County. the analytic procedure is described in detail in Snyder and others (1977), who pointed out that due to a major problem of sample leakage, the calculated values underestimate the in-situ gas content of the shales by as much as one order of magnitude.

Gas Development History

Exploration and production of this resource has been difficult and costly, in part because of the unconventional nature of the shale reservoir. Conventional reservoir rock is an aggregate of sedimentary particles, with hydrocarbons stored in and delivered from intergranular pore space that is relatively easy to analyze. In contrast, the Devonian shales have gas stored both in the open pore space and adsorbed onto clay and kerogen particles. Effective gas delivery from the shale reservoir depends almost entirely on the presence of open fractures, which are relatively difficult to identify or predict.

The natural gas resources of the Appalachian Basin are relatively well developed in mature gas fields like the giant Big Sandy Field of eastern Kentucky and western West Virginia, in addition to a large number of smaller fields (Fig. 3). In the Illinois Basin, development of Devonian shale gas has been limited to a number of small fields. In western Kentucky these fields include the Brandenburg Station, Doe Run, and Rockhaven Fields of Meade County, and the Shrewsbury Field of Grayson, Edmonson, and Butler Counties (Fig. 3).

Gas was first produced commercially from the Devonian shales of Kentucky when the Moreman well was drilled near Brandenburg in Meade County in 1863 (Jillson, 1922). In 1888 The Rock Gas Company was formed to pipe produced gas to Louisville, and an 8-inch pipeline with a capacity of 10 million cubic feet of gas per day (MMcfgpd) was completed in 1890, producing the 30 best of over 100 field wells (Jillson, 1931). In 1907 the Louisville Gas and Electric Company opened a 12-inch gas pipeline from Martin County in eastern Kentucky to transport gas produced from Mississippian reservoirs in eastern Kentucky and adjacent West Virginia, successfully competing with the previously established production from the New Albany Shale. In 1918 a second 10-inch gas line was connected from Martin County to Lexington and Frankfort by the Central Kentucky Natural Gas Pipe Line Company (Jillson, 1919).

The Big Sandy Field was discovered with a well drilled in 1915 in the Beaver Creek area of Floyd County, Kentucky (Frankie and others, 1986c). Drilling activity summarized in Table 1 shows that development of the Big Sandy Field reached a peak in the 1940's, with the drilling of as many as 1,400 gas wells in the field area in the 10-year period. In 1951, 97 percent of the gas production in Kentucky came from the Big Sandy Field,

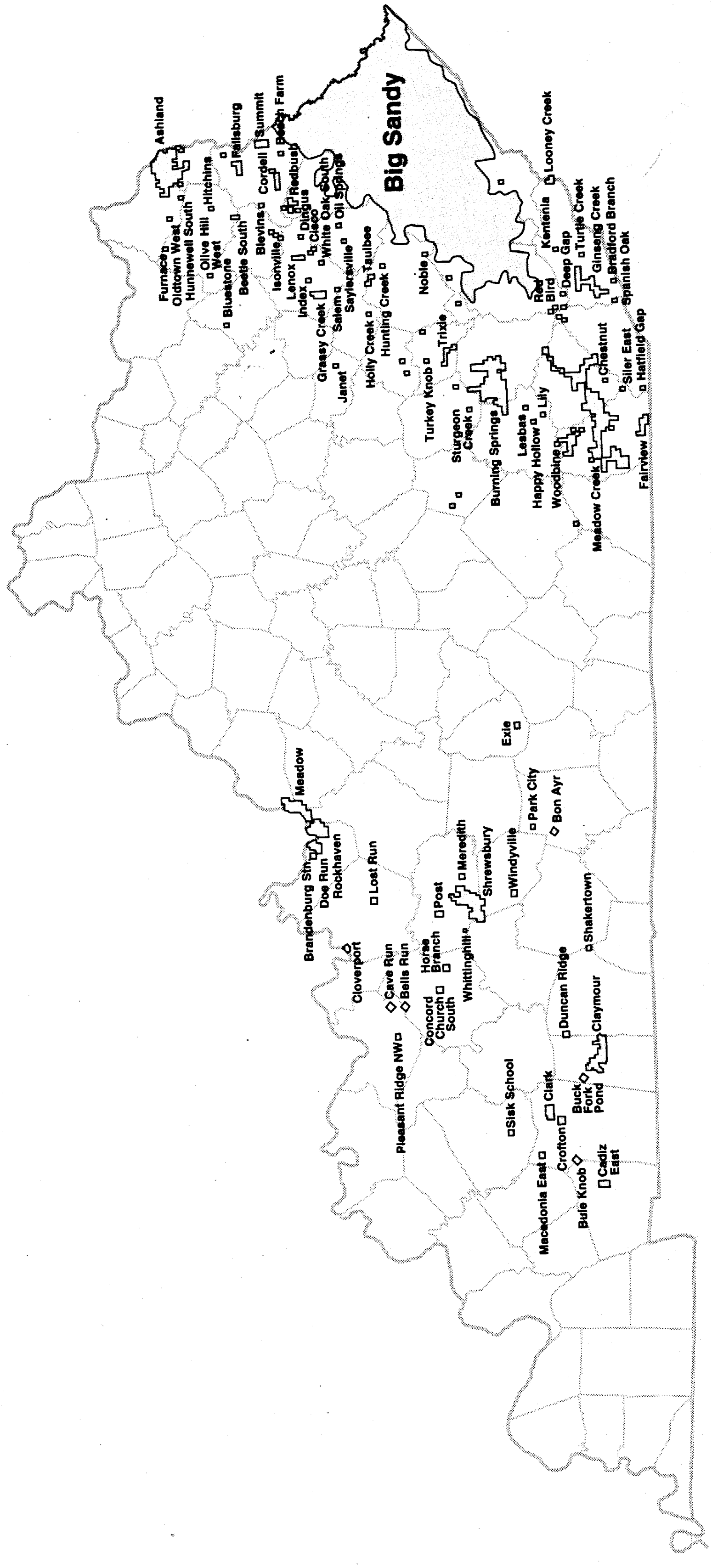

Figure 3. Selected Devonian shale gas fields of Kentucky. Field data from Wilson and Sutton (1973, 1976), Nuttall (1989a), and Hamilton-Smith and others (in press).

with more than 70 percent of that coming from Devonian shale completions (Hunter and Young, 1953). A gradual decline in drilling activity followed until the late 1970's, when rising natural gas prices, followed by Section 29 tax incentives, resulted in the drilling of over a thousand new gas wells in the Big Sandy Field area from 1981 to 1990.

High gas prices in the late 1970's also resulted in Devonian shale gas discoveries in western Kentucky. In November 1976 the Cadiz East Field in Trigg County was discovered with the completion of the Vincent and Reynolds Ira Humphries 1 well. In the Clark Field of Christian County, New Albany Shale gas was discovered as deeper pay production in January 1977 with the drilling of the Orbit Gas Company King-Badgett 1 well. The Claymour Field in Todd County was discovered in May 1979 with the drilling of the Huff Drilling Company Richard Mallory 1 well (Duffy and Schwalb, 1979). The Shrewsbury Field of Grayson, Butler, and Edmonson Counties had been discovered in 1933, but was not significantly developed until high gas prices stimulated extensive drilling in the late 1970's. In all, over 21 new Devonian shale gas fields were discovered in western Kentucky as a result of high gas prices (Table 2).

HYDROCARBON GENERATION AND MIGRATION

Introduction

Understanding the process of hydrocarbon generation and migration in the Devonian shales is important to gas exploration for two reasons. First, in order to effectively find gas, it is very helpful to know from where the gas came. Second, it is likely that the process of hydrocarbon generation in the shales had a significant effect on the fracturing that makes the shales an effective gas reservoir. If the origins of fractures in the Devonian shales are better understood, the chances of correctly locating effective reservoirs will be improved.

Oil and Gas Generation

One of the most relevant facts about the Devonian shales is that they have acted as the source rocks for the bulk of the oil in both the Illinois and Appalachian Basins. Barrows and Cluff (1984) identified the New Albany Shale as an effective source rock, and suggested that over 90 percent of the oil discovered in the Illinois Basin was derived from the Devonian shale. Chou and others (1991) and Hatch and others (1991) compared various Illinois Basin oils with bitumen extracts from the New Albany Shale and other potential source rocks and confirmed that the New Albany shale is an effective source rock for oil in the Illinois Basin. Hatch and others (1991) concluded that over 99 percent of Illinois Basin oil discovered to date was derived from the Devonian shales. In the Appalachian Basin, Cole and others (1987) analyzed reservoir oils and potential source rocks in Ohio, including the Ohio Shale and the Sunbury Shale. They concluded that oil discovered in all reservoirs younger than Silurian were derived from the Devonian and earliest Mississippian shales. Curtis (1988b) analyzed samples of the Lower Huron Member of the Ohio Shale and of the Rhinestreet Shale from wells in southern Ohio, western West Virginia, and eastern Kentucky, and concluded that these rocks were effective source rocks for oil.

Table 1.—Gas Well Drilling History, Showing Number of Gas Wells Drilled in the Big Sandy Field Area, Kentucky. Data from Frankie and Others (1986a–c), Moody and Others (1987a–b), and Nuttall (1986, 1987, 1988, 1989a, 1990, 1991).

	County					*Total Field*
Years	*Floyd*	*Martin*	*Pike*	*Letcher*	*Knott*	*Area*
1911–1920	5	1	0	0	1	7
1921–1930	582	43	26	0	43	694
1931–1940	385	161	175	0	209	930
1941–1950	276	214	602	0	308	1,400
1951–1960	48	94	691	47	205	1,085
1961–1970	90	34	210	81	95	510
1971–1980	18	40	132	68	87	345
1981–1990	147	209	561	77	169	1,163
1911–1990	1,551	796	2,397	273	1,117	6,134

Table 2.—Selected New Albany Shale and Chattanooga Shale Gas Fields of Kentucky. Data for Multipay Fields Apply Only to Devonian Shales. Data from Hamilton-Smith and Others (in press[a]). IOF=Initial Open Flow.

Field	*County*	*Number of Wells*	*Average IOF (Mcfgpd)*	*Discovery Date*
Bells Run	Ohio	1	2	1980
Bon Ayr	Barren	NA	NA	1929
Brandenburg Station	Meade	3	NA	1863
Buck Fork Pond	Todd	1	2	1983
Buie Knob	Trigg	1	6	1979
Cadiz East	Trigg	3	254	1976
Cave Run Consoli-dated	Daviess	1	NA	1938
Clark	Christian	7	84	1977
Claymour	Todd	38	23	1979
Cloverport	Breckin-ridge	NA	NA	1889
Concord Church South	Ohio	NA	NA	1971
Crofton	Christian	2	51	1979
Doe Run	Meade	65	500	1858
Duncan Ridge	Logan	1	NA	1978
Exie	Green	1	250	1979
Horse Branch	Ohio	1	1	1938
Lost Run	Breck-ridge	1	45	1939
Macedonia East	Christian	2	80	1989
Meadow	Bullitt, Jefferson	25	158	1890
Meredith	Grayson	1	20	1942
Park City	Barren	NA	NA	1937
Pleasant Ridge Northwest	Daviess	1	NA	1980
Post	Grayson	3	53	1973
Rockhaven Consoli-dated	Meade	48	486	1858
Shrewsbury Consoli-dated	Grayson, Butler, Edmonson	86	161	1939
Shakertown	Logan	1	250	1952
Sisk School	Hopkins	1	NA	1977
West Point	Hardin	NA	NA	1890
Windyville	Edmonson	1	30	1981
Whittinghill	Grayson	1	5	1980

A vitrinite reflectance map of the Devonian shales of Kentucky (Fig. 4) suggests that much of the New Albany Shale has reached a level of thermal maturity adequate for abundant oil generation; subsequent gas generation resulted from thermal cracking of generated oil in the deepest part of the basin (Barrows and Cluff, 1984; Cluff and Byrnes, 1991). Similar conclusions have been drawn for the Ohio Shale of eastern Kentucky (Curtis, 1988b; Rimmer and Cantrell, 1989). Figure 4 shows that the level of thermal maturity as measured by vitrinite reflectance in the Devonian shales was similar in both the Illinois Basin of western Kentucky and the Appalachian Basin of eastern Kentucky. This level of thermal maturity is consistent with the identification of the Devonian shales as major source rocks for oil in both the Illinois and Appalachian Basins.

The effectiveness of the Devonian shales as source rocks for oil generation is further substantiated by the widespread occurrence of free oil in pore space of Ohio Shale cores from eastern Kentucky, West Virginia, and southern Ohio (Soeder, 1986). Oil production has also been documented from the Devonian shales. Over 2,000 oil wells have been drilled and completed in the Ohio Shale near the Burning Springs Anticline of west-central West Virginia and adjacent Ohio (Watts and others, 1988). Well records indicate the production of mi-

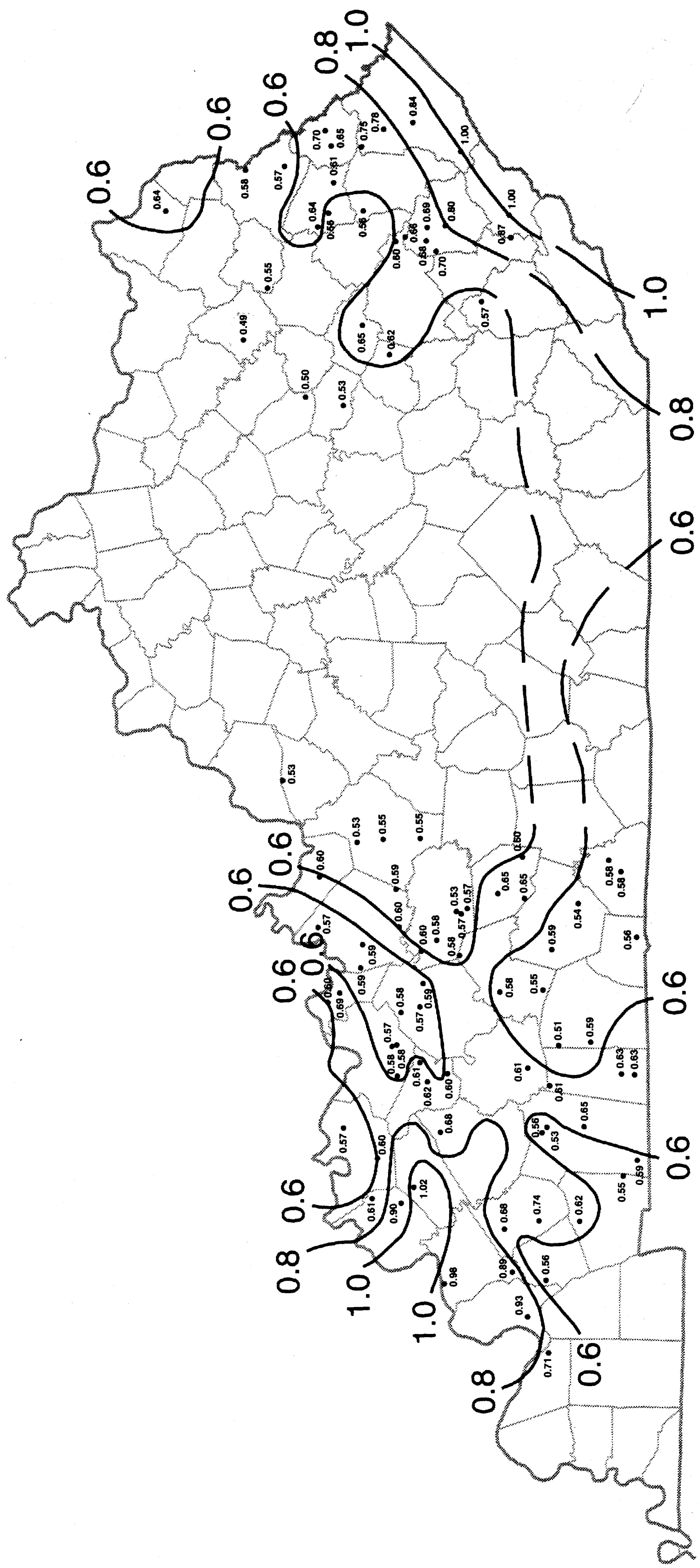

Figure 4. Vitrinite reflectance map of Devonian shales of Kentucky. Data from Barrows (1985), Curtis (1987), and Rimmer and Cantrell (1988).

nor amounts of oil from the Chattanooga Shale or the New Albany Shale in over 15 fields in western and south-central Kentucky (Nuttall, 1989a). Instances of Devonian shale oil production appear to be restricted either to areas such as the tear faults of the Burning Springs thrust sheet, where fracturing was particularly intense, or to areas near the surface, where existing fractures may be expected to be unusually open.

It has been suggested (Price and Barker, 1985; Barker, 1991) that vitrinite reflectance measurements in shales rich in amorphous kerogen may be suppressed to some degree by retention of bitumen by vitrinite particles, so that the actual level of thermal maturity in the shales is higher than suggested by direct measurement. Rimmer and Cantrell (1989) extrapolated an ideal conductive thermal gradient tied to measured vitrinite reflectance in Pennsylvanian coals, and suggested that the vitrinite reflectance of the Ohio Shale in eastern Kentucky has been suppressed by 0.3 to 0.5 percent R_0. However, Comer and others (in press) compared vitrinite reflectance values for the New Albany Shale to measurements from Rock-Eval pyrolysis, and concluded that the magnitude of any possible suppression was no greater than 0.1 to 0.2 percent R_0 (vitrinite reflectance).

The vitrinite reflectance data of the Devonian shales must be approximately correct, if only because the broad extent of the apparent "oil window" between 0.6 and 1.0 percent R_0 generally matches the history of the Devonian shales as an effective source rock for oil in both the Appalachian and Illinois Basins. Higher thermal maturities are not required in order to generate gas. In addition, the assumption by Rimmer and Cantrell (1989) of an ideal conductive geothermal gradient is not a good one. Evidence of hydrothermal mineralization and oil and gas migration indicates large-scale fluid movement that must have been accompanied by convective heat transport.

Generation of oil from the Devonian shales does not preclude the simultaneous generation of associated gas. The volume of associated gas generation depends not only on the level of thermal maturity, but also on the kerogen type, in particular on the degree of admixture of kerogen of humic origins. Identifiable macerals in the Devonian shales include both humic and algal types, indicating a mixture of kerogens. Kerogen in the Devonian shales has been generally identified as Type II, which is considered effective for the generation of oil. However, the bulk of kerogen in the Devonian shales is amorphous, and of enigmatic origins. Powell and others (1982, p. 434) found no consistent relationship of amorphous organic matter either to hydrogen-carbon ratio or pristine-phytane ratio, and concluded that "amorphous organic matter can be either of algal/microbial or terrestrial origin." Hutton (1991) pointed out that classification of kerogen into Types I, II, and III by the results of bulk elemental analysis as shown on a van Krevelen diagram represents the average chemical composition of the kerogen maceral assemblage, rather than characteristics of any single kerogen type. With specific reference to the Ohio Shale, he suggested that the Type II bulk chemical composition may result from a mixture of Type I tasmanitid telalginite and amorphous bituminite of Type III affinities. Robl and others (1991) suggested that New Albany Shale amorphous bituminite may be derived in part from bacterial degradation of humic vitrinite.

Assuming that kerogen of humic origins comprises a significant part of the amorphous organic matter in Devonian shales, then a significant degree of associated gas generation may be expected within the oil window. Robert (1980) cited data indicating substantial generation of gas from humic organic matter beginning at a vitrinite reflectance level of 0.70 percent. Snowdon and Powell (1982) provided an example of significant gas generation from Type III kerogen at maturity levels as low as 0.6 percent R_0. Pyrolysis experiments by Duppenbecker and others (1991, Fig. 2) show a variation of gas-oil ratio with maturity indicative of an early thermal phase of gas generation from Type II kerogen. In an empirical study, Claypool and others (1978) estimated that 13 percent of the organic matter in the Ohio Shale of Martin County, Kentucky, had been converted to gas, at a maximum maturity level of 0.6 to 0.8 percent R_0, as shown in Figure 4.

Table 3 shows that gases produced from the Devonian shales of Kentucky are typically not entirely methane, but contain variable amounts of methane and heavier hydrocarbons, up to 29 mole percent. Carbon isotope data reviewed by Comer and others (in press) ranged between –41.7 and –57.0 per mil $\delta^{13}C$ for methane produced from the New Albany Shale. Claypool and others (1978) showed a similar range of carbon isotope values for methane produced from the Ohio Shale. These ranges of heavier hydrocarbon and carbon isotope content were used by Schoell (1983, p. 2225) to identify such methane as "thermogenic associated" in origin, derived by thermal modification of kerogen accompanied by the abundant generation of oil

Table 3.—Hydrocarbon Composition of Natural Gas Produced from New Albany Shale and Ohio Shale of Kentucky. Data from Claypool and Others (1978) and KGS Files.

County	*Field*	*Location*	*C1/(C1–C5)*
Trigg	Cadiz East	Hoffman Major 1	0.99
Christian	Clark	Orbit King-Badgett 1	0.97
Grayson	Shrewsbury	Equitable Likens 1	0.88
Boyd	Ashland		0.90
Lawrence	Cordell	Little Blaine Creek	0.89
Martin	Big Sandy	E. B. Paine	0.79
Martin	Big Sandy	Tomahawk	0.82
Floyd	Big Sandy	Puncheon	0.71
Pike	Big Sandy		0.77
Pike	Big Sandy	Johns Creek	0.77
Pike	Big Sandy	Johns Creek	0.78
Knott	Big Sandy	Puncheon	0.79
Perry	Big Sandy	Carey	0.81

Migration and Compositional Fractionation

Bethke and others (1991) showed that long-distance migration of petroleum was significant in the Illinois Basin, mainly through a carrier zone immediately beneath the New Albany Shale. Long-distance migration has also been suggested for the Appalachian Basin (Oliver, 1986; Haynes and Kesler, 1989). An understanding of the significance of migration leads to the conclusion that the presence and nature of hydrocarbons in a well cannot be taken as an indicator of conditions of oil and gas generation at that specific location. More practically, petroleum migration is a process that needs to be well understood in order to locate oil and gas accumulations.

Gusso (1954) first suggested separation of oil and gas during long-distance hydrocarbon migration, citing geological evidence from the Alberta and Anadarko Basins. This interpretation was subsequently used to explain oil and gas accumulations in several different provinces (Gussow, 1955; Walters, 1958; Gill, 1979; Schowalter, 1979). Silverman (1965) discussed segregation of oil and gas in terms of phase relationships at different pressure and temperature conditions. Thompson (1988, p. 239) described separation of oil and gas condensate during migration with examples from the Tertiary of the Gulf Coast:

> Relative permeability to gas can greatly exceed that to oil. Values which are higher by a factor of approximately ten can occur, should oil saturation be reduced too 50% …. This differential is compounded with that due to differences in the viscosity of oil and gas. Typically, gas is one hundred-fold less viscous than oil under representative reservoir conditions. Using these values, the flow rate of gas would exceed that of oil by one thousand-fold.

Thompson (1988, p. 237) proposed the term "evaporative fractionation" to describe the compositional segregation of oil and gas resulting from the pressure decline accompanying migration. He described the characteristic composition of oils resulting from evaporative fractionation as having a dominant normal alkane of C_{10} to C_{20}, rather than the usual C_5 to C_6. Figure 5 shows chromatographs of hydrocarbon extracts from the Ohio Shale of West Virginia, interpreted by Curtis (1988a) as representative of both in-place and migrated hydrocarbons. The chromatograph of the in-place hydrocarbon of Curtis (1988a) closely resembles the pattern suggested by Thompson (1988) as indicative of evaporative fractionation. In contrast, the migrated hydrocarbon of Figure 5 is substantially enriched in natural gas.

Compositional fractionation between gas and oil may be expected to be even more significant in low-permeability organic-rich shales than in the conventional reservoirs considered by Gussow (1954) and Thompson (1988). Leythaeuser and others (1982) obtained evidence of active transport of natural gas through organic-rich shales, volumetrically significant enough to result in accumulations of commercial significance at relatively low thermal-maturity levels. The gas transport was assumed to be a combination of desorption, molecular diffusion, and Darcy flow through local open pore space. Experiments by Kroos (1988) showed that both desorption and diffusion were of significance to gas transport through shales, with desorption becoming more dominant with increasing thermal maturity. Leythaeuser and Poelchau (1991, p. 44) interpreted release of natural gas from Type III kerogen-rich shales as being caused by the evaporative fractionation process of Thompson (1988), and characterized the process as "fractionation-controlled expulsion due to gaseous solution occurring at moderate maturity levels."

Unlike conventional reservoirs, Devonian shales include significant volumes of hydrocarbons adsorbed on clay and kerogen surfaces in addition to the hydrocarbons included in the open pore space (Frost and Thomas, 1978; Thomas and Frost, 1978; Schettler and Parmely, 1987b; Schettler and others, 1988). The volume of natural gas stored by adsorption may be much greater than that available in the open pore space, possibly by a factor of 7 to 20 (Bumb and McKee, 1988).

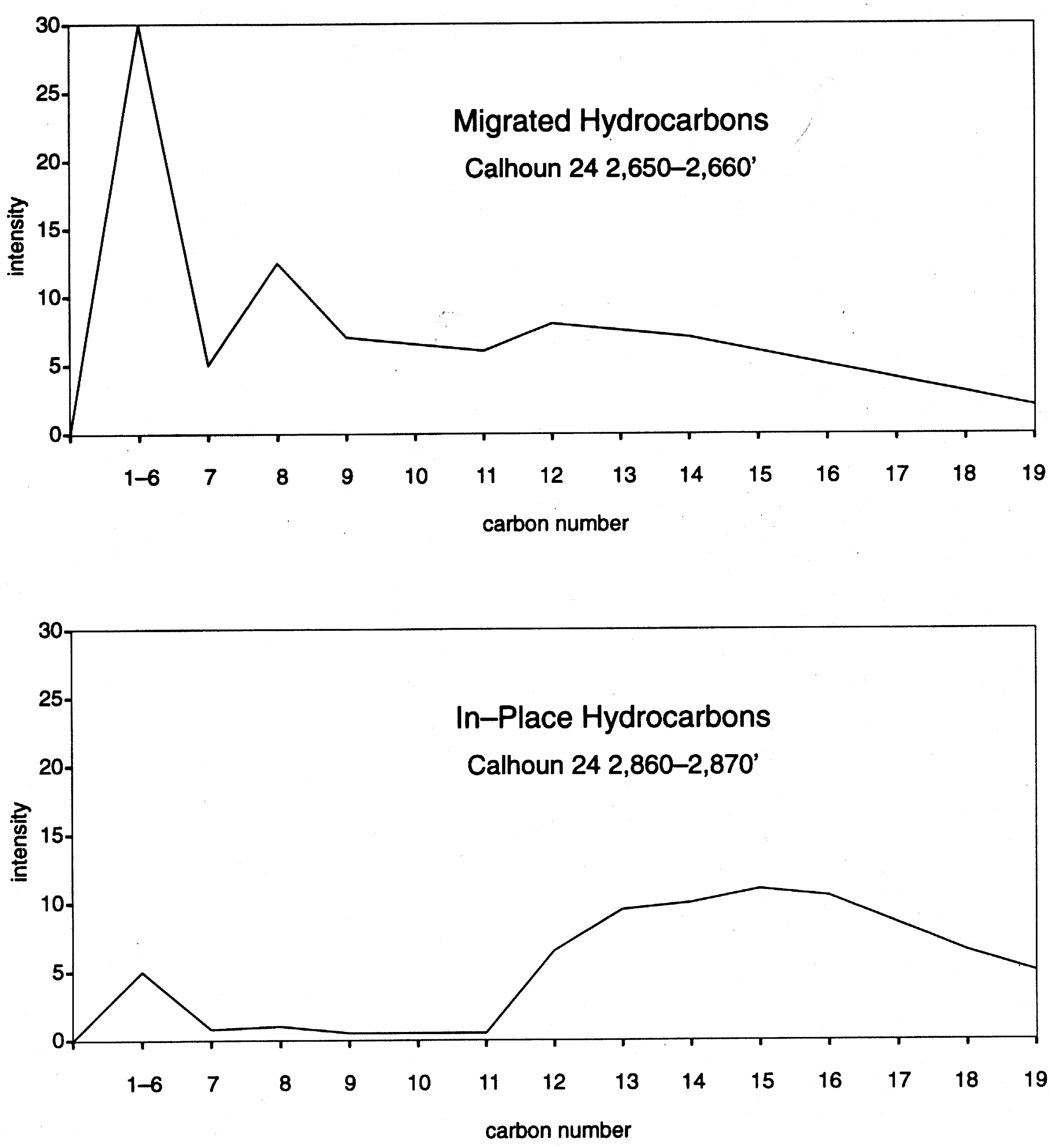

Figure 5. Composition of migrated and in-place hydrocarbons, Ohio Shale, West Virginia. Modified after Curtis (1988a).

The release of gas from Devonian shales due to desorption is strongly dependent on composition. Methane is a relatively non-polar molecule compared to ethane or heavier hydrocarbons, and as such is relatively easily desorbed (Schettler and Parmely, 1987a). Studies of the composition of gas released from a core of the New Albany Shale showed a 60 percent decrease in methane concentration with time, and a corresponding increases in the concentrations of methane, propane, and n-butane (Meinschein, 1981).

Compositional fractionation accompanying hydrocarbon migration explains the predominant production of thermogenic-associated gas from the Devonian shales of Kentucky, despite the shales being oil rich and having generated large volumes of oil. One specific result of the variable extent of compositional fractionation is that gases produced from the Devonian shales are typically not uniform in hydrocarbon composition, but contain variable amounts of ethane and heavier hydrocarbons, ranging from as little as 1 percent to as much as 29 percent (Table 3). Compositional fractionation can also result in the composition of natural gas produced from a shale-rich reservoir becoming more oil rich as desorption continues (Schettler and Parmely, 1987a). This process explains the observation of Avila (1976) that the Btu content of Ohio Shale gas from eastern Kentucky increases with time.

FRACTURED DEVONIAN SHALE RESERVOIRS

Fracturing has been recognized for many years as essential to gas production from the Devonian shales (Lafferty, 1935; Thomas, 1951; Sorgenfrei, 1952; Hunter and Young, 1953). The low level of matrix permeability in the Devonian shales requires that natural fractures be present in order for the shale to act as an effective gas reservoir. Matrix permeability values in a core of the New Albany Shale from Clark County, Indiana, varied from 0.0000025 to 1.9 millidarcies, with a geometric average of 0.0014 millidarcies (Zielinski and Moteff, 1980). Matrix permeability values at native state fluid saturations in a core of the Ohio Shale from Breathitt County, Kentucky, were all less than 0.00001 millidarcies (Luffel and Guidry, 1989).

Fractures have often been described from cores and outcrops of the Devonian shales (Kulander and others, 1977; Kalyoncu and others, 1979; Miller and Johnson, 1979; Ault, 1990). Fractures in the shales have also been described from specialized borehole logs such as the formation microscanner (Guidry and others, 1991). Fractures may also be interpreted from conventional geophysical logs. In the example shown in Figure 6, the vertical extent of the new Albany Shale is indicated by the relatively high gamma ray and low density log readings between 3,820 and 4,055 feet. Gas entry into the wellbore is suggested by the temperature anomaly at 3,940 feet. A gas-filled fracture at 3,940 feet is suggested by the unusually high neutron porosity reading at that depth. This well had an initial open flow of 42 Mcfgpd from the New Albany Shale after stimulation, and was completed as a Cypress oil well farther uphole.

Many different types of fractures have been recognized in the Devonian shales, some of which appear to contribute to reservoir permeability, while others do not (Kulander and others, 1977; Vinopal and others, 1979; Lowry and others, 1989a). I suggest that Devonian shale gas reservoirs in Kentucky include two major types of effective reservoir fractures, with distinct genetic characteristics. These two types are a simple fault-related variety, and a second more complex type that results both from structural flexure and overpressuring. An understanding of these different fracture types can result in an improved exploration strategy, directed more clearly toward the location of fractured shale gas reservoirs with maximum economic potential.

Fractures Adjacent to Faults

A commonly recognized type of fractured reservoir in the Devonian shales is closely associated with major faults. In the Devonian shales, faults were most commonly propagated upward from older faults in the basement, reactivated during the Alleghenian Orogeny (Shumaker, 1986; Nelson, 1991). An example of such a fault in western West Virginia is shown in Figure 7. The Warfield Fault has a large normal offset at the near-basement level, and locally constitutes the southern boundary of the Rome Trough. Reverse offset at the Onondaga level shows that the fault was reactivated as a high-angle thrust fault at some time after the Middle Devonian, during either the second phase of the Acadian or during the Alleghenian Orogeny (Lowry and others, 1989a; Hamilton-Smith, 1993). Many of these major faults reach the surface, particularly in western Kentucky, and are documented by field mapping (McDowell and others, 1981).

Such fault-related reservoirs should be highly fractured, but may not be well sealed. If the fault extends to the surface, it is likely that no effective seal exists on the fracture system, and that any gas encountered will be in the process of migrating to the surface from deeper within the basin. Such reservoirs are often revealed by prominent surface seeps, such as the gas observed bubbling out of the Ohio River in 1870 between Meade County, Kentucky, and Harrison County, Indiana (Collett, 1879). If the fault does not extend to the surface, it is still possible that no effective seal exists in the Devonian shale sequence, so that gas will migrate through the fractured shales, and will accumulate in reservoirs at shallower levels. In the area of western West Virginia evaluated by Lowry and others (1989b), fractured Devonian shales associated with the Warfield Fault were not productive, but a monocline developed in the Berea Sandstone above the fault had trapped significant volumes of gas.

The fractures of such fault-related reservoirs may be relatively poorly sealed, but productive at the low and variable rates of actively migrating gas. The fracture system will not be uniformly saturated with gas,

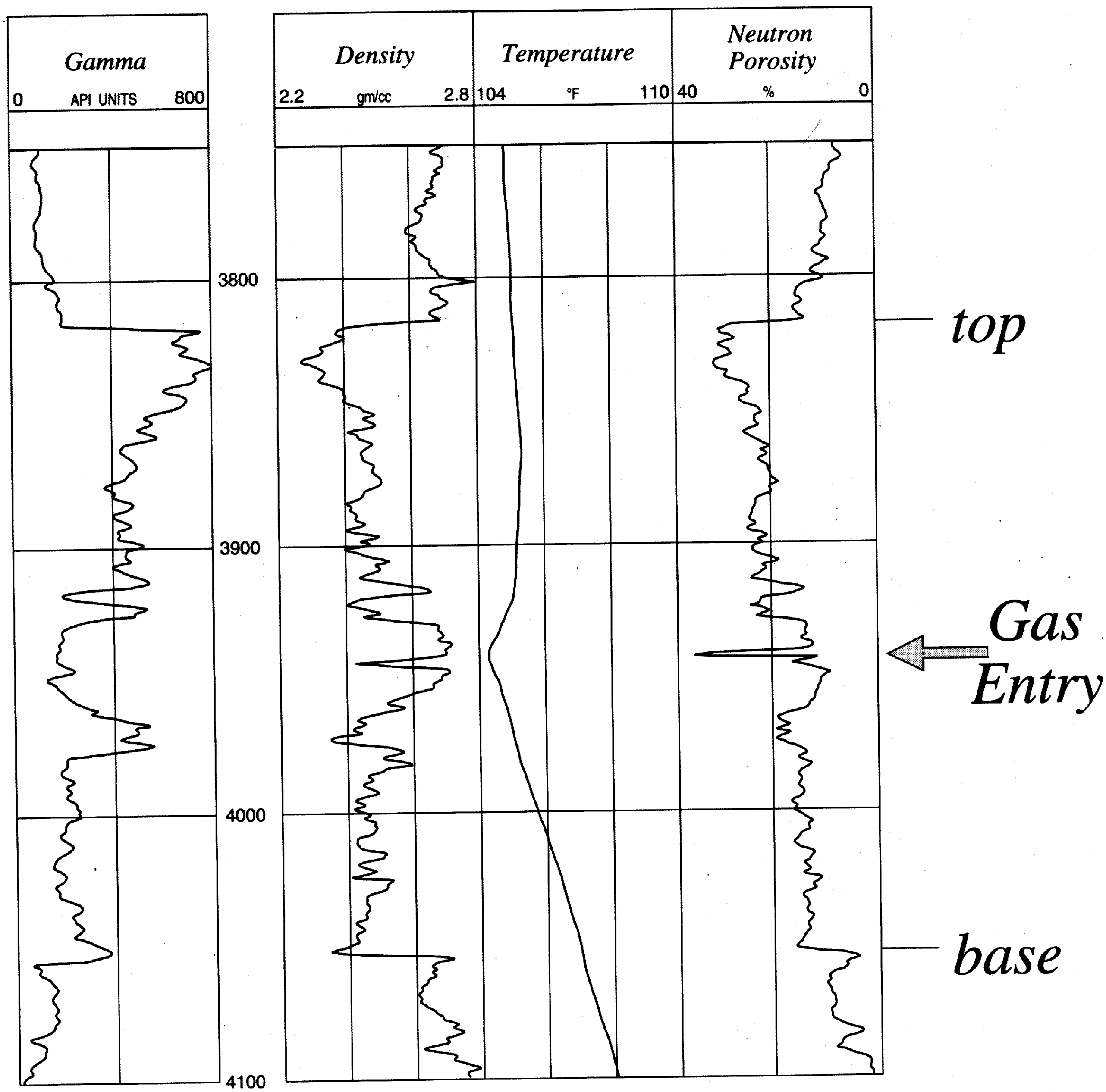

Figure 6. New Albany Shale fractured gas reservoir, western Kentucky. Geophysical logs of Equitable Resources K10001 Hopkins in Carter coordinate section 16-K-27, Hopkins County.

depending on the flow paths established by gas migration. Wells located within flow paths in the fracture system may have moderate flow rates; wells located within the fracture system away from flow paths would have low flow rates. Initial open-flow rates in such reservoirs may be relatively low, but as the reservoir is constantly recharged through migration, production at low rates may go on indefinitely. A suggested example of a Devonian shale gas field with such a fault-related fracture system is the Clark Field of Christian County in western Kentucky, developed along a branch of the Pennyrile Fault. Figure 8 is a histogram of initial open flows from seven field wells completed in the New Albany Shale. The distribution is highly skewed, with a peak at an initial flow rate less than 120 Mcfgpd, and maximum initial flow rate less than 480 Mcfgpd.

Fractures Associated with Flexures

Another process commonly resulting in fracturing in hydrocarbon reservoirs is folding (Nelson, 1985). The formation of folds of various types may be highly variable and complex. One of the most common fracture system types associated with the early growth of flexure-slip folds is shown in Figure 9. Fractures resulting from the principal stress parallel to dip develop early in the history of a fold, and are characterized by large-scale simple fracture patterns, often consisting of the one associated fracture type (extension, shear, or conjugate-shear) that develops first under the prevailing stress conditions (Stearns and Friedman, 1972). One fold type of particular interest consists of "drape folds" developed over reactivated basement faults (Stearns, 1971). Vertical displacement, of either normal or high-angle reverse sense, produces flexures in overlying strata of comparable magnitude (McConnell, 1986). In contrast, strike-slip displacement on a basement fault may result in a complex composite flexure of relatively low relief (Sylvester, 1988), such as that associated with Trenton reservoirs of the Michigan Basin (Prouty, 1988).

Fractured reservoirs in the Devonian shales are commonly associated with flexures or monoclinal folds. Shumaker (1987, p. 133) noted that "highest production follows the flanks of very low folds above Cambrian-age basement faults." Although these flexures are commonly developed over deeply buried basement faults, the fact that the faults have not propagated to the surface or even into the shale section improves the chances of preservation of an effective reservoir seal. A flexure developed in the Berea Sandstone above the tip of the buried Warfield Fault is shown in Figure 7. A suggested example of a Devonian shale gas field with flexure-related fracturing is the Shrewsbury Field of Grayson, Butler, and Edmonson Counties of western Kentucky. Figure 10 is a histogram of initial open-flow values from 77 Shrewsbury Field wells completed in the New Albany Shale. The distribution is skewed, but not as much as the distribution of Figure 8. The peak value for the Shrewsbury Field between 120 and 240 Mcfgpd is greater than that for the Clark Field. The maximum initial flow of as much as 600 Mcfgpd is also greater than the figure of 480 Mcfgpd for the Clark Field.

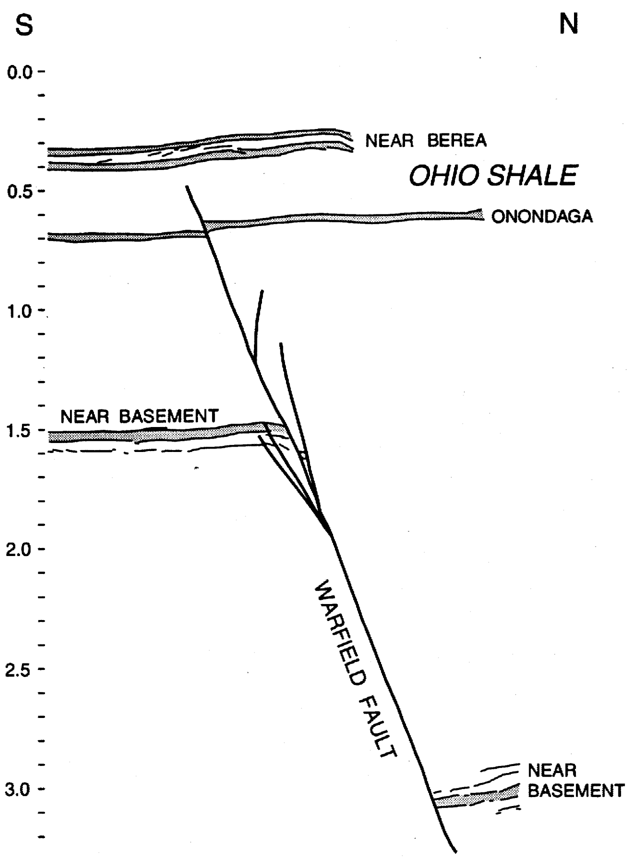

Figure 7. Interpreted seismic section across Warfield Fault, western West Virginia. Vertical scale is two-way time in seconds. Data courtesy of CNG Development Company. After Lowry and others (1989b, Fig. 10).

Devonian shale production associated with low-amplitude structural flexures has been described from numerous localities, including the Cottageville and Midway-Extra Fields of West Virginia (Shumaker, 1987), the Big Sandy Field of eastern Kentucky (Negus-de Wys, 1979), and the Harrison County fields of southern Indiana (Sorgenfrei, 1952). In the case of the Cottageville Field, three-dimensional seismic interpretation permitted identification of the basement faults and their relationship to overlying flexures (Sundheimer, 1978; Wilson and Swimm, 1985). Devonian shale reservoirs related to flexures should be well sealed. Intensity of fracturing would be greatest in the harder, more brittle shale lithologies, with the more plastic shale beds acting as seals. Fracturing in these reservoirs would also be enhanced by increasing the amplitude and the curvature of the flexure. However, flexures associated with gas production from the Devonian shales are frequently so subtle as to be difficult to recognize. It would seem that the amplitudes and the curvatures of flexures in the Devonian shales are so small as to preclude fracturing from structural deformation alone.

Overpressuring and Fracturing

Devonian shale reservoirs are not overpressured at the present time, but some 250 million years ago, at the time of maximum burial of the Devonian shales, when hydrocarbon generation was actively taking place (Cole and others, 1987), overpressuring was probably substantial and very widespread.

For the purposes of discussion, pore pressure gradients will be compared either to a nominal hydrostatic gradient of 0.45 pound per square inch per foot (psi/ft.)

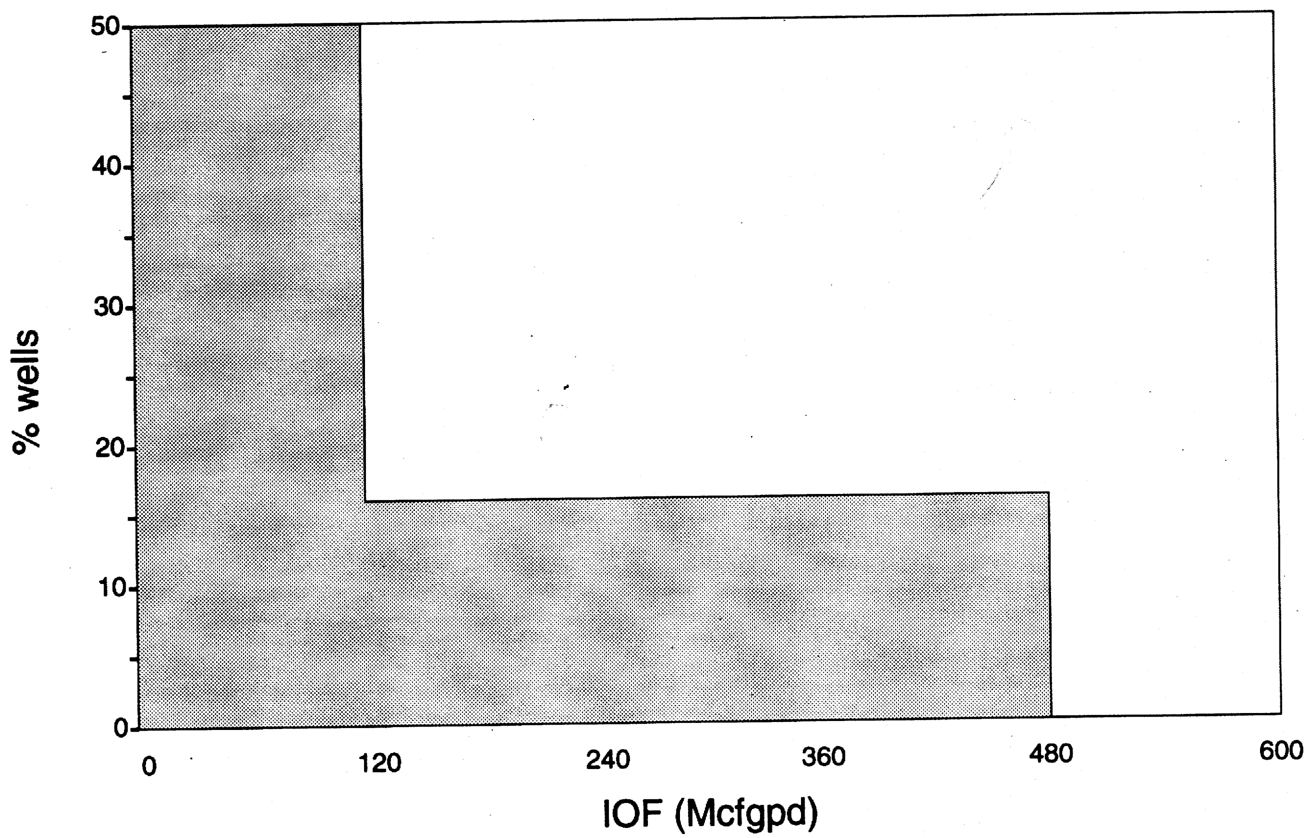

Figure 8. Initial open flow (IOF) histogram, New Albany Shale, Clark Field, western Kentucky. Initial open flow measured in thousands of cubic feet of gas per day (Mcfgpd).

or to a nominal lithostatic gradient of 1.0 psi/ft. Hydrostatic gradients in reservoirs range from a maximum of nearly 0.5 psi/ft. for brines to 0.433 psi/ft. for fresh water at 60ºF, depending on the pressure, temperature, and salinity of the water (Craft and Hawkins, 1959). Lithostatic or overburden pressure results from the combined weight of the formation rock and fluids (Dake, 1978).

Increasing the pressure of the fluids contained within the pores of a rock may either result directly in fracturing, or may contribute to the development of fracturing by other means. If the local differential stress is negligible and the pore pressure exceeds the lithostatic gradient, then extension fracturing will result. The fracture

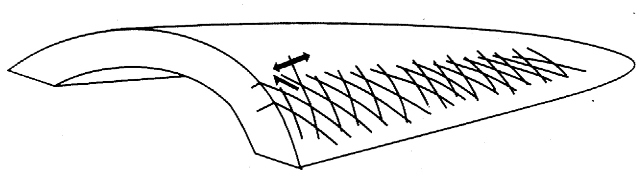

Figure 9. Schematic drawing of early fractures in a flexure-slip fold. Arrows indicate extension and shear fractures. Modified after Stearns and Friedman (1972).

system orientation developed under these conditions would be expected to be controlled by rock fabric, or would be distributed randomly if no pronounced rock fabric is present (Lorenz and others, 1991).

The more general consequence of overpressuring is a contribution to fracturing by other means. If the local differential stress is large, then the overpressuring required for failure will be relatively small, and either extension or shear fracturing may take place (Meissner, 1978; Watts, 1983). Lorenz and others (1991) have suggested that overpressuring in combination with regional patterns of differential stress are responsible for the origin of regional joint systems. Dean and Overbey (1980, p. 7) concluded that "the natural fractures essential to production from Devonian shale are predominantly joints that originated as natural hydraulic fractures, induced by excessive fluid pore pressure that built up at various times during its post-depositional history." In particular, the contribution of overpressuring may explain the tendency of fractured reservoirs to be developed in the Devonian shales along relatively low-amplitude and low-curvature flexures.

Overpressuring in sedimentary rocks may result from

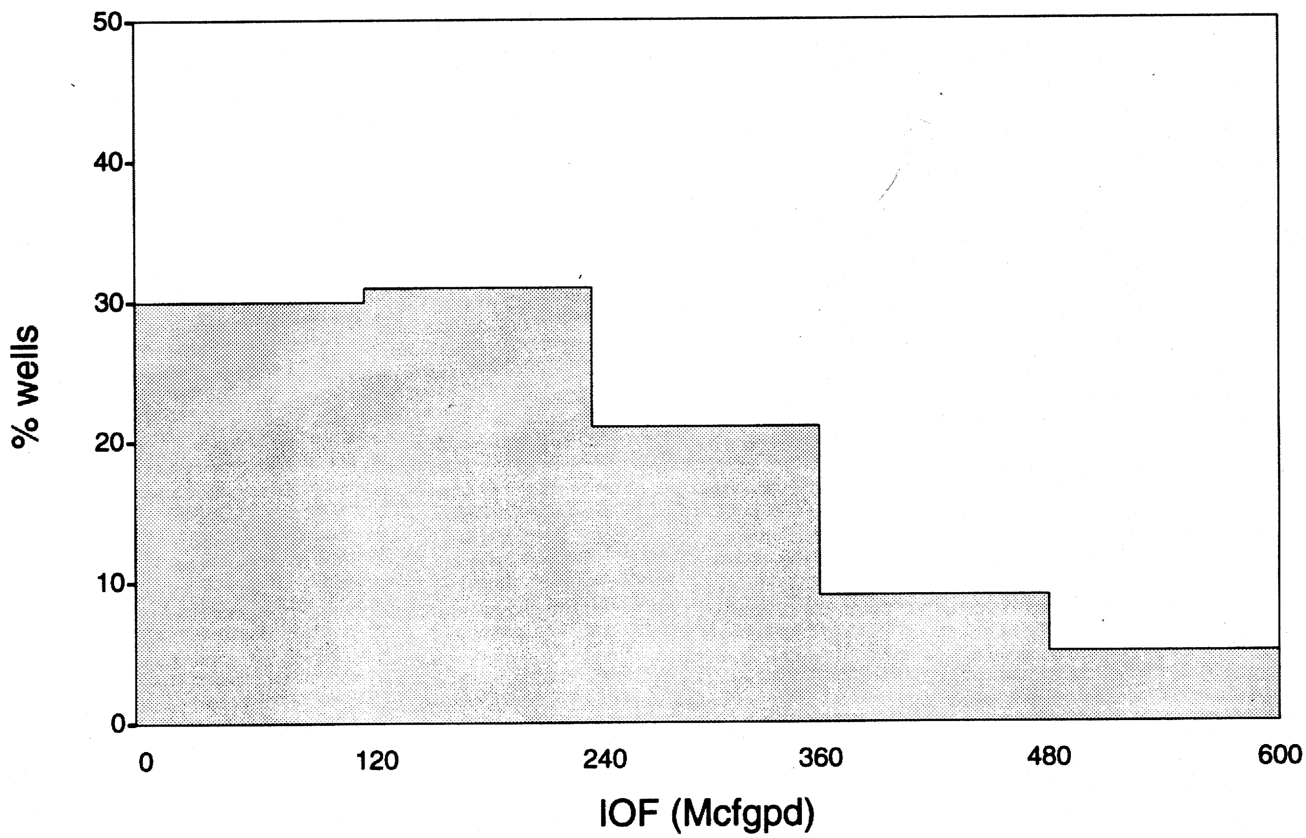

Figure 10. Initial open flow (IOF) histogram, New Albany Shale, Shrewsbury Field, western Kentucky. Initial open flow measured in thousands of cubic feet of gas per day (Mcfgpd).

a variety of different mechanisms. Of particular interest to gas exploration in the Devonian shales is the overpressuring that would be expected to accompany hydrocarbon generation. Braun and Burnham (1990) suggested that significant overpressuring begins during oil generation, because pore fluids are produced faster than they can be expelled from the source rock. Spencer (1987) observed that in deep Rocky Mountain basins, regionally overpressured rocks generally had minimum vitrinite reflectance values of 0.6 percent in oil-prone source beds, and 0.7 percent in gas-prone source beds. These observations suggest that overpressuring develops early in the oil window, and that kerogen type is not a decisive factor. Barker (1990) showed that in a closed system, cracking (subjecting to pryolysis) of as little as 1 percent of the generated oil to gas would be sufficient to raise the reservoir pressure from hydrostatic to lithostatic, resulting in fracturing.

Fracturing associated with hydrocarbon generation has been documented in many source rocks throughout the world, and has even been claimed as a fundamental mechanism of primary oil migration (Duppenbecker and others, 1991). Comer and Hinch (1987) described microfracturing associated with petroleum expulsion and early migration processes in Devonian shales from Oklahoma and Arkansas.

Reservoir fracturing resulting from the combination of differential stress and overpressuring due to hydrocarbon generation is particularly well documented for the Altamont-Bluebell Field of the Uinta Basin and for the Antelope Field of the Williston Basin. The case of the Altamont-Bluebell Field illustrates the formation of fractures by the combination of regional stress and overpressuring proposed by Lorenz and others (1991). In the Antelope Field, fracturing resulted from the combination of overpressuring due to hydrocarbon generation and differential stress due to local flexure.

In the Altamont-Bluebell Field, fractured reservoir rocks are closely associated with organic-rich lacustrine shales of the Green River Formation, the most prolific source rock of the Uinta Basin. A set of regional joints was developed at the time of maximum burial of the reservoir section (Narr and Currie, 1982). Maximum pressure gradients in the reservoir are in excess of 0.8

psi/ft., or 178 percent of hydrostatic pressure (Lucas and Drexler, 1975). Hydrocarbon generation profiles in oil field wells closely match overpressure curves (Fig. 11), which suggests that the overpressuring is a result of hydrocarbon generation, and contributed significantly to joint formation (Sweeney and others, 1987).

The fractured reservoir of the Antelope Field is closely associated with organic-rich marine shales of the Bakken Formation, one of the most important source rocks of the Williston Basin (Dow, 1974). The field structure consists of a northwest–southeast-trending asymmetric anticline, interpreted as a forced fold resulting from reactivation of a major basement fault (Thomas, 1974; Brown, 1978; Meissner, 1978). The reservoir pressure gradient in the field is 0.73 psi/ft., or 162 percent of hydrostatic pressure (Spencer, 1987), and is closely associated with high temperatures and the active generation of oil (Meissner, 1978; Webster, 1987). Reservoir fracturing and field oil production do not occur at the crest of the structure, but are limited to the zone of maximum curvature immediately to the east (Murray,

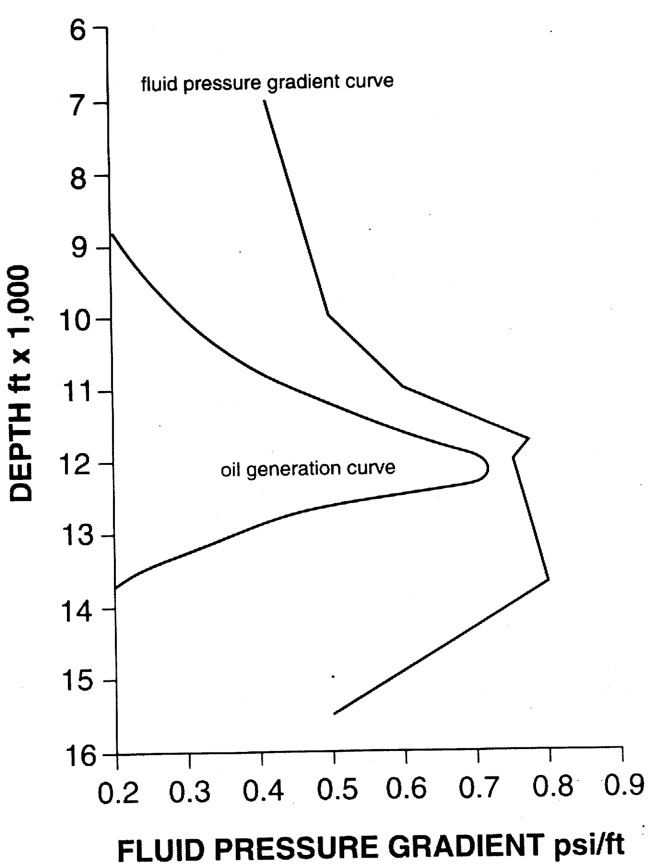

Figure 11. Oil generation and overpressuring, Altamont-Bluebell Field, Utah. Data from Shell Oil 1-11B4 Brotherson well. Modified after Sweeney and others (1987, Fig. 13).

1968). It would seem that in the Antelope Field, overpressuring due to hydrocarbon generation has significantly contributed to fracturing in the zone of maximum curvature of the fold.

Examples of fracturing caused entirely by overpressuring are less common, but they do exist. An example of such fracturing may be the irregular to bedding-parallel fractures of the organic-rich Bazhenov Formation of the Salym Field of the West Siberian Basin, where pore pressures are significantly greater than hydrostatic, and locally approach the lithostatic pressure gradient (Dobrynin and Martynov, 1980; Abdullin, 1981; Dorofeyeva, 1981; Khalimov and Melik-Pashayev, 1981; Skorobogatov, 1981; Nesterov and others, 1982; Korofeyeva and others, 1983; Filina and others, 1987; Gurari, 1987). Horizontal extension fractures are also well documented from the organic-rich Posidonia Shale of Germany (Leythaeuser and others, 1988; Littke and others, 1988). These fractures are absent from adjacent organic-poor mudstones, occur in the Posidonia Shale only in thermally mature areas with vitrinite reflectance greater than 0.68 percent R_0, and are attributed to overpressuring resulting from hydrocarbon generation.

Kulander and others (1977, p. 25–26) described horizontal extension fractures in the Ohio Shale of the Big Sandy Field of eastern Kentucky: “Calcite fibers always grow perpendicular to the sub-horizontal fracture walls, indicating the direction of separation and principal tension to be vertical. This configuration implies the presence of abnormal fluid pressure within the shale at the time of crack inception and separation.” An example of such a fracture is shown in Figure 12. The appearance of these horizontal fractures is very similar to those of the Posidonia Shale documented by Leythaeuser and others (1988) and Littke and others (1988). Such horizontal fractures may be easily confused with thin siltstone laminae, but can be recognized petrographically and nave been identified in several cores from the Big Sandy Field (Lowry, 1992, personal communication).

The formation of such horizontal extension fractures strongly suggests that the pore pressure in the Ohio Shale of the Big Sandy Field locally exceeded the lithostatic gradient at some time in the past.

Paleoreservoir Pressure Calculation

Gas production information indicates that Devonian shale gas reservoirs are significantly underpressured at this time (Table 4). Production practices have reduced the reservoir pressure, but even before production, average reservoir pressure varied from about 46 percent of hydrostatic pressure in the Big Sandy Field of eastern Kentucky to approximately 53 percent of hydrostatic

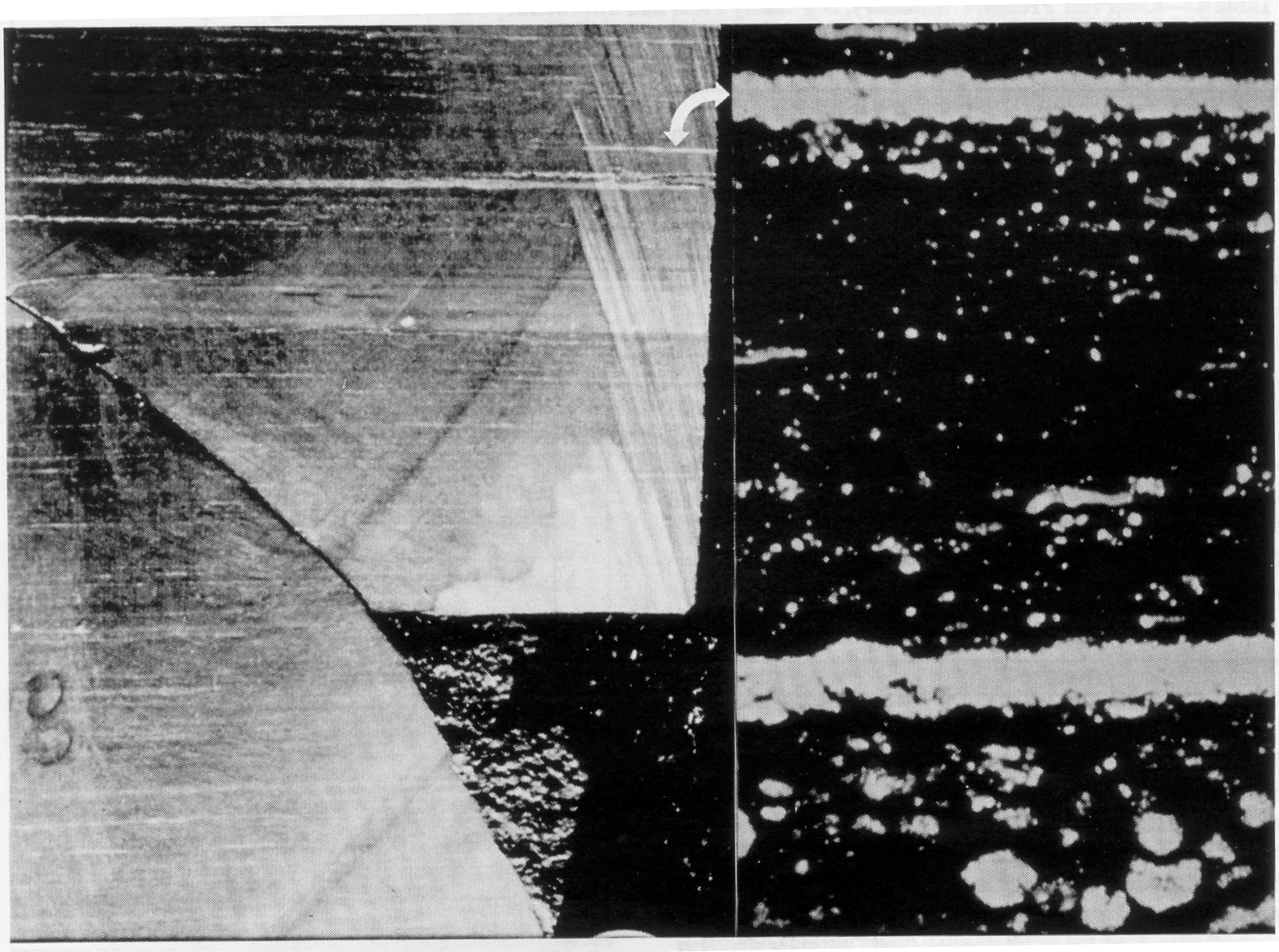

Figure 12. Horizontal extension fractures, Ohio Shale, Big Sandy Field, eastern Kentucky. Core photograph to left, and corresponding photomicrograph to right (arrow indicates same fracture on photograph and photomicrograph). Core is from the Ashland Exploration 91 E. J. Evans well and is approximately 3.5 inches in diameter. Courtesy of K&A Energy Consultants and Gas Research Institute.

pressure in the Shrewsbury Field of western Kentucky. Several processes could have contributed to loss of reservoir pressure, including increase of reservoir volume due to fracture dilation, and loss of pressure seal due to penetration by a reactivated fault. If we assume that dilation was a relatively minor effect, and consider only fields where reservoir seals maintained their integrity, then the most important process resulting in reservoir pressure decline was probably uplift and erosion in the 250 million years following the Alleghenian Orogeny.

Barker (1972) considered a pressure-temperature-density diagram for water and showed that, for any geothermal gradient greater than about 15ºC per kilometer (0.82ºF per 100 feet), the pressure in an isolated volume of water increases with increasing temperature more rapidly than the pressure in surrounding non-isolated fluids. This effect was called "aquathermal pressuring." Barker (1972, p. 2068) also considered the effect of temperature decrease:

> If a normally pressured system becomes isolated and is then subjected to a decrease in temperature (for example, if erosion removes considerable quantities of overburden) the pressure in the system will fall below the external hydrostatic pressure. This may have happened in some areas which now have abnormally low pressures

This observation suggests a procedure for back-calculation of the pressure that occurred in the Devonian shale reservoir prior to erosion, uplift, and cooling, if the magnitudes of the eroded overburden and of the aquathermal pressure gradient are known. This calculation is not suggested as an accurate depiction of reality, as it neglects the effects of hydrocarbon generation,

Table 4.—Reservoir Pressure Summary, Big Sandy Field and Shrewsbury Field, Kentucky. Big Sandy Field Data from Hunter and Young (1953) and Kuuskraa and Others (1985). Shrewsbury Field Data from KGS Files. Pressure Measured in Pounds per Square Inch (Gauge) (psig).

Field	*Location*	*Pressure (psig)*	*Depth (ft.)*	*Hydrostatic (psig)*	*% of Hydrostatic*
Big Sandy	Martin County (1980)	375	3,038	1,367	27
	Pike County (1980)	590	3,878	1,745	34
	Pike County (1920)	800	3,878	1,745	46
Shrewsbury	Equitable Haynes 1	420	1,612	725	58
	Equitable Knight 1	401	1,572	707	57
	Equitable Tomes 1	410	1,594	717	57
	Equitable Bowles 1	300	1,849	832	36
	Equitable Woosley 1	460	1,603	721	64
	Equitable Dotson 1	476	1,863	838	57
	Equitable Burge 1	350	1,863	838	42
	Equitable Moeller 4	350	1,755	790	44
	Equitable Burge 2	476	1,869	841	57
	Equitable Huff 1	454	1,663	748	61
	Equitable Meyer 1	410	1,625	731	56
	Equitable Warren 1	400	1,600	720	56
	Equitable Wells 1	411	1,623	730	56
	Average	409	1,699	765	53

but it illustrates the substantial degree of overpressuring that has affected the Devonian shales in the past.

Magara (1981) calculated the theoretical aquathermal pressure gradient to be 1.8 psi/ft., assuming a geothermal gradient of 1.4ºF per 100 feet (25.5ºC per kilometer). Using shale compaction data calibrated to homogenization temperatures of fluid inclusions, Magara (1975, 1976) had empirically found somewhat lower aquathermal pressure gradients of 1.5 psi/ft. for the Alberta Basin, and 1.4 psi/ft. for the Gulf Coast Basin. The difference between the results for the Gulf Coast and Alberta was due to the difference in the average geothermal gradient of the two localities. The differences between the empirical and the theoretical results were attributed to the fluid systems not being perfectly sealed.

Cluff and Byrnes (1991) estimated that approximately 2,000 feet of rock had been removed from the Shrewsbury Field area by erosion in the last 245 million years. If an aquathermal pressure gradient of 1.5 psi/ft. is applied to 2,000 feet of erosion, a simple calculation (Table 5) shows that the reservoir pressure of the Shrewsbury Field before post-Alleghenian erosion would have been over 3,400 psi at a depth of 3,700 feet, or 205 percent of the paleohydrostatic pressure at that depth. This overpressuring would have been greater than that currently observed in the Altamont-Bluebell and Antelope Fields, and equivalent to 92 percent of lithostatic pressure. This value would not have been great enough in itself to cause natural hydraulic fracturing, but certainly would have been adequate to result in fracturing in combination with significant structural flexure.

Similarly, O'Hara and others (1990) estimated 2 kilometers (6,562 feet) of rock have been removed by post-Alleghenian erosion in the Big Sandy Field area. By the same calculation, the reservoir pressure of the Big Sandy Field before erosion would have been over 10,600 psi at a depth of 10,440 feet, or 227 percent of the paleohydrostatic pressure at that depth. This overpressuring would have been equivalent to 102 percent of lithostatic pressure, probably adequate to cause the natural hydraulic fracturing suggested by the horizontal extension fractures described by Kulander and others (1977) and shown in Figure 12. Magara (1981) pointed out that any overpressuring due to hydrocarbon generation would have been supplemental to aquathermal pressuring. As discussed previously, there is every reason to expect that substantial overpressuring would have been generated by hydrocarbon generation in the Devonian shales. It is likely that aquathermal pressuring resulted in the horizontal extension fractures of the Big Sandy Field at a relatively early stage, given that the fractures are filled with calcite deposited from aqueous solution. Subsequent hydrocarbon generation probably maintained a high degree of overpressuring in the shales, while flushing the free water from the rock to produce and overpressured fractured shale reservoir saturated in hydrocarbons. The sustained high degree of overpressuring facilitated fracturing in regions of structural flexure. Subsequent loss of overpressure during erosion, uplift, and cooling probably resulted in a partial collapse of the fracture system, as well as a phase change in the hydrocarbons accentuating the compositional segregation of oil and gas.

Table 5.—Calculation of Paleoreservoir Pressures, Big Sandy Field and Shrewsbury Field, Kentucky. Current Pressure Values and Depth are Taken from Table 4. Section Eroded Values are from Cluff and Byrnes (1991) for the Shrewsbury Field, and from O'Hara and Others (1990) for the Big Sandy Field. Paleodepth is the Sum of Current Depth and Section Eroded. Paleoreservoir Pressure is the Product of the Section Eroded and the Aquathermal Pressure Gradient, Plus the Current Reservoir Pressure. The Aquathermal Pressure Gradient of 1.5 psi/ft. is from Magara (1981). Paleohydrostatic Pressure is the Product of Paleodepth and a Nominal Hydrostatic Gradient of 0.45 psi/ft. Paleolithostatic Pressure is the Product of Paleodepth and a Nominal Lithostatic Gradient of 1.0 psi/ft.

	Shrewsbury	*Big Sandy*
Current Pressure (psig)	409	800
Current Depth (ft.)	1,699	3,878
Section Eroded (ft.)	2,000	6,562
Paleodepth (ft.)	3,699	10,440
Paleoreservoir Pressure (psig)	3,409	10,643
Paleohydrostatic Pressure (psig)	1,665	4,698
Paleolithostatic Pressure (psig)	3,699	10,440
Paleoreservoir Pressure (Percent of Paleohydrostatic)	205	227
Paleoreservoir Pressure (Percent of Paleolithostatic)	92	102

EXPLORATION POTENTIAL OF THE DEEP MOORMAN SYNCLINE

Figure 13 shows surface faulting in Kentucky. Also shown on this map are regions of maximum potential for fractured Devonian shale gas production, in both the Appalachian and Illinois Basins. In the Appalachian Basin, the region of maximum potential is interior to the Rome Trough but does not include areas of surface faulting. In the Illinois Basin, the regions of maximum potential are interior to the Moorman Syncline but also do not include areas of surface faulting. Avoiding areas of surface faulting will improve the prospects of maintaining an effective seal for a Devonian shale gas accumulation.

In both eastern and western Kentucky, the regions of maximum potential include the areas of maximum thermal maturity as indicated by average vitrinite reflectance. Figure 4 shows that in the maximum potential region of the Appalachian Basin, the average vitrinite reflectance increases from less than 0.60 to 1.00 percent R_0 from northwest to southeast. In the maximum potential region of the Illinois Basin the average vitrinite reflectance has the same range, increasing from less than 0.60 to over 1.00 percent R_0 from east to west. Within this range of vitrinite reflectance, oil generation with associated gas would have been effective, and significant overpressuring would have accompanied hydrocarbon production. Both gas generation and overpressuring would have been more pronounced with increasing vitrinite reflectance. Greater overpressuring would have increased the possibility of significant fracturing developing in the Devonian shale section.

The maximum potential region of the Appalachian Basin as indicated on Figure 13 includes the Big Sandy Field, as can be seen by a comparison with Figure 3. The Big Sandy Field has been developed in areas of no surface faulting interior to the Rome Trough, where vitrinite reflectance values are greater than 0.60 percent R0. One of the maximum potential regions of the Illinois Basin includes the Shrewsbury Field in its eastern part, but the remainder is essentially unexplored. The Shrewsbury Field has also been developed in an area with no surface faulting, although preliminary structural mapping suggests a northeast-trending structure at the New Albany Shale level. The average vitrinite reflectance of the New Albany Shale in the Shrewsbury Field is less than 0.60 percent R_0, significantly lower than the range of 0.60 to 1.00 percent R_0 found both in the Big Sandy Field and in the maximum potential zones of the Moorman Syncline to the west of the Shrewsbury Field.

The best potential for Devonian shale gas exploration in Kentucky is along the axis of the Moorman Syncline. It is in this area that gas accumulations may be found in fractured shale reservoirs formed by a combination of structural flexure and overpressuring due to hydrocarbon generation. These gas accumulations should be well sealed, and may have somewhat higher reservoir pressures than the fault-associated reservoirs found around the margins of the moorman Syncline. The average initial open flow of these well-sealed res-

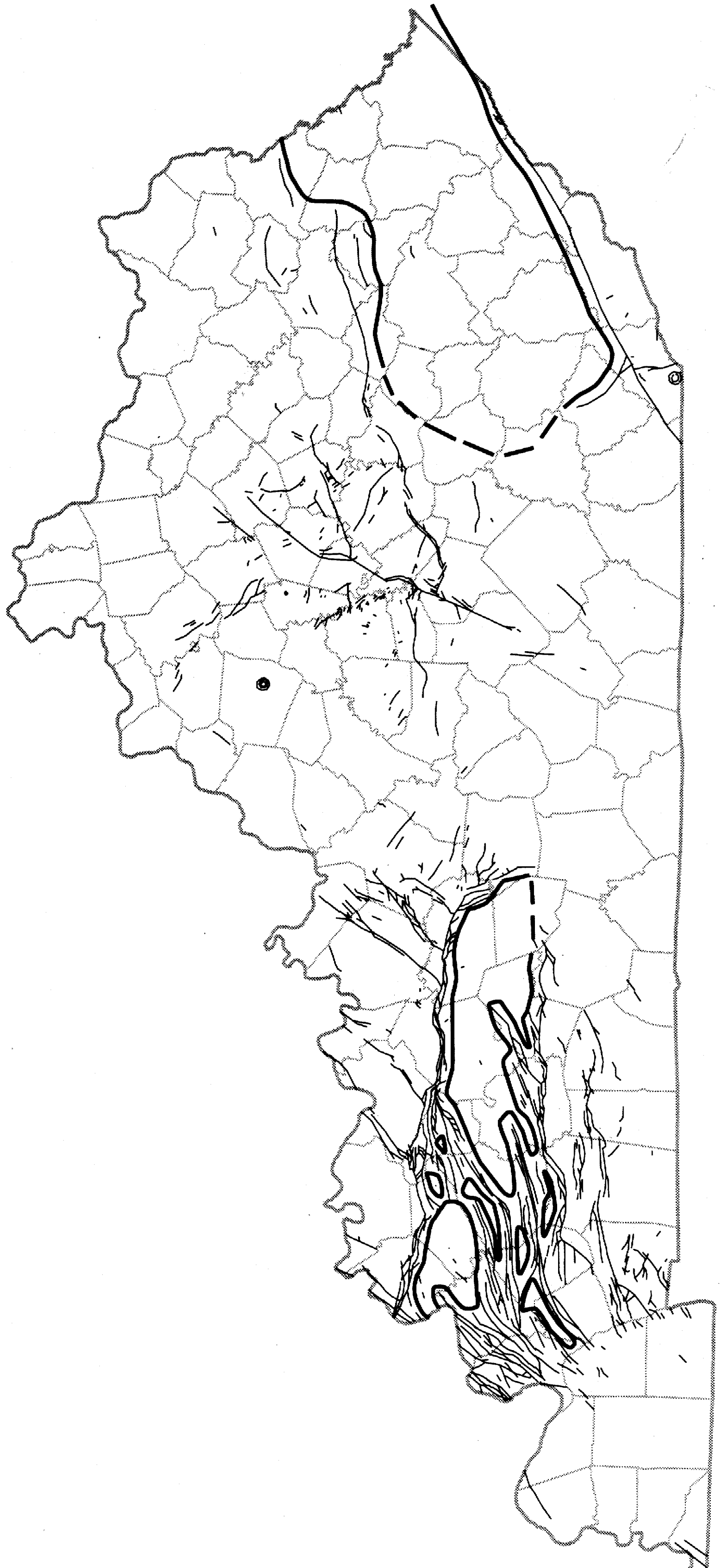

Figure 13. Gas exploration map, Devonian shale, Kentucky. Light lines indicate surface faults (from McDowell and others, 1981). Heavy lines indicate boundaries of maximum gas exploration potential areas.

ervoirs should be relatively high. The size of the gas accumulations would be determined by the size of the associated structural flexures.

Effective exploration for gas in the Devonian shales of Kentucky requires an appreciation of the unconventional nature of the fractured reservoir. Areas of surface faulting should be identified and downgraded as prospects. The distribution of New Albany Shale gas production around the periphery of the Moorman Syncline suggests that fault zones provide effective conduits for gas migration. Fault zones that extend to the surface are likely to act as conduits for gas seeps. Gas accumulations in the neighborhood of such fault zones will be controlled by gas migration. High initial open-flow rates may be obtained from exceptional wells located directly on flow paths within the fault zone, but most wells will be significantly less productive. At best, such poorly sealed fractured shale reservoirs should be considered a secondary target.

Areas of maximum paleoreservoir pressure in the Devonian shales should be identified and further evaluated. This can be done first by locating regions of high thermal maturity through mapping of such indicators as vitrinite reflectance, liptinite fluorescence, or T_{max} from pyrolysis (Tissot and Welte, 1978). In addition, the degree of post-Alleghenian erosion and its effect on reservoir pressure needs to be analyzed. This step will identify the areas in which significant overpressuring due to hydrocarbon generation would have occurred in the shales. Areas that have undergone significant overpressuring will have most likely undergone significant fracturing in response to relatively minor flexures. In addition, the degree of original gas generation and the size of the potential accumulation increases with the degree of thermal maturity.

Specific drilling locations may be identified by detailed structural analysis. Maps should be made to identify specific flexures that could have been effective in the development of fractured reservoirs in combination with overpressuring. Mallory (1977, p. 26) described the variety of structural flexures associated with fractured shale reservoirs in Colorado, and discussed exploration methods:

> A structure map showing rate of dip can be considered a first derivative map. A second derivative map showing rate of change of dip can be derived from the first. Belts where the rate is high are considered as "fracture fairways" .... Proposed drill sites should be located where rates are highest .... High values on the tensional, convex face of a flexure should indicate the most attractive sites.

Murray (1968) developed a quantitative model for fracturing in the Antelope Field of the Williston Basin, assuming the location of fractures was controlled by bed thickness and structural curvature, equivalent to the second derivative of Mallory (1977). The fracture permeability was calculated to be a function of the cube of the product of the bed thickness and the structural curvature. Murray (1968) pointed out that the dependence of permeability on the third power of curvature made even small values of curvature significant for fracture development. Some 75 percent of the oil from the Antelope Field was produced from the area of maximum structural curvature on the convex side of the flexure.

The potential productivity of fractured reservoirs in the New Albany Shale of the deep Moorman Syncline is suggested by the southwest Shrewsbury Field, which has an average initial open flow of 242 Mcfgpd. This average is not much less than the average initial open flow of 290 Mcfgpd for the Big Sandy Field in eastern Kentucky (Hunter and Young, 1953). As discussed above, the gas in place in the New Albany Shale of western Kentucky is also comparable to that of the Ohio Shale of eastern Kentucky at about 30 tcf. It is consequently reasonable to suggest that additional gas fields of the productivity of the Big Sandy Field may yet to be discovered in the deep Moorman Syncline, which to date is virtually untested by drilling in the Devonian shale.

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