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DIAGENETIC CONTROLS ON RESERVOIR PROPERTIES OF LOW-PERMEABILITY SANDSTONE, FRONTIER FORMATION, MOXA ARCH, SOUTHWEST WYOMING

TOPICAL REPORT

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DISCLAIMER

RESEARCH SUMMARY

Title	Diagenetic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708, entitled "Geologic Analysis of Primary and Secondary Tight Gas Sands Objectives."
Principal Investigator	S. P. Dutton
Report Period	April 1989 - January 1991 Topical Report
Objectives	To determine the composition of Frontier Formation sandstones, document their diagenetic history, and investigate how diagenesis has modified reservoir porosity and permeability.
Technical Perspective	Since 1982, the Gas Research Institute (GRI) has supported geologic investigations designed to develop knowledge necessary to efficiently produce natural gas from low-permeability sandstone reservoirs. As part of that program, the Bureau of Economic Geology has conducted research on low-permeability sandstone in the Upper Cretaceous Frontier Formation along the Moxa Arch in the Green River Basin, southwest Wyoming. Diagenetic history is one important factor that influences reservoir quality in these sandstones. Although the Frontier Formation has generally low permeability and has been designated a tight gas sandstone, diagenetic variations contribute to significant reservoir-quality differences within and between fields along the Moxa Arch.
Results	The Upper Cretaceous Frontier Formation, a low-permeability gas reservoir along the Moxa Arch in southwest Wyoming, comprises marine and nonmarine facies deposited in a fluvial-deltaic depositional system. The Second Frontier interval is present along the entire Moxa Arch and contains the most prolific Frontier gas reservoirs. Clean sandstone in the Second Frontier commonly occurs in marine upper-shoreface facies and fluvial channel-fill facies. According to petrographic examination of 199 thin sections, Frontier sandstones are fine- to medium-grained litharenites and sublitharenites having an average composition of 64 percent quartz, 6 percent feldspar, and 30 percent rock fragments. Clean sandstones contain an average of 1.6 percent primary intergranular porosity and 4.4 percent secondary porosity, which formed by dissolution of feldspar, chert, and mudstone clasts. Microporosity, estimated as the difference between porosimeter and thin-section porosity, averages 6 percent. Calcite, quartz, mixed-layer illite-smectite, and illite are the most abundant cements. Authigenic mixed-layer clays consist of about 80 percent illite layers, suggesting that clays may be only moderately sensitive to fresh water. On the basis of petrographic evidence, the relative order of

occurrence of the major events in the diagenetic history of Frontier sandstones were (1) mechanical compaction by grain rearrangement and deformation of ductile grains, (2) formation of illite and mixed-layer illite-smectite rims, (3) precipitation of quartz overgrowths, (4) precipitation of calcite cement, (5) generation of secondary porosity by dissolution of calcite cement and detrital feldspar, chert, and mudstone, and (6) chemical compaction by intergranular pressure solution and stylolitization.

Low permeability in Frontier sandstones is caused by (1) loss of porosity due to compaction, (2) occlusion of pores by cements, particularly calcite and quartz, and (3) lining of primary pores by fibrous illite. Unstressed permeability to air averages 0.21 md in 56 upper-shoreface sandstones (porosity = 15 percent), 0.14 md in 121 fluvial channel-fill sandstones (porosity = 10 percent), and 0.08 md in 279 lower-shoreface sandstones (porosity = 12 percent).

Technical Approach

The composition of Frontier sandstones was determined using core samples from 11 wells on and adjacent to the Moxa Arch. Most cores were from the First and Second Benches of the Second Frontier, but cores of the First Frontier and the Third and Fourth Benches of the Second Frontier also were studied. From each core, representative samples were selected from different facies and from the total depth range available. Composition of Frontier sandstones and mudstones was determined by standard thin-section petrography, scanning electron microscopy (SEM) with an energy dispersive X-ray spectrometer (EDX), electron microprobe analysis, and X-ray analysis. Analyses of more than 600 core plugs form the data base for porosity and permeability. All porosity and permeability samples were measured under unstressed conditions, and some were also measured under stressed conditions, at calculated in situ overburden pressure.

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INTRODUCTION

The Frontier Formation produces gas from low-permeability ("tight gas") sandstone reservoirs along the Moxa Arch in the western Green River Basin, Wyoming. Diagenetic history is one important factor that influences reservoir quality in these sandstones. Although the Frontier Formation has generally low permeability and has been designated a tight gas sandstone, diagenetic variations contribute to significant reservoir-quality differences within and between fields along the Moxa Arch. The purpose of this study was to investigate how the diagenetic history of the sandstones has modified reservoir porosity and permeability. Although this paper focuses only on the control of diagenesis on reservoir quality of Frontier sandstones, many other factors, including depositional environment (Dutton and Hamlin, 1991) and the presence of natural fractures (Laubach, 1991), also influence Frontier reservoir properties.

The Frontier Formation is being studied in a program of geologic investigations of low-permeability sandstones supported by the Gas Research Institute (GRI). This geologic research is just one aspect of a broad, multidisciplinary program designed to increase knowledge and ultimate recovery of unconventional gas resources through integration of geology, log analysis, reservoir engineering, and fracture modeling.

This report presents one component of the geologic study of the Frontier Formation: determining the composition of Frontier sandstones, their diagenetic history, and the causes of their low permeability. Previous studies of the diagenesis of the Frontier Formation along the Moxa Arch (Winn and Smithwick, 1980; Stonecipher and others, 1984; Winn and others, 1984; and Schultz and Lafollette, 1989) have provided the foundation upon which this study builds. Most of the previous work concentrated on the central part of the Moxa Arch (T20N to T24N). This study extends evaluation of the Frontier Formation farther to the north (to T28N) and south (to T17N), as well as to the east, off the Moxa Arch in the Green River Basin.

GEOLOGIC SETTING

The Green River Basin is a large Rocky Mountain basin with abundant natural gas reserves (Crews and others, 1973; Law and others, 1989). The most prolific area of Frontier gas production occurs along the Moxa Arch, a broad, gently folded intrabasin uplift paralleling the Thrust Belt on the western margin of the basin (fig. 1). Depth to the Frontier Formation increases from north to south along the Moxa Arch, ranging from about 6,000 ft to 15,000 ft below ground surface. The Frontier dips steeply eastward of the Moxa Arch into the Green River Basin (fig. 1). The La Barge Platform, which encompasses the intersection between the northern end of the Moxa Arch and the Thrust Belt, is the largest Frontier gas-producing area in the basin and includes Big Piney, La Barge, Hogsback, Tip Top, Chimney Butte, and other important Frontier fields (fig. 2). Other Frontier fields, including Fontenelle, Whiskey Buttes, and Church Buttes, extend southward down the arch from the La Barge Platform (fig. 2).

The Upper Cretaceous Frontier Formation is 200 to 1,500 ft thick, and it consists of marine and nonmarine sandstone and mudstone. The First Frontier marine sandstone occurs only at the north end of the Moxa Arch, and it is separated from the Second Frontier by several hundred feet of marine mudstone (fig. 3). The Second Frontier extends the length of the arch (fig. 4) and contains the most prolific gas reservoirs. At the north end of the arch, the Second Frontier is divided into several sandstone benches (B1 through B5, fig. 3). The Second Bench forms the main reservoir. At the south end of the Moxa Arch, the Second Frontier generally contains only one or two sandstones (fig. 4). The Third and Fourth Frontier underlie the Second Frontier at the north, but they grade into the upper Mowry Shale at the south end of the Moxa Arch.

The Second Frontier interval formed in an eastward-prograding fluvial-deltaic depositional system (Moslow and Tillman, 1986 and 1989; Myers, 1977; Winn and others, 1984). Most of the Second Frontier sandstone occurs in fluvial channel-fill and marine shoreface facies. Rivers

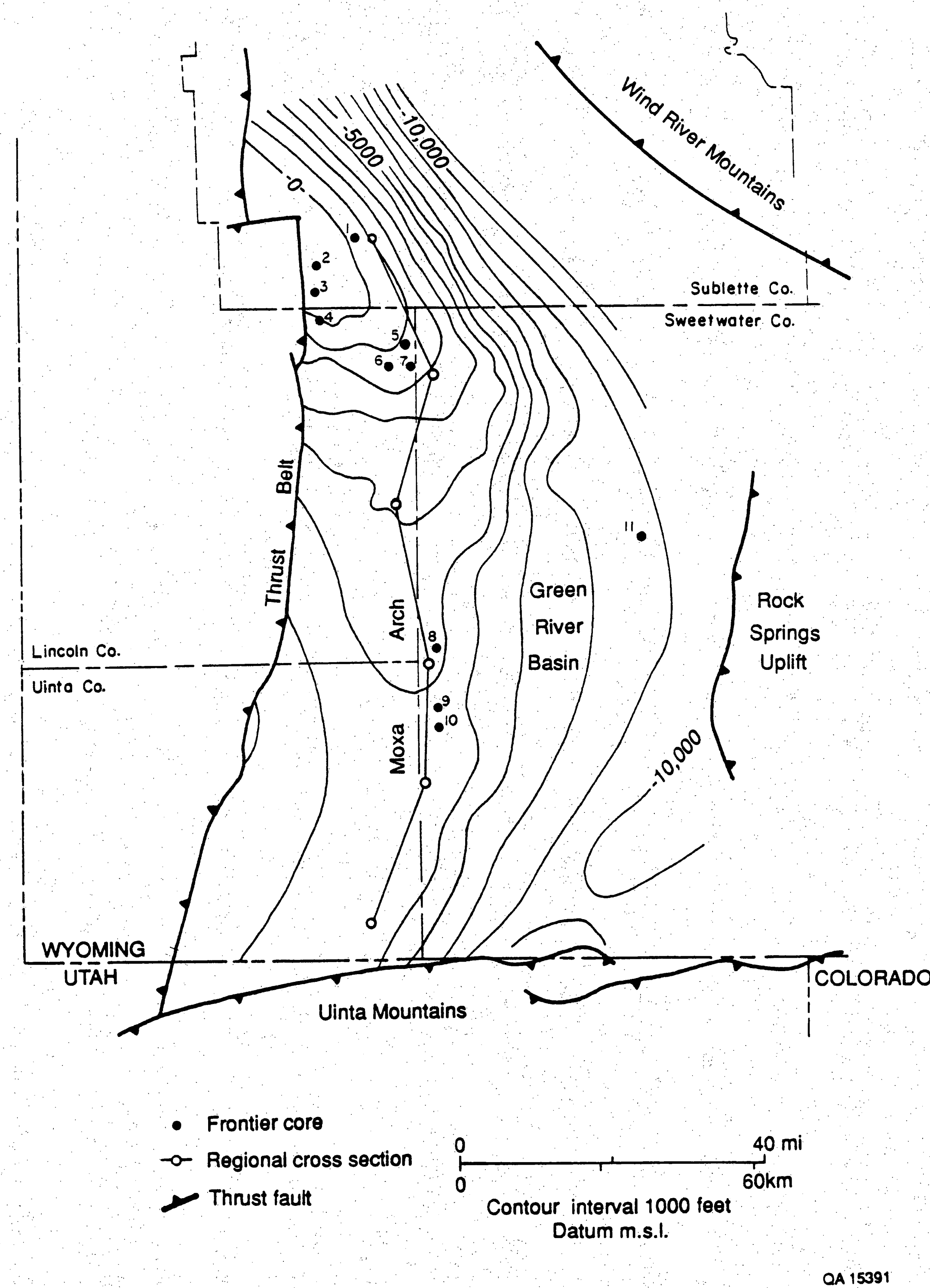

Figure 1. Structure contour map of the top of the Second Frontier Sandstone, showing major structural elements of the western Green River Basin (from Dutton and Hamlin, 1991). Location of wells from which Frontier cores were taken is also shown; see table 1 for well names. The north-south cross section along the Moxa Arch is shown in fig. 4.

Table 1. Frontier cores used in this study.

	Well and field	County	Depth (ft)
1.	S. A. Holditch & Associates SFE No. 4-24 Chimney Butte field	Sublette	6,777-6,796; 7,226-7,240.2; 7,310-7,493; 7,607-7,647; 7,753-7,785; 7,963-8,004
2.	Mobil Tip Top No. T71X-6G-28N-113W Tip Top field	Sublette	6,970-7,030
3.	Mobil Hogsback No. T72X-29G-28N-113W Hogsback field	Sublette	6,369-6,396; 6,856-6,941
4.	Enron South Hogsback No. 13-8A South Hogsback field	Lincoln	7,006-7,284
5.	Natural Gas Corporation of California No. 32-31 Federal, Fontenelle field	Lincoln	8,541-8,572
6.	Natural Gas Corporation of California No. 41-14E Federal, Fontenelle field	Lincoln	8,613-8,640; 8,652-8,710
7.	Terra Resources (Pacific Enterprises) Anderson Canyon No. 3-17, Fontenelle field	Lincoln	9,015-9,142; 9,151-9,188
8.	Texaco State of Wyoming UNCT 2 No. 1 Bruff field	Sweetwater	11,501-11,550
9.	Wexpro Church Buttes No. 41 Church Buttes field	Sweetwater	12,186-12,245
10.	Wexpro Church Buttes No. 48 Church Buttes field	Sweetwater	12,045-12,072; 12,145-12,203
11.	Energy Reserves Group No. 1-30 Blue Rim Federal, wildcat	Sweetwater	16,053-16,134

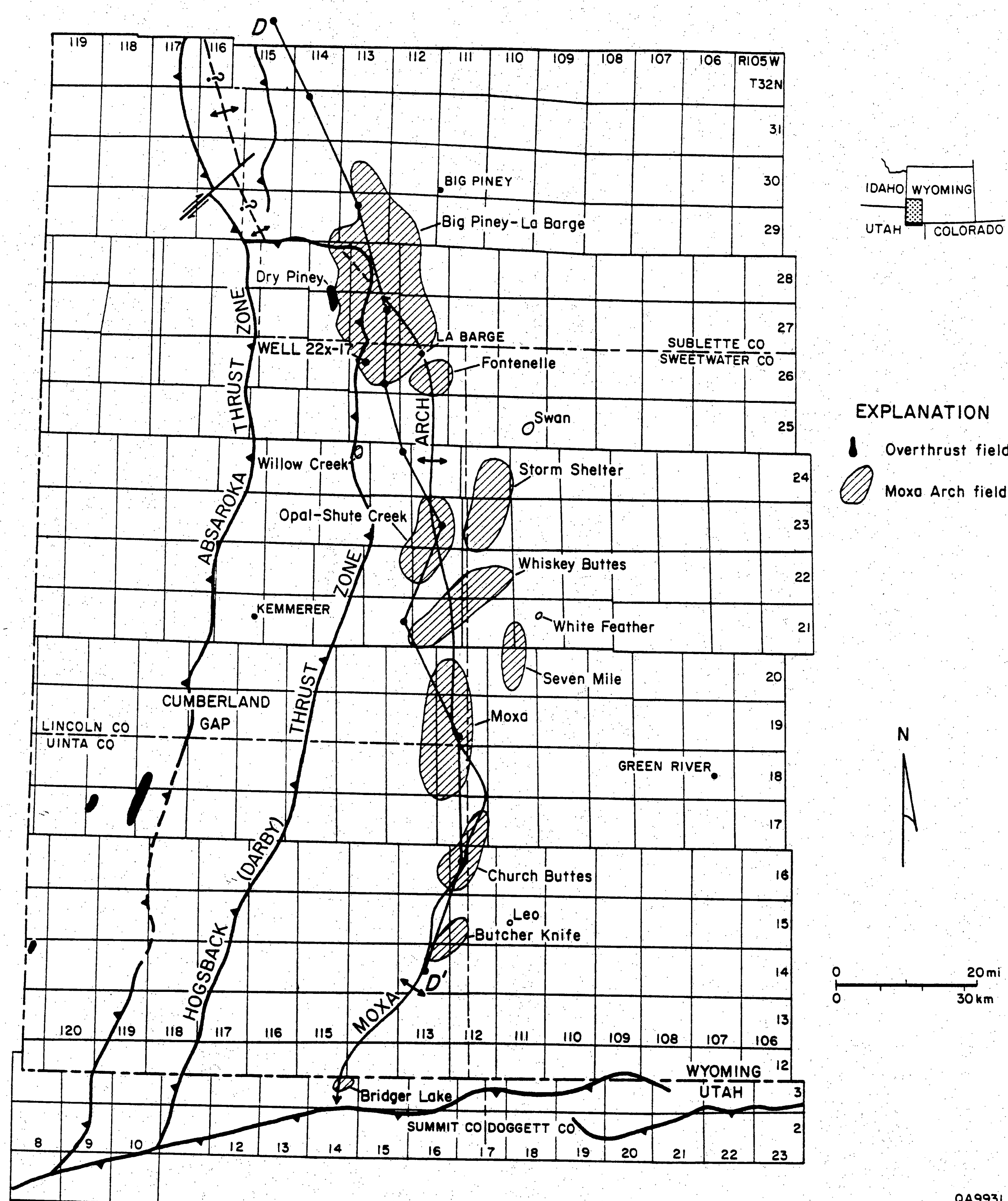

Figure 2. Map of major Frontier fields associated with the Moxa Arch, western Green River Basin (from Baumgardner and others, 1988; modified from Wach, 1977, fig. 1).

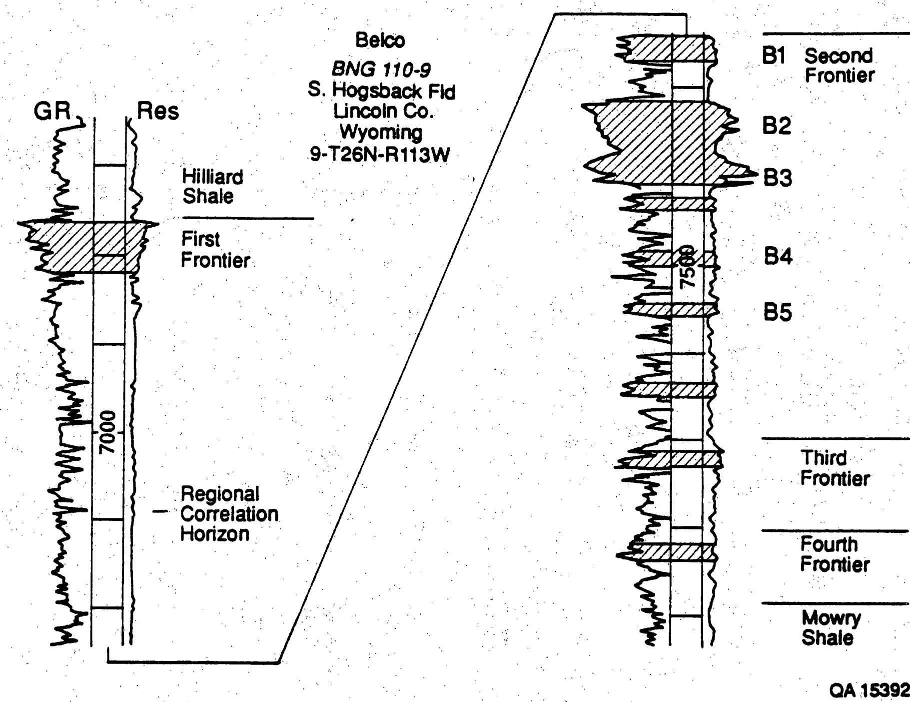

Figure 3. Typical gamma-ray/resistivity log, Frontier Formation, northern Moxa Arch (from Dutton and Hamlin, 1991). Frontier sandstones are shaded.

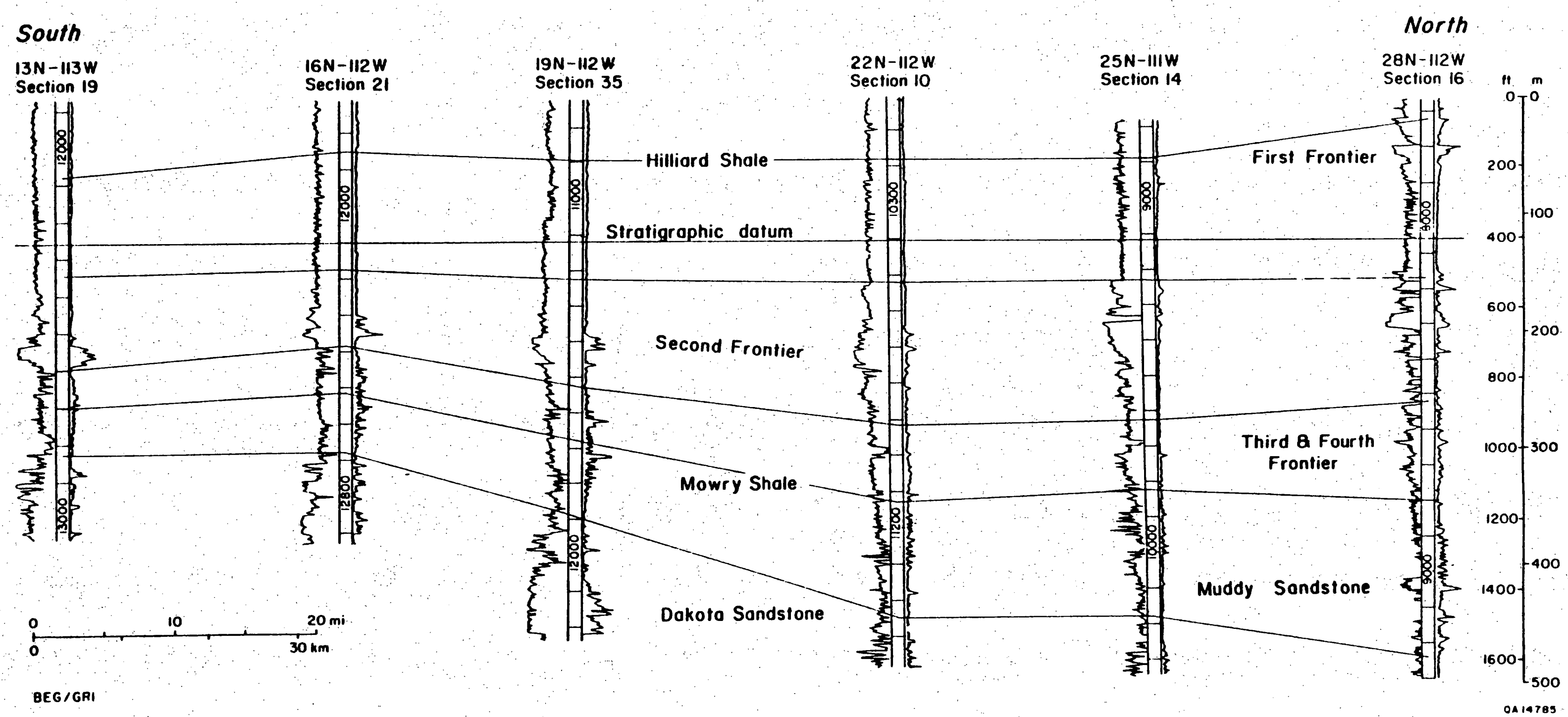

Figure 4. Regional north-south, gamma-ray/resistivity cross section along the Moxa Arch (from Dutton and Hamlin, 1991). Line of section shown in fig. 1.

transported sand to the coast, where wave- and wind-driven currents redistributed it along the shoreline. The shoreface sandstones form broad shore-parallel sheets, whereas the fluvial channel-fill sandstones form narrow belts oriented perpendicular to the shoreface (Hamlin and Buehring, 1990; Dutton and Hamlin, 1991). Along the south part of the Moxa Arch, the fluvial channels commonly eroded into the underlying marine shoreface (Moslow and Tillman, 1986 and 1989; Schultz and Lafollette, 1989).

Most marine shoreface sandstones in the Second Frontier comprise a lower bioturbated part and an upper well-stratified part (figs. 5, 6). Lower shoreface deposits consist primarily of muddy sandstone in which stratification was destroyed by burrowing organisms. Upper shoreface deposits are characterized by clean, well-sorted sandstone with horizontal, planar stratification and high-angle cross stratification. Fluvial channel-fill deposits on the La Barge Platform generally contain less clean sandstone than do the marine shoreface facies (Dutton and Hamlin, 1991). Mud rip-up clasts are abundant at the base of channels, and the upper parts of channel-fill sandstones contain clay laminations and contorted beds of sandstone and mudstone that formed along the channel margins.

METHODS

Frontier cores were available from 11 wells on and adjacent to the Moxa Arch (fig. 1). Ten of the cores were from three areas along the Moxa Arch: (1) the Hogsback area (wells 1-4, fig. 1) on the La Barge Platform, (2) the Fontenelle area (wells 5-7, fig. 1) southeast of Hogsback, where the arch changes from northwest-southeast to north-south orientation, and (3) the Church Buttes-Bruff area (wells 8-10, fig.1), along the southern part of the arch. Three of these cores are from cooperative wells that were sampled by GRI in conjunction with operators: Terra Resources (now Pacific Enterprises) Anderson Canyon No. 3-17, Wexpro Church Buttes No. 48, and Enron South Hogsback No. 13-8A (table 1). Core was also available from the S. A. Holditch & Associates Staged Field Experiment (SFE) No. 4 well. This was a research well drilled by GRI on a

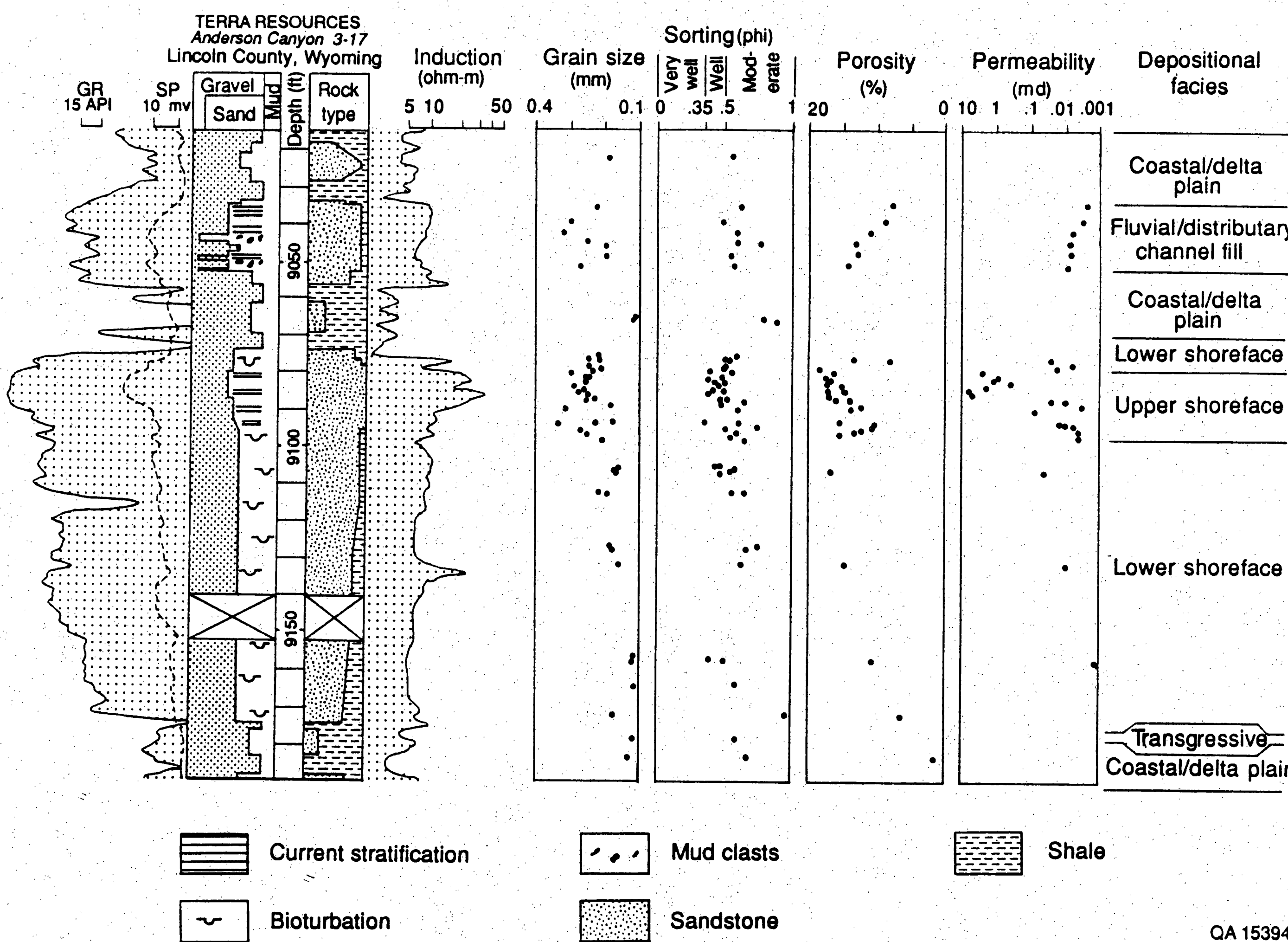

Figure 5. Log response and rock properties in core from the First and Second Benches of the Second Frontier, Terra Anderson Canyon No. 3-17 well, Fontenelle field (from Dutton and Hamlin, 1991).

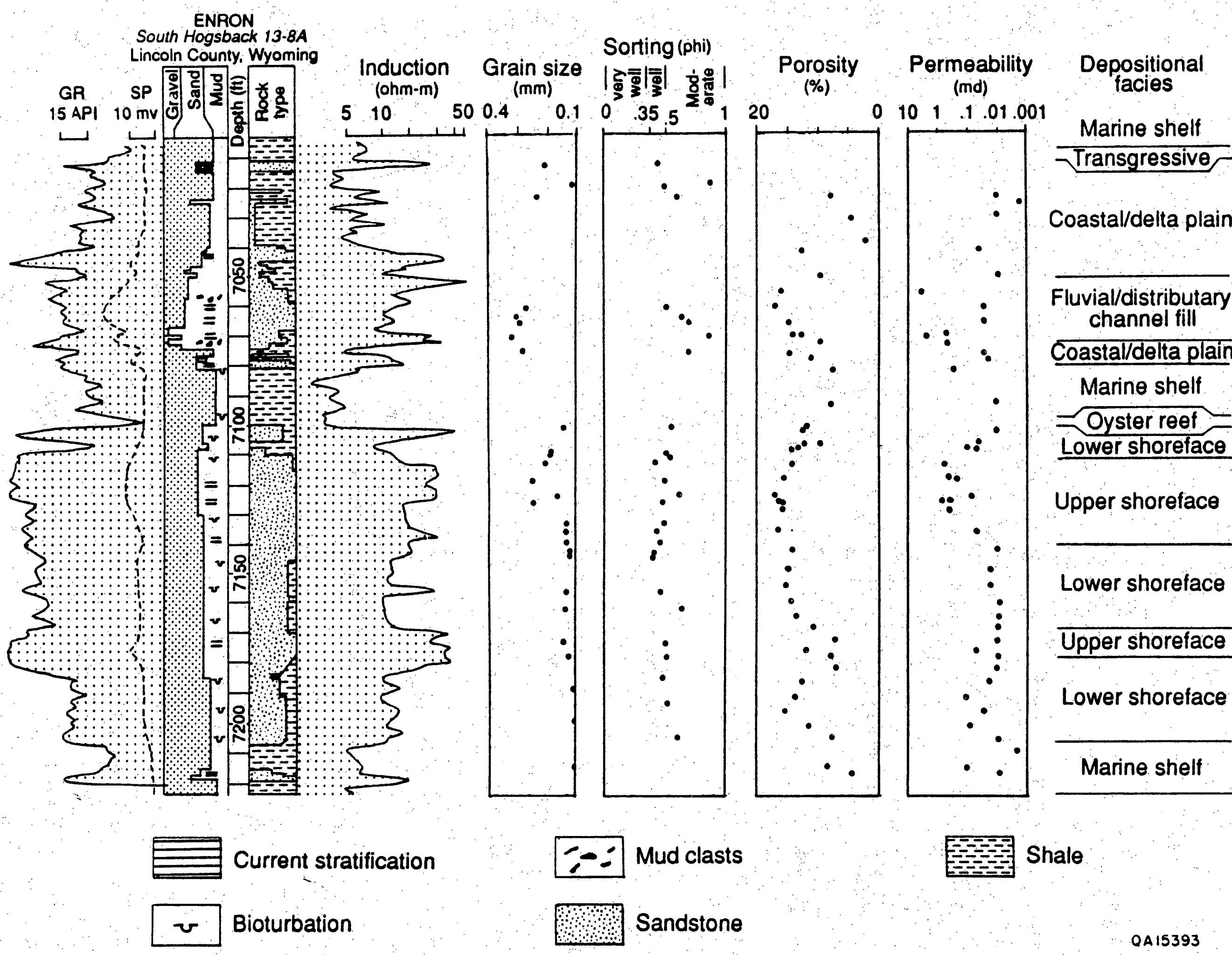

Figure 6. Log response and rock properties in core from the First and Second Benches of the Second Frontier, Enron South Hogsback No. 13-8A well, South Hogsback field.

lease acquired through the cooperation and assistance of Enron Oil and Gas Company. The other cores used in the study were made available by operators. Most cores were from the First and Second Benches of the Second Frontier, but cores of the First Frontier and the Third and Fourth Benches of the Second Frontier also were studied.

Analyses of more than 600 core plugs form the data base for porosity and permeability. All samples were measured under unstressed conditions, that is, under ambient, or near ambient pressure (0 or 800 psi confining pressure), and some were also measured under stressed conditions, at calculated in-situ overburden pressure. Porosity was measured by helium injection, and permeability measurements were made on dried, extracted plugs using nitrogen gas or air as the fluid. Contribution to effective reservoir permeability by natural fractures was not considered in this study.

The composition of Frontier sandstones was determined from 199 thin sections selected from different facies and from the total depth range in each core. Of these, 149 thin sections are from the ends of core-analysis plugs. Only thin-sections that are directly comparable to core-analysis plugs were used to compare petrographic and petrophysical data. Standard thin-section petrography, scanning electron microscopy (SEM) with an energy dispersive X-ray spectrometer (EDX), electron microprobe analysis, and X-ray analysis were used to identify and determine the chemical composition of detrital and authigenic components of sandstone and mudstone. Thin sections were stained with sodium cobaltinitrite (potassium feldspars) and with potassium ferricyanide and alizarin red-S (carbonates). Point counts (200 points) determined mineral composition and porosity. Grain size and sorting of framework grains were measured by grain-size point counts (50 points) of the apparent long axis of grains. By comparing point-count data of thin sections with core analyses, the influence of parameters such as grain size, sorting, compaction, volume of authigenic cements, and pore type (primary versus secondary) on porosity and permeability was determined.

FRONTIER COMPOSITION

The Frontier Formation in the study area is composed mainly of sandstones, muddy sandstones, and sandy mudstones. Of 119 clean Frontier Formation sandstones (defined in this report as containing ≤2 percent detrital clay matrix), 66 are fine grained (0.125 to 0.25 mm) and 43 are medium grained (0.25 to 0.5 mm). Clean Frontier sandstones are mostly well sorted (0.35 to 0.5ϕ) to moderately well sorted (0.5 to 0.71ϕ), according to the definition of Folk (1974). Because grain size was measured only on sand and silt grains, mean grain size and sorting in sandstones with abundant detrital clay-sized grains refers only to the population of framework grains.

Frontier Formation sandstones, particularly those that were deposited in lower shoreface environments, have varying amounts of clay matrix mixed with the sand- and silt-sized grains. The volume of matrix in lower shoreface sandstones varies mostly from 5 percent to 30 percent; volume of clay typically decreases upwards in these progradational shoreline sandstones. Fluvial channel-fill and upper shoreface sandstones contain an average of 1 percent and 2 percent matrix, respectively (table 2).

Mudstones in the Frontier Formation formed in nonmarine floodplain and marine-shelf environments. Floodplain mudstones typically contain between 30 percent and 75 percent clay-sized grains; the remaining volume is mostly sand- and silt-sized grains of quartz. Marine-shelf deposits above the Second Frontier sandstone were cored in the Enron S. Hogsback No. 13-8A and Wexpro Church Buttes No. 48 wells. These deposits are also mudstones that contain 30 percent to 75 percent clay-sized grains.

The finest grained deposits in the Frontier Formation are bentonite beds in the Third and Fourth Benches of the Second Frontier. Bentonite is defined as aggregates of clay, largely smectite, formed by in situ alteration of volcanic ash (Blatt and others, 1972). These beds are composed of more than 90 percent clay-sized grains and are classified as claystones.

Table 2. Average composition of Frontier sandstones by depositional environment.

	Fluvial channel $Q_{57}F_6R_{37}$ (n = 60)	Upper Shoreface $Q_{67}F_3R_{30}$ (n = 48)	Lower Shoreface $Q_{69}F_5R_{26}$ (n = 53)
Grain size (mm)	0.25	0.19	0.14
Sorting (phi standard deviation)	0.55	0.49	0.52
Detrital clay matrix (%)	1	2	9
Quartz cement (%)	8	4	2
Calcite cement (%)	3	3	6
Total cement (%)	15	11	10
Thin-section primary porosity (%)	0.9	2.2	0.7
Thin-section secondary porosity (%)	2.6	6.1	3.4
Porosimeter porosity (%)	10.3 (n=124)	14.6 (n=57)	12.4 (n=292)
Unstressed permeability (md) (Mean of log values)	0.14 (n=121)	0.21 (n=56)	0.08 (n=279)
Stressed permeability (md) (Mean of log values)	0.015 (n=46)	0.06 (n=39)	0.01 (n=177)

Sandstone composition can be divided into four parts: (1) framework (i.e., detrital) grains, (2) matrix, (3) porosity, and (4) cement (i.e., authigenic minerals). The relative abundance of each of these four categories has an important influence on permeability.

Framework Grains

Frontier Formation sandstones are mainly litharenites to sublitharenites having an average composition of 64 percent quartz, 6 percent feldspar, and 30 percent rock fragments ($Q_{64}F_6R_{30}$) (fig. 7). The relative proportion of the essential framework grains is quite variable. (Essential framework grains are those used to classify sandstones: quartz, feldspar, and rock fragments.) Detrital quartz composes an average of 48 percent of the total rock volume in clean sandstones and forms between 26 percent and 89 percent of the essential constituents.

Plagioclase composes an average of 4 percent of the total sandstone volume and 0 to 67 percent of the essential framework grains. Orthoclase feldspar is lacking in most samples. Feldspar content was greater at the time of deposition because some feldspar has been lost by dissolution or replacement by carbonate cements. The original feldspar content can be estimated from petrographic data. Secondary porosity forms an average volume of 4.4 percent of Frontier sandstones, and approximately half is estimated to have formed by feldspar dissolution. Carbonate cement has an average volume of 4.7 percent; approximately half is estimated to replace feldspar. Therefore, the original feldspar content may have been about 8 percent of the total rock volume, and the original sandstone composition was approximately $Q_{60}F_{11}R_{28}$.

Plagioclase grains vary from fresh to sericitized and vacuolized. Partial to complete dissolution of plagioclase along cleavage planes results in delicate honeycombed grains and secondary porosity. Plagioclase grains in the Frontier Formation have been extensively albitized. Feldspars from 4 Frontier sandstones were analyzed by electron microprobe to determine major-element composition. Plagioclase composition in 156 analyses ranges from

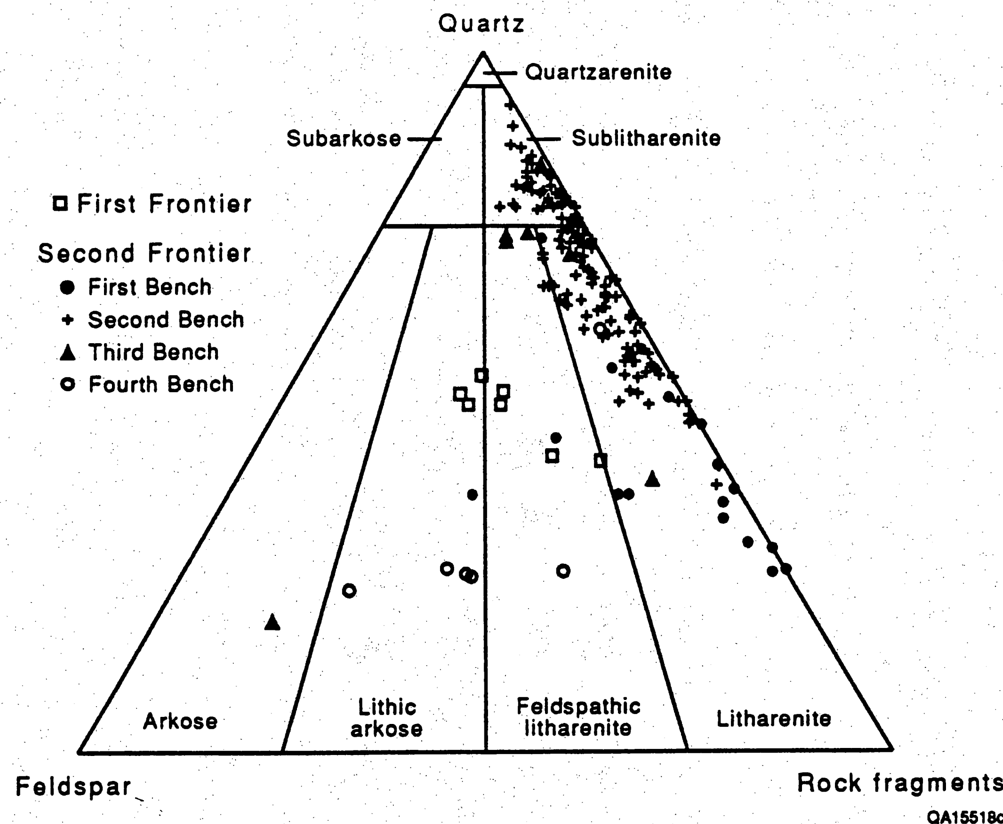

Figure 7. Compositional classification of First and Second Frontier sandstones.

Ab_{86} to Ab_{100}; 80 percent of the grains have compositions of greater than Ab_{98}. The average composition of all Frontier plagioclase is $Ab_{97.8}$. The original detrital composition of the plagioclase is unknown, but it was probably more calcic than it is now. The presence in the Frontier Formation of plagioclase of composition Ab_{86} indicates that the source area contained feldspars at least as calcic as oligoclase. Therefore, at least some of the Frontier feldspars were probably albitized after burial. However, some of the albite may have been inherited from older, albitized sandstones or from low-grade metamorphic rocks in the source area.

Rock fragments range from 10 percent to 75 percent of the framework grains. Sedimentary rock fragments, particularly chert but also including chalcedony, shale, sandstone, and phosphate, are the most common lithic grains. Low-rank metamorphic rock fragments are common in some samples. Volcanic rock fragments and ripped up and transported pieces of bentonite occur mainly in the Third and Fourth Bench sandstones in the Second Frontier. Plutonic rock fragments are rare. Accessory grains such as biotite and glauconite are locally common.

Framework-grain composition of Frontier sandstones is influenced both by depositional environment and by stratigraphic position. Sandstones deposited in fluvial channels contain less quartz than do sandstones deposited in shoreface environments (fig. 8) Fluvial-channel sandstones have an average composition of $Q_{57}F_6R_{37}$, upper shoreface sandstones average $Q_{67}F_3R_{30}$, and lower shoreface sandstones average $Q_{69}F_5R_{26}$ (table 2). The relationship between depositional environment and sandstone composition in the Frontier Formation was observed previously (Winn and Smithwick, 1980; Stonecipher and others, 1984; Winn and others, 1984). Shoreface sandstones probably contain a high percentage of detrital quartz because wave abrasion removed many of the mechanically unstable rock fragments (Winn and others, 1984) and because differences in hydraulic properties allowed wave action to winnow quartz from chert. Fluvial-channel sandstones contain abundant chert because they are coarser grained than are shoreface sandstones, and chert and other rock fragments tend to occur in the coarser sand fraction. The average grain size of fluvial-channel sandstones is 2.0 ϕ (0.25 mm), compared with

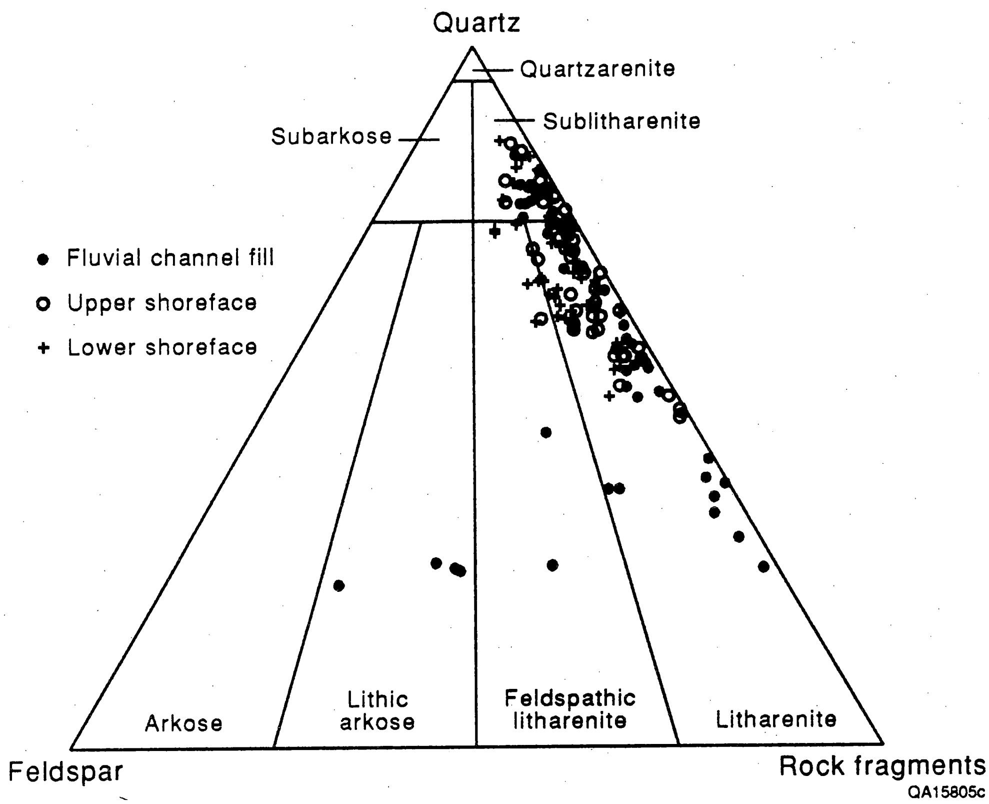

Figure 8. Compositional classification of Second Frontier sandstones by depositional environment.

2.4 ϕ (0.19 mm) for upper shoreface sandstones and 2.8 ϕ (0.14 mm) for lower shoreface sandstones (table 2. Upper shoreface sandstones are well sorted (ϕ standard deviation of 0.49), whereas fluvial and lower shoreface sandstones are moderately well sorted (ϕ standard deviation of 0.55 and 0.52, respectively).

In core from Church Buttes field, differences in framework grain composition were observed at a millimeter scale between individual laminations. Small differences between quartz and chert in density and hydraulic properties resulted in some laminations having abundant detrital quartz grains, and laminations only a few millimeters away containing abundant chert grains. Much of the primary porosity in quartz-rich laminae was filled by quartz cement, but because quartz does not nucleate as well on chert grains, the chert-rich laminae retained more intergranular porosity.

The composition of fluvial channel-fill sandstones is strongly dependent on stratigraphic position. Most First Bench fluvial channel-fill sandstones contain abundant rock fragments, primarily chert, and little feldspar (fig. 7). In contrast, fluvial channel-fill deposits from the Third and Fourth Benches contain abundant plagioclase and biotite. The Third and Fourth Bench sandstones also contain volcanic rock fragments and bentonite clasts and thus were derived from a source terrain that included volcanic rocks. Marine sandstones of the First Frontier have a similar composition (fig. 7) and probably were derived from a source area similar to that of the Third and Fourth Bench sandstones. The quartz- and chert-rich sandstones of the First and Second Benches probably were derived primarily from older sedimentary rocks.

Matrix

Matrix, defined as detrital grains too small to be identified in thin section, composes from 0 percent to 94 percent of the volume of Frontier rocks. Matrix occurs in sandstones that either had clay-sized grains mixed into an originally well-sorted sandstone by burrowing organisms or that were deposited in an alternating high- and low-energy environment (such as rippled sandstones with clay laminations). X-ray diffraction analysis (<5 μm size fraction) indicates that clay minerals constitute an average of 75 weight-percent of the matrix. Clay-sized quartz forms most of the remainder of the matrix. Mixed-layer illite-smectite and illite are the most abundant clay minerals; kaolinite and chlorite are also present. The mixed-layer illite-smectite contains approximately 20 percent expandable smectite layers.

Cements

Cements and replacive minerals constitute between 0 percent and 38 percent of the sandstone volume in Frontier Formation samples. Pore-filling cement is most abundant in clean sandstones that contain little detrital clay matrix; the average volume of cement in clean Frontier sandstones is 15 percent. Fluvial sandstones contain a greater volume of cement than do shoreface sandstones (table 2). There is no significant correlation of total cement with depth.

Quartz, calcite, and mixed-layer illite-smectite and illite (which cannot be distinguished in thin section) are the most abundant authigenic minerals in Frontier sandstones. Less abundant authigenic minerals include chlorite, kaolinite, ankerite, albite, and pyrite. On the basis of petrographic evidence, the relative order of occurrence of the major events in the diagenetic history of Frontier sandstones were (1) mechanical compaction by grain rearrangement and deformation of ductile grains, (2) formation of illite and mixed-layer illite-smectite rims, (3) precipitation of quartz overgrowths, (4) precipitation of calcite cement, (5) generation of secondary porosity by dissolution of calcite cement and detrital feldspar, chert, and mudstone, and (6) chemical compaction by intergranular pressure solution and stylolitization (Dutton, 1990).

Authigenic Clays

Authigenic clays occur in most clean Frontier sandstones, where they have a large effect on permeability (Winn and Smithwick, 1980; Stonecipher and others, 1984; Schultz and Lafollette, 1989; Luffel and others, 1991). Illite and mixed-layer illite-smectite with approximately 20 percent smectite layers are the most common authigenic clays in general, but in two wells in the Hogsback area, kaolinite is most abundant (table 3). Authigenic chlorite is more abundant in the deep samples from the southern part of the Moxa Arch than in shallow samples from the northern end (table 3). No kaolinite was observed in sandstones at the southern part of the study area, in Church Buttes and Bruff fields (T17N to T19N), and kaolinite is lacking in Frontier sandstones at least as far north as Wilson Ranch field (T20N) (Stonecipher and others, 1984).

Some of the illite and mixed-layer illite-smectite occurs as rims of tangentially oriented flakes that developed around detrital grains early in the diagenetic history (fig. 9). The tangentially oriented illite crystals may have entered the sandstone by burrowing or mechanical infiltration and may have been recrystallized during burial diagenesis. In the Terra Anderson Canyon No. 3-17 well, some illite rims apparently were thick enough to inhibit the precipitation of quartz cement. Later dissolution of detrital feldspar grains generated secondary porosity and resulted in many of the illite rims being left as delicate rims around secondary pores. Other illite, with a flaky to fibrous morphology, is clearly authigenic and extends into and across primary pores (figs. 10, 11). Fibrous illite lines most primary pores, but it rarely occurs in secondary pores, indicating that most of the authigenic illite precipitated prior to the dissolution of feldspar.

The relatively low expansibility of the authigenic mixed-layer illite-smectite suggests that it may be only moderately sensitive to fresh water. In tests conducted to evaluate fluid-sensitivity of Frontier sandstones (Luffel and others, 1991), permeability to fresh water was

Table 3. Semi-quantitative X-ray diffraction mineralogy data (less than 5 μm in diameter fraction).

	Wt. % Bulk Rock		Clay Minerals Normalized to 100%				
Depth (ft)	Total fines <5 μm	Total clay minerals	Kaolinite	Chlorite	Illite	MLIS[1]	%Illite in MLIS
Mobil Tip Top (MT)							
6,982.7[2]	11.1	8.2	56	07	14	23	79
6,986.5	8.1	6.1	54	02	15	29	78
6,999.6[2]	3.5	2.5	67	03	08	22	79
Mobil Hogsback (MH)							
6,889.0[2]	3.0	1.9	73	—	10	17	86
6,894.3[2]	1.7	1.1	68	—	12	20	82
6,907.8*	6.8	5.0	49	06	16	29	81
6,912.0*	6.4	4.2	50	06	17	27	79
*Sample contains abundant calcite cement, some of which probably was ground to <5 μm during sample preparation.							
Enron South Hogsback (ES)							
7104	N.R.	14	21	—	14	64	80
7120	N.R.	17	6	6	29	59	80
7137	N.R.	19	21	Tr	16	63	80
7148	N.R.	22	23	—	18	59	80
Terra Resources Anderson Canyon 3-17 (TA)							
9,064.0	44.8	31.5	08	09	21	62	72
9,082.9[2]	5.2	3.7	27	03	19	51	77
9,085.3[2]	3.3	1.9	—	—	27	73	78
9,088.0[2]	3.1	1.7	—	—	26	74	80
9,095.7[2]	7.8	5.5	—	—	24	76	80
9,110.0	6.1	4.9	—	03	20	77	74
9,118.0	6.1	4.9	—	05	23	72	76
Texaco State of Wyoming #1 (TW)							
11,515.5[2]	3.8	2.2	—	11	22	67	83
11,527.9	4.8	3.9	—	07	23	70	84
Church Buttes (WC)							
12,163.2[2]	7.1	4.3	—	17	26	57	85
12,165.1[2]	1.8	0.9	—	13	30	57	79
12,169.6[2]	3.8	2.8	—	13	31	56	86
12,173.5[2]	5.3	3.8	—	14	19	67	84

1 Mixed-layer illite-smectite.
2 Samples containing only authigenic clay.
N.R. Not reported.
Tr Trace

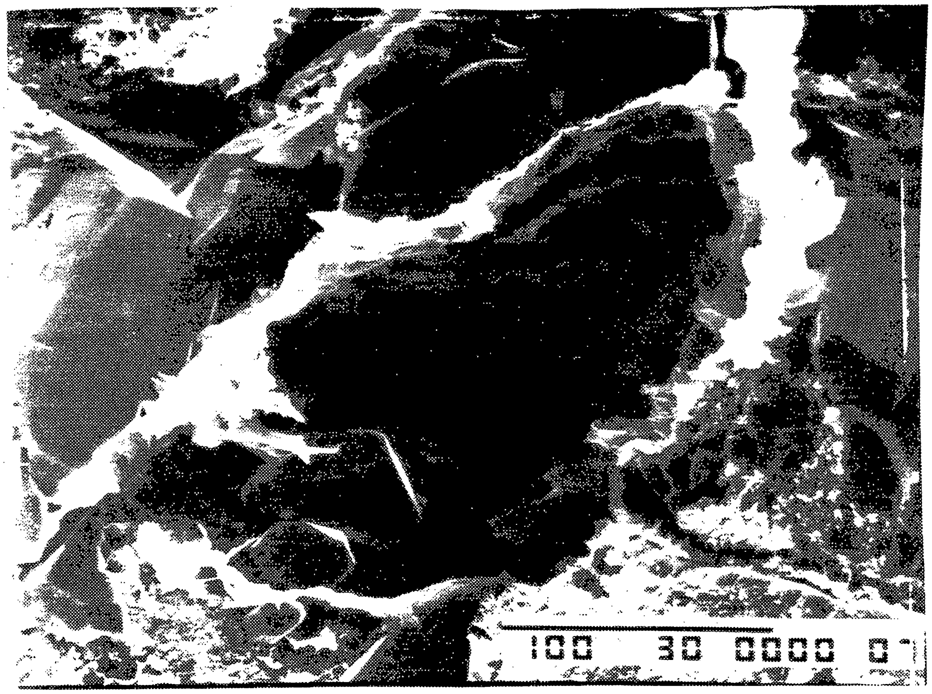

Figure 9. Tangentially oriented illite around a secondary pore; quartz crystals project into pore. Sample from a depth of 9084.7 ft, Terra Anderson Canyon No. 3-17 well. Sample was prepared by critical point drying. SEM photo by K. L. Herrington. Scale bar is 100 µm.

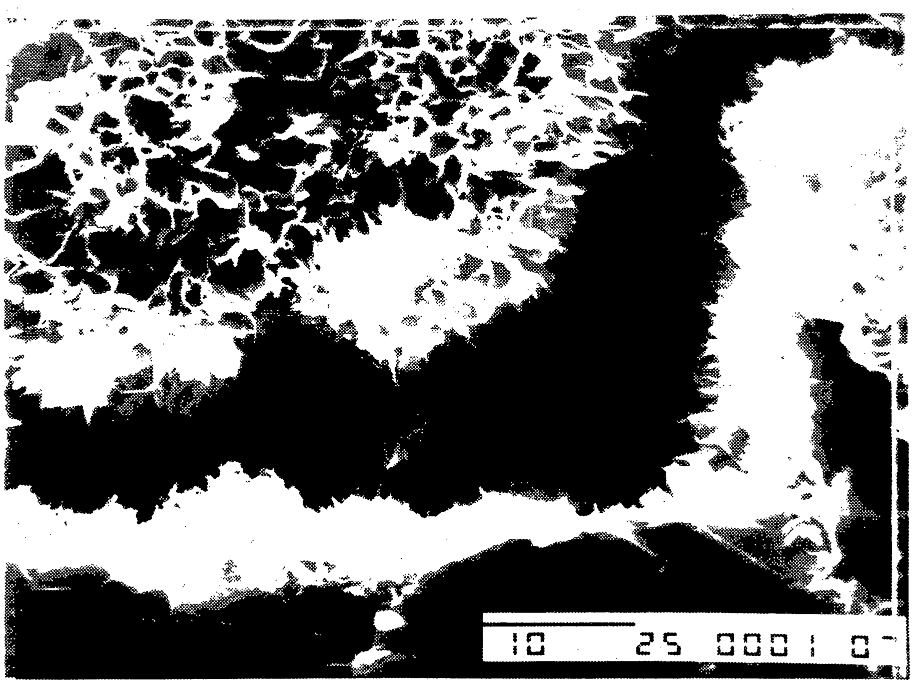

Figure 10. Authigenic fibrous illite lines primary pore. Sample from a depth of 9079.9 ft, Terra Anderson Canyon No. 3-17 well. Sample was prepared by freeze drying. SEM photo by K. L. Herrington. Scale bar is 10 µm.

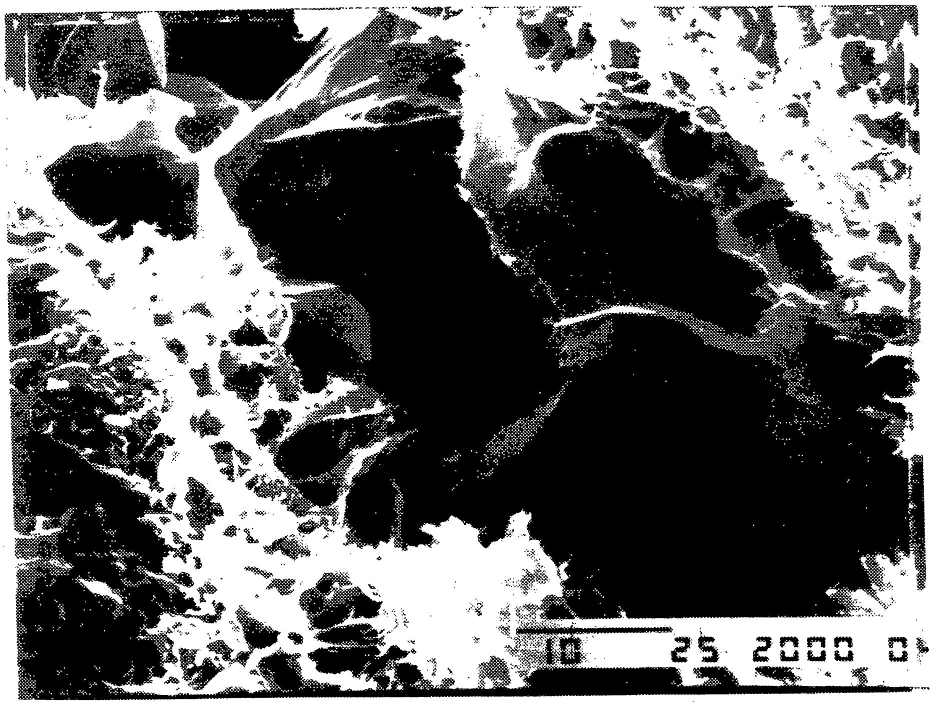

Figure 11. Sheets of authigenic illite bridging a pore. Sample from a depth of 9079.5 ft, Terra Anderson Canyon No. 3-17 well. Sample was prepared by air drying. SEM photo by K. L. Herrington. Scale bar is 10 μm.

reduced 25 to 50 percent compared with permeability to brine. A more important effect of clays on permeability seems to be a result of their distribution and morphology. Fibers and sheets of illite that bridge intergranular pores and pore throats significantly lower permeability (Luffel and others, 1991). Stressed permeability to air measured on dried, extracted plugs in which the fibrous illite has matted against the pore walls is 10 to 100 times higher than in situ gas permeability at connate water saturation in plugs with undisturbed illite (Luffel and others, 1991). Thus, permeability to air, measured in dried core samples, may be one or two orders of magnitude higher than actual reservoir permeability.

Authigenic flakes and rosettes of chlorite (fig. 12) precipitated relatively early in the burial history, before precipitation of quartz overgrowths. In sandstones from Church Buttes field, chlorite around detrital grains commonly is engulfed by quartz overgrowths (fig. 13), resulting in small, chlorite-filled pores between detrital quartz grains and overgrowths. On the basis of textural relationships, it appears that most of the chlorite precipitated before quartz, but there may have been some overlap in the timing between the precipitation of quartz and chlorite.

Kaolinite occurs mainly within secondary pores (fig. 14). It is a reaction product of feldspar dissolution and thus probably occurred later in the diagenetic history than precipitation of illite and chlorite. Because it is somewhat isolated within secondary pores, kaolinite probably has less impact on sandstone permeability in the Frontier than does illite. Kaolinite only occurs in the shallower Frontier sandstones at the northern end of the Moxa Arch; no kaolinite was observed in sandstones deeper than 9,000 ft (fig. 15). Stonecipher and others (1984) suggested that kaolinite occurs only in sandstones at the northern end of the Moxa Arch because this part of the arch experienced more uplift and erosion during Late Cretaceous folding. As a result, Frontier sandstones at the northern end of the arch were exposed to dilute, acidic meteoric water. Meteoric fluids that reached the southern end of the arch had experienced more rock-water interaction because of following a longer flow path, and

Figure 12. Cluster of authigenic chlorite flakes from a depth of 12,175 ft in the Wexpro Church Buttes No. 48 well. SEM photo by K. L. Herrington. Scale bar is 10 μm.

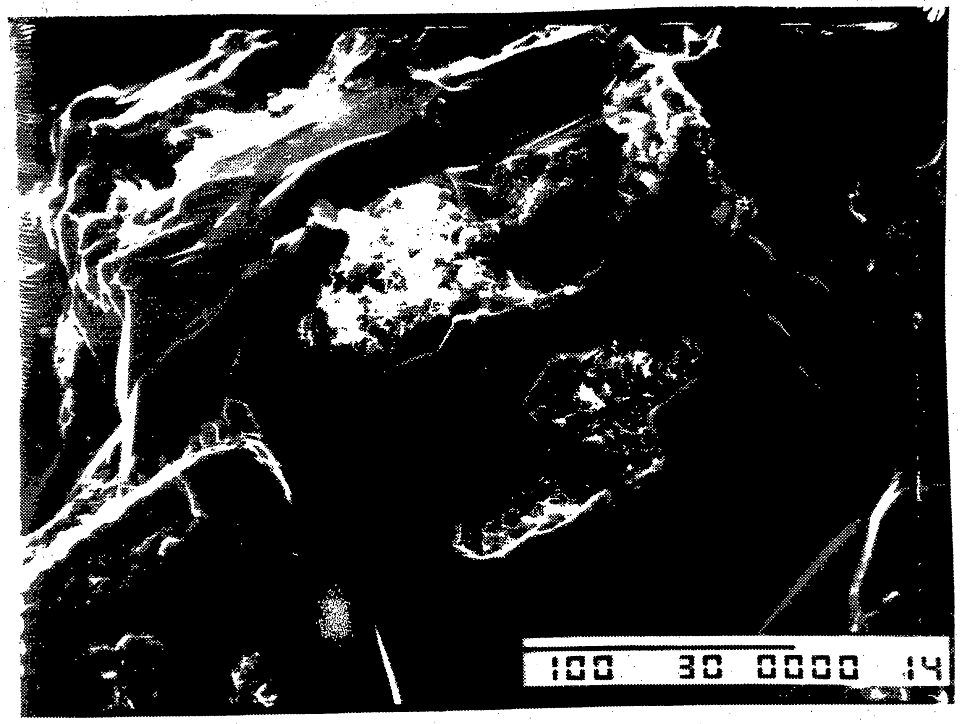

Figure 13. Quartz overgrowth engulfing illite and chlorite cement. Sample from a depth of 12,163.2 ft in the Wexpro Church Buttes No. 48 well. SEM photo by K. L. Herrington. Scale bar is 100 μm.

Figure 14. Authigenic kaolinite within a secondary pore. Sample from a depth of 6,985.5 ft in the Mobil Tip Top No. T71X-6G-28N-113W well. SEM photo by K. L. Herrington. Scale bar is 10 μm.

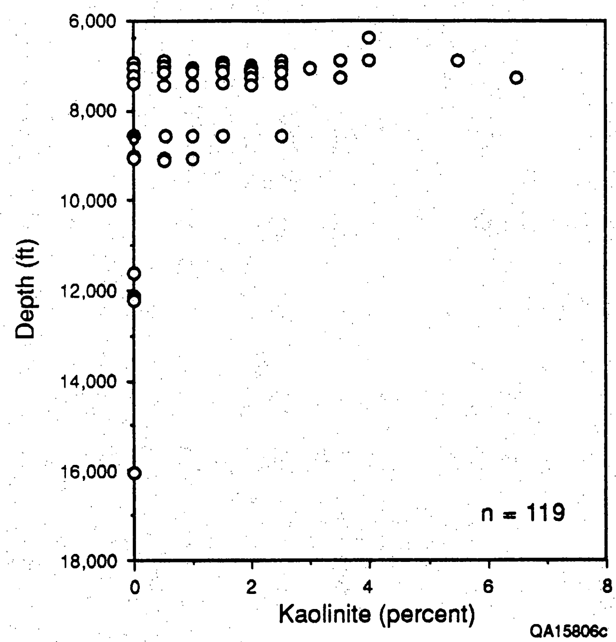

Figure 15. Kaolinite cement volume in clean sandstones as a function of present burial depth. No kaolinite was observed in Frontier sandstones deeper than 9,000 ft.

thus may have contained too high a solute concentration to precipitate kaolinite (Stonecipher and others, 1984).

Another possible explanation for the lack of kaolinite in the deeper Frontier sandstones is that kaolinite may have been altered to illite or chlorite at the southern end of the Moxa Arch. The factors that control kaolinite stability relative to chlorite are pH, temperature, and log ($[Mg^{+2}][Fe^{+2}]$) product (Kaiser, 1984). Deeper Frontier sandstones at the southern end of the Moxa Arch and in the Green River Basin are at higher temperatures than those at the northern end of the arch and may be in the stability field for chlorite, not kaolinite. X-ray data indicate that there is an increase in authigenic chlorite in deeper sandstones (table 3).

Quartz Overgrowths

Quartz is volumetrically the most abundant cement in Frontier sandstones, ranging from 0 to 18 percent of bulk rock volume. Volume of quartz cement in clean Frontier sandstones increases significantly with depth (fig. 16). In clean sandstones at the northern end of the Moxa Arch, quartz cement does not occlude porosity significantly, filling an average volume of only 4 percent. In contrast, in the Church Buttes area to the south (including well 11), the average volume of quartz cement in clean sandstones is 11 percent, and quartz cementation was an important cause of porosity loss. Quartz cement probably is more abundant at the southern end of the Moxa Arch and in the basin because Frontier sandstones are more deeply buried there and have developed numerous stylolites, which would be a source of additional silica. Many chert grains in the deeper sandstones from the Church Buttes area appear partly dissolved, and chert dissolution could be another source of silica.

Fluvial channel-fill sandstones contain significantly more quartz cement than do shoreface sandstones (table 2), but the reason probably is the greater depth of the fluvial samples. Because of the sample distribution, the average depth of fluvial sandstones is 10,800 ft, compared with 8,300 ft for shoreface sandstones. The greater volume of quartz cement

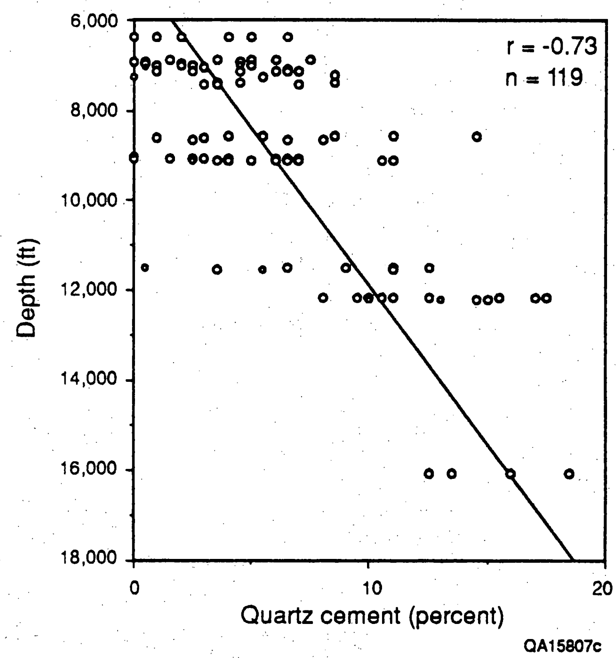

Figure 16. Quartz cement volume in clean sandstones as a function of present burial depth. Quartz cement increases significantly with depth. Linear regression equation relating depth and quartz cement is:

$$\text{quartz cement (\%)} = -7.0 + 1.4 \times \text{depth (ft)} \times 10^{-3}.$$

observed in fluvial sandstones is simply a function of the greater depth from which the samples were taken. No correlation exists between volume of quartz cement and grain size or sorting.

There is some evidence for multiple periods of quartz cementation. For example, some quartz cement clearly precipitated prior to feldspar dissolution, because quartz overgrowths do not extend beyond where the grains used to be. However, quartz overgrowths project into secondary pores in other cases (fig. 9). Based on comparison with other quartz cemented sandstones (Dutton and Diggs, 1990), perhaps an early generation of quartz cement precipitated from deeply circulating meteoric fluid, and later quartz cement was derived internally from dissolution of chert and along stylolites. Because the Frontier sandstones at the southern end of the Moxa Arch and in the basin had more internal sources of silica from dissolution and stylolitization, they contain more total quartz cement.

Calcite

Calcite was the last of the volumetrically significant cements to precipitate in Frontier sandstones. Textural relationships between quartz and calcite clearly show that calcite precipitation followed quartz overgrowths. The average composition of the calcite cement is $(Ca_{0.96}Mg_{0.01}Fe_{0.01}Mn_{0.02})CO_3$, determined by 92 microprobe analyses of calcite cement in 3 sandstone samples from Fontenelle field.

Calcite abundance in clean sandstones averages 4.6 percent and ranges from 0 percent to 35 percent, which includes both pore-filling and grain-replacing calcite. In clean sandstones, an average of 2 percent calcite cement fills primary pores, and an average of 2.6 percent of the calcite cement replaces framework grains, mainly feldspars. Calcite cement is more abundant in lower shoreface sandstones (average of 6 percent) than in either upper shoreface or fluvial channel-fill sandstones (average of 3 percent in both (table 2). Of the 28 sandstones with particularly abundant calcite cement (>10 percent), 7 are in fluvial sandstones, 5 in upper shoreface, and 15 in lower shoreface.

Clean sandstones in the Hogsback area have significantly greater volumes of calcite cement (8.1 percent) than do clean sandstones from either the Fontenelle (1.7 percent) or Church Buttes areas (3.2 percent) (table 4). Of the 28 Frontier samples containing more than 10 percent calcite cement, 21 are from the Hogsback area.

Dissolution of calcite in some sandstones reopened pores that formerly were filled with cement. For example, the top of the upper-shoreface sandstone that constitutes the pay zone in the Terra Anderson Canyon No. 3-17 well contains extensive secondary porosity and remnants of calcite cement. Secondary porosity is abundant throughout the entire pay zone (table 5), but remnants of partly dissolved calcite cement only occur at the top of the sandstone. It is not clear whether calcite formerly occurred throughout the entire sandstone and was completely dissolved everywhere but at the top, or whether calcite was only present at the top of the sandstone and has been partly dissolved there.

Porosity

Porosity in Frontier sandstones observed in thin section varies from 0 percent to 19 percent; porosimeter measured porosity ranges from 1.4 percent to 19.3 percent. Average porosimeter porosity in clean Frontier sandstones is 12.3 percent, compared with an average of 6.0 percent thin-section porosity. In general, thin-section porosity is lower than porosimeter porosity because of the difficulty of accurately identifying the volume of microporosity in thin section. The two measures of porosity in Frontier sandstones are related by the following equation: porosimeter porosity = 8.4 + 0.62 × (thin-section porosity) ($r = 0.69$). The largest difference between thin-section and porosimeter porosity is at low porosity values; samples with no thin-section porosity contain an average of 8.4 percent porosimeter porosity. Both primary and secondary porosity identified in thin section are significantly correlated to porosimeter porosity ($r = 0.57$ and 0.63, respectively).

Table 4. Characteristics of clean Frontier sandstones in three areas along the Moxa Arch.

	Hogsback	Fontenelle	Church Buttes[1]
Grain size (mm)	0.18	0.22	0.26
Sorting (phi)	0.5	0.5	0.5
Quartz cement (%)	3.3	4.9	11.1
Calcite cement (%)	8.1	1.7	3.2
Total cement (%)	15.7	10.9	19.0
Primary porosity (%)	1.0	3.0	1.0
Secondary porosity (%)	3.8	6.1	3.1
Total thin-section porosity (%)	4.8	9.1	4.1
Porosimeter porosity (%)	11.9	15.3	9.3
Unstressed permeability (md)	0.15	0.46	0.18
Stressed permeability (md)	0.06	0.09	-
Depth (ft)	7,000	8,900	12,500

[1]Includes data from Energy Resources Group No. 1-30 Blue Rim Federal well (well 11, fig. 1)

Table 5. Petrographic data from pay zones of GRI cooperative wells.

	Holditch SFE No. 4 (7,400-7,412 ft)	Enron S. Hogsback No. 13-8A (7,114-7,140 ft)	Terra Anderson Canyon No. 3-17 (9,079-9,086 ft)
Grain size (mm)	0.16	0.17	0.24
Sorting (phi)	0.45	0.48	0.45
Quartz cement (%)	5.9	4.8	6.1
Calcite cement (%)	4.8	0.6	0.9
Pore-filling calcite (%)	1.0	0.1	0.4
Total cement (%)	15.6	9.4	11.3
Primary porosity (%)	0.8	1.7	5.0
Secondary porosity (%)	4.4	4.7	8.8
Total thin-section porosity (%)	5.2	6.4	13.8
Porosimeter porosity (%)	11.9	15.6	17.6
Unstressed permeability (md) (measured on dry core plugs)	0.10	0.19	2.79
Stressed permeability (md) (measured on dry core plugs)	0.03	0.10	1.32
Reservoir permeability (md)[1]	0.005	0.1	0.05
Pre-fracture flow rate (mcf/day)	9	170	70

[1]Reservoir permeability calculated from pressure build-up tests (personal communication, Bradley M. Robinson, S. A. Holditch & Associates, January, 1991).

Based on thin-section identification, average primary porosity in clean Frontier sandstones is 1.6 percent, and average secondary porosity is 4.4 percent. Most secondary pores formed by the dissolution of framework grains, particularly feldspar, chert, clay clasts, and biotite, so secondary pores are approximately the same size as detrital grains. Some secondary pores contain remnants of the original detrital grains or reaction products such as kaolinite (fig. 14). Dissolution of calcite cement also generated some secondary porosity (Schultz and Lafollette, 1989), but apparently less commonly than dissolution of framework grains.

Microporosity is abundant in Frontier sandstones, but it cannot be accurately quantified by routine thin-section point counts. However, an estimate of the volume of microporosity can be obtained by taking the difference between porosimeter-measured porosity and thin-section porosity. The average volume of microporosity in Frontier sandstones estimated by this method is 6.3 percent. Microporosity occurs between authigenic clay crystals (figs. 10, 12, and 14) and within detrital clay matrix. Micropores also developed by dissolution of some of the tiny (0.2 μm) quartz crystals that compose chert grains (figs. 17 and 18).

Much of the depositional porosity in Frontier sandstones has been lost by mechanical and chemical compaction. Many chert grains have undergone intergranular pressure solution. Stylolites, oriented both parallel and perpendicular to bedding, are common in sandstones from the southern end of the Moxa Arch and in the basin. Intergranular pressure solution and stylolitization are examples of chemical compaction, which is defined as bulk volume reduction caused by the dissolution of framework grains at points of contact (Houseknecht, 1987). Chemical compaction reduces porosity by causing closer packing of framework grains. Mechanical compaction is bulk volume reduction resulting from processes other than framework grain dissolution, such as reorientation of competent grains and deformation of ductile grains (Houseknecht, 1987). Many of the sedimentary and metamorphic rock fragments in Frontier sandstones are ductile and have been deformed during compaction, causing a reduction of primary porosity. Minus-cement porosity, which is the amount of porosity that remained after compaction but before cementation, averages only 14 percent in clean Frontier

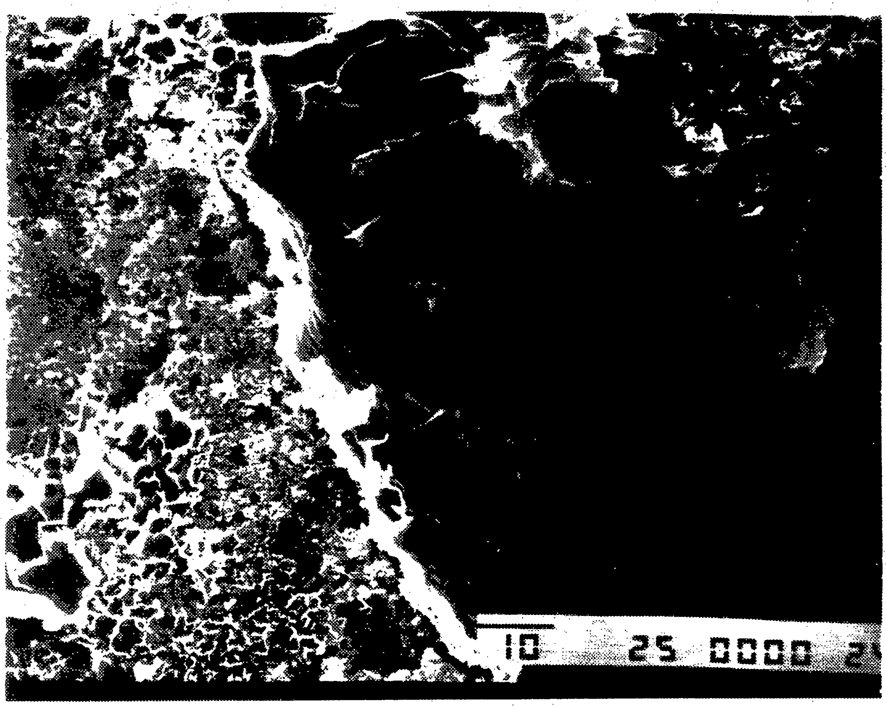

Figure 17. SEM photo of chert grain (left side) showing abundant microporosity. Note thin rim of tangentially oriented clay around detrital chert grain. Sample from a depth of 9,087.8 ft in the Terra Anderson Canyon No. 3-17 well. SEM photo by K. L. Herrington. Scale bar is 10 µm.

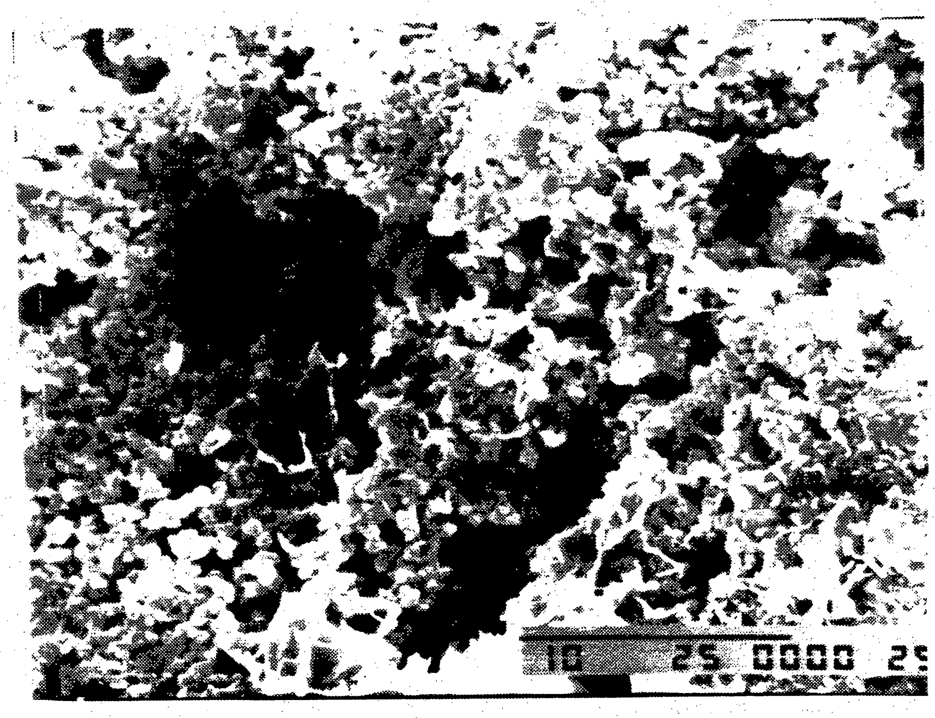

Figure 18. Close-up of surface of chert grain shown in figure 17. Partial dissolution of chert has resulted in abundant micropores. SEM photo by K. L. Herrington. Scale bar is 10 µm.

sandstones. At the time of deposition, well-sorted Frontier sandstones probably had porosity of at least 40 percent (Pryor, 1973; Atkins, 1989). Thus, about 26 percent porosity (65 percent of the original porosity) was lost by compaction. Much of the remaining intergranular porosity was occluded by precipitation of an average of 12 percent pore-filling cement in clean Frontier sandstones.

DIAGENETIC CONTROLS ON RESERVOIR QUALITY

Porosity

Matrix-free sandstones deposited in high-energy upper shoreface and fluvial channel-fill environments had the highest porosity and permeability at the time of deposition. However, porosity was reduced by compaction and cementation in many of these sandstones during burial diagenesis. Loss of porosity by compaction in clean sandstones was most severe where ductile grains, such as chert, mud rip-up clasts, biotite, glauconite, and metamorphic rock fragments, were abundant. For example, many fluvial channel-fill sandstones contain abundant chert and mud rip-up clasts and thus have lost considerable porosity by mechanical compaction.

The most quartz-rich sandstones were deposited in upper shoreface environments, and these sandstones have lost the least porosity by compaction. However, even within the upper shoreface, variations in depositional energy resulted in variable framework grain composition and extent of compaction. In the Terra Anderson Canyon No. 3-17 well, Fontenelle field, the most quartz-rich sandstones($Q_{79}F_2R_{19}$) (fig. 5, depth 9,078 to 9,086 ft [2,767 to 2,770 m]) were deposited in a high-energy foreshore environment. Average primary porosity in this section is 5 percent, porosimeter porosity is 15.9 percent, and average stressed permeability to air is 0.75 md. Sandstones (fig. 5, depth 9,087 to 9,098 ft [2,770 to 2,773 m]) deposited in a slightly lower energy environment, but still on the upper shoreface, contain more ductile rock fragments ($Q_{63}F_2R_{35}$). As a consequence of greater mechanical compaction in this interval, average primary porosity in this section is 3 percent, porosimeter porosity is 13.2, and average stressed permeability to air is 0.009 md.

Porosity has also been lost in Frontier sandstones by cementation. The most important control on porosity in clean Frontier sandstones is the total volume of cement (fig. 19). More than half of the variation in porosity is explained by variation in total cement volume (r^2 = 0.55). Fluvial sandstones have undergone the most cementation, containing an average of 15 percent cement, compared with an average of 10 to 11 percent in upper and lower shoreface sandstones (table 2). Calcite is the individual cement that has the largest effect on porosity. In clean sandstones with less than 10 percent calcite cement, porosity is highly variable, but in sandstones having more than 10 percent calcite, there is an excellent inverse relationship between porosimeter porosity and calcite cement (fig. 20). No significant relationship exists between porosity and grain size, sorting, or quartz cement.

Permeability

Stressed permeability in Frontier sandstones varies from 0.003 md to 22 md. Porosity is not always a good predictor of permeability in Frontier sandstones because the correlation between porosimeter porosity and unstressed permeability in clean Frontier sandstones is relatively low (fig. 21). Primary and secondary porosity are interpreted to contribute about equally to permeability in Frontier sandstones. The correlation coefficient between primary porosity and unstressed permeability is 0.54, and it is 0.55 between secondary porosity and unstressed permeability. (Unstressed permeability has been compared to petrographic parameters because there are 97 thin sections of clean Frontier sandstones with corresponding unstressed permeability measurements but only 50 with stressed permeability measurements). The correlation between total cement volume and permeability is low (r = -0.35) but statistically significant at the 99 percent confidence level. Weak but statistically significant relationships also exists between volume of calcite cement and permeability (r = -0.44) and between grain

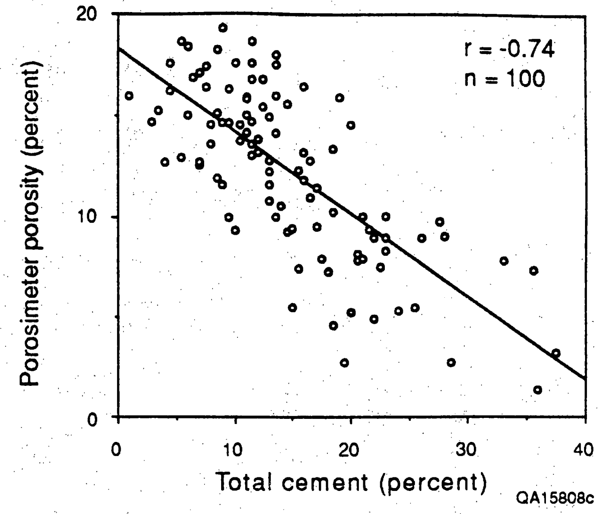

Figure 19. Inverse relationship between total cement volume and porosimeter porosity in clean Frontier sandstones (≤2 percent matrix). Volume of authigenic cement is a major control on porosity in Frontier sandstone.

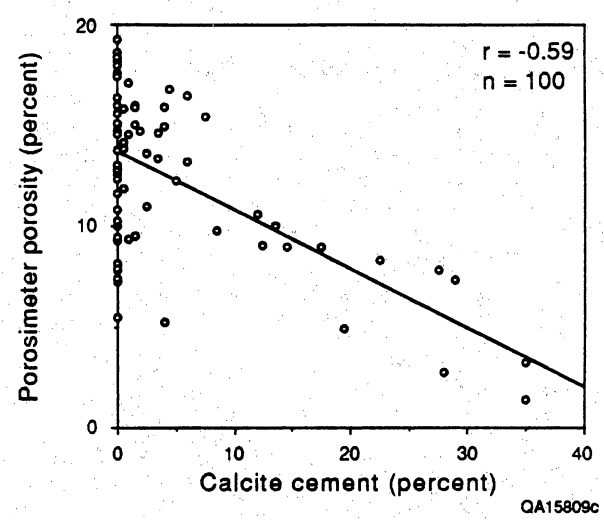

Figure 20. Inverse relationship between calcite cement volume and porosimeter porosity in clean Frontier sandstones (≤2 percent matrix).

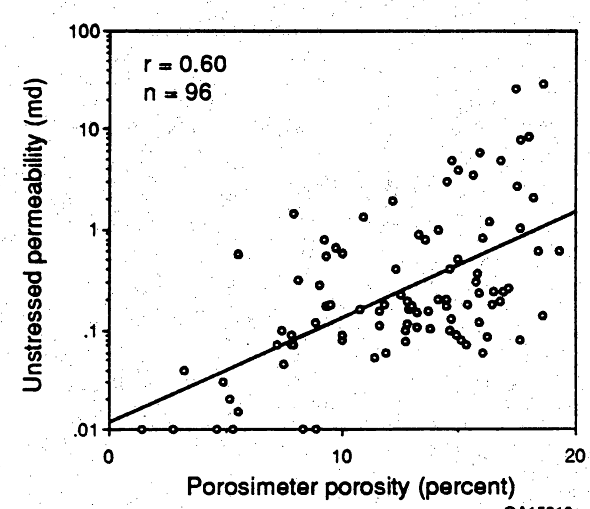

Figure 21. Plot of porosimeter porosity versus unstressed permeability in 96 clean Frontier sandstones (≤2 percent matrix).

size and permeability (r = -0.33; correlation coefficient is negative because grain size is in ϕ units). No significant relationship (at the 99 percent confidence level) exists between permeability and volume of quartz cement or sorting in clean Frontier sandstones. Finally, permeability decreases significantly in clean sandstones from the Fontenelle area with increasing volume of ductile grains (r = -0.67). However, no relationship between volume of ductile grains and permeability was observed for Church Buttes or Hogsback clean sandstones.

One reason for the scatter in the porosity versus permeability plot (fig. 21) is the abundance of microporosity, which is measured by porosimeter but does not contribute significantly to permeability. Another reason for the low correlation is the presence of abundant fibrous illite and mixed-layer illite-smectite in many Frontier sandstones. The fibrous clay has little effect on porosity, but it dramatically lowers permeability. The presence of variable amounts of fibrous illite in Frontier sandstones makes the porosity-permeability relationship less predictable than in other low-permeability sandstones, such as the Lower Cretaceous Travis Peak Formation in East Texas (Luffel and others, 1989).

Depositional Environment

In our study area, important differences in average porosity and permeability exist among sandstones from the three major depositional environments—fluvial channel-fill, upper shoreface, and lower shoreface—as a result of depositional differences in grain size and sorting, and subsequent diagenetic modifications, particularly compaction and cementation (table 2). Upper shoreface sandstones have average porosimeter porosity of 14.6 percent and unstressed permeability of 0.21 md. Fluvial sandstones have average porosimeter porosity of 10.3 percent and unstressed permeability of 0.14 md. Lower shoreface sandstones have average porosimeter porosity of 12.4 percent and unstressed permeability of 0.08 md. Thus, in our study area, upper shoreface sandstones have the best reservoir quality. They are well sorted and probably had good porosity and permeability at the time of deposition. Because of their quartz-rich composition, they have undergone less compaction than sandstones from fluvial or lower shoreface environments. They also have lost less porosity by cementation (table 2).

Frontier reservoirs in fluvial channel-fill sandstones in the study area generally have lower porosity and permeability than do upper shoreface sandstones (table 2). Fluvial channel-fill sandstones have coarser grain size but poorer sorting. The abundance of chert and mud rip-up clasts in some fluvial channel-fill sandstones caused them to lose considerable porosity by compaction. In addition, fluvial channel-fill sandstones contain abundant authigenic cement (table 2). High volumes of cement occur primarily in fluvial sandstones at the southern end of the Moxa Arch.

Important differences exist between fluvial sandstones at the northern end of the Moxa Arch (Hogsback and Fontenelle areas) and the southern end (Church Buttes area and well 11, in the Green River Basin). Fluvial sandstones at the southern end of the arch are relatively quartz rich ($Q_{66}F_2R_{31}$) and thus have not lost much porosity by ductile grain deformation (pre-cement porosity = 18 percent). However, the average volume of quartz cement in these sandstones is 11 percent and the total volume of cement is 18 percent. As a result, fluvial sandstones at the southern end of the Moxa Arch have poor reservoir quality mainly because of extensive cementation. In contrast, fluvial sandstones from the northern end of the Moxa Arch have an average of only 10 percent total cement, including 3 percent quartz cement. However, the average framework-grain composition of the northern fluvial sandstones is $Q_{41}F_{12}R_{47}$. The large volume of rock fragments suggests that mechanical compaction by ductile grain deformation was the most important porosity-reducing process in the northern fluvial sandstones (pre-cement porosity = 8 percent). Therefore, at the northern and southern ends of the Moxa Arch, different but equally effective diagenetic modifications have resulted in low average porosity and permeability in fluvial channel-fill sandstones.

Lower shoreface sandstones have the lowest permeability in the study area (table 2). They probably had low porosity at the time of deposition because of their fine grain size and abundance of detrital clay matrix. As much as 80 percent of the depositional porosity was lost by compaction, and most of the remaining porosity has been occluded by calcite cement. Of the 28 Frontier sandstone samples that contain more than 10 percent calcite, 15 are in lower shoreface sandstones. As a result of both compaction and cementation, permeability is lowest in the lower shoreface sandstones. Unfortunately, lower shoreface sandstones are volumetrically more abundant in the study area than are either fluvial channel-fill or upper shoreface sandstones.

Geographic Area

Diagenetic differences occur among sandstones in the three areas studied along the Moxa Arch. However, comparison of diagenesis in the three geographic areas assumes that the limited volume of sample available from each area is representative of that area. The total volume of cement in clean sandstones from the Fontenelle area is significantly lower, and the average porosity and permeability significantly higher, than in sandstones from either the Hogsback or Church Buttes areas (table 4). As noted previously, sandstones from the Church Buttes area have low porosity and permeability because they contain variable amounts of calcite cement and very abundant quartz cement, probably because of their greater burial depth. Low porosity and permeability in sandstones from the Hogsback area probably result from the finer grain size and heavier calcite cementation compared with sandstones from the other two areas (table 4). Shoreface sandstones in Hogsback wells contain more calcite cement than do shoreface sandstones in either the Church Buttes or Fontenelle areas. Upper shoreface sandstones from the Hogsback area contain an average of 6.5 percent calcite, compared with an average of 0.8 percent in Fontenelle upper shoreface sandstones. (No upper shoreface sandstones occur in the Church Buttes cores.) Similarly, lower shoreface sandstones from the Hogsback wells contain an average of 8.9 percent calcite. Fontenelle lower shoreface sandstones average 0.9 percent calcite, and Church Buttes samples average 2.7 percent. It is not known why shoreface sandstones from the Hogsback area are so much more extensively cemented by calcite than are shoreface sandstones from the Fontenelle and Church Buttes areas.

Comparison of Diagenesis in Three Frontier Wells

Diagenetic differences in the pay zones of the SFE No. 4, Enron S. Hogsback, and Terra Anderson Canyon wells may explain some of the differences in initial gas production among the three wells (tables 1 and 5). The Enron S. Hogsback well had the highest pre-fracture production of 170 mcf/day. The Terra Anderson Canyon well had a pre-fracture flow rate of 70 mcf/day, and the SFE No. 4 had a flow rate of 9 mcf/day. On the basis of thin-section analysis of the reservoir sandstones, SFE No. 4 would be expected to have the lowest pre-fracture flow rate of the three wells, and it did. Sandstones in the pay zone from SFE No. 4 contain more total cement and consequently have lower porosity and permeability than do sandstones in the other two wells (table 5).

The reason for a higher flow rate in the Enron S. Hogsback well compared with the Terra Anderson Canyon well is not as clear. In thin sections, sandstones from the Terra Anderson Canyon well have significantly more porosity than do sandstones from the Enron S. Hogsback well, and permeability to gas measured in dried core plugs is higher in samples from the Terra Anderson Canyon than from the Enron S. Hogsback well (table 5). One reason for the higher gas flow rate in the Enron S. Hogsback well is the thicker pay interval of 26 ft, compared to only 7 ft in the Terra Anderson Canyon well (table 5). In addition, the Terra Anderson Canyon well may have a lower than expected flow rate because of the presence of abundant fibrous illite in the pore network of the reservoir sandstones. Fibrous illite has little effect on porosity, but it drastically lowers permeability to gas at connate water saturation (Luffel and others, 1991). The Enron S. Hogsback well apparently contains less fibrous illite in the pay zone, which may explain why it has higher well-test permeability and gas flow rates than does the Terra Anderson Canyon well (Luffel and others, 1991). Reservoir permeability calculated from pressure-build-up tests is 0.1 md for the Enron S. Hogsback well, and only 0.05 md for the Terra Anderson Canyon well.

CONCLUSIONS

The major causes of porosity loss in Frontier sandstones during burial diagenesis were mechanical and chemical compaction and cementation by calcite, quartz, and authigenic clays. Quartz cement is most abundant in deeply buried fluvial channel-fill sandstones at the southern end of the Moxa Arch and in the Green River Basin. Calcite cement is most abundant in Frontier sandstones deposited in lower shoreface environments. Both upper and lower shoreface sandstones from the Hogsback area at the northern end of the Moxa Arch contain significantly more calcite cement than do shoreface sandstones in either the Fontenelle or Church Buttes areas.

Despite extensive diagenetic modification, the best reservoir quality in the Frontier Formation occurs in facies that had the highest porosity and permeability at the time of deposition. Original intergranular porosity has been substantially reduced in these clean sandstones by compaction and precipitation of authigenic cements, but they still retain higher porosity and permeability than do in sandstones with abundant detrital clay matrix. Thus, exploration for Frontier reservoirs should focus on locating clean sandstones deposited in high-energy depositional environments (Hamlin and Buehring, 1990). The reservoir intervals in the wells in this study occur mainly in clean upper shoreface and fluvial channel-fill sandstones.

However, reservoir quality in clean sandstones is variable because diagenetic modification is highly variable. Whereas some upper shoreface sandstones have low porosity and permeability because of abundant calcite cement, other sandstones from the same depositional environment lack calcite and have relatively high porosity and permeability. Similarly, upper shoreface sandstones with abundant rock fragments have lost more intergranular porosity by mechanical compaction than have quartz-rich upper shoreface sandstones. Some fluvial channel-fill sandstones are extensively cemented by quartz, and others are not. Fibrous illite can drastically reduce reservoir permeability in any facies.

The general distribution of quartz cement is predictable because a strong correlation exists between volume of quartz cement and depth. Thus, fluvial channel-fill sandstones at the southern, deeper end of the Moxa Arch can be expected to contain a greater volume of quartz cement than do fluvial channel-fill sandstones from the northern end. Unfortunately, occurrences of calcite and fibrous illite are not predictable on the basis of current understanding, and these two cements exert a very important control on porosity and permeability in Frontier reservoirs.

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