Diagenesis and Fracture Development in the Bakken Formation, Williston Basin: Implications for Reservoir Quality in the Middle Member

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By Janet K. Pitman, Leigh C. Price, *and* Julie A. LeFever

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By Janet K. Pitman,[1] Leigh C. Price,[1] *and* Julie A. LeFever[2]

Abstract

The middle member of the Bakken Formation is an attractive petroleum exploration target in the deeper part of the Williston Basin because it is favorably positioned with respect to source and seal units. Progressive rates of burial and minor uplift and erosion of this member led to a stable thermal regime and, consequently, minor variations in diagenesis across much of the basin. The simple diagenetic history recorded in sandstones and siltstones in the middle member can, in part, be attributed to the closed, low-permeability nature of the Bakken petroleum system during most of its burial history. The dominant mineral cements consist of anhedral nonferroan planar dolospar, rhombic nonferroan dolospar grains with ferroan rims, and calcite commonly replaced by dolomite. Other authigenic phases include syntaxial quartz and K-feldspar overgrowths, euhedral pyrite crystals, well-ordered illite, and Fe-bearing chlorite. Bitumen is widespread in sandstones and siltstones that are adjacent to thermally mature shales.

Most diagenesis ceased in the middle member when oil entered the sandstones and siltstones in the Late Cretaceous. Porosity-depth relationships are consistent with petrographic results, which show that porosity in shallowly buried (<3,000 m), immature to marginally mature rocks was controlled by mechanical compaction and mineral cementation. In more deeply buried, thermally mature rocks (>3,000 m), porosity varies more widely in response to emplacement of oil and increased burial of the section. Most oil in the Bakken Formation resides in open, horizontal fractures in the middle member. Core analysis reveals that sandstones and siltstones associated with thick mature shales typically have a greater density of fractures than sandstones and siltstones associated with thin mature shales. Fractures were caused by superlithostatic pressures that formed in response to increased fluid volumes in the source rocks during hydrocarbon generation.

Introduction

The Upper Devonian–Lower Mississippian Bakken Formation in the Williston Basin, North Dakota (fig. 1), is a closed, low-permeability petroleum system that generated approximately 200 to 400 billion barrels of oil in place. Most of this generated oil was expelled into very fine grained sandstones and siltstones within the middle member, which is bounded by organic-rich shales that are both sources and seals. Source-rock thickness, thermal maturity, and total organic carbon (TOC) contents controlled the amount of oil generated and expelled from the shales.

The middle member of the Bakken is an oil reservoir in the thermally mature part of the basin and has been extensively cored; thus, it offers the opportunity to examine the major controls on reservoir quality. In this study, petrographic and geochemical analysis are used to characterize the mineralogy and diagenesis of the fine-grained reservoir sandstones and siltstones, and to relate the timing of diagenesis to the generation and expulsion of hydrocarbons from associated organic-rich shales. The study also links variations in porosity and permeability in sandstones and siltstones to the occurrence and distribution of natural hydraulic fractures in the middle member. Knowledge of the origin and timing of diagenesis and the processes controlling fracture formation is essential to developing an empirical model for reservoir-quality prediction in the basin.

Analytical Methods

Forty sandstone samples from lithofacies characterizing the middle member of the Bakken Formation were obtained

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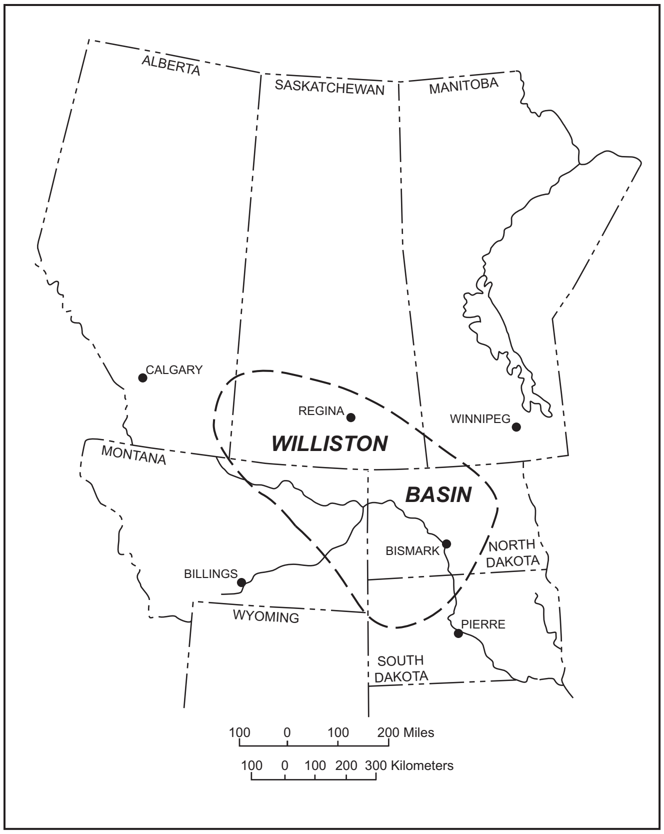

Figure 1. Index map showing approximate extent of the Williston Basin.

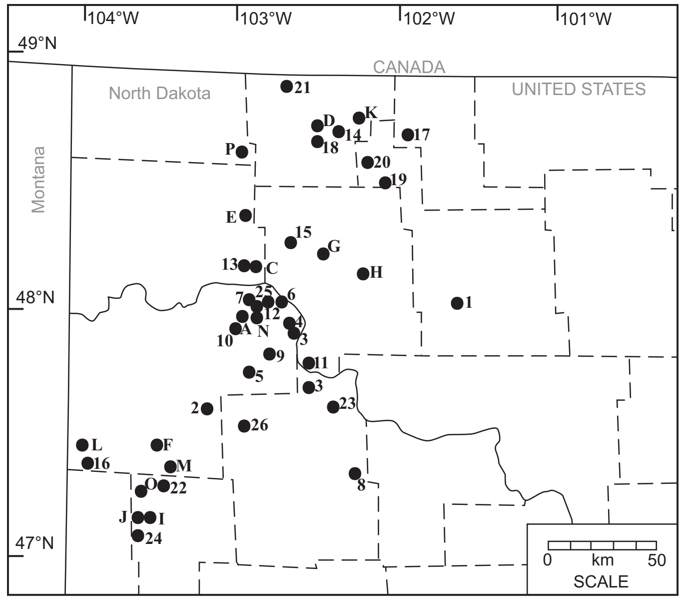

Figure 2. Map showing location of wells sampled for petrographic, geochemical, and reservoir quality analysis. Wells are listed in tables 1 and 2.

from drill core for petrographic and geochemical analysis (fig. 2; table 1). Depth intervals for which the sample suite was taken ranged from approximately 2,300 to 3,900 m.

Standard thin sections were impregnated with blue epoxy to aid in identification of open natural fractures and stained to facilitate mineral identification. Staining with Alizarin Red-S and potassium ferricyanide permitted Fe-free and Fe-bearing carbonate minerals to be readily distinguished; sodium cobaltinitrate stain aided in the identification of K-feldspar. Mineral paragenesis and textural data were obtained from petrographic examination of the stained samples.

Clay-mineral identification on the <2-µm size fraction of selected samples was conducted following standard procedures (Gary Skipp, analyst, U.S. Geological Survey, Denver, Colo.). X-ray diffraction of oriented mounts was performed on each sample after they were air-dried, glycol-saturated, and heated to 500°C. Relative abundances of minerals in the <2-µm size fraction were determined by plotting relative peak heights above background.

Representative samples of fracture-fill calcite cements were analyzed isotopically (Augusta Warden, analyst, U.S. Geological Survey, Denver, Colo.) using the phosphoric acid reaction technique (McCrea, 1950). Carbon and oxygen ratios are presented in the standard delta notation (δ) relative to the PeeDee Belemnite (PDB) standard. Data reproducibility is precise to ±0.2 per mil (‰). Fourteen doubly polished thin sections of fracture-fill calcite were analyzed using a McLimans stage to determine homogenization temperatures of primary fluid inclusions in the calcite fill (Jim Reynolds, analyst, Fluid Inc., Englewood, Colo.).

Geologic and Structural Setting

The Williston Basin is an intracratonic, structural, and sedimentary feature that overlies the Superior craton, the Trans-Hudson orogenic belt, and the Wyoming craton in the United States and Canada. The basin occupies portions of North Dakota, South Dakota, Montana, Saskatchewan, and Manitoba (see fig. 1).

Sedimentation occurred in the North Dakota portion of the Williston Basin from Cambrian through Tertiary time and is represented by a stratigraphic section more than 4,878 m thick. Basin sedimentation was characterized by cyclical transgressions and regressions with repeated deposition of carbonates and clastics. Paleozoic strata are dominated by carbonates, whereas Mesozoic and Cenozoic strata consist mainly of clastic rocks.

Initial sedimentation occurred over an irregular Precambrian surface. Repeated clastic/carbonate sequences interrupted by major erosional events are characteristic of deposits of Cambrian to Devonian age. During the Devonian, the orientation of the seaway occupying the study area shifted to the north as a result of tectonic activity along the Transcontinental arch. Devonian sediments show repeated transgressional-regressional

Table 1. Locations of wells sampled for petrographic and geochemical analysis.

[See figure 2 for well locations. NDGS, North Dakota Geological Survey; T. N., Township (north); R. S., Range (south); Sec., section; m, depth in meters]

Map no.	Well ID (NDGS)	Well name	T. N.	R. S.	Sec.	Top, middle member (m)	Base, middle member (m)
1	105	Stanolind Oil & Gas Co., Waswick #1	153	85	2	2308.9	2313.4
2	527	California Oil Co., Rough Creek Unit #1	148	98	13	3421.4	3432.7
3	607	Socony-Vacuum Oil Co., F32-24-D	149	93	24	3206.8	3223.0
4	1202	Amerada Petrol Co., Jens Strand #1	152	94	6	3131.8	3145.8
5	1405	Amerada Petrol Corp., Catherine Peck #2	150	96	27	3279.3	3290.6
6	1886	Amerada Petrol Corp., John Dinwoodie #1	153	94	3	3239.4	3255.3
7	2602	Texaco Inc., Garland #5	153	95	6	2965.7	2973.3
8	2618	Pan American Petro. Corp., Jacob Huber #1	145	91	15	2984.6	2995.0
9	2820	Texaco Inc., No. 4FP Keogh	151	95	5	3227.5	3239.7
10	2967	Texaco Inc., A.S. Wisness #2	152	96	3	3123.0	3135.8
11	4113	Texaco Inc., Ft. Berthold #437 A1	150	93	4	3250.7	3264.4
12	4264	Texaco Inc., Gov't. Dorough # A3	153	95	3	3035.2	3049.8
13	4340	Pan American Petrol. Corp., Marmon #1	154	95	2	3019.3	3037.6
14	4508	Northern Pump Co., Pederson #1	161	90	7	2286.9	2299.1
15	5088	Shell Oil Co., Texel #21-35	156	93	35	3099.5	3136.4
16	7579	Shell Oil Co., USA #42-24 A	145	104	24	3309.8	3312.3
17	8637	Clarion Resources Inc., Pierce #1-18	161	87	18	2060.1	2067.8
18	8638	Clarion Resources Inc., Slater #1-24	161	91	24	2407.3	2419.2
19	8697	Clarion Resources Inc., Pullen #1-33	159	88	33	2343.6	2350.9
20	8699	Clarion Resources Inc., Flecton #1-20	160	89	20	2332.9	2343.3
21	8850	Clarion Resources Inc., Nelson #1-29	163	92	29	2254.6	2272.0
22	9351	Supron Energy Corp., F6-144-101 #3	144	101	6	3187.3	3196.4
23	9707	Shell Oil Co., Young Bear BIA #32-4	148	92	4	3180.3	3191.3
24	10659	Maxus Exploration Co., Short Fee #31-3	142	102	3	3205.3	3207.4
25	11617	Cox Edwin L & Berry, Hagen #1-13	153	95	13	3158.6	3162.6
26	12785	Maxus Exploration Co., Carus Fee #21-19	147	96	19	3445.5	3457.0

cycles related to deposition in the Elk Point Basin, and reorientation of the seaway during the Mississippian opened this basin to the west through the central Montana trough.

A structure map constructed on the top of the Bakken Formation (fig. 3) shows the Nesson anticline to be the most prominent structural feature in the study area. The anticline trends northward for 176 km from the Killdeer Mountains, Dunn County, to just south of the Canadian border. Associated with the Nesson anticline is the western Nesson fault, a feature that extends along the west flank of the fold. Episodic movement along the fault and the development of the Nesson anticline have been related to basement tectonics (Gerhard and others, 1982, 1987; LeFever and others, 1987).

Thickness and Age Relationships

The Bakken Formation in North Dakota reaches a maximum thickness of 46 m in the central portion of the basin (fig. 4), and the depocenter, which is located to the east of the Nesson anticline, trends in a north-south direction. The middle member of the Bakken displays abrupt thickening and thinning in the study area, and there are only isolated occurrences of the lower member in north-central North Dakota. Fluids moving along a basement fault separating the Superior craton from the Trans-Hudson orogenic belt (also referred to as the Precambrian province) (Green and others, 1985) may have been responsible for dissolution of salt in the Devonian Prairie Formation, and in turn, the thickness variations in the overlying Bakken Formation. (McCabe, 1959; Christopher, 1961; Anderson and Hunt, 1964; Webster, 1982, 1984; Martiniuk, 1988; LeFever and LeFever, 1995).

The Bakken Formation is an easily recognizable sequence on wireline logs of drill holes. The shales bounding the middle member have abnormally high gamma-ray readings (>200 API), high sonic transit times (80 to 120 μs/ft), and low resistivity (<100 ohm-m) readings in the shallower, thermally immature portion of the basin and high resistivity readings (>100 ohm-m) in the deeper, thermally mature part (Meissner, 1978; Webster, 1982, 1984; Hester and Schmoker, 1985). The middle member exhibits wireline log characteristics typical of

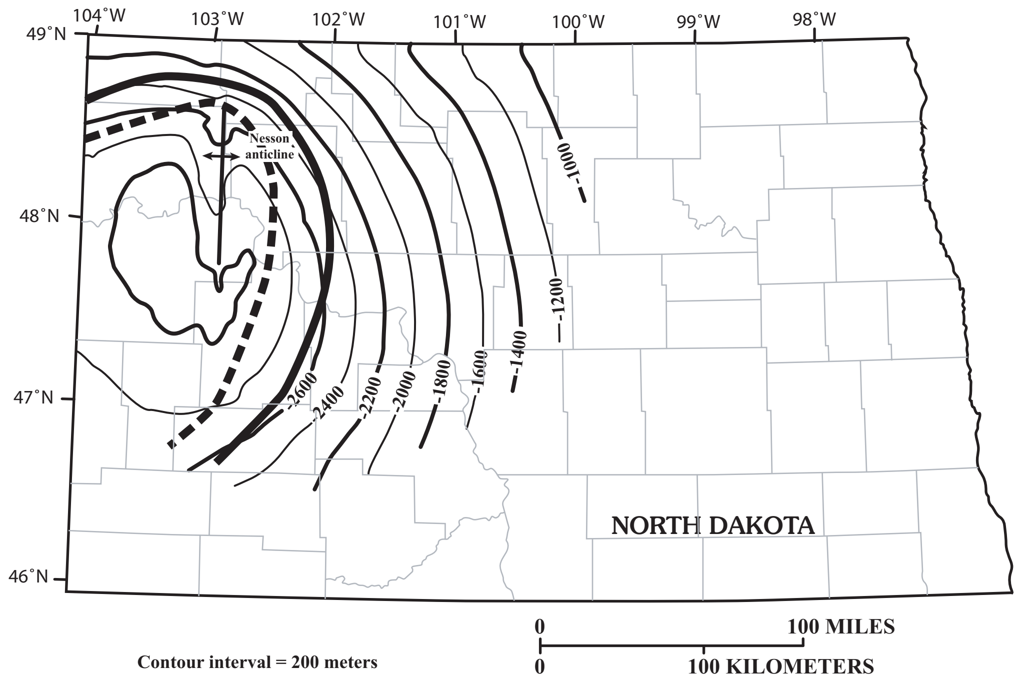

Figure 3. Structure map on the top of the Bakken Formation. Dashed line indicates area of marginally mature source rocks; solid line indicates area of active hydrocarbon generation.

clastic and carbonate rock and can be difficult to distinguish from the underlying Devonian Three Forks Formation if the lower shale is absent.

Early workers assigned a Mississippian age to the Bakken Formation based on lithology and limited paleontological data (Nordquist, 1953; Thomas, 1954; Fuller, 1956). However, more recent data suggest that the Bakken is Devonian and Mississippian in age (Hayes, 1984; Thrasher, 1985; Holland and others, 1987). On the basis of macrofossils, these studies placed the Devonian-Mississippian boundary within the middle member, which is in close agreement with conodont fauna from the shales that suggest the systemic boundary occurs at or near the contact between the middle and upper members.

Lithostratigraphy

The Bakken Formation overlies the Upper Devonian Three Forks Formation and underlies the Lower Mississippian Lodgepole Formation. In North Dakota, the Bakken occurs solely in the subsurface and has been informally subdivided into lower, middle, and upper members. The lower member consists of dark-gray to brownish-black to black, competent and massive to fissile, slightly to highly organic rich shale that is locally calcareous at its base. In the deeper portion of the basin, the shale is a kerogen-rich, mature source rock with the organic material evenly distributed throughout. The contact between the lower member and the middle member is irregular and sharp in places but gradational in others and is a sequence boundary.

The lithology of the middle member is highly variable and consists of a light-gray to medium-dark-gray, interbedded sequence of siltstones and sandstones with lesser amounts of shale, dolostones, and limestones rich in silt, sand, and oolites (Webster, 1982; Hayes, 1984; Thrasher, 1985). A general description of the lithofacies composing the middle member in the study area is shown in figure 5. The siltstones and sandstones typically are massive or coarse bedded with rare trough or planar crossbed sets. Much of the unit is well sorted, although bioturbation commonly disturbs the bedding, especially in the more argillaceous strata. Features indicative of soft sediment deformation, including microfaults and flow structures, are also present. Fossils in the middle member include articulate and, less commonly, inarticulate brachiopods, pelmatozoan fragments, gastropods, and various trace fossils. Conodonts, plant spores, and ostracods are also observed but are rare (Hayes, 1984).

The upper member of the Bakken is lithologically similar to the lower member and consists of dark-gray to brownish-black to black, fissile, slightly calcareous, organic-rich shale (Webster, 1982; Hayes, 1984). It differs from the lower member in that it lacks crystallized limestones and greenish-gray shale beds and has a higher organic matter content.

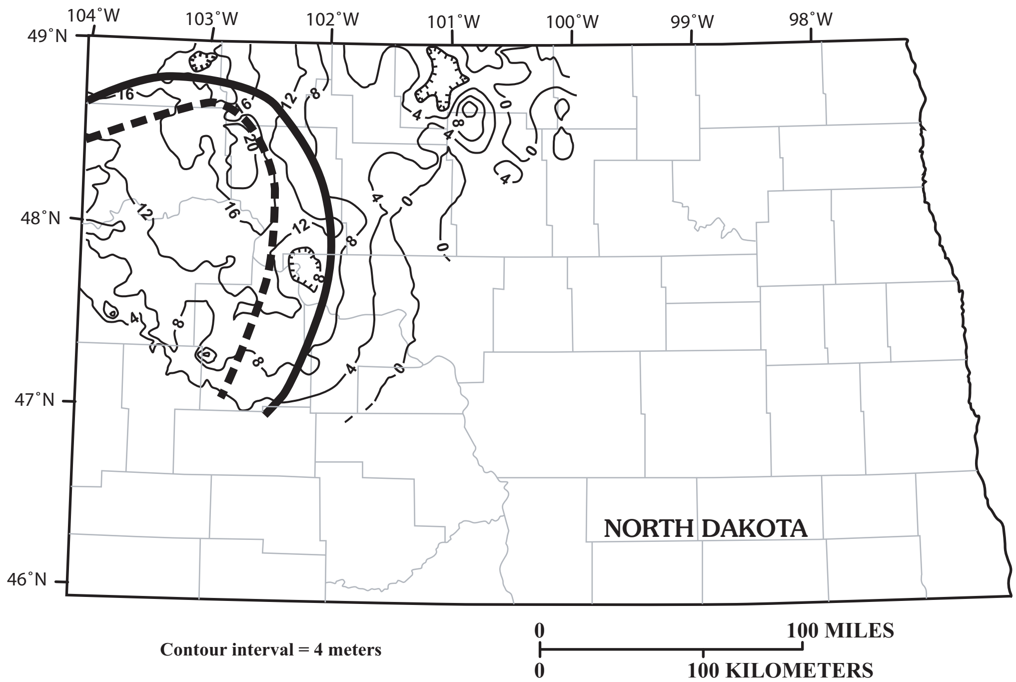

Figure 4. Isopach map of the Bakken Formation. Dashed line indicates area of marginally mature source rocks; solid line indicates area of active hydrocarbon generation.

Depositional History

A variety of paleoenvironmental interpretations ranging from broad coastal swamps and lagoons to an open-marine system with and without a stratified water column and anoxic bottom-water conditions have been proposed for the Bakken Formation (McCabe, 1959; Christopher, 1961; Webster, 1982, 1984; Lineback and Davidson, 1982; Smith, 1996). Sandberg and others (1982) proposed a model for Western Interior Middle Devonian to Upper Mississippian rocks based on eustatic sea-level changes. According to their model, deposition of the Bakken Formation was initiated by a marine transgression related to tectonic activity in the Antler and Acadian orogenic belts, an interpretation largely based on the presence of a sharp disconformity between the Three Forks and Bakken Formations. Smith (1996) expanded upon the eustatic sea-level model and demonstrated that the preexisting topography of the Saskatchewan portion of the Williston Basin was due not only to tectonic deformation but also to partial dissolution of the Devonian Prairie salt and erosion of the Three Forks Formation. In North Dakota, there is no clear evidence that significant tectonic relief existed before or during deposition of the Bakken Formation; however, topographic variations due to dissolution of the Prairie salt occur locally.

The lower and upper members of the Bakken Formation were deposited in an offshore marine environment during periods of sea-level rise (Webster, 1982, 1984; LeFever and others, 1991; Smith, 1996). Benthic fauna and geochemical data (Webster, 1982; Lineback and Davidson, 1982) provide evidence that deposition of shales in the lower and upper members took place in a stratified hydrologic regime. Such conditions reflect the temperate climate that existed during the time of deposition. Anaerobic bottom-water conditions are indicated by the presence of pyrite, high organic-matter content, and rare benthic fauna in the shales.

The middle member was deposited in a coastal regime following a rapid sea-level drop and deposition of the lower shale (Smith and Bustin, 1995). In the central portion of the basin, argillaceous, greenish-gray, highly fossiliferous, pyritic siltstones in the lower part of the member indicate a shallow-water (offshore) marine environment that was moderately well oxygenated and occasionally dysaerobic. Progradation of the shoreline basinward is indicated by interbeds of highly bioturbated shale and sandstone higher in the section, and the presence of *Cruiziana sp*. suggests lower shoreface deposition. In the middle part of the member, flaser- or wavy-bedded, lower shoreface sandstones containing *Skolithos sp*. grade into massive or trough and tabular crossbedded sandstone devoid of *Skolithos sp*. These latter sandstones, which produce hydrocarbons in Canada, probably formed in tidal channels (LeFever and others, 1991). On the basis of disarticulated brachiopods concentrated in thin, well-sorted beds of gray siltstones and very fine grained sandstones, LeFever and others (1991) suggested that the upper part of the member was deposited in a marine environment with strong current action.

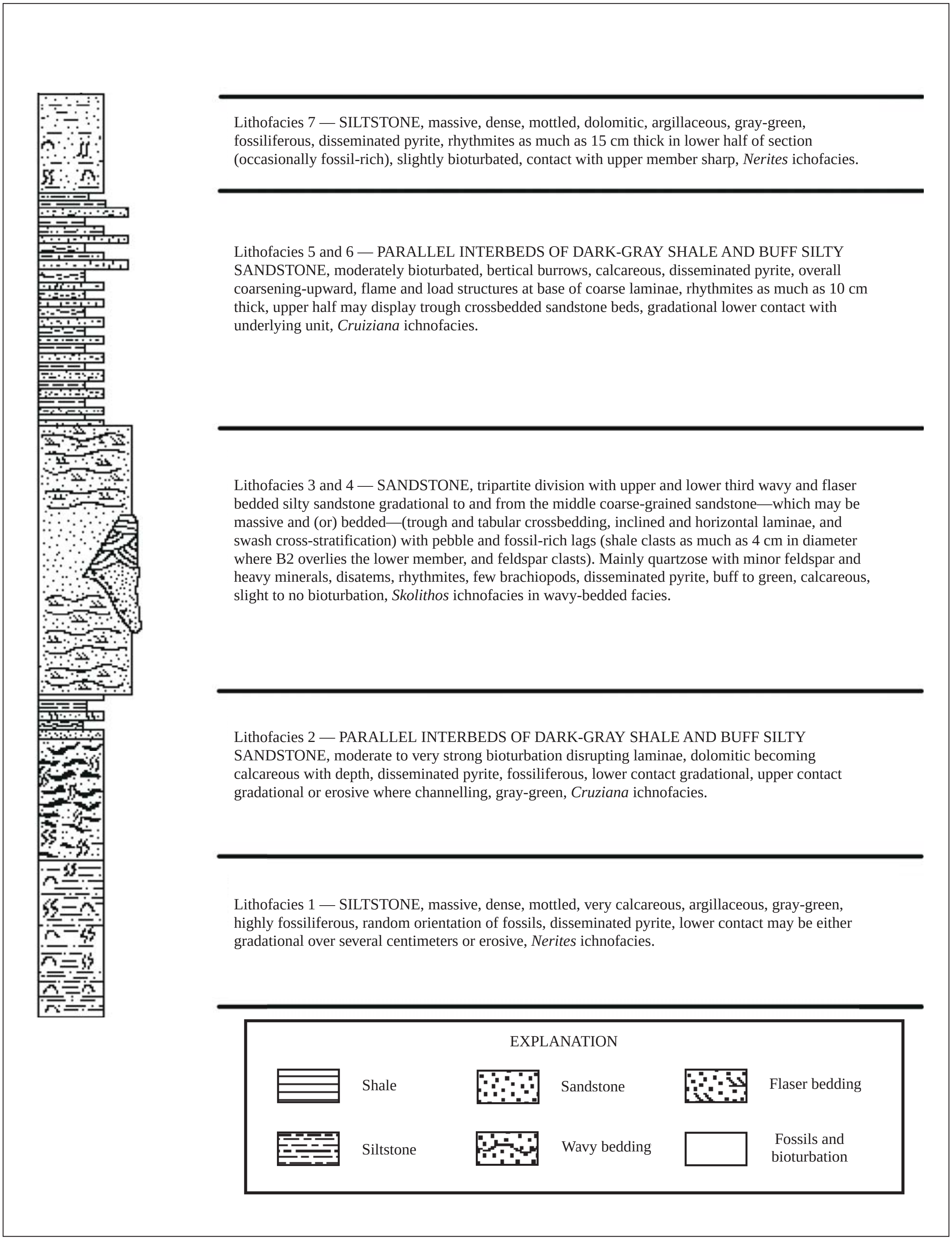

Figure 5. Lithologic column depicting lithofacies and sedimentologic characteristics of the middle member of the Bakken Formation (modified from LeFever and others, 1991).

Mineralogy and Diagenesis

Detrital Mineralogy

Sandstones and siltstones in the middle member, the primary focus of this study, typically consist of fine-grained to very fine grained, matrix-rich rocks composed of quartz, minor feldspar, and variable rock fragments; locally, the grain size increases into the medium sand range. Most framework grains are well rounded to rounded, but in some samples the finer grained material is subrounded to subangular. Generally, the sandstones are moderately well to well sorted but poorly sorted locally.

Overall, the sandstones and siltstones exhibit a relatively uniform framework-grain composition with only minor variations within and between wells. Most quartz in sandstones occurs as subrounded to angular monocrystalline fragments generally devoid of overgrowths. Slight increases in detrital grain size occur in northern North Dakota reflecting closer proximity to sediment sources in the north. The dominant feldspar type is orthoclase, and individual fragments are subrounded, approximating the size of quartz grains. In some sandstones, quartz and feldspar grains display altered clay rims. Common lithic fragments in the sandstones and siltstones include detrital carbonate (limestone and dolomite) grains and deformed mudstone clasts. Fossil bioclasts are found locally in sandstones close to carbonate beds, and glauconite occurs sparsely in burrows. The matrix in most sandstones consists of a variable mix of carbonate mud and allogenic clay.

Diagenetic Alteration

Postdepositional alteration in sandstones and siltstones includes mechanical and chemical compaction, diagenetic cementation, and mineral dissolution. Textural features indicate various degrees of mechanical and chemical compaction, depending on the extent to which the rocks have been buried. In moderately to deeply buried sandstones, long and concave-convex grain contacts are present if the amounts of matrix and pseudomatrix, resulting from mechanical compaction of labile lithic grains, are small. The best evidence of chemical compaction is the presence of microstylolites that are best developed in coarser grained sandstones with a large number of detrital carbonate grains. Most stylolites contain organic matter (bitumen?) along their seams and locally display dissolution at grain contacts.

Authigenic phases observed in fine-grained sandstones are predominantly carbonate minerals (fig. 6). Authigenic carbonate cements also are most common in the coarser grained sandstones, particularly those that have high concentrations of fossil grains, and consist of abundant dolomite and rare calcite. In lithofacies 4, 5, and 6 (fig. 5), for example, nonferroan planar dolospar forms a finely crystalline (~ 2–10 µm) and anhedral, pore-filling cement and grain replacement. In many sandstones, there are discrete rhombic, ferroan dolospar crystals that form a cement where they are widespread. Individual dolospar grains consisting of nonferroan cores with angular ferroan rims also are abundant in many samples. Like dolomite, calcite is both ferroan and nonferroan in nature. Nonferroan calcite is distributed as a patchy syntaxial cement in sandstones containing fossil bioclasts, and rare ferroan calcite locally replaces nonferroan calcite. Both calcite phases are commonly replaced by dolomite.

Other authigenic phases in sandstones and siltstones include secondary quartz, K-feldspar, and pyrite (fig. 7). Rare syntaxial overgrowths of quartz are developed on quartz grains and a few of the coarser grained samples contain quartz cement. Authigenic K-feldspar is distributed as overgrowths on detrital feldspar grains and locally forms a cement where overgrowths are intergrown. K-feldspar also replaces clay coatings on quartz and feldspar grains. Pyrite grains or nodules and small euhedral pyrite crystals (<2 µm in size) associated with organic matter occur in some sandstones. There are also sporadic lenses of coarser grained material in which the intergranular porosity is filled with pyrite. Burrows filled with pyrite, and fossils partially or completely replaced with pyrite, are present in some intervals. Bitumen, ranging in color from dark brown to black, is a common pore-filling material in very fine grained, thinly laminated, quartz-rich sandstones and siltstones associated with thermally mature, hydrocarbon-generating shales. It is generally absent in sandstones and siltstones where the adjacent shales are thermally immature. Hematite staining was noted in the basal portion of one well. Anhydrite occurs sparsely in a few samples, and its mode of occurrence ranges from small scattered patches to medium-size poikilotopic crystals. Because of the composition of the drilling mud, it is possible that this anhydrite may not be part of the burial diagenetic sequence.

On the basis of X-ray diffraction, the clay suite in sandstones and siltstones comprises illite and chlorite (fig. 8). Illite has a small percent of expandable layers (<5 percent) and is identified on the basis of sharp, well-ordered (001) and (003) peaks. Chlorite exhibits a reduced intensity of odd-ordered (001) peaks relative to even-ordered peaks and an approximate 2:1 ratio of the (001) and (003) peaks, which are features indicating that it is an iron-rich variety (Moore and Reynolds, 1989). In thin section, both illite and chlorite are too fine grained and dispersed to be easily recognized.

Secondary Porosity

Minor porosity of secondary origin occurs locally in sandstones and resulted from the removal of authigenic mineral cements and, to a lesser extent, detrital framework grains (see fig. 7). In carbonate-cemented samples, evidence of dissolution includes corrosive contacts between successive carbonate phases and relict cement in pores. Carbonate dissolution features also are observed along the margins

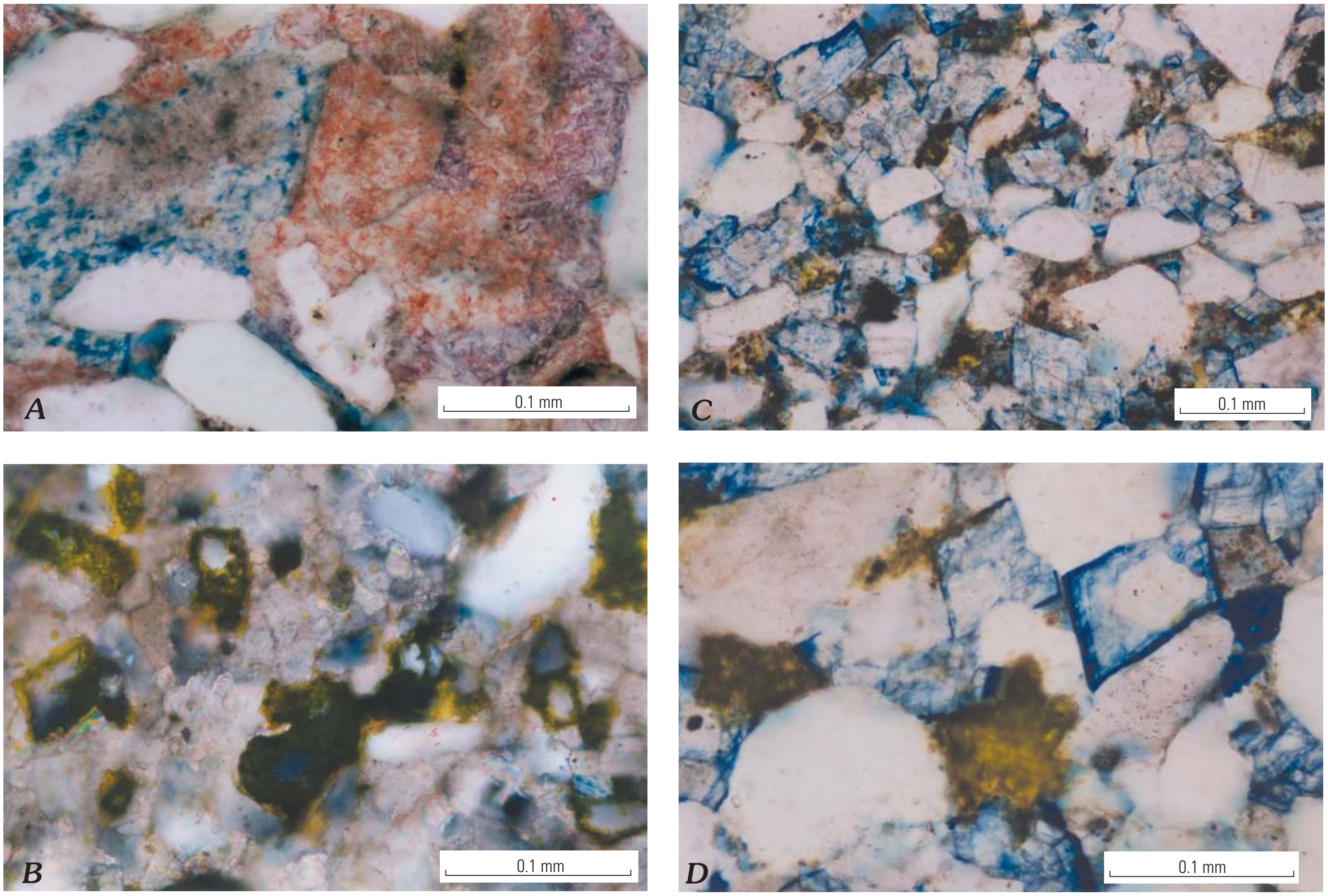

Figure 6. Thin section photomicrographs of sandstone samples showing *A*, multiple generations of authigenic carbonate including non-Fe-calcite (red), Fe-calcite (purple), non-Fe-dolomite (beige), and Fe-dolomite (blue), NDGS 4340; 3,023 m; *B*, anhedral dolomite cement, NDGS 9707; 3,185 m; *C*, planar ferroan dolospar crystals (stained blue), NDGS 8850; 2,259 m; and *D*, euhedral dolospar crystals (beige) with ferroan dolomite rims (blue) NDGS 8850; 2,259 m.

of some fractures. Collectively, the dissolution features in sandstones indicate that carbonate cements were previously more widespread before they were partially to extensively dissolved.

Fracture Occurrence

Multiple fracture types occur on a macroscopic and microscopic scale in the Bakken Formation and are most abundant in the lower and middle members. In sandstones and siltstones in the middle member, the vast majority of these fractures are open (nonmineralized), discontinuous features oriented subparallel (horizontal) to bedding with aperture widths commonly exceeding 30 µm (fig. 9). Resinous or vitreous pods of carbonaceous material ("dead oil") are present locally along some horizontal fractures. An important characteristic of these fractures is that they typically form a dense network that is highly visible on wetted, slabbed rock surfaces if the host sandstones and siltstones have high residual oil saturations (fig. 10). Such fractures are generally absent in rocks that have little or no residual oil.

A few fractures in the middle member are V-shaped and occluded with pyrite and fine- to coarse-crystalline calcite cement. These fractures, which tend to be small, resemble fluid-escape structures. Rare vertical extension fractures were identified in fine-grained sandstones from wells in the vicinity of the Nesson anticline. Like the fluid-release fractures, they are cemented with quartz and calcite (see fig. 9).

Fractures in the lower member typically are open bedding plane, or open hair-like vertical features. Irregular and blocky or smooth and conchoidal fractures are common in the more siliceous shales. One or more of these fractures may be healed with calcite or pyrite.

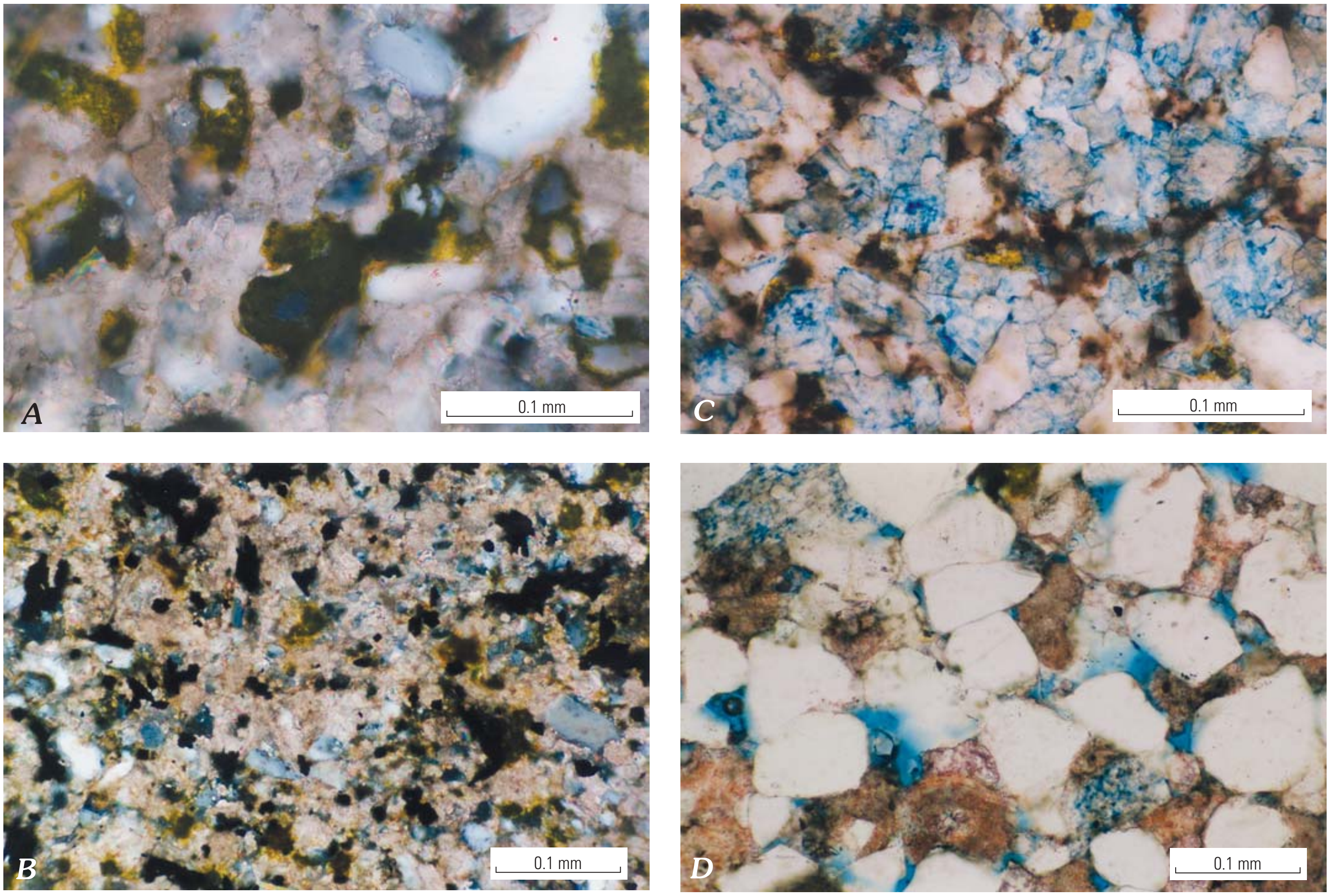

Figure 7. Thin section photomicrographs of sandstones illustrating *A*, occurrence and distribution of K-feldspar grains (stained yellow). Note presence of authigenic K-feldspar overgrowths on some detrital quartz grains, NDGS 9707; 3,185 m; *B*, disseminated pyrite (dark grains), NDGS 9707; 3,190 m; *C*, bitumen (opaque material) filling pores and permeating matrix, NDGS 9351; 3,189 m; and *D*, secondary intergranular porosity with relict carbonate cement (c) in pores, NDGS 4340; 3,023 m.

Time-Temperature History and Burial Diagenesis

The diagenetic evolution of the middle member of the Bakken Formation is depicted in conjunction with the reconstructed burial-thermal history of the unit in the deep part of the Williston Basin (fig. 11). The burial-thermal model takes into account differences in deposition and erosion, as well as variations in thermal regime during the basin's history. Thermal data constrain the maximum amount of erosion during the late Tertiary to about 500 m, which agrees closely with previously reported erosional estimates (Webster, 1984; Sweeney and others, 1992). The paleogeothermal gradient used in the model (~40°C/km; Gosnold, 1990) was assumed to be constant throughout most of the basin, except in the vicinity of the Nesson anticline, where thermal maturation data indicate that maximum burial temperatures were substantially higher despite maximum burial depths similar to those in areas away from the anticline (where the maximum burial temperatures were much lower) (Price and others, 1984; Sweeney and others, 1992; Burrus and others, 1996). Reservoir sandstones and siltstones generally are devoid of minerals suitable for isotopic dating; hence, absolute ages of individual events are difficult to establish. However, petrographic observations demonstrate that mineral diagenesis was more or less continuous until hydrocarbons entered the sandstones. The age of hydrocarbon expulsion thus places an upper limit on the timing of sandstone diagenesis. The temperatures used to bracket individual diagenetic events are based on experimental studies (Surdam and others, 1989).

Sandstones and siltstones in the middle member display a relatively simple diagenetic history owing to the closed, low-permeability nature of the petroleum system during most of its burial history (fig. 12). The major diagenetic events observed include (1) mechanical compaction, (2) development of minor quartz overgrowths, (3) precipitation of planar dolospar and syntaxial calcite, (4) crystallization of illite and chlorite, (5)

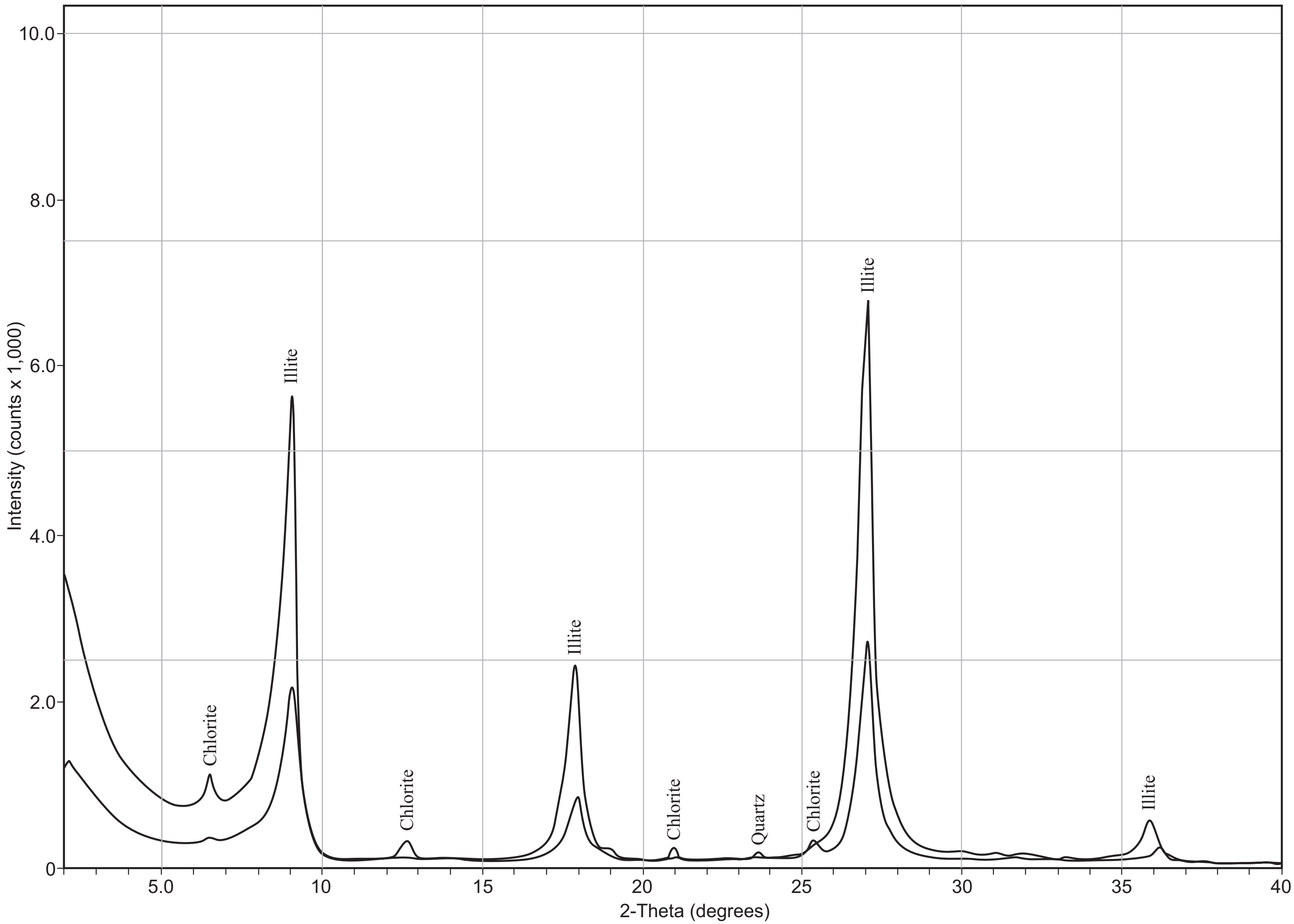

Figure 8. Graph showing relative peak heights of clay minerals in the <2-µm fraction of sandstones in the middle member of the Bakken Formation.

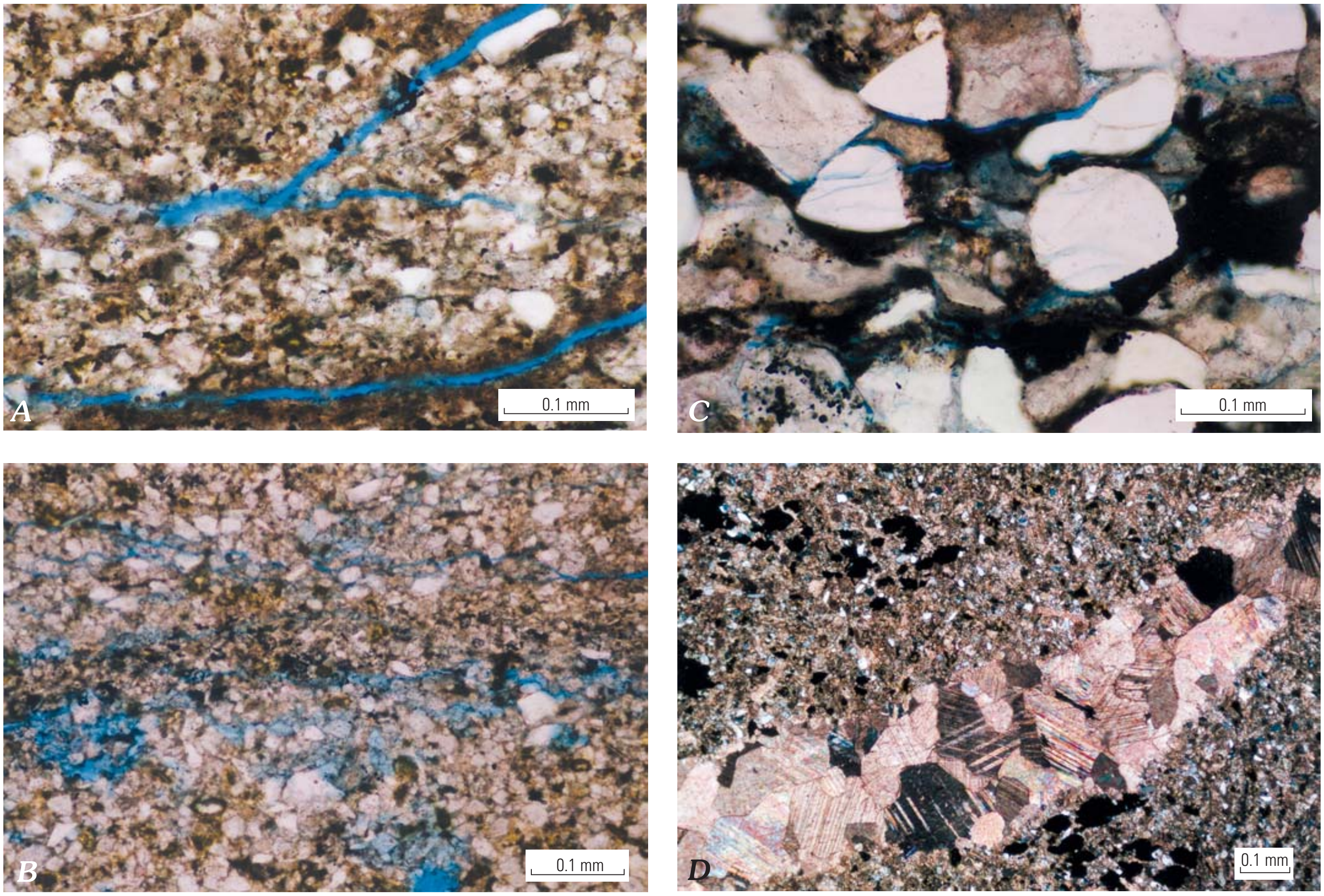

Figure 9. Thin section photomicrographs of sandstones depicting *A*, open (noncemented), discontinuous fractures parallel to bedding. Such fractures are abundant and form a pervasive network in sandstones adjacent to mature shales, NDGS 607, 3,223 m; *B*, secondary porosity associated with horizontal fracture swarms, NDGS 9707, 3,184 m; *C*, microscopic fractures cross-cutting framework quartz grains. Note bitumen filling secondary (?) intergranular pores, NDGS 105, 2,312 m, and *D*, calcite cemented vertical fracture, NDGD 9707, 3,186 m.

partial dissolution of dolospar(?) and calcite, (6) formation of grain-rimming ferroan dolomite and K-feldspar, and (7) hydraulic fracturing coincident with petroleum emplacement. Most diagenetic events began soon after burial and ended when oil entered the reservoirs in the Late Cretaceous. It is noteworthy that there are no substantial variations in authigenic mineral type related to changes in depositional facies across the basin. In addition, the paragenetic sequence remains relatively constant with no major changes in diagenesis relative to variations in thermal maturity or burial depth. A similar sequence of alterations has been reported for temporally equivalent, fine- to medium-grained sandstones in the middle member of the Bakken Formation in Manitoba, Canada (Last and Edwards, 1991).

The paragenetic sequence in reservoir sandstones and siltstones can be broadly divided into early and late stages based on interpretation of diagenetic events that are thought to be closely related (see fig. 12). Early events are associated with lithification and involve cementation and recrystallization or transformation reactions related to unstable detrital components. These events occurred soon after deposition and include precipitation of calcite and dolomite cements from neutral to weakly alkaline solutions at temperatures less than 80°C. Other reactions may have involved precipitation of secondary quartz and authigenic illite and chlorite. Spatial relationships indicate that silica in authigenic quartz was derived predominantly from chemical compaction of framework grains. Well-ordered illite is present in immature as well as mature samples; thus, it is probably mostly detrital, although it cannot be ruled out that some authigenic illite may have precipitated during burial. The lack of expandable layers even in samples that have never been deeply buried limits the ability of this 10Å mineral to act as a thermal maturity indicator. The origin of chlorite is uncertain; it may have formed by recrystallization of amorphous aluminosilicates or as an alteration product from degraded ferromagnesian minerals in shales.

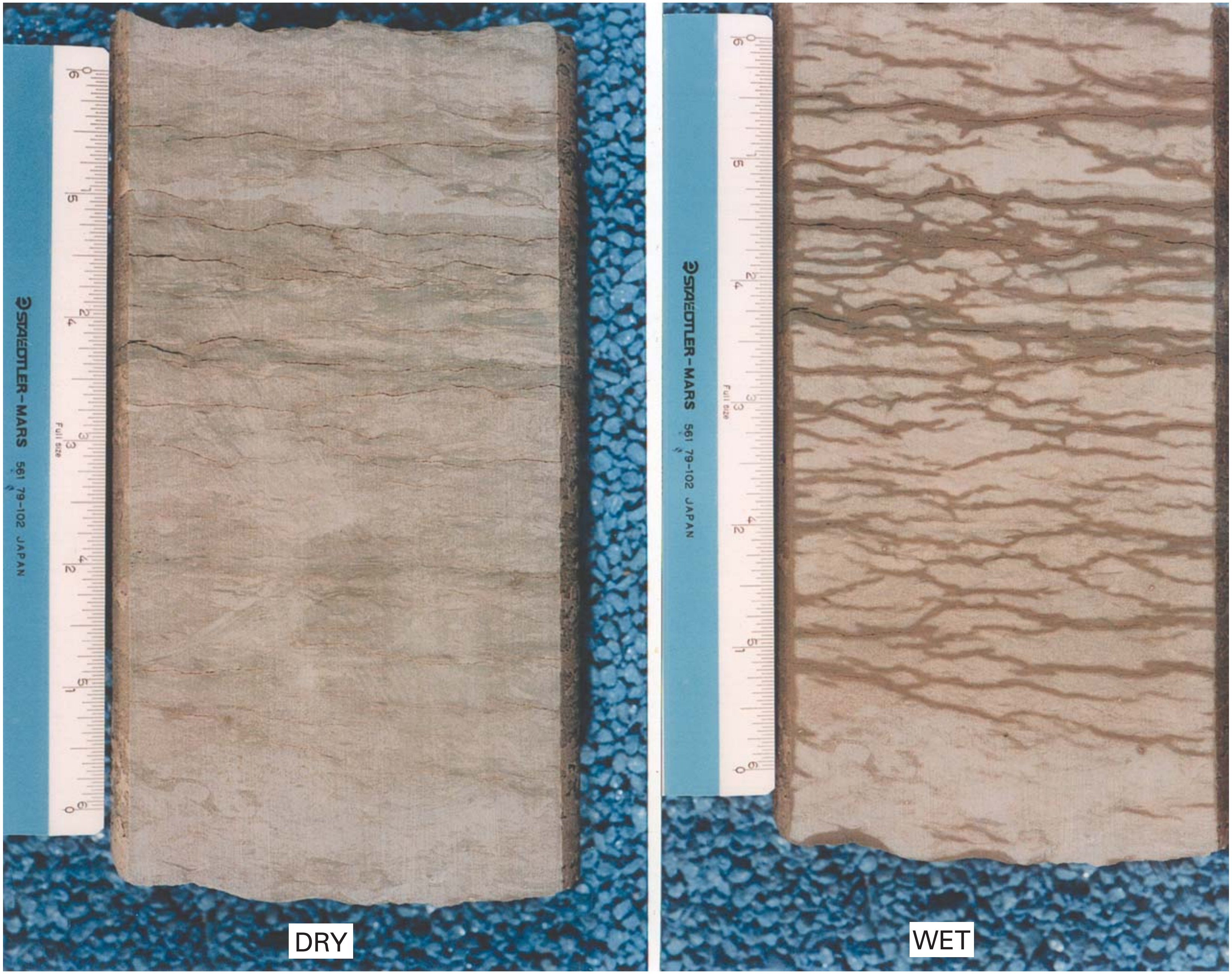

Figure 10. Slabbed sandstone displaying reticulated fracture network on wet surface. Note that the permeable nature and distribution of fractures are not apparent when surface is dry. NDGS 8902, 3,186 m.

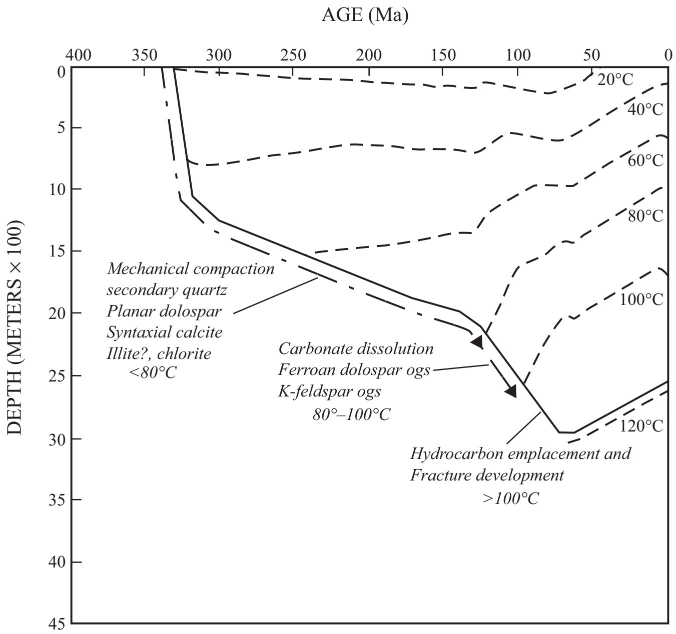

Figure 11. Reconstructed burial and thermal history curves of the Bakken Formation showing relative timing of major diagenetic events in the deep part of the Williston Basin. Textural features observed petrographically and age of hydrocarbon generation constrain timing of diagenesis. Paleoisotherms were modified from Sweeney and others (1992), and temperatures bracketing diagenetic events were taken from Surdam and others (1989).

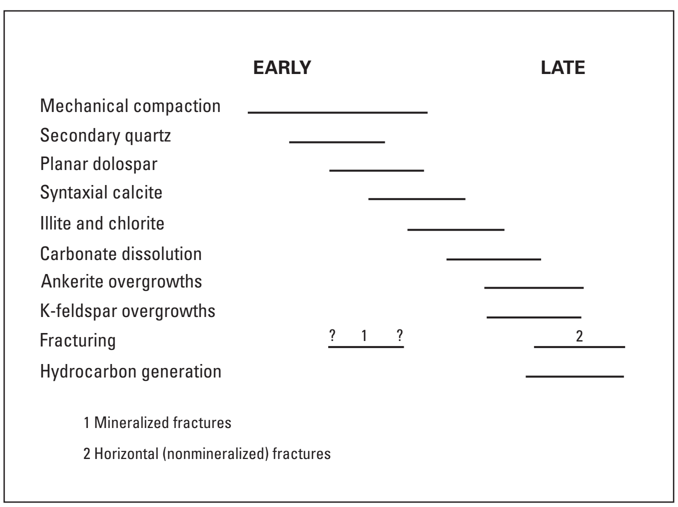

Figure 12. Chart depicting postdepositional events observed in sandstones and siltstones of the middle member of the Bakken Formation.

Late diagenetic alterations involved dissolution of earlier formed carbonate cements and precipitation of ferroan dolomite overgrowth cement and K-feldspar grain overgrowths. These alterations occurred before oil entered reservoir sandstones and are interpreted to have resulted from changes in temperature and pore-fluid chemistry associated with progressive burial of the sedimentary strata. The processes that controlled mineral dissolution are uncertain because the Bakken Formation is a sealed system with negligible fluid transmissibility. However, organic acids released during maturation of organic-rich shales may have come into contact with preexisting carbonate cements, causing local dissolution of these minerals. Experimental studies have shown that organic acids are present at temperatures of 80°–200°C and reach a maximum at 80°–100°C (Carothers and Kharaka, 1978), which is comparable to the temperature range (~80°–120°C) predicted for porosity-producing reactions in sandstones (Surdam and others, 1989). Iron and aluminum are mobile at temperatures approaching 100°C due to complexing with organic acids, which favors the formation of iron-bearing phases such as ferroan dolomite during deeper burial. The most likely source of iron for ferroan dolomite in sandstones in the middle member is sulfide minerals in the shales. An internal source of potassium from a preexisting mineral is favored for the formation of authigenic K-feldspar grain overgrowths. The common occurrence of early clay rims on quartz and feldspar grains, and illitic matrix, indicates that these phases may have been the source of the potassium ions incorporated into authigenic K-feldspar during late-stage diagenesis.

On the basis of the burial model, petroleum emplacement in the reservoir interval took place in the deep part of the basin in the Late Cretaceous when the sedimentary section was close to its maximum burial (~3,000 m) and temperature (110°–120°C). It is noteworthy that sandstones and siltstones in the middle member commonly display large increases in organic richness as a consequence of secondary oil migration when adjacent shales are mature and generating hydrocarbons, but they show little to no petroleum enrichment if the potential source rocks are thermally immature with little to no capacity to generate hydrocarbons. The distribution of oil in sandstones and siltstones associated with moderately mature to mature source rocks can be nonuniform, indicating that slight facies variations and the generally impermeable nature of the reservoir strata inhibited continuous movement of oil into these fine-grained rocks.

Reservoir Quality

Regional variations in reservoir quality of the middle member of the Bakken Formation were determined by evaluating conventional core analyses for 22 wells (North Dakota Geological Survey, unpub. data) (table 2). The most common geologic controls on sandstone porosity and permeability in unconventional reservoir rocks are thermal maturity, framework grain composition, and sorting. In the Bakken Formation, the thermal maturity of shales adjacent to sandstones can vary widely and thus can have an important influence on sandstone reservoir quality. Mineral composition, on the other hand, does not play an important role because there are only minor variations in detrital grain composition in sandstones and siltstones within and between wells. Sorting also is not a defining

Table 2. Wells used in reservoir quality analysis.

[See figure 2 for well locations. NDGS, North Dakota Geological Survey; T. N., Township (north); R. S., Range (south); Sec., section; m, depth in meters]

Map no.	Well ID (NDGS)	Well name	T. N.	R. S.	Sec.	Top, middle member (m)	Base, middle member (m)
A	3167	Texakota, Inc., Quale #1	153	95	31	3108.4	3121.8
B	4168	PelTex Inc. & Conoco, Drags Wolf #1	152	94	27	3222.0	3235.5
C	4297	Pan American Petroleum Corp., Hove #1	154	95	2	3021.2	3025.1
D	4958	John B. Hawley Jr. Trust #1, Ingerson #2	161	91	2	2310.4	2323.8
E	5656	Texakota, Inc., Borstad 1	157	95	3	2939.2	2948.6
F	7494	Pennzoil Expl. & Prod. Co., BN Depco #15-22	146	101	15	3336.0	3350.7
G	7851	Brooks Exploration, Rogstad	155	91	11	2860.9	2870.3
H	8069	Marathon Oil Co., Jensen #12-44	154	90	12	2795.0	2806.0
I	8251	Chambers Exploration, Chambers Citgo #1-24	143	102	24	3167.8	3169.3
J	8363	Coastal Oil & Gas Corp & ALAQ, BN #1	143	102	23	3157.4	3159.6
17	8637	Clarion Resources, Inc., Pierce #1-18	161	87	18	2060.3	2067.8
18	8638	Clarion Resources, Inc., Slater #1-24	161	91	24	2407.3	2419.2
19	8697	Clarion Resources, Inc., Pullen #1-33	159	88	33	2343.6	2350.9
20	8699	Clarion Resources, Inc., Fleckten #1-20	160	89	20	2332.9	2343.3
K	8824	C & K Petroleum, Inc., Koch #2-28	162	89	28	2145.5	2155.9
L	8902	Shell Oil Co., 33-23-154 USA	146	104	23	3234.8	3237.9
M	9569	Cities Service Co., Federal DG-1	145	100	34	3334.2	3341.8
23	9707	Shell Oil Co., 32-4 Young Bear BIA	148	92	4	3180.3	3191.3
N	11194	Texaco, Silurian 37 No. 1	153	95	18	3072.6	3086.3
25	11617	Edwin L. Cox & Berry R. Cox, Hagen #1-13	153	95	13	3158.6	3162.6
O	12886	Shell Western Expl. & Prod., Connell #24-27	144	102	27	3208.0	3209.8
P	13318	Conoco, Inc., Watterud "A" #17	160	95	11	2695.0	2704.5

parameter in the middle member inasmuch as most sandstones exhibit only small differences in sorting.

Porosity

Measured core porosities in the middle member range from 1 to 16 percent but generally are low, averaging about 5 percent (fig. 13). Only slight variations in porosity occur between individual lithofacies (table 3). A few high-pressure mercury injection measurements indicate in situ porosities are on the order of about 3 percent (Ropertz, 1994).

The relationship between thermal maturity and porosity development in the middle member was evaluated by plotting mean sandstone porosity versus depth of burial (fig. 14). Burial depth can be used to assess levels of thermal maturity and, in turn, to determine porosity development because the sedimentary section in most areas of the basin experienced only minor uplift and erosion before and after maximum burial and thus does not have to be restored to its original stratigraphic position. At burial depths less than 3,000 m, which correspond to low to moderate levels of thermal maturity, porosity values in sandstones and siltstones in the middle member fall within a relatively narrow range (from about 5 to 7 percent, with one exception). At depths greater than 3,000 m and high levels of thermal maturity, porosity displays a much broader range of values (from about 3 to 6 percent). The higher values in the upper part of the middle member likely reflect less advanced diagenesis in sandstones and siltstones in contrast to the deeper, more mature rocks that experienced both mechanical compaction—indicated by the lower porosity values—and an influx of oil—reflected by the higher porosity values.

Petrographic observations are consistent with porosity-depth trends showing that porosity in immature to moderately mature sandstones and siltstones (burial depths <3,000 m) is due primarily to mechanical compaction and mineral cementation. In deep, thermally mature rocks (depths >3,000 m), preserved porosity records the extent to which diagenesis had modified the sandstones before oil was emplaced from source shales. In sandstones with high porosity values, average 6 percent, migration of oil displaced residual water from matrix pores and terminated diagenesis, a process that preserved the existing porosity at the time of oil ingress despite increased burial of the stratigraphic section. A small fraction of this

Table 3. Porosity and permeability of facies in the middle member of the Bakken Formation.

[*, fractured interval]

Lithofacies	Mean porosity (percent)	Mean permeability (millidarcy)
1	3.7	0.01
2	5.5	0.22
3	7.0	*0.6
4	8.0	0.08
5	7.0	0.2
6	5.5	*48.5
7	0.02 to 12.8	*54.5

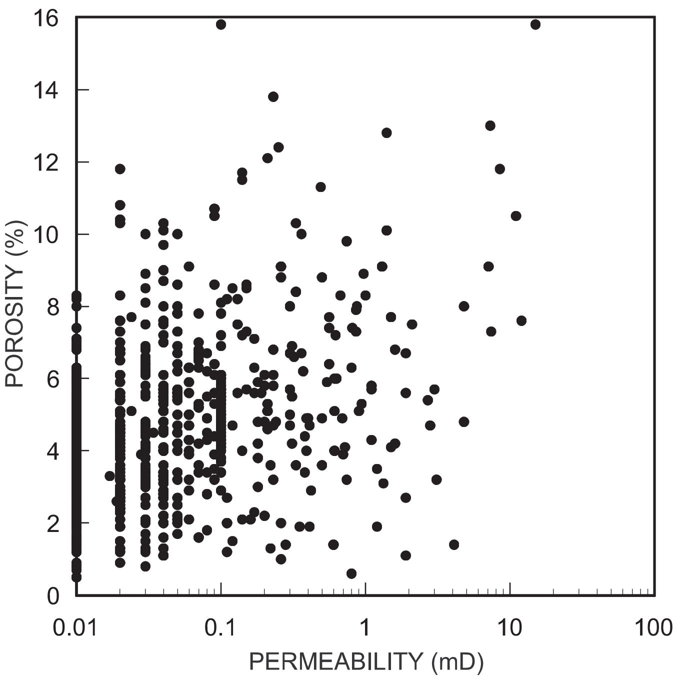

Figure 13. Plot of core porosity versus permeability in sandstones and siltstones of the middle member of the Bakken Formation. Each point represents a single value.

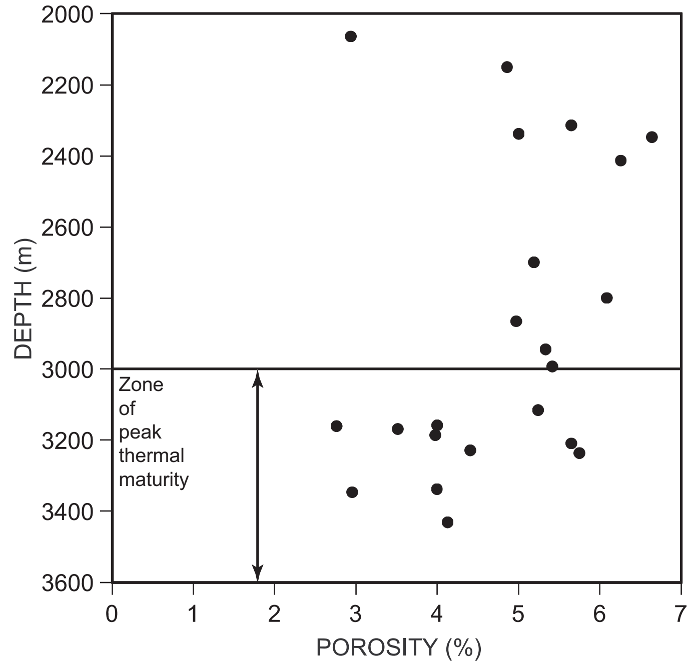

Figure 14. Plot of mean sandstone porosity versus burial depth in the middle member of the Bakken Formation. Each point represents a mean value for one well.

porosity may also be due to secondary dissolution processes.

Visible, intergranular porosity in sandstones and siltstones commonly is related to open natural fractures, whereas microporosity, which is invisible even at the highest optical resolution, is associated with the rock matrix. Intergranular porosity resulted from carbonate cement dissolution and is preserved locally along fracture margins in some sandstones.

Permeability

Measured permeability ranges from 0 to 20 millidarcies in the middle member and typically is very low, averaging 0.04 millidarcies (fig. 13). At any given depth, permeability in sandstones can vary markedly (fig. 15). It also can vary along with the thermal maturity of the source shales. As burial depth increases, permeability in sandstones has been shown to decrease from a range of about 0.06 to 0.01 millidarcies, where the adjacent shales are immature, to a range of about ≤0.01 to 0.01 millidarcies where these shales are mature. This decrease in permeability is attributed to carbonate precipitation in response to the generation of CO_2 during kerogen maturation of the shales.

Core studies reveal that reservoir rocks with permeability values greater than 0.01 millidarcies in the middle member commonly contain open, natural hydraulic fractures (see fig. 15 and table 3). Reservoir sandstones and siltstones adjacent to thermally immature, kerogen-poor shales typically are devoid of fractures and have lower permeabilities. In contrast, reservoir rocks associated with thermally mature, kerogen-rich shales generally have a high fracture density along with a large residual oil content (hence, significant permeability enhancement). The highest permeabilities in the middle member correspond to sandstones and siltstones with high residual oil concentrations and well-developed open fractures. At depths greater than 2,500 to 3,000 m, permeable fractures focus hydrocarbon fluids and locally serve as oil reservoirs.

Formation of Fractures

The distribution and frequency of open, horizontal fractures in the middle member of the Bakken Formation can be linked to source-rock thickness and level of thermal maturity,

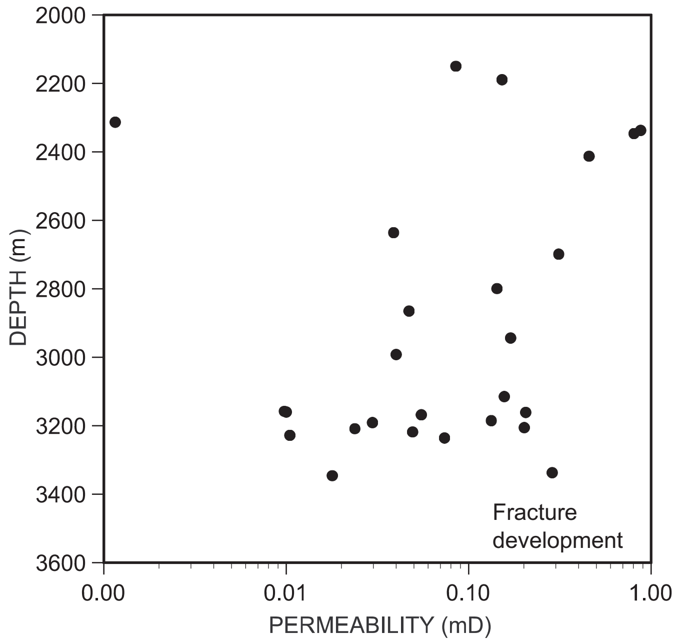

Figure 15. Plot of mean sandstone permeability versus burial depth in the middle member of the Bakken Formation. Each point represents a mean value for one well.

extent of hydrocarbon generation in shales bounding the reservoir unit, and proximity to source facies. The extent of fracture development also may be related to facies variations within reservoir strata. Sandstones and siltstones display virtually no horizontal fractures if the adjacent source rocks are thermally immature with little to no potential of generating oil. However, the concentration, density, and vertical distribution of fractures in the reservoir interval all dramatically increase as source rocks are progressively buried and proceed through the hydrocarbon-generation window. In areas where source rocks are at the onset of hydrocarbon generation, horizontal fracture development in the middle member increases toward the boundary of the upper and lower shales. The best developed and most extensive fracture network occurs in oil-saturated reservoir rocks adjacent to mature to over-mature source rocks that are actively generating hydrocarbons. The fractures in these rocks are highly visible when the rock is wet (see fig. 10), indicating they are highly permeable with excellent fluid-retention properties relative to the rock matrix, which has a very high capillary resistance to fluid flow.

Horizontal fracturing in the middle member is hypothesized to have resulted from expulsion of bitumen from upper and lower shales into interbedded, low-permeability sandstones and siltstones by means of early-generated CO_2 (Price and others, 1998). Large amounts of CO_2 can form in the organic-rich shales by H_2O chemically reacting with kerogen. In this reaction, hydrogen in H_2O is taken up by the kerogen and oxygen is given off as CO_2. Small amounts of carbon-normalized (C_1-C_4) gas, which can be substantial when normalized per rock weight, also are generated as part of this reaction. The uptake of H_2O by kerogen and generation of CO_2 and associated C_1-C_4 gases is a process in which the products of the reaction (oil and gas) increase in volume by about 150 percent relative to the reactant kerogen (Meissner, 1978; Price and Clayton, 1992). Increases in fluid volume due to this reaction in the Bakken resulted in the generation of superlithostatic pore pressures and, ultimately, primary migration of oil from mature shales in the lower and upper members into sandstones and siltstones in the middle member. The degree of abnormal pressure development and the extent of fracturing simultaneous with oil migration was a function of the organic richness, thickness, and maturity of the upper and lower shales. Fracture density in the middle member, whose source rocks have the same high levels of thermal maturity, can vary significantly as a function of source-rock thickness. Thus, reservoir strata associated with thick mature shales typically have more fractures than reservoir rocks associated with thin mature shales. The cross-cutting relations of fractures indicate that oil expulsion from the upper and lower shales did not occur during one event; rather, it took place episodically initiated by periodic pressure buildups in the source-rock interval (Meissner, 1978; Momper, 1980). These buildups indicate that the limestone units bounding the Bakken source system acted as pressure seals to the impermeable shales and sandstones.

Mineralized fluid-release and extension fractures formed during burial diagenesis and, unlike the hydrocarbon-generated fractures, have no capacity to take up or transmit fluids. The fluid-release fractures are interpreted to have formed during early burial in response to pressure release resulting from minor pore-pressure buildup during sediment dewatering and lithification. Extension fractures formed later in response to mild tectonic stress (i.e., Nesson anticline). The calcite cement filling fluid-release and extension fractures was derived mostly from marine carbonate rock with little input from organic matter, as indicated by $\delta^{13}C$ values ranging from +3.2 to –5.3 per mil (table 4; fig. 16). In well C12785 (3,450 m), fracture calcite contains secondary, two-phase fluid inclusions with consistent liquid-to-vapor ratios. Homogenization temperatures of the inclusions (110°–115°C) closely approximate the present-day reservoir temperature (~120°C), indicating that the burial depths in the past were not significantly greater than they are today. This finding agrees with the interpretation that little erosion occurred throughout the North Dakota portion of the Williston Basin.

Conclusions

Fine-grained sandstones and siltstones in the middle member of the Bakken Formation experienced diagenetic modification during their burial history that included mechanical compaction, precipitation of authigenic cements, and dissolution of mineral cements and detrital grains. These modifica-

Table 4. Stable isotope compositions of fracture-fill calcites in sandstones and siltstones of the Bakken Formation.

[See figure 2 for well locations. NDGS, North Dakota Geological Survey]

Well no.	Well ID (NDGS)	Depth (m)	$\delta^{13}C$ (per mil, PDB)	$\delta^{18}O$ (per mil, PDB)
Fluid-release fractures				
23	9707	3185	+2.6	–6.1
26	12785	3435	+2.1	–6.2
26	12785	3462	–5.3	–8.6
Extension fractures				
2	527	3434	–0.9	–7.9
2	527	3435	–0.8	–8.0
2	527	3436	–0.8	–8.0
23	9707	3186	+3.5	–6.2
26	12785	3449	–2.7	–6.5

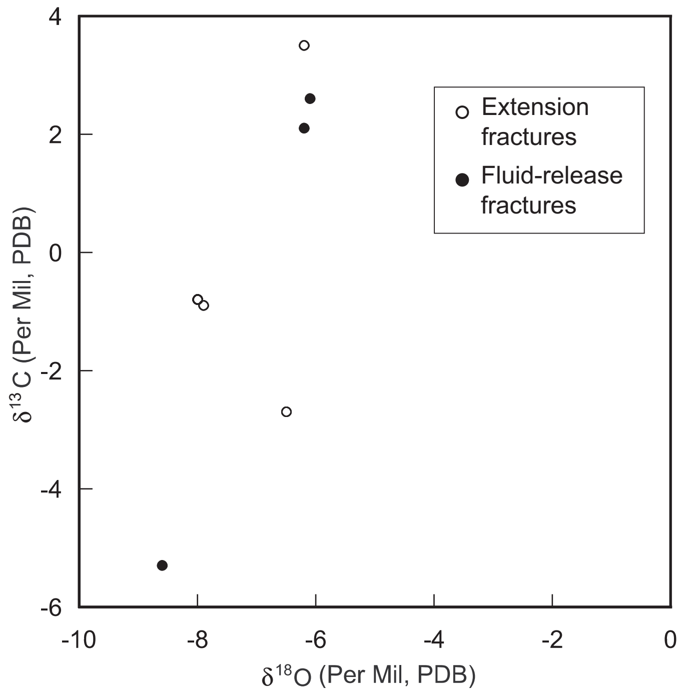

Figure 16. Cross-plot showing stable isotope compositions of fracture-fill calcite cements in the middle member of the Bakken Formation.

tions occurred before oil was emplaced in the sandstones and included precipitation of planar dolospar, syntaxial calcite, ferroan dolomite grain overgrowths, illite and chlorite, and authigenic K-feldspar. Oil migrating into the reservoirs displaced residual water from the matrix pores and prevented further diagenetic alteration from taking place in the sandstones and siltstones. Dissolution of carbonate cement and detrital grains also occurred during burial. On the basis of burial-thermal reconstruction and the age of hydrocarbon generation (Late Cretaceous), mineral diagenesis took place during sediment burial in late Paleozoic and Mesozoic time. Early diagenetic cements (dolospar and calcite) are interpreted to have formed at low to moderate temperatures (<80°C) during sediment compaction; late diagenetic cements (i.e., ferroan dolomite and authigenic K-feldspar) precipitated at elevated temperatures (~100°–110°C) during deep burial. Thermal conditions, maturation levels, and high concentrations of organic matter in the upper and lower shales are consistent with the formation of organic acids during the early stages of hydrocarbon generation just prior to or concurrent with maximum burial. The presence of such acids might explain the observed carbonate cement dissolution in the rock matrix and adjacent to hydraulic fractures.

Reservoir porosity of sandstones and siltstones in the middle member is poor, varying from 1 to 16 percent and averaging about 5 percent. Under in situ conditions, porosity is as low as 3 percent. Most porosity in the middle member is associated with open, hydrocarbon-generated fractures; some secondary porosity caused by organic acids is also associated with fractures. Permeability in sandstones and siltstones ranges from about 0 to 20 millidarcies and averages 0.04 millidarcies. Permeability values greater than 0.01 millidarcies are associated with rocks that have high residual oil saturations and a high incidence of hydraulically induced fractures.

Most oil in the Bakken petroleum system resides in open, horizontal (bedding-parallel) fractures and in secondary microporosity adjacent to fractures, with only small amounts dispersed in matrix pores. Horizontal fractures form a pervasive network in deeply buried reservoir rocks with high residual oil saturations, but they are generally absent in shallowly buried rocks with little to no residual oil. These fractures resulted from superlithostatic pressures that formed in response to increased fluid volumes in the source rocks during hydrocarbon generation. Unlike mineralized fractures that are incapable of transmitting fluids, porous and permeable horizontal fractures serve to focus hydrocarbon fluids and locally enhance the quality of oil reservoirs at depth.

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