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VOLUME II:
GEOLOGIC CHARACTERISTICS OF SELECTED LOW-PERMEABILITY GAS SANDSTONES

TOPICAL REPORT
(May-July 1988)

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16. Abstract (Limit: 200 words)
Geological, engineering, and economic data on selected formations were compiled to provide a basis for siting the fourth Staged Field Experiment (SFE) for the Tight Gas Sands research program. The geologic units chosen are the Abo, Cleveland and Frontier Formations, and the Mesaverde Group. Extrapolation potential is good for all formations except the Cleveland, whose thin deltaic package has no good analogy in other low-permeability sandstones. The Abo has the best potential for extrapolation to other low-permeability formations. Average thickness of reservoirs is about 250 ft in the Mesaverde and Abo, 160 ft in the Frontier, and 120 ft in the Cleveland. Deepest production depth varies from 4,750 ft (Abo) to 12,198 ft (Second Frontier sandstone). Estimated resource base ranges from 3 TCF (Abo) to 86 TCF (Mesaverde). Pre-stimulation production ranges from too small to measure (Cleveland, Frontier, Mesaverde) to 314 MCFD (Frontier). Post-stimulation production ranges from 3 MCFD (Mesaverde) to 12,250 MCFD (Cleveland). Permeability ranges from less than 0.0001 md (Frontier) to 1.3 md (Frontier). Natural fractures have been shown to be significant locally in the Mesaverde, but their contribution to reservoir permeability in the other formations is not well-documented.

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RESEARCH SUMMARY

Title	Geologic characteristics of selected low-permeability gas sandstones
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708, entitled "Geologic Analysis of Travis Peak/Hosston and Corcoran-Cozzette Tight Gas Sandstones."
Principal Investigators	R. J. Finley, S. P. Dutton
Report Period	May-July 1988
Objective	This report is primarily a compilation of geologic information covering four low-permeability gas-bearing sandstone formations: Abo, Cleveland, and Frontier Formations, and Mesaverde Group. Engineering and economic data are also included. The purpose of the study was to gather information about each formation that could serve as a basis for siting Staged Field Experiment (SFE) No. 4.
Technical Perspective	Previous SFE's were located in the Travis Peak Formation in East Texas Basin. A nationwide survey of low-permeability formations was then undertaken to select a different basin for SFE No. 4. The initial stage of this survey eliminated all but four formations from consideration. This report comprises the second phase of the search, describing the remaining four formations in terms of their structural setting, stratigraphy, and diagenesis, as well as their recent production history and relevance to technology developed during the drilling of SFE's 1 through 3. This report summarizes the current geologic literature and engineering and economic data available for these formations.
Results	Each formation presents different possibilities for application of technology from SFE's 1 through 3. Structural settings, depositional environments, and mineralogy of sandstones range widely. Reservoir thickness, depth to pay zone, and estimated gas-in-place are quite variable. Fracture treatments, necessary in most completion programs, increase production rates as much as 4- to 100-fold. All formations are about equally accessible to pipelines, although the Abo was shut-in in June 1988, due to the presence of arsenic, presumably produced along with the gas.
Technical Approach	Thorough literature studies were conducted. Commercial databases were consulted to obtain information about recent completion practices, depth of drilling, production rates, and level of drilling activity. Industry representatives provided information about current difficulties faced during completion of wells in these low-permeability formations.

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ABSTRACT

Geological, engineering, and economic data on selected formations were compiled to provide a basis for siting the fourth Staged Field Experiment (SFE No. 4) for the Tight Gas Sands Research program of the Gas Research Institute. Four formations in four basins were chosen for study after a review of several criteria. These included size of designated tight gas area, level of current drilling activity, estimated gas-in-place, presence of FERC-designated low permeability sandstones, depth to the formation, and relevance of problems involved in gas production to the goals of the Tight Gas Sands Research program. The geologic units chosen are the Abo (Permian Basin), Cleveland (Anadarko Basin), and Frontier Formations (Green River Basin), and the Mesaverde Group (Piceance Basin). Although all of these formations meet the criteria for the location of SFE No. 4, important differences exist among them.

Extrapolation potential is good for all formations except the Cleveland, whose thin deltaic package has no good analogy in other low-permeability sandstones. The Abo has the best potential for extrapolation to other low-permeability formations.

Depositional facies range from fluvial deposits to marine-shelf muddy sands. The Mesaverde Group is the most diverse, whereas the Cleveland is made up of primarily marine-shelf and associated deposits. Mineralogic maturity ranges from subarkose (Upper Abo and Cleveland) to litharenite (Mesaverde and Frontier). All formations contain detrital clay and authigenic cements, including authigenic clays.

Average thickness of the formations range from 120 ft in the Cleveland to more than 2,000 ft in the Mesaverde. Average thickness of reservoirs is about 250 ft in the Mesaverde and Abo, 160 ft in the Frontier, and 120 ft in the Cleveland. Gross perforated interval is mostly less than 200 ft for the Mesaverde and Abo and less than 70 ft for the Frontier and Cleveland. Average net pay thickness ranges from 10 ft in the Cleveland to 70 ft in the lower Mesaverde. Depth to top of the

perforated zone ranges from 552 ft (Mesaverde) to 12,198 ft (Second Frontier). Deepest production depth varies from 4,750 ft (Abo) to 12,198 ft (Second Frontier).

Estimated resource base ranges from 3 TCF (Abo) to 86 TCF (Mesaverde). Maximum recoverable gas is 2.3 TCF (Mesaverde) to 4.9 TCF (Frontier). Pre-stimulation production ranges from too small to measure (Cleveland, Frontier, Mesaverde) to 314 MCFD (Frontier). Post-stimulation production ranges from 3 MCFD (Mesaverde) to 12,250 MCFD (Cleveland). Average post-stimulation production is 764 MCFD (Mesaverde) to 3,018 MCFD (Cleveland).

Almost all wells require stimulation, mostly fracturing and some acidizing. Typical fracture treatments in the Mesaverde require massive amounts of material, averaging 250,000 gal of fluid and 400,000 lb of sand. The Frontier is similar, with fracture treatments using up to 200,000 gal of fluid and 300,000 lb of sand. Stimulating the Cleveland usually takes less material: 40,000 to 80,000 gal of fluid and 70,000 to 80,000 lb of sand. Fracture treatments have increased flow volume from 4- (Mesaverde) to 100-fold (Abo). Few successful wildcats have been drilled recently. Most successful wells result from infill drilling.

Porosity ranges from 5 percent (Abo) to 20.7 percent (Frontier). Permeability ranges from less than 0.0001 md (Frontier) to 1.3 md (Frontier). Natural fractures have been shown to be significant locally in the Mesaverde, but their contribution to reservoir permeability in the other formations is not well-documented. Fifteen percent of wells completed in the Mesaverde since January 1983 did not require stimulation. In other basins the percentage was lower.

Formation fluids produced in association with gas are condensate (average = 29 BPD per well producing condensate in the Frontier) and water (average = 25 BPD per well producing water in the Frontier). Water saturation in typical pay zones ranges from 30 to 40 percent in the Cleveland. Calculated water saturation values range from 30 to 50 percent. Other basins have intermediate values.

Pipelines are available for all formations, although the Abo fields were temporarily shut-in beginning in July 1988 owing to the presence of arsenic in the gas, presumed to be produced along with gas. Industry interest in all areas is moderate to high.

Maximum formation temperatures range from 115°F for the Abo to 250°F for the Mesaverde. Thermal gradient varies from 1.2°/100 ft (Frontier, Cleveland) to 2.9°/100 ft (Mesaverde). Pressure gradient varies from 0.3 psi/ft (Mesaverde) to 0.54 psi/ft (Frontier). Average pressure is 878 psi (Abo) to 3,211 psi (Frontier).

Extensional and compressional stress regimes are represented in these basins, but there are few data on relative magnitude of in situ stresses, except in the vicinity of the Multiwell Experiment site in the Piceance Creek Basin. High compressive stress may exist locally in the Frontier.

Core availability is inconsistent. No cores available to the public have been identified for the Abo or the Cleveland, but 44 wells in the Frontier and 36 in the Mesaverde have cores in public core libraries.

Local relief is very low for the Abo and Cleveland areas. Relief reaches 1,000 ft locally in the Frontier area, and ranges from 1,000 to 3,000 ft in the Mesaverde area. Accessibility, therefore, is limited to river valleys in the Piceance Creek Basin, is locally limited in the Green River Basin, but is not restricted in the Anadarko and Permian Basins. Similarly, weather conditions usually do not interrupt drilling activities, except occasionally during the winter in the Piceance Creek Basin.

INTRODUCTION

The purpose of this study is to evaluate low-permeability formations in four basins as possible sites for drilling the fourth Staged Field Experiment (SFE No. 4) well in the Tight Gas Sands program. The objective of SFE No. 4 is to extend and apply, in a new area, techniques for the engineering, geological, and geophysical characterization of low-permeability sandstone reservoirs that were developed in the Tight Gas Sands program during the drilling of SFE wells 1 through 3. The process of selecting a site for SFE No. 4 began with an appraisal of 183 low-permeability (less than 0.1 md) formations located from the Rocky Mountains to the Appalachian Mountains. The procedures used to select the four formations with the best potential for drilling SFE No. 4 are summarized in a separate report (ICF-Lewin Energy Division, 1988b). Where applicable, the appraisal of low-permeability formations used information reported by Finley (1984), supplemented by updated information from each area. Finley (1984) assembled data on geology, engineering characteristics, economic factors, and operating conditions for 15 sedimentary basins containing blanket-geometry, low-permeability gas sands. Thirty-one different stratigraphic units were described in that report, including two of the formations examined in this report. However, the Mesaverde (with the exception of the Corcoran and Cozzette sandstones) and Abo Formations were not covered by Finley (1984).

Staged Field Experiments 1 through 3 were drilled and completed in the Travis Peak Formation in the East Texas Basin. Preliminary geologic research on the Travis Peak Formation included analyses of the structure, stratigraphy, depositional systems, diagenesis, and engineering properties of the formation (Finley and others, 1985). On the basis of that work, SFE's 1 through 3 were drilled in Harrison and Nacogdoches Counties, Texas. The goal of the drilling program for those three wells was to use a complete geological/geophysical characterization of a formation, coupled with a detailed and accurate fracture treatment analysis, to characterize fracture treatments in a low-permeability reservoir. Improvements in fracture treatment techniques should increase the supply of natural gas produced from such reservoirs and improve the economics of developing them (Gas Research Institute, 1988).

SFE No. 4 will be located in a basin different from the sites of SFE's 1 through 3. Part of the motivation for selecting another basin is the need to solve different technical problems involved in the evaluation and production of low-permeability gas-bearing formations, and to determine whether technology developed while drilling SFE's 1, 2, and 3 can be applied to another low-permeability formation. In general, the criteria used for siting SFE No. 4 are those listed in table 1. These are the factors that were used to select 12 formations in 8 basins (fig. 1, table 2). Narrowing this list to the selected basins included in this report was accomplished by eliminating the basins that are problematic in some regard: (1) formation has insufficient gas resource, or the FERC-designated low-permeability area is too small, (2) formation is already being actively drilled, indicating that technical problems are not limiting exploration and development, (3) formation

Table 1. Criteria used for defining candidate formations shown in figure 1. From ICF-Lewin Energy Division (1988a).

1.	Criterion:	Current operator activity
	Purpose:	Reduce GRI's costs of cooperative wells and SFE's
		Maximize availability of geological/production data
	Proxies:	Wells drilled into formation in past 5 years
		Annual production in past 10 years
		Recent development activity (anecdotal sources)
		NGPA Section 107 well filings
2.	Criterion:	High incremental resource potential
	Purpose:	Maximize contribution of GRI technology
	Proxies:	High estimates of gas-in-place
		High estimates of recoverable gas based on modeling
		Modest drilling activity compared with that of other areas
		Demonstrable market potential in area
3.	Criterion:	Scientific challenge to be overcome
	Purpose:	Focus of GRI program
	Proxies:	Anecdotal evidence of constrained development relative to potential
		Quantifiable geological or reservoir difficulty

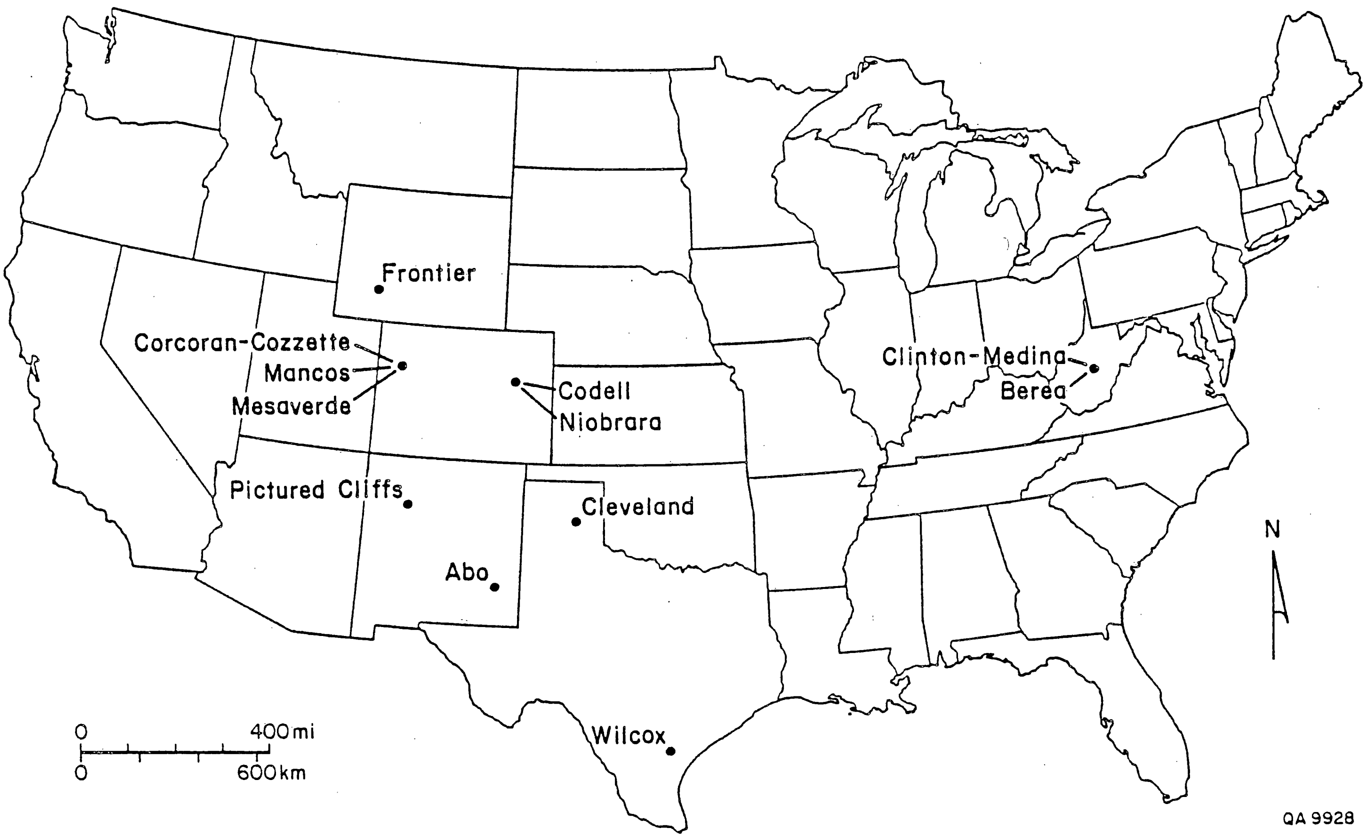


Figure 1. Location map of candidate formations. Modified from ICF-Lewin Energy Division (1988a).

Table 2. Twelve candidate formations chosen for possible location of Staged Field Experiment 4 (SFE No. 4). From ICF-Lewin Energy Division (1988a).

	Basin	Formation
1.	Anadarko	Cleveland
2.	Appalachian	Berea Clinton-Medina
3.	Denver	Codell Niobrara
4.	Green River	Frontier (Moxa Arch/Rock Springs Uplift)
5.	Permian	Abo
6.	Piceance	Corcoran-Cozzette Mancos Mesaverde
7.	San Juan	Pictured Cliffs
8.	South Texas	Wilcox

depth is shallow, which reduces the likelihood that vertical fractures will develop, or (4) formation presents technical or geological problems (such as geopressure) that have not been addressed by work at previous SFE's, the goal of which was to increase production from low-permeability sandstones via hydraulic fracturing.

METHODOLOGY

The model for this study is the report by Finley (1984) covering low-permeability gas sandstones. The body of this report is composed primarily of analysis and summary of literature published on these four formations. Information provided in Finley's (1984) report in tabular form has been updated and is included in the Appendix. For each formation, four tables describe general attributes, geologic parameters, engineering parameters, and economic factors. These can be reviewed for a concise summary of the data presented in the body of this report. Finley's (1984) tables have been updated using data from commercial data sources, such as Petroleum Information and Dwight's On-Line Service, and from recent publications. For the Abo Formation and Mesaverde Group, which were not included in Finley's (1984) report, equivalent information has been collected from commercial databases, published sources, and industry representatives.

FRONTIER FORMATION, GREEN RIVER BASIN

The Upper Cretaceous Frontier Formation in the Greater Green River Basin is a regressive deposit of alternating sandstone and shale lying between the Mowry and Baxter marine shales (fig. 2). Finley and others (1983, p. v) recommended that the Frontier Formation "should be considered when the need arises to test barrier, offshore bar, and possibly deltaic facies." Furthermore, they suggested that the Frontier be used for tests on specific facies or for particular engineering practices where technical experience is required at greater drilling depth.

Structural Setting - Greater Green River Basin and Moxa Arch

The Greater Green River Basin of southwestern Wyoming and northwestern Colorado is a structural basin that has a surface area of about 23,000 mi^2. Cretaceous and Tertiary rocks in the basin have an average thickness of 15,000 ft. Depth to the top of the First Frontier sandstone ranges from about 6,700 ft in the northwest to 8,300 ft in the south. Depth to the top of the Second Frontier sandstone varies from 7,250 ft in the northwest to more than 15,000 ft in the southeast. The Frontier is at greater depth off the axis of the Moxa Arch. In the Big Piney-La Barge area surface elevations range from about 6,800 to 8,400 ft.

The present form of the basin resulted from folding and faulting during Late Cretaceous-early Tertiary compressional episodes. The basin is bounded by the Overthrust Belt on the west and on the other margins by basement-cored positive features (Laramide uplifts) including the Wind River, Rawlins, and Uinta Uplifts (fig. 3, table A1). In Wyoming the basin is divided into three subbasins by the north-trending Rock Springs Uplift and the east-trending Wamsutter Arch (fig. 3). The Moxa Arch is an intrabasin uplift in the western subbasin adjacent to the Overthrust Belt (National Petroleum Council, 1980). It is a broad basement high locally faulted on the west side

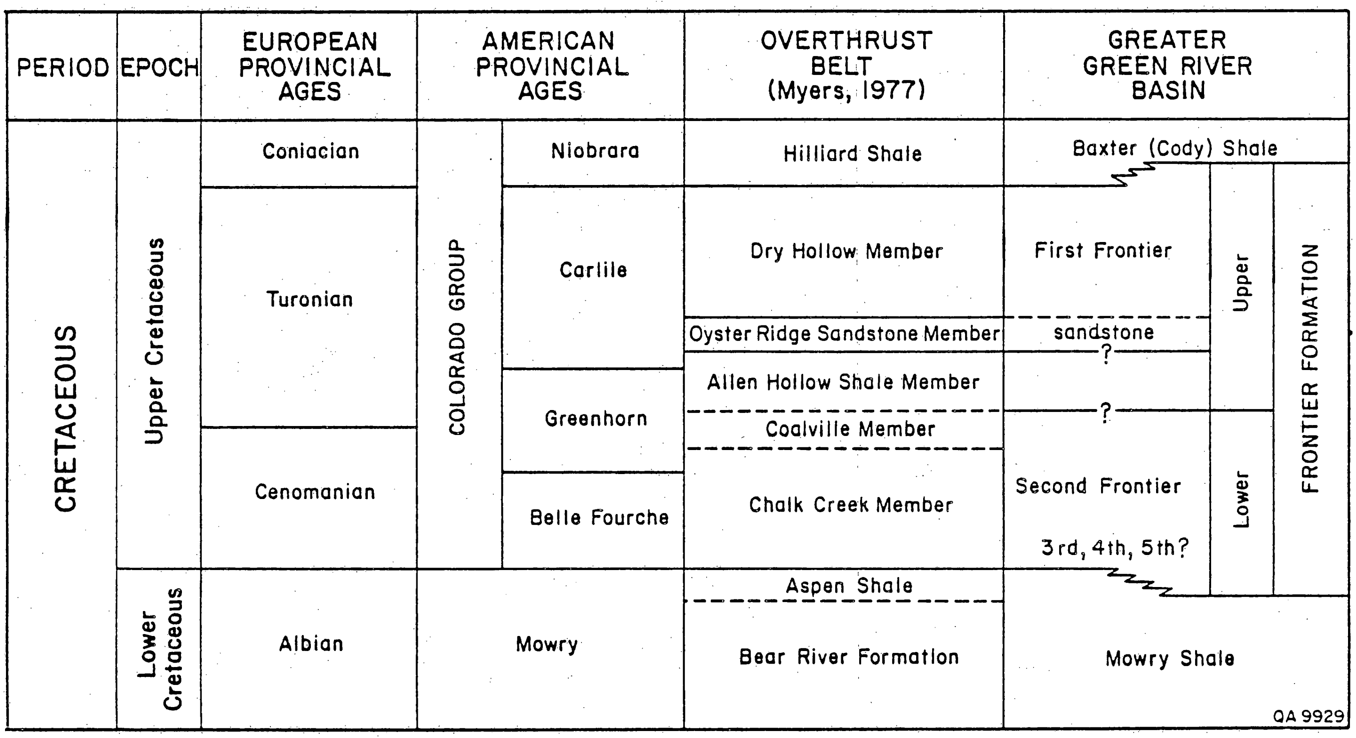


Figure 2. Stratigraphic chart of the Frontier Formation, southwestern Wyoming. Modified from Finley and others (1983, fig. 75).

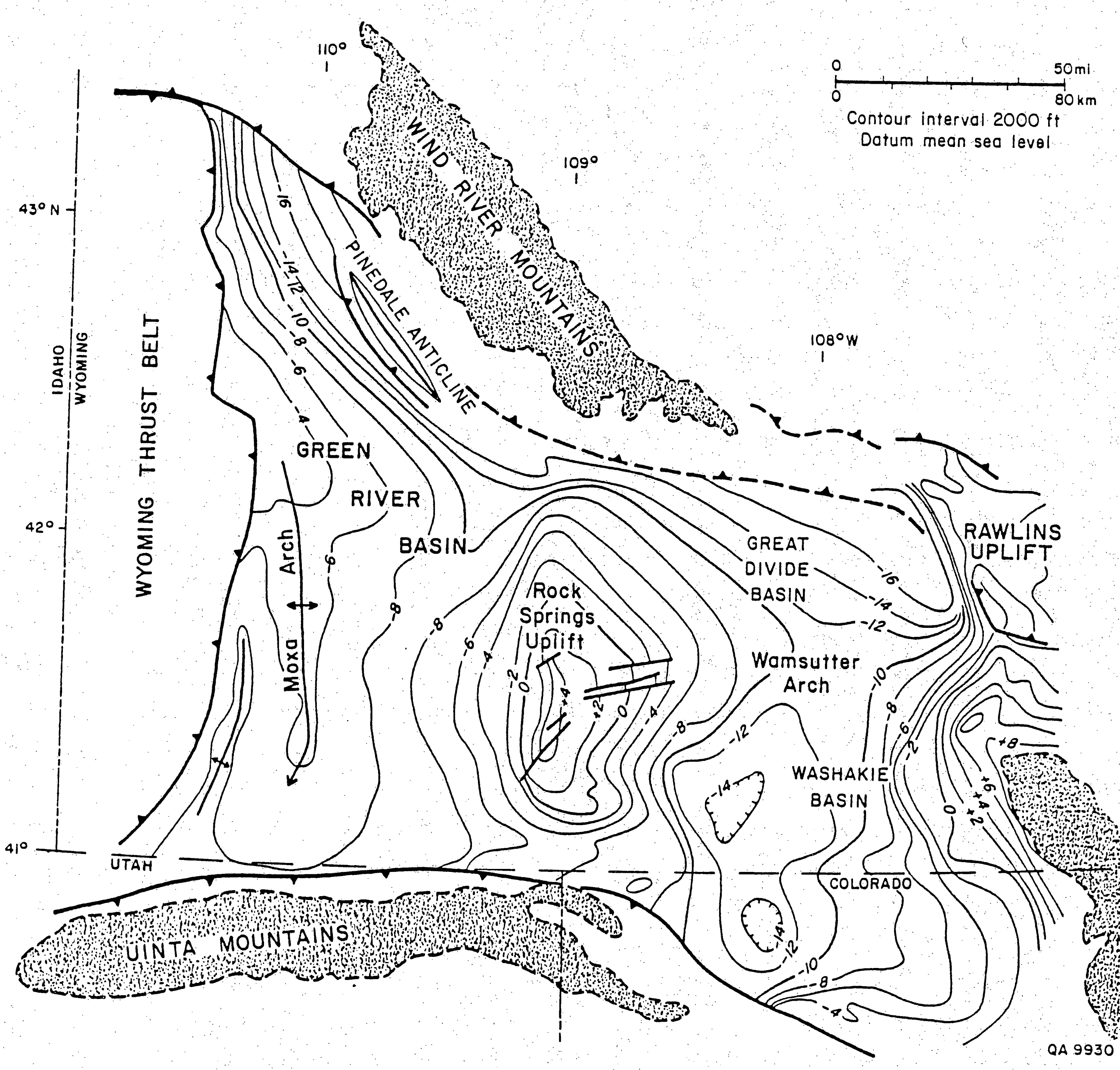


Figure 3. Generalized structure-contour map of the Greater Green River Basin. Contours are on top of the Lower Cretaceous Dakota Sandstone and equivalents. From Spencer (1987, fig. 2).

(Dixon, 1982). The arch trends north from the Utah-Wyoming border along the east flank of the thrust belt, and intersects the thrust belt west of Big Piney, Wyoming (fig. 4).

Overthrust Belt, Foreland Basin, and Laramide Basement Uplifts

The Greater Green River Basin is located on the boundary between two structural provinces, the Overthrust Belt and the Rocky Mountain foreland region. The Overthrust Belt in Wyoming is a region of north-trending folds and thin-skinned, imbricate thrust faults that dip gently west and that have a characteristic ramp-flat geometry (fig. 5a). Thrust movement occurred from the latest Jurassic to the early Eocene, and ceased about 40 mya (Wiltschko and Dorr, 1983). In general, the age of movement on individual thrusts is younger to the east, toward the less-deformed foreland area (Armstrong and Oriel, 1965; Dorr and Gingerich, 1980). In the eastern part of the Overthrust Belt, adjacent to the Greater Green River Basin, thrusting has resulted in approximately 50 percent east-west shortening by duplication of stratigraphic section (Royse and others, 1975). Unlike many of the folds and faults in the adjacent Rocky Mountain foreland region to the east, the faults in the Overthrust Belt west of the study area do not involve crystalline basement at the present structural level of exposure. The principal thrust faults west of the Greater Green River Basin, from east to west, are the Hogsback (Darby), Absaroka, Crawford, Meade, and Paris Thrusts. North of the Moxa Arch, the Hogsback Thrust bifurcates into the Prospect and Darby Thrusts (fig. 5b).

The area east of the Overthrust Belt is in the Rocky Mountain foreland region, a structural province composed of an extensive foreland basin and younger, isolated Laramide basement uplifts that have broken the foreland basin into smaller structural and depositional basins. The foreland basin of the Overthrust Belt extends from northern Canada to the Gulf of Mexico and is the western part of the Cretaceous Interior Seaway (Kauffman, 1977). Foreland basins are elongate, subsiding troughs that commonly occur on the cratonic side of overthrust belts. These basins typically have an asymmetric cross section, with thicker strata and steeper dips on the side next to the orogenic belt. This side of the basin may show much erosion of sediments, with numerous unconformities in

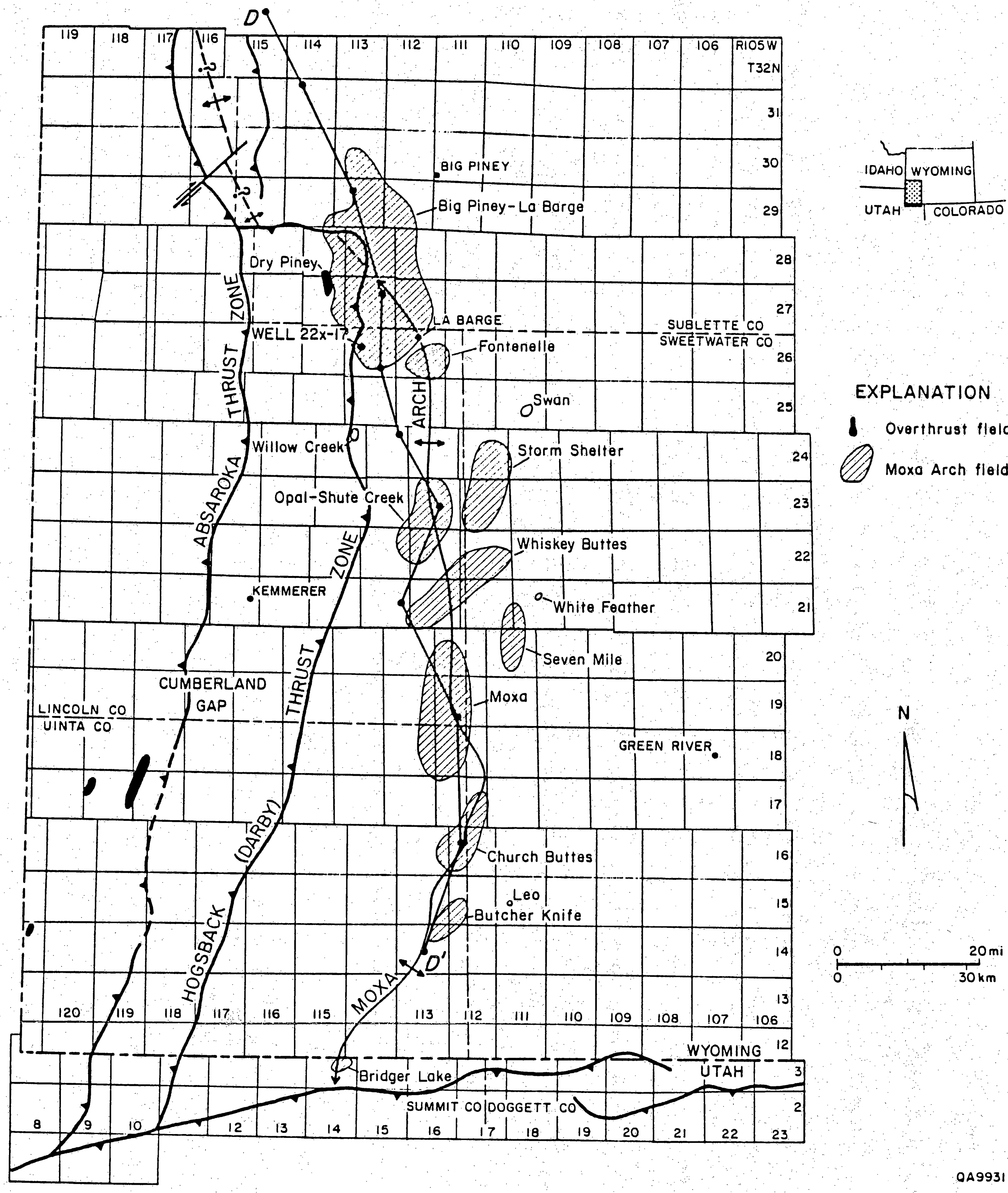


Figure 4. Location map of major structural elements and producing fields associated with the Moxa Arch. Cross section D-D' is shown in fig. 12. Modified from Wach (1977, fig. 1).

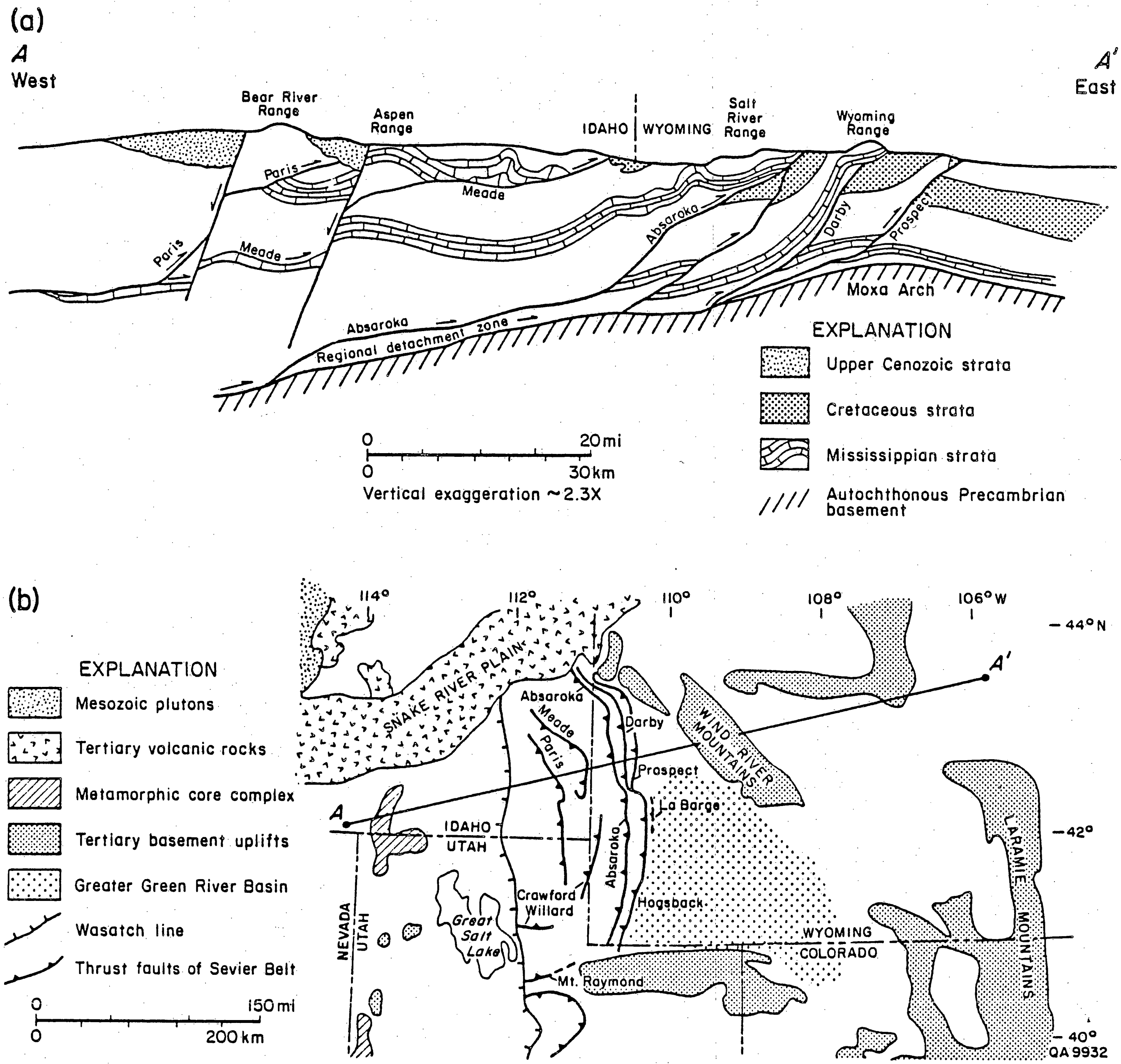


Figure 5. (a) Generalized schematic cross section (A-A') across Idaho-Wyoming thrust belt. (b) Location and tectonic map showing Idaho-Wyoming thrust belt. Modified from Jordan (1981, figs. 1 and 2).

the section. Deformation, some of which may be synsedimentary, becomes younger and less pronounced away from the orogenic belt. Depositional axes migrate away from the thrust front. This type of basin is partly caused by the weight of imbricate thrusts emplaced on the basin margin (Beaumont, 1981; Jordan, 1981). Thrust loading governed the shape of the Wyoming-Idaho-Utah foreland basin and the distribution of thick sediment accumulations within it (Jordan, 1981).

Disruption of the foreland depositional basin and most of the deformation within the Greater Green River Basin is due to movement of Laramide basement uplifts that occurred between 70 and 40 mya as a result of subduction of the Farallon Plate beneath western North America, and to the resulting east-northeast compression (Coney and Reynolds, 1977; Dickinson and Snyder, 1978). However, pre-Laramide movement has been noted for several of the uplifts (Merewether and Cobban, 1986), including the Moxa Arch (Wach, 1977). Uplift on the Moxa Arch appears to have occurred during deposition of the Baxter Shale (equivalent to the Hilliard Shale, fig. 2) and the lower Mesaverde Group, as suggested by thickening of these units away from the axis of the arch. The Rock Springs Uplift may be slightly younger than the Moxa Arch. The steep dip of Paleocene strata indicates a post-Paleocene age for much of the Rock Springs Uplift (Stearns and others, 1975).

In contrast to the low-angle, imbricate faults and lack of basement involvement in the Overthrust Belt, the Laramide basement uplifts are bounded by low- to high-angle reverse faults through crystalline basement, with differential vertical displacement of as much as 6.2 mi (Burchfiel and Davis, 1975; Coney, 1976, 1978; Hamilton, 1987). For example, the Wind River Uplift, north of the Greater Green River Basin, has been displaced vertically perhaps as much as 50,000 ft and moved horizontally 20 mi or more to the south-southwest (Blackstone, 1979; Gries, 1983b). In the Wyoming segment of the cordillera, the Overthrust Belt and Laramide uplifts were active concurrently for at least part of their history; consequently, structures in the foreland near the Overthrust Belt show evidence of interference between gently-dipping thrust faults and basement uplifts. The Moxa Arch is an example of structural interference between the thrust belt and the foreland.

Moxa Arch

The major structure in the western Greater Green River Basin is the Moxa Arch, located on the edge of the Overthrust Belt. The southern part of the Moxa Arch is east of the frontal thrust of the Overthrust Belt, but the northern portion of the Moxa Arch is overprinted by and overridden by the Overthrust Belt. The southern Moxa Arch, originally defined in southernmost Wyoming, is a broad, north-trending, basement-cored uplift with east vergence (Thomaidis, 1973). Toward the north relief increases, and near T24N (fig. 4) the basement is offset by a west-dipping reverse fault (Kraig and others, 1987). Thinning of the Frontier Formation and an angular unconformity at the base of the Paleocene Fort Union Formation indicate that the major uplift of the southern segment of the Moxa Arch occurred during the Late Cretaceous (Thomaidis, 1973; Wach, 1977). This segment of the uplift lies well east of the frontal thrusts of the Overthrust Belt.

North of T25N (fig. 4), the Moxa Arch bends northwestward for approximately 80 mi. This northwest-trending segment, called the La Barge Platform (Krueger, 1960), has more than 8,530 ft of structural relief on the southwest limb (Dixon, 1982; Royse, 1985). The surface trace of the frontal thrust of the Overthrust Belt (the Hogsback Thrust) crosses the Moxa Arch southwest of Big Piney, Wyoming (fig. 4), and the arch is thought to continue north beneath the Overthrust Belt (Royse and others, 1975; Dixon, 1982). The intersection of the Moxa Arch and the Overthrust Belt is also marked by disruption of the north-south continuity of individual thrusts (Armstrong and Oriel, 1965), presumably as a result of the interaction of the thrusts with previously uplifted basement (Wach, 1977; Blackstone, 1979). Wiltschko and Eastman (1983) used the kinematic history of the interaction between the Hogsback (Darby) Thrust and the Moxa Arch as an example of the effects of a stress-concentrating buttress (Moxa Arch) on thrust propagation. The deep crustal structure of the basement high is a low-angle, east-dipping thrust (Kraig and others, 1987). Although Dixon (1982) inferred normal faults on the west margin of the northern Moxa Arch, Royse (1985) suggested that east to northeast compression produced reverse faulting and asymmetric folding of basement.

Hydrocarbon production from the Frontier Formation along the Moxa Arch can be subdivided structurally into fields within the Overthrust Belt, fields on the margin of the Overthrust Belt, and fields east of the Overthrust Belt (fig. 4). West of the Hogsback (Darby) Thrust, hydrocarbon accumulation is essentially structurally controlled, but to the east, accumulation is stratigraphically and structurally controlled (McDonald, 1973; De Chadenedes, 1975). The Big Piney-La Barge field straddles the intersection between the Overthrust Belt and the Moxa Arch and shows a range of structural involvement from the less complex Moxa Arch structures to thrust belt structures toward the west (fig. 6) (Shipp and Dunnewald, 1962). Fields east of the Overthrust Belt, such as Church Buttes and Moxa, generally have relatively simple anticlines and mixed structural and stratigraphic traps (De Chadenedes, 1975; Law and others, 1986).

Stress directions

The Greater Green River Basin is in the Colorado Plateau stress province, near the boundary between the Colorado Plateau stress province on the southeast and the Northern Basin and Range stress province on the northwest (fig. 7) (Zoback and Zoback, 1980). The boundary between the two stress provinces follows the trace of the Overthrust Belt, but the exact location and nature of the boundary is uncertain. Northwest of the boundary, least horizontal stress in the Overthrust Belt trends northwest (Zoback and Zoback, 1980). Power and others (1976) used surface seismic monitoring of hydraulic fracture propagation to determine the orientation of least horizontal stress. They reported a trend of N65W at 9,105 ft depth near Pinedale, Wyoming (fig. 8), adjacent to the Wind River Uplift in the northern Green River Basin. Stress regime is reported to be strike-slip (Zoback and Zoback, 1980). The Green River Basin southeast of the stress-province boundary, in the Colorado Plateau stress province, has a north-northeast-directed least horizontal stress (fig. 7). The boundary of the Midcontinent stress province (northwest least horizontal stress) crosses east-central Wyoming. The location of this boundary is uncertain.

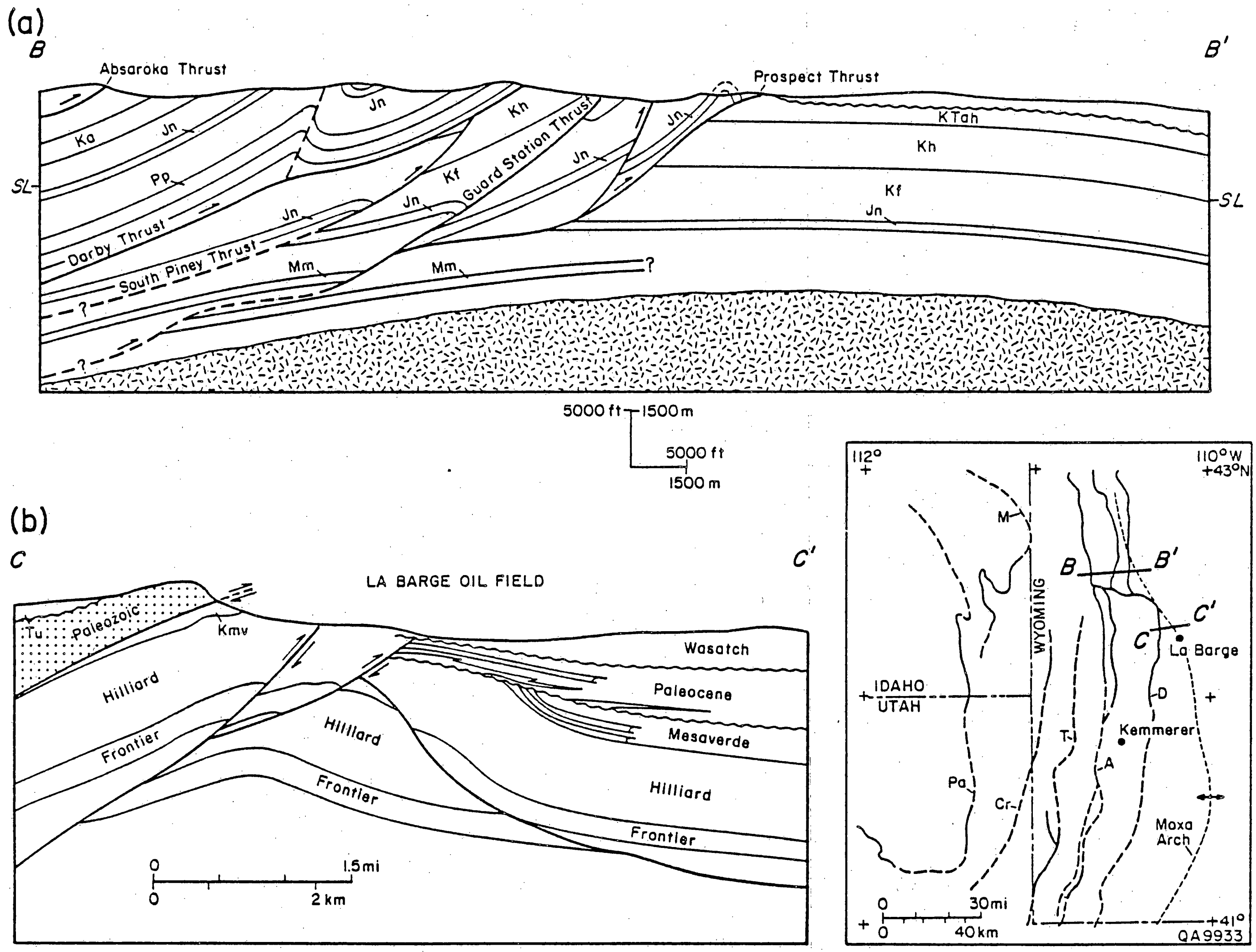


Figure 6. (a) West-east structure section (B-B') across the Moxa Arch. Symbols: Ka=Aspen Shale; KTah=Tertiary Hoback Formation and Cretaceous Adaville Formation, undivided; Kh=Hilliard Shale; Kf=Frontier Formation; Jn=Nugget Sandstone; Pp=Phosphoria Formation; Mm=Madison Limestone. Hatched pattern is basement. From Wiltschko and Eastman (1983, fig. 8). (b) West-east structure section (C-C') across La Barge field. Symbols: Kmv=Cretaceous Mesaverde Group; Tu=Tertiary, undifferentiated. From McDonald (1973, fig. 15). See inset for location of cross sections. Symbols on inset are as follows: A=Absaroka Thrust; Cr=Crawford Thrust; D=Darby Thrust; M=Meade Thrust; Pa=Paris Thrust; T=Tunp Thrust.

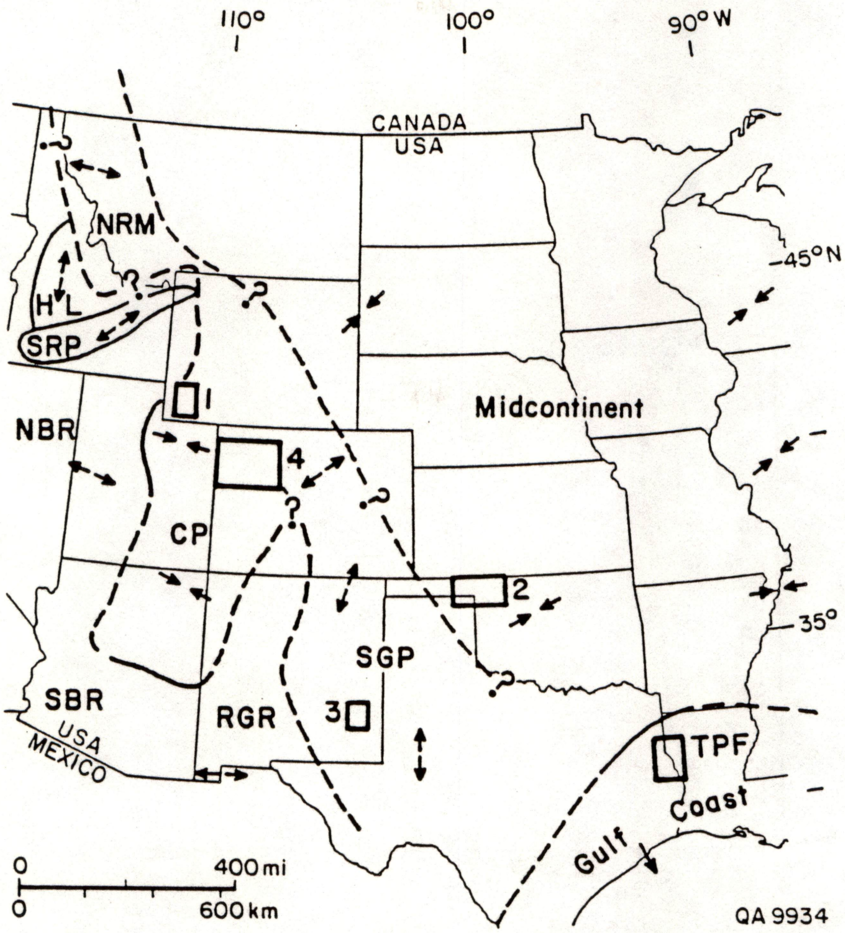


Figure 7. Generalized stress map of the conterminous United States. Arrows represent direction of either least (outward directed) or greatest (inward directed) principal horizontal compression. Small boxes correspond to selected formations: 1=Frontier, in the Green River Basin, 2=Cleveland, in the Anadarko Basin, 3=Abo, in the Permian Basin, 4=Mesaverde, in the Piceance Basin, TPF=Travis Peak Formation, in the East Texas Basin. Letters identify stress provinces: CP=Colorado Plateau, HL=Hegben Lake-Centennial Valley, NBR=northern Basin and Range, NRM=northern Rocky Mountains, PNW=Pacific Northwest, RGR=Rio Grande rift, SBR=southern Basin and Range, SGP=southern Great Plains, SRP=Snake River plain-Yellowstone. Modified from Zoback and Zoback (1980, fig. 5).

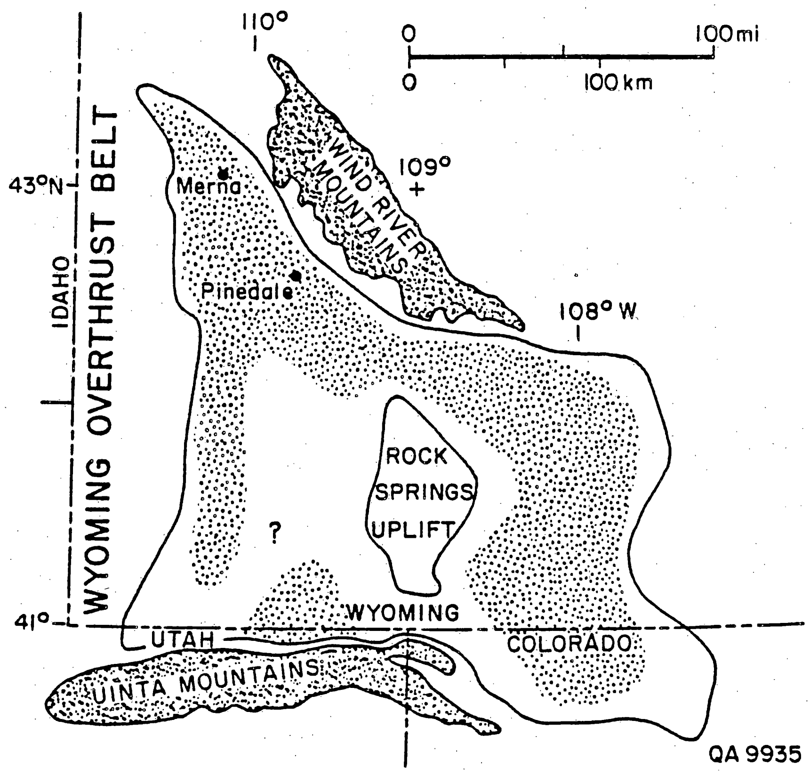


Figure 8. General distribution of overpressuring (shaded area) in Greater Green River Basin, and location of the Merna well (fig. 9). From Spencer (1987, fig. 3).

Results of hydraulic fracture experiments in the Greater Green River Basin confirm north-northwest least horizontal stress and east-northeast maximum horizontal stress, and suggest that locally, hydraulic fractures may have multiple, non-parallel wings (Power and others, 1976). Passive surface seismic detection of hydrofracture hypocenters in the Pinedale area indicated that hydraulically induced fractures grew northeast (N30E to N45E) (Power and others, 1976). The fracture also showed predominant growth of one wing, a curved fracture trajectory, and possible growth of a third fracture wing at right angles to the principal northeast-trending fracture. This pattern may be due to intersection of the induced fracture with a natural fracture zone or fault, and possible reactivation of the fracture zone or fault.

Overpressure

Overpressuring (above-normal pore pressure) is common in low-permeability hydrocarbon-bearing reservoirs in Cretaceous rocks throughout much of the Rocky Mountain region (Spencer, 1987). Overpressure is reported in the Second Frontier sandstone on the Moxa Arch (Finley, 1984). The gradient is approximately 0.54 psi/ft in the area of Docket no. 189-80 application. Overpressure in southwestern Wyoming is regionally distributed (fig. 8). The highest reservoir pressure identified in the Rocky Mountain region (Spencer, 1987) occurs in the northern Green River Basin at the Merna well site (figs. 8 and 9). The first occurrence of overpressure in the Merna well is at about 10,600 ft depth, where borehole temperature is approximately 194° F (fig. 9) (Law, 1984). Pressures at the top of the Cody (Baxter) Shale and the base of the Mesaverde Group are approximately 16,700 psi at 17,200 ft depth, equivalent to a gradient of 0.97 psi/ft.

In the Greater Green River Basin, above-normal pressures generally occur in gas-bearing, low-permeability, marine to fluvial, Cretaceous to Paleocene sandstone reservoirs (Spencer, 1983, 1987; Law, 1984). Overpressured Cretaceous, low-permeability, gas-bearing reservoirs are found at depths ranging from less than 10,000 ft to more than 20,000 ft (Law and others, 1986). There is no discrete stratigraphic or structural boundary acting as a pressure seal (Law and others, 1986). Rocks older

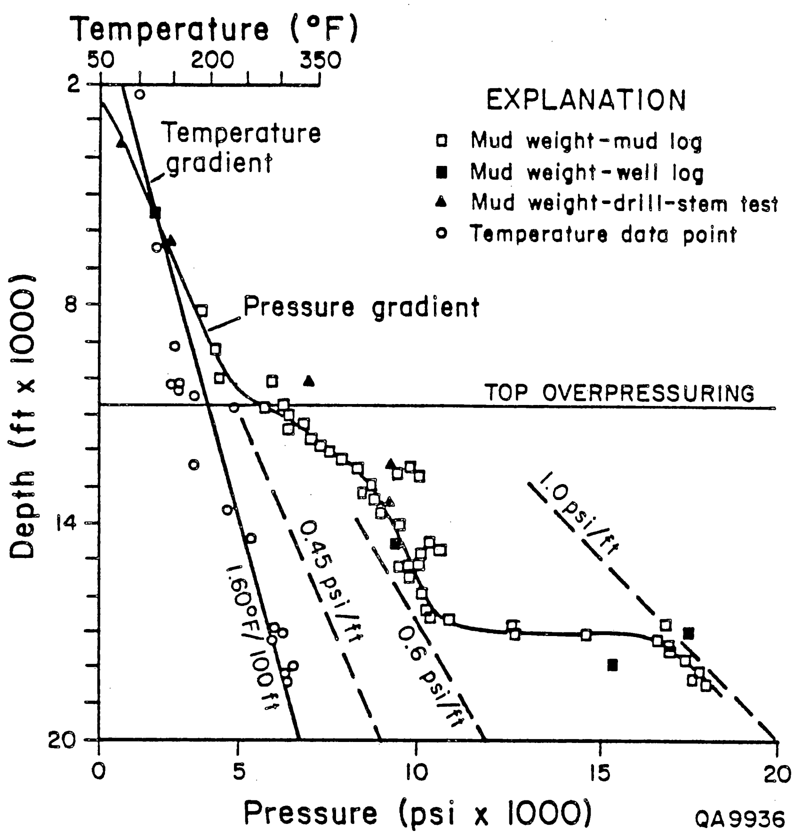


Figure 9. Pressure profile of Belco 3-28 Merna Unit well, Sec. 28, T36N, R112W, Sublette County, Wyoming. For location, see figure 8. From Spencer (1987, fig. 4a).

than Cretaceous are not regionally overpressured. Figure 8 shows the general distribution of overpressuring in the Greater Green River Basin, and the location of the pressure profile is shown in figure 9.

Some of the characteristics common to overpressured reservoirs in the Rocky Mountain region that Spencer (1987) recognized include:

1. Overpressuring occurs in low-permeability rocks.

2. Hydrocarbons are generally the fluid pressuring phase.

3. Overpressuring commonly occurs in rocks with present-day temperatures of about 200° F or higher.

4. Natural fracturing is important for high production rates.

Law (1984) and Spencer (1987) concluded that overpressuring in many Rocky Mountain basins results from thermal generation of hydrocarbons. The factors that control overpressuring in the Greater Green River Basin are permeability, rates of gas accumulation and depletion, and thermal maturity (Law and others, 1986).

Reservoir-scale faults, fractures, and other small-scale structures

Tectonic fractures, stylolites, and small-scale faults are common in, and adjacent to, the Overthrust Belt and areas near the Laramide basement uplifts. Fractures, stylolites, and faults can therefore be expected in Moxa Arch reservoir rocks, and fractures have in fact been observed in core from the Frontier Formation. Law and others (1986) and Spencer (1987) noted that fractures are important for high production rates from low-permeability reservoirs in the Greater Green River Basin. Fractures in thrust belt rocks can be widespread (Mitra, 1987; Laubach, 1988) and may influence reservoir quality (Nelson, 1985). Fracture patterns in thrust belts and basement uplifts can also be predicted (Hancock, 1985). For example, small differences in finite strain caused by gentle folding can produce significant increases in fracture intensity (Wayhan and McCaleb, 1969). Mapping the rate-of-change-of-dip or degree of curvature (second-derivative maps) of brittle rock, such as quartzite, has been used to predict increased fracture intensity in reservoir rocks in basement uplifts in southern Wyoming (Harrison and Tilden, 1988). The effect of fractures and tectonic stylolites on reservoir quality is reviewed by Nelson (1985). He showed that they could contribute significantly to permeability anisotropy in reservoir rocks.

Stratigraphy

General stratigraphy

The Upper Cretaceous Frontier Formation of southwest Wyoming is formally defined as a coal-bearing sandstone sequence that paraconformably overlies the Aspen Shale and is conformably overlain by the Hilliard Shale (figs. 2 and 10) (Knight, 1902; Cobban and Reeside, 1952; Myers, 1977). The top of the Frontier is lithologically designated by the first sandstone below the marine Hilliard Shale; the base is formed by the contact between non-marine Frontier mudstones and sandstones and the marine Aspen Shale. Along the north-south Green River Basin axis, the Frontier Formation lies 17,000 to 18,000 ft below the surface and may attain a thickness of 2,000 ft (Weimer, 1960; Myers, 1977). However, in most areas on the Moxa Arch the Frontier section varies from 400 to 600 ft in thickness (Finley, 1984), and the top occurs at a depth of 6,700 to 8,300 ft.

During Cenomanian and Turonian time the western shoreline of the Cretaceous Interior Seaway underwent regression. This is exemplified by thickening of the Frontier Formation northwestward from the Colorado-Wyoming border (fig. 11) and by facies changes within the Frontier (west-to-east) from sandstone to shale (Weimer, 1960; 1962). The east-northeast-trending isopach "thicks" in Sweetwater County, Wyoming (fig. 11), depict the location of major depocenters that formed eastward of and along the axis of the Moxa Arch in the Green River Basin.

Transgressive marine and non-marine rocks intertongue with regressive sandstones and constitute five lithologically variable stratigraphic members of the Frontier Formation. Myers (1977) provides detailed lithologic descriptions and interpretations of depositional environments

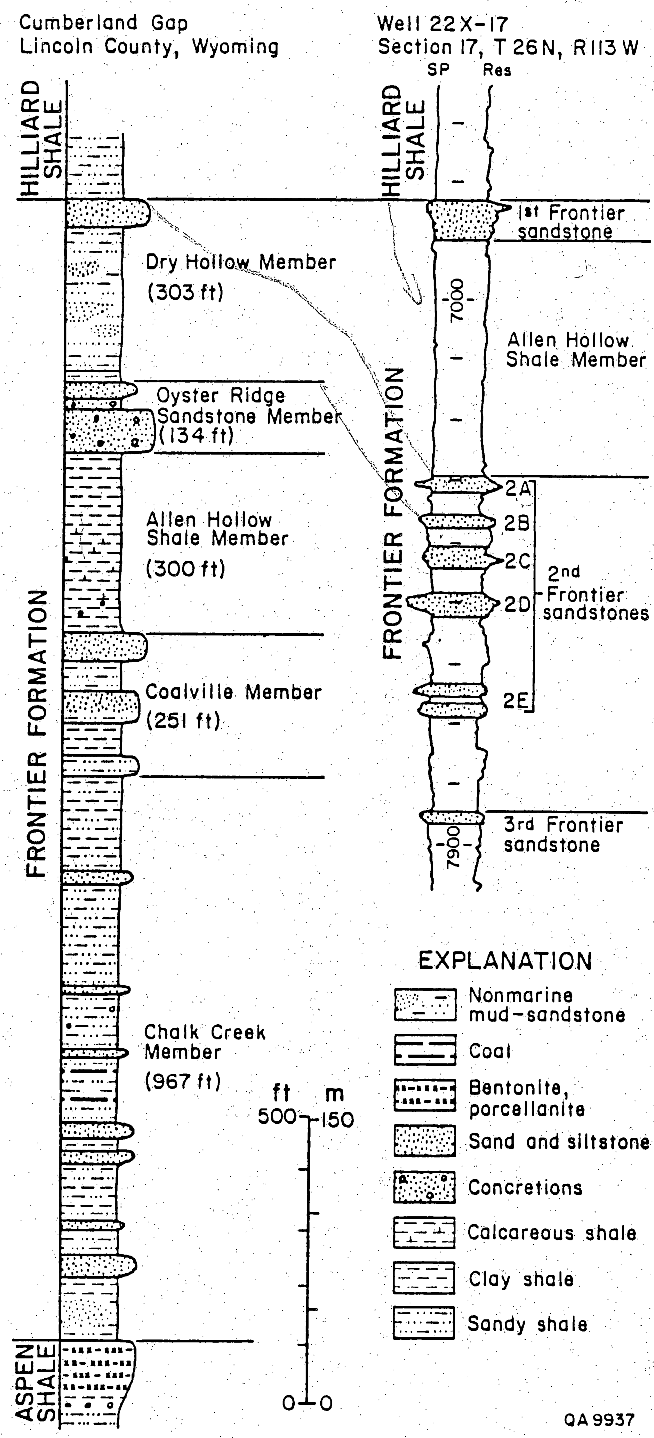


Figure 10. A typical SP/Resistivity log (right) and a stratigraphic section (left) for the Frontier Formation, Moxa Arch area. Note how the five stratigraphic members of the Frontier Formation and the local sandstone names compare. For location of wells see figure 4. Modified from Myers (1977, figs. 2 and 6).

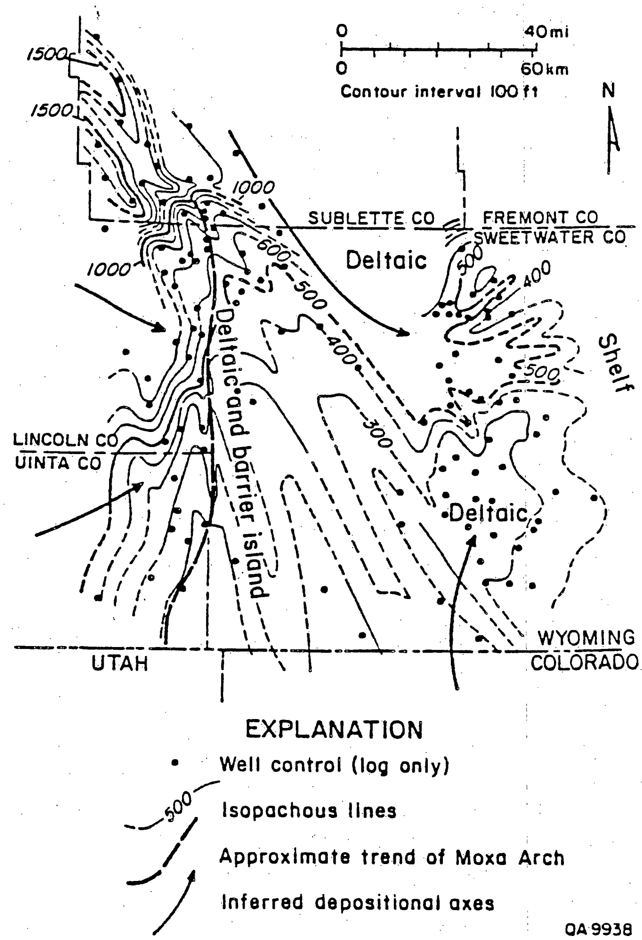


Figure 11. Isopach and paleogeographic map of the Frontier Formation in the Moxa Arch area of the Green River Basin, Wyoming. Modified from Finley and others (1983, fig. 76).

for each member of the Frontier in the vicinity of Kemmerer, Wyoming (fig. 10). Brief descriptions of each member follow in ascending order:

Chalk Creek Member: This member ranges from 967 to 1,400 ft in thickness. It thins eastward and pinches out east of the Moxa Arch. Fine-grained, well-sorted, and calcareous, upward-coarsening sandstones of deltaic and tidal-channel origin are interbedded with swamp and marsh mudstones. These deposits may represent one or more regressive cycles of delta plain (red bed) and nearshore sedimentation.

Coalville Member: Sandstone, shale, coal, and oyster beds of this member range from 100 to 150 ft in thickness. They represent the earliest incursion of brackish to marine conditions and establishment of estuarine, lagoonal, and shoreline environments in the Frontier. Upward-coarsening, fossiliferous, and bioturbated transgressive-shoreline sandstones overlie oyster beds. Coal beds as much as 6 ft in thickness cap the transgressive sandstones.

Allen Hollow Shale Member: This member is a 300-ft-thick calcareous, sand-free, transgressive marine deposit. Local intertonguing of the Allen Hollow Shale Member with the overlying Oyster Ridge Sandstone may represent repeated transgressions and regressions or shifts in depocenter locations.

Oyster Ridge Sandstone Member: Fresh- to brackish-water deltaic deposits, nearshore marine sandstones, and marine shales comprise this 50- to 200-ft-thick section. One or two sandstones coarsen upward. These sandstones pinch out into marine shale, representing a progradational (beach) depositional setting. Estuarine and tidal-channel deposits overlie the deltaic deposits.

Dry Hollow Member: Lithologically variable sediments (300-ft section of mudstone, sandstone, conglomerate, and coal) were deposited in deltaic environments. These sediments overlie the Oyster Ridge Sandstone, which was scoured, locally, by distributary channels. Laterally persistent transgressive marine sandstone and shale form the top of this member.

An informal but commonly used subsurface stratigraphic classification for the Frontier Formation is based on a numbering system for the major sandstones. The stratigraphically highest sandstone is termed the "First Frontier sandstone," and progressively deeper sandstones are numbered as they are encountered in the section (fig. 10). As many as five productive Frontier sandstones may be encountered in a well. The Second Frontier sandstone is further subdivided into a series of sandstone benches designated alphabetically as benches 2A through 2E (fig. 10) (Myers, 1977; Wach, 1977). Owing to the deltaic and marginal marine depositional setting for most of the Frontier Formation, Frontier sandstones and the Second Frontier benches are neither continuous nor stratigraphically equivalent throughout the basin (Hawkins, 1980).

Depositional environments and reservoir characteristics

Finley and others (1983) summarized regional sedimentologic and stratigraphic studies in the Frontier (Masters, 1952; Goodell, 1962; Shipp and Dunnewald, 1962; McDonald, 1973; De Chadenedes, 1975). Depositional systems in the Frontier are interpreted to be primarily deltaic and associated coastal-plain and nearshore environments (barrier island, estuary, river, tidal channel, lagoon, swamp, and marsh) (table A2). Shipp and Dunnewald (1962) proposed a fluvial/deltaic setting for sandstone, shale, and coal deposits of the First Frontier sandstone (Oyster Ridge Sandstone Member, Myers, 1977) in the Big Piney-La Barge gas field area near the northeastern end of the Moxa Arch (fig. 4). These sandstones are progradational. Brackish to fresh-water delta-plain sediments overlie deltaic and marine sandstones, and they grade laterally and vertically into beach and estuarine deposits. The presence of beach, tidal-channel, and lagoonal (oyster mounds) deposits overlying deltaic deposits implies that sediment reworking followed delta lobe abandonment or marine transgression. To the east, the First Frontier sandstones pinch out and are separated from the Second Frontier sandstones by 450 to 500 ft of marine shale (Allen Hollow Shale Member).

Interpretations of a deltaic depositional setting for the Second Frontier sandstones in the vicinity of Moxa and Whiskey Buttes fields (fig. 4) were refined by Moslow and Tillman (1986). Analyses of numerous cored wells revealed a wave-dominated delta system supplied from the west by fluvial channels. Eastward migration of the depocenter occurred by progradation of distributary channels and shoreline advance. Sediment delivered to the Cretaceous Seaway was reworked by waves and distributed along the shoreline in strandplain, barrier-island, and spit environments adjacent to distributary channels.

Fluvial and marine processes in this depositional setting juxtaposed distributary-channel and nearshore marine depositional environments. Nearshore and shoreface deposits are shore-parallel (strike-oriented) and continuous along depositional strike, but they are lenticular parallel to depositional dip. Laterally equivalent distributary-channel sandstones are perpendicular to the paleoshoreline, and are continuous along depositional dip. However, they are largely lenticular and discontinuous parallel to depositional strike.

Wave-dominated deltaic deposition in the Frontier formed blanket-geometry shoreline sandstones that were cut by lenticular channels. Migration of distributary channels reworked and modified the geometry of the strandplain deposits. As a result, along depositional strike, discontinuous channel sandstone reservoirs in the vicinity of deltaic depocenters grade laterally into more continuous (wave-reworked) shoreline sandstones.

Myers (1977) describes western and eastern sandstone tongues in the First Frontier sandstone that are most productive in the Dry Piney overthrust structure (fig. 4). Thickness of the western tongue reaches 100 ft, and porosity ranges from 12 to 25 percent, whereas maximum thickness for the stratigraphically lower eastern tongue is 80 ft, porosity 10 to 18 percent. At La Barge field to the east, the First Frontier sandstone produces from two elongate sandstone bodies draped over the La Barge structural nose. Porosities range from 12 to 25 percent in these sandstones. Production and reservoir quality in the First Frontier sandstone diminish to the north and east due to increased clay content. To the south, production is limited strictly to the Second Frontier sandstone (De Chadenedes, 1975; Myers, 1977).

In the subsurface of the Moxa Arch area, the second and occasionally third and fourth Frontier sandstones are equivalent to the Chalk Creek and Coalville Members of the Frontier Formation (fig. 10) (Myers, 1977). De Chadenedes (1975) named two large deltaic complexes, the La Barge and Cumberland deltas, that lie east of the approximate location of paleoshorelines in the Second Frontier sandstone. The largest deltaic depocenter, the La Barge, is located near the northern end of the Moxa Arch in Sublette County. Fifty miles south of La Barge, near Cumberland Gap, Wyoming (fig. 4), second Frontier sandstones thicken locally at the Cumberland delta. In both depocenters, fluvial and paludal coastal-plain sediments grade eastward into deltaic deposits that thin due to draping across a structural platform. Reservoir sandstones are interbedded with, and sealed by, delta-plain and marine shales. Structural and stratigraphic traps in the Big Piney-La Barge field area contain gas reserves in excess of 1.8 trillion cubic feet (TCF), and the Frontier is the principal reservoir (McDonald, 1973). Although some Moxa Arch wells produce from Second Frontier sandstones at the eastern limit of the Cumberland delta, De Chadenedes (1975) reported only unsuccessful tests of the Second Frontier at Church Buttes and Moxa (Bruff and Wilson Ranch) Units.

Hydrocarbon production from the Frontier Formation in the study area is strongly controlled by structural and stratigraphic traps formed by Late Cretaceous and Early Paleocene deformation of the sandstones deposited over Moxa Arch (McDonald, 1973; Myers, 1977; Wach, 1977; Moslow and Tillman, 1986). Most reservoirs are found in deltaic and littoral sandstones (Wach, 1977), although some gas is recovered from fluvial deposits. Cross section D-D' (fig. 12) illustrates the southward thinning of deltaic and littoral deposits along Moxa Arch. As a result of this thinning, there are probably more exploration targets in deltaic and littoral sandstones toward the northern end of Moxa Arch than near the southern end.

According to Moslow and Tillman (1986), productive second Frontier sandstones in Moxa and Whiskey Buttes fields (fig. 4) were deposited in distributary-channel, crevasse-splay, foreshore, shoreface, and inner-shelf environments. These authors noted that production is greatest from distributary channels close to Moxa Arch and saw no correlation between thickness of the perforated intervals and production rates. Porosity values are generally highest in channel deposits (10 to 12 percent) and lowest in nearshore sandstones (8 to 9 percent). In contrast, Hawkins (1980) attributed low permeabilities in barrier sandstones to clay linings in pores. Wach (1977) stated that deltaic reservoirs are discontinuous, low-quality sandstones; therefore, he concluded that production was greatest from the nearshore sands.

McDonald (1973) observed that high permeability values do not necessarily correspond to thick sandstones and that a high-permeability zone trends north-northeast in the Second Frontier sandstone. Distributary-channel reservoirs described by Moslow and Tillman (1986) possess vertical and lateral permeability barriers, must be modeled as heterogeneous reservoirs, and demonstrate minimal communication between wells drilled on 360-acre spacing. These observations concur with the conclusion of Shipp and Dunnewald (1962), who found that reservoir compartmentalization was common despite consistent pressures observed in different reservoirs.

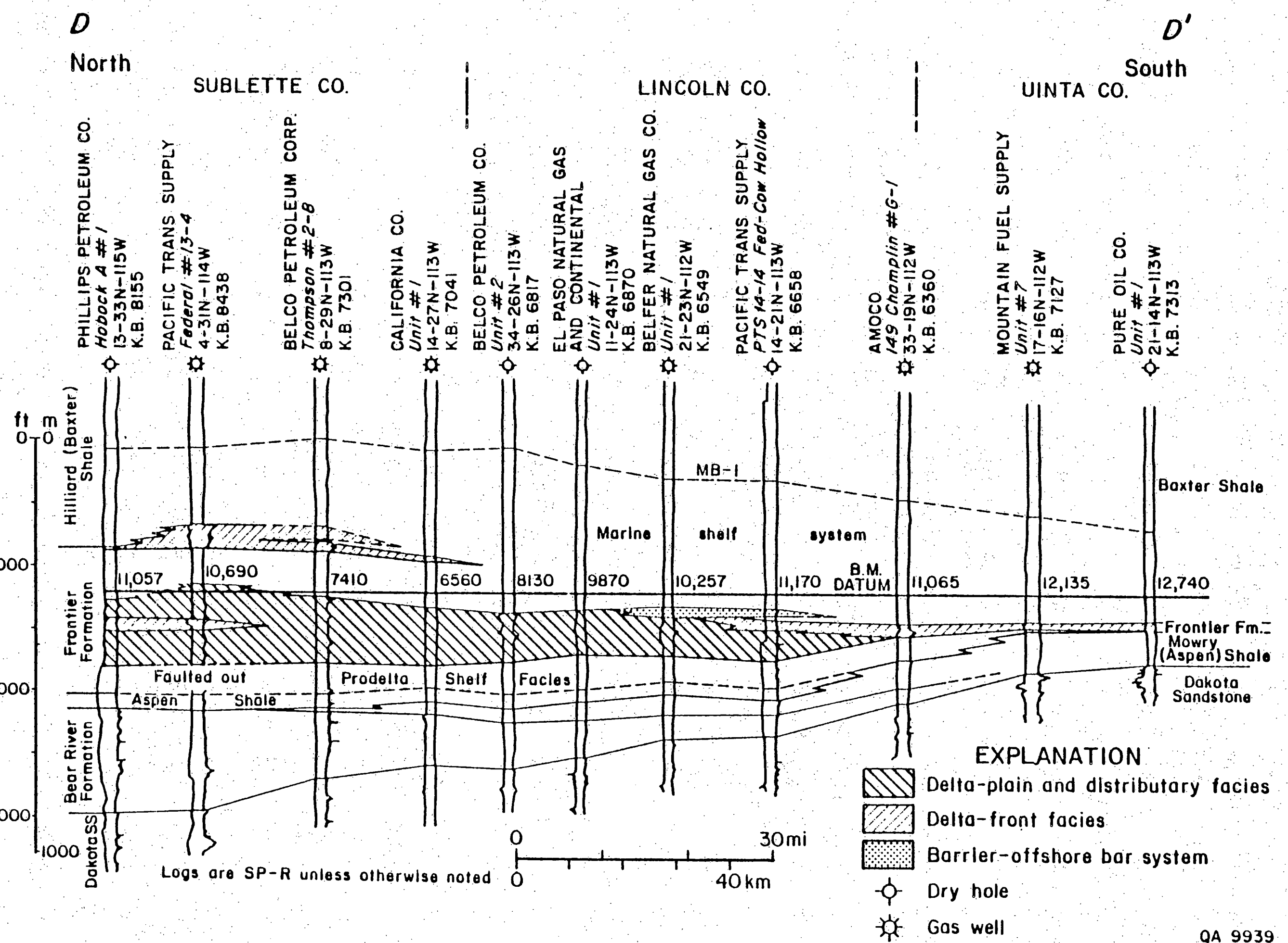


Figure 12. North-south stratigraphic cross section (D-D') of the Frontier Formation and adjacent units along the axis of the Moxa Arch. See figure 4 for location. From Finley and others (1983, fig. 73).

In Moxa field (fig. 4), channel sandstones are perforated most frequently, despite their stacked and laterally discontinuous nature and the presence of numerous internal permeability barriers (Moslow and Tillman, 1986). Laterally continuous, regressive barrier-island sandstones occupy the interdeltaic area along the Frontier paleoshoreline (Hawkins, 1980). North of Moxa field, a larger percentage of wells are completed in foreshore and shoreface sandstones. Barrier sandstones form continuous and homogeneous reservoirs that overlie inner-shelf marine shale and are overlain by lagoonal and tidal-flat deposits (Hawkins, 1980; Moslow and Tillman, 1986).

Although large gas reserves exist in the B and C benches of the second Frontier, and the D bench (fig. 10) is thought to contain commercial reserves, production from the second Frontier sandstone in the 1970's benefitted primarily from increased gas prices and improvements in fracture technology (Wach, 1977). The C bench of the second Frontier is believed to hold the greatest potential because (1) the A bench is non-productive south of Big Piney-La Barge area, (2) the B bench has tested unsuccessfully in several wells, and (3) the D bench is a fine-grained clay-rich marine sandstone. Average initial production (IP) values for the C bench are 3 to 4 million cubic ft per day (MMCFD).

Shale, mudstone, and coal interbedded with the Second Frontier benches apparently provide reservoir seals. Owing to thicknesses that range from 50 to 150 ft, they may provide a complete or partial barrier to artificial fracture propagation. The 400-ft-thick Allen Hollow Member should act as a fracture barrier. Although every attempt has not been successful, most wells in this area respond favorably to fracture stimulation (Wach, 1977).

De Chadenedes (1975) reports that substantial clay content in the Second Frontier sandstone at La Barge is likely to damage the reservoir when it is contacted by water-based drilling fluids. Generally, wells drilled with gel mud produce at lower rates than those drilled with oil-based mud, and sand/oil fracture treatments are standard procedure. He also states that hole-caving is a problem in the La Barge area that hinders logging operations and formation evaluation. Commonly, core analyses are unreliable, and drill stem tests yield artificially low production values.

Lithology and Diagenesis

The petrography and diagenesis of Frontier sandstones on the Moxa Arch have been summarized by Stonecipher and others (1984), Winn and others (1984), and Moslow and Tillman (1986), and the following discussion is based on their work. Lower (Second) Frontier sandstones on the Moxa Arch are mainly fine- to very fine grained litharenites to sublitharenites that contain subequal amounts of quartz and rock fragments and minor feldspar (dominantly plagioclase). The rock fragments are mainly chert, although rare metamorphic and volcanic rock fragments are present. The framework grain composition of Frontier sandstones varies with depositional environment; marine sandstones (marine-sand-ridge and shoreline sandstones) contain fewer rock fragments and proportionally more quartz than do fluvial sandstones.

Most marine-sand-ridge sandstones are poorly sorted and contain abundant matrix clay, both detrital clay and clay that was mixed into the sand by burrowing. The clay is mixed-layer illite/smectite, which could cause formation damage if it comes in contact with fresh water during well completion. Because of the abundant clay matrix, compaction during shallow burial significantly reduced porosity and permeability in these sandstones. Thus, low values of porosity and permeability in most marine-sand-ridge sandstones are due to pore-plugging clay matrix. However, shallow-water sandstones reworked by waves are well-sorted and relatively rich in detrital quartz. Most of the well-sorted marine-sand-ridge sandstones contain abundant quartz overgrowths, and thus have low porosity and permeability because of cementation. Some of the well-sorted offshore sandstones were cemented early in the burial history (prior to quartz cementation) by calcite that later dissolved, generating secondary porosity. These more porous zones within the marine-sand-ridge sandstones are patchy and poorly connected (Stonecipher and others, 1984).

Marine shoreline sandstones from lower shoreface, foreshore, and backshore environments coarsen and become better sorted upwards. Lower shoreface sandstones are poorly sorted and contain abundant clay matrix. As a result, original porosity and permeability in lower shoreface sandstones were low and were further decreased by compaction during early burial. Sandstones deposited in the higher-energy foreshore environments are better sorted and more quartz-rich. Backshore sandstones are similarly quartz-rich because sand deposited in the backshore was derived from the beach deposits. Thus, most of these sandstones had high original porosity and permeability. However, these clean, quartz-rich sandstones were extensively cemented by quartz during burial diagenesis, and now have low porosity and permeability. Most of the porosity in these sandstones is secondary porosity that developed by dissolution of clay clasts, but these secondary pores are not well-connected.

Fluvial point-bar and crevasse-splay sandstones in the Frontier Formation contain more abundant detrital chert than do marine sandstones. Point-bar sandstones are coarsest at the base (medium- to coarse-grained sand) and fine upward to fine- to very fine grained sand; sorting also decreases upward. Chert is most abundant in the coarser grained deposits at the base of fluvial sand bodies. Because most of the upper parts of point-bar sandstones were fine grained and contained abundant clay matrix, they had poor primary porosity that was further reduced by compaction. Some well-sorted upper-point-bar sandstones exist, but they are relatively quartz-rich and thus were cemented by quartz. In contrast, lower-point-bar sandstones had generally good original porosity and permeability. Because chert grains are abundant in lower-point-bar sandstones, quartz overgrowths did not develop as readily, and those sandstones have retained high porosity and permeability. Thus, the best Frontier reservoirs are found at the base of fluvial sandstones.

Another trend in reservoir quality has been observed in the comparison of fluvial sandstones at the southern and northern ends of the Moxa Arch. At the northern end, pores are commonly filled by neomorphosed mixed-layer illite/smectite and authigenic chlorite and kaolinite. Reservoir quality in fluvial sandstones is better at the southern end of the Moxa Arch because authigenic clay is rare. These regional differences in diagenetic history are represented by differences in permeability. The most permeable fluvial sandstones at the southern end of the Moxa Arch are an order of magnitude more permeable than the most permeable fluvial sandstones at the northern end (10 md vs 1 md), although their porosities are similar (13 percent vs 15 percent). Hence, the basal fluvial sandstones at the southern end of the Moxa Arch have the highest permeability in the study area.

Average porosity and permeability values in different reservoir facies in Frontier sandstones are summarized in figures 13 and 14. The highest porosity occurs in fluvial-channel deposits, which probably have the highest permeability. High permeability values listed for the clay-rich lower-shoreface and shelf-transition facies (fig. 14) may be due to bypassing or artificial fracturing of core samples during analysis (Moslow and Tillman, 1986).

Production, Resource Potential, Logistics

Well completion data from Petroleum Information Services (undated) give the following information on the production history and resource potential of the Frontier Formation. During the period from 1982 to January 1988, most wells were spudded and completed in 1983 and 1984 (fig. 15); sixteen operators have drilled the Frontier since 1982 (fig. 16). Most wells drilled between January 1983 and May 1987 are near La Barge, Wyoming, in the Big Piney-La Barge and Fontenelle fields (fig. 17). Depth to the top of the perforated interval ranges from 6,040 to 12,198 ft (fig. 18, table A1). Most of the 82 wells for which information was available had been hydraulically fractured using either sand/foam, sand/gel, or sand/water treatments (fig. 19, table A3). Typically, a well was hydraulically fractured using 90,000 to 200,000 gal of fluid (fig. 20) and 100,000 to 350,000 lb of sand. Pre-stimulation production rates for 63 wells averaged 253 MCFD with a maximum of 2,630 MCFD (Finley, 1984). The average post-stimulation production rate for 104 wells was 1,496 MCFD and ranged from 48 to 8,240 MCFD (fig. 21). Production decline curves for six of the Frontier wells in the Whiskey Buttes field are given in figure 22. Estimated gas-in-place is 20.3 TCF with estimated recoverable gas of 4.9 TCF (table A1).

ICF-Lewin Energy Division (1988c) surveyed stimulation treatments for four fields from the Frontier Formation tight sand designation. These fields represent both the most active areas in the designation in terms of number of producing wells (Whiskey Buttes, Fontenelle) as well as areas with few producing wells (Pine Canyon, Bird Canyon). Table A4 gives a cost survey for drilling and stimulation of the Frontier Formation.

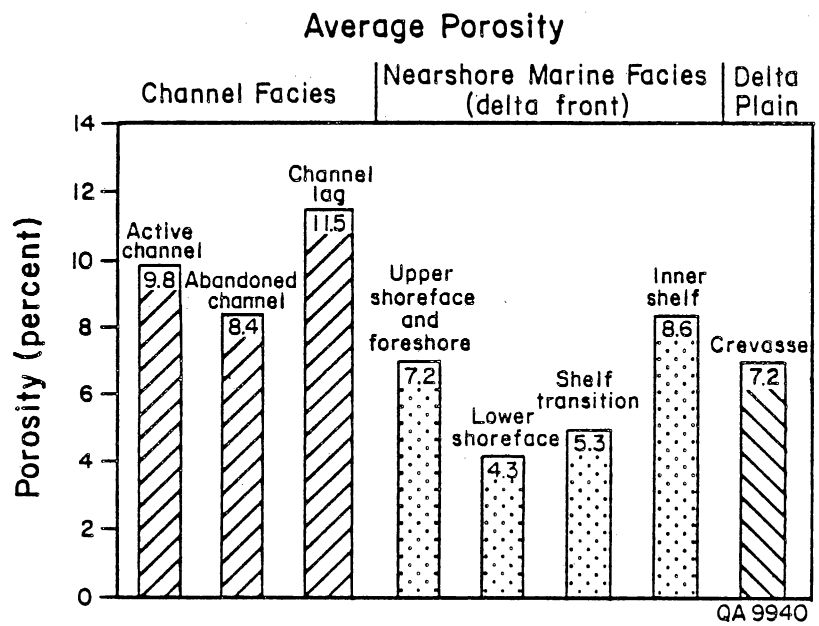


Figure 13. Average porosity values for cored facies in Moxa Arch area wells. Porosity measurements are from whole core analysis and plugs. From Moslow and Tillman (1986, fig. 21).

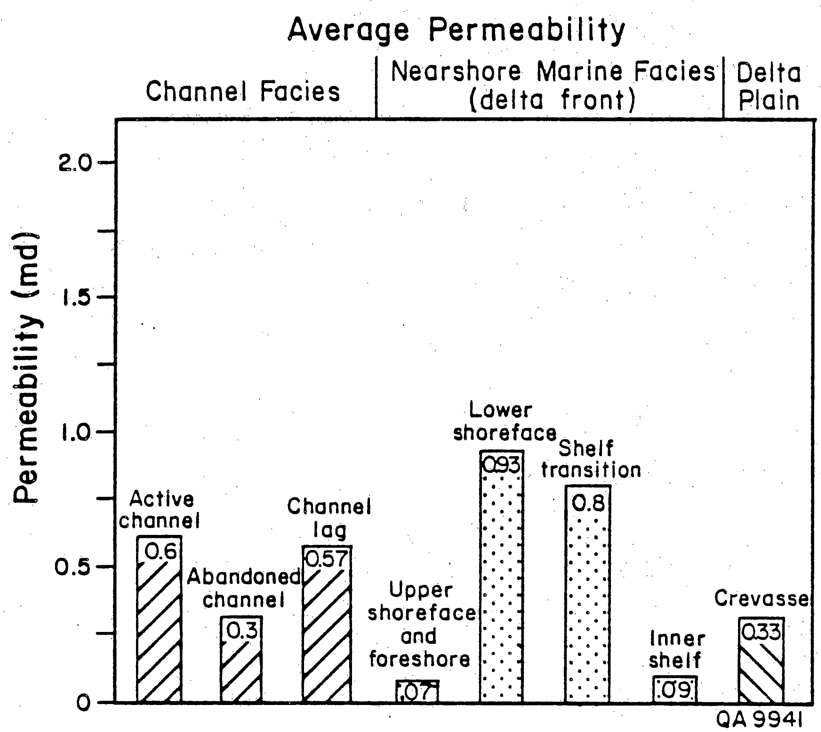
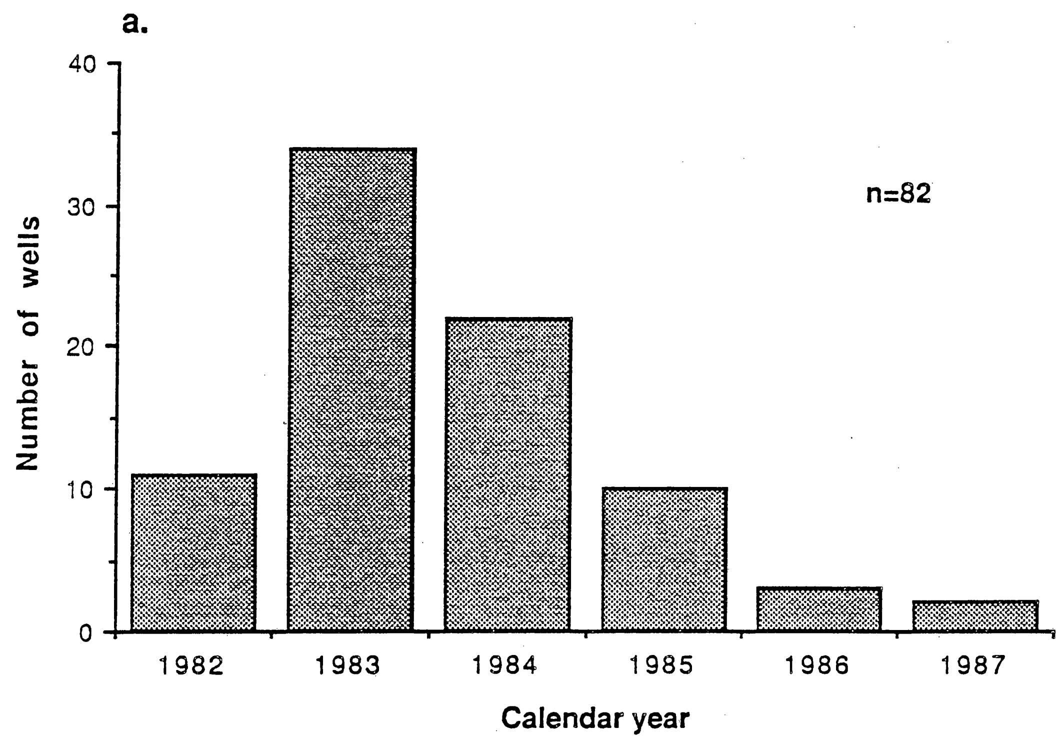


Figure 14. Average permeability values for cored facies in Moxa Arch area wells. From Moslow and Tillman (1986, fig. 22).



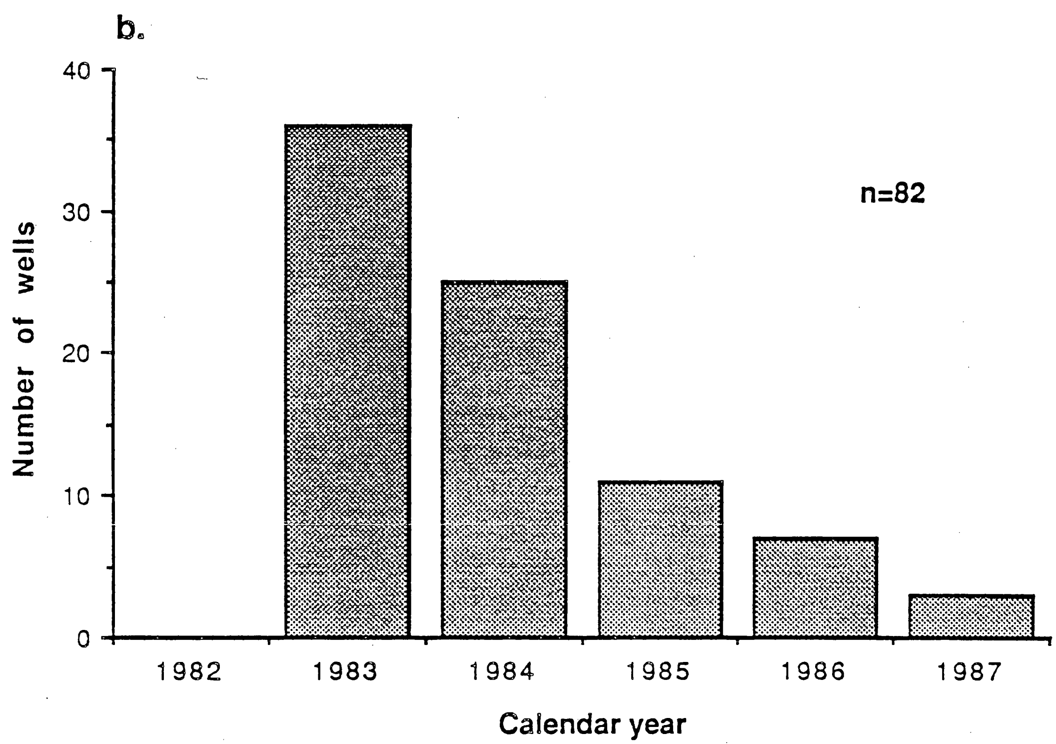


Figure 15. Number of wells (a) spudded and (b) completed in the Frontier Formation between February 1982 and April 1988. No successful gas wells were completed between May 1987 and April 1988.

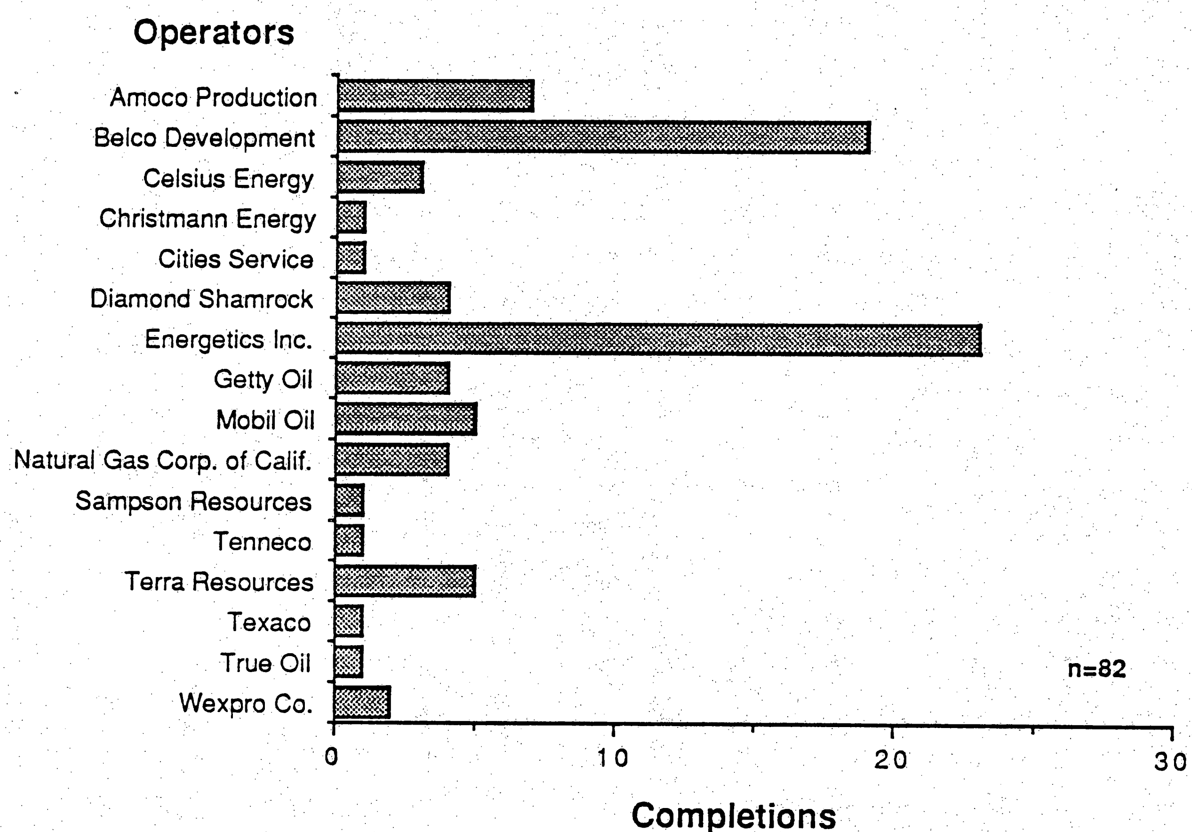


Figure 16. Operators that completed wells in the Frontier Formation between January 1983 and April 1988. No successful gas wells were completed between May 1987 and April 1988.

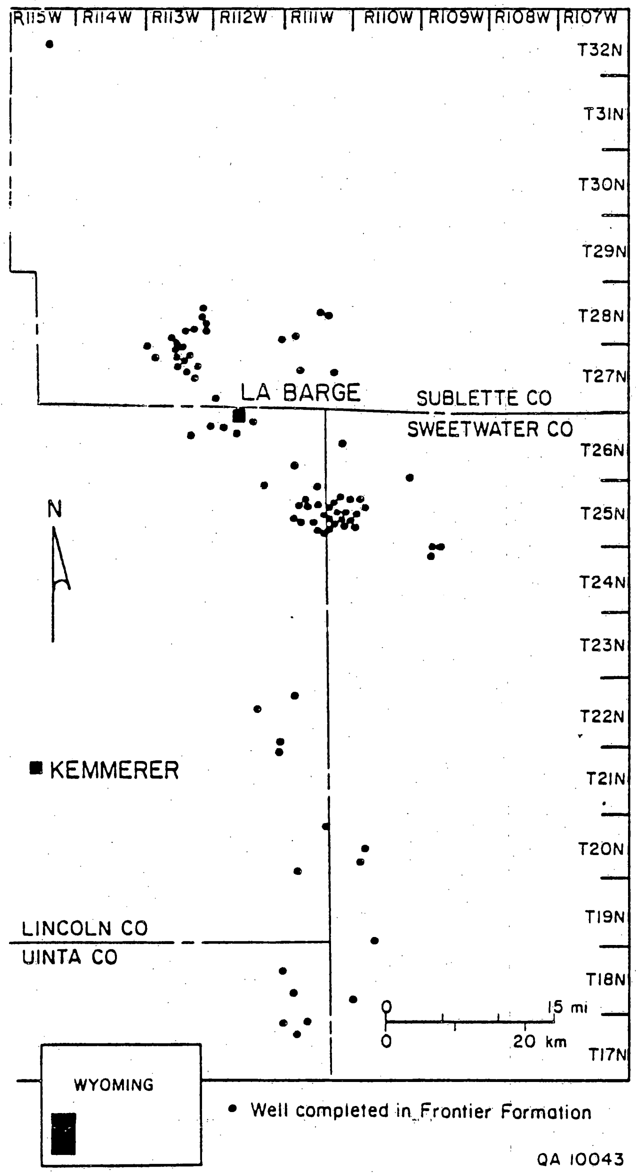


Figure 17. Map of wells completed in the Frontier Formation between January 1983 and April 1988.

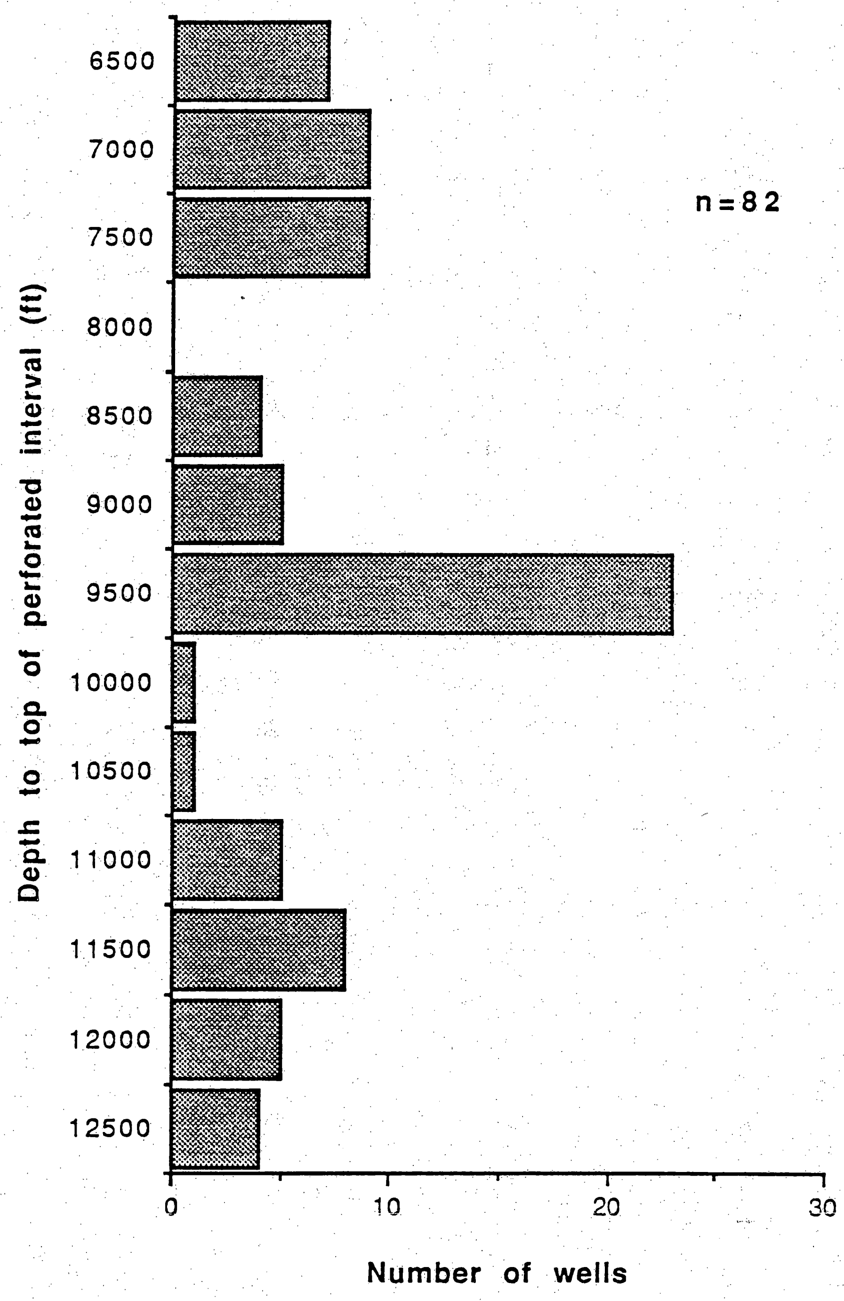


Figure 18. Depth to top of perforated interval in the Frontier Formation ranges from 6,040 to 12,198 ft.

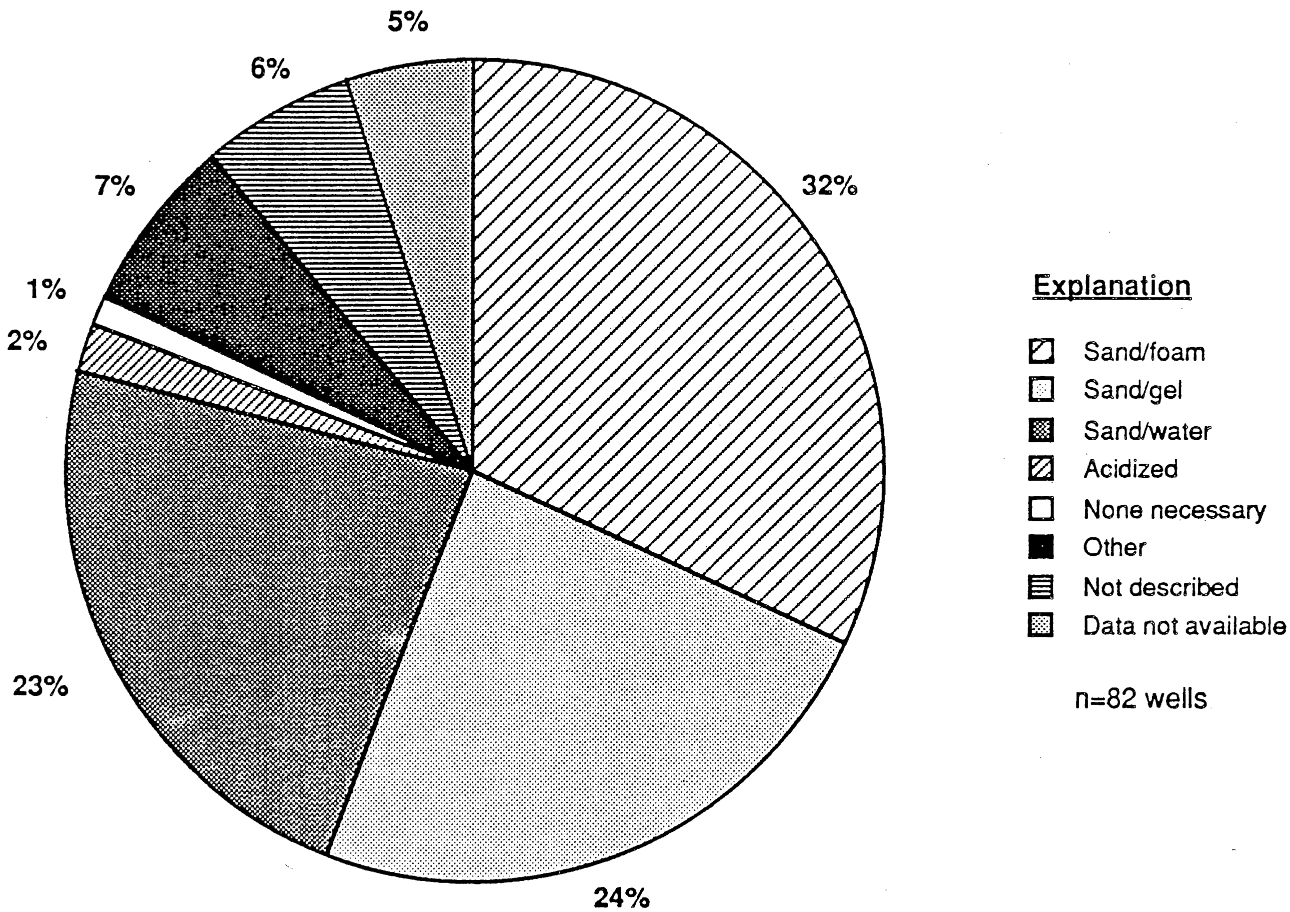


Figure 19. Methods of well stimulation for successful gas wells completed between January 1983 and April 1988. More than three-fourths of all wells were hydraulically fractured. Fracture treatments designated as "not described" include wells that were fractured, but for which no additional information was available. Wells designated "data not available" are wells for which no information of any sort was provided.

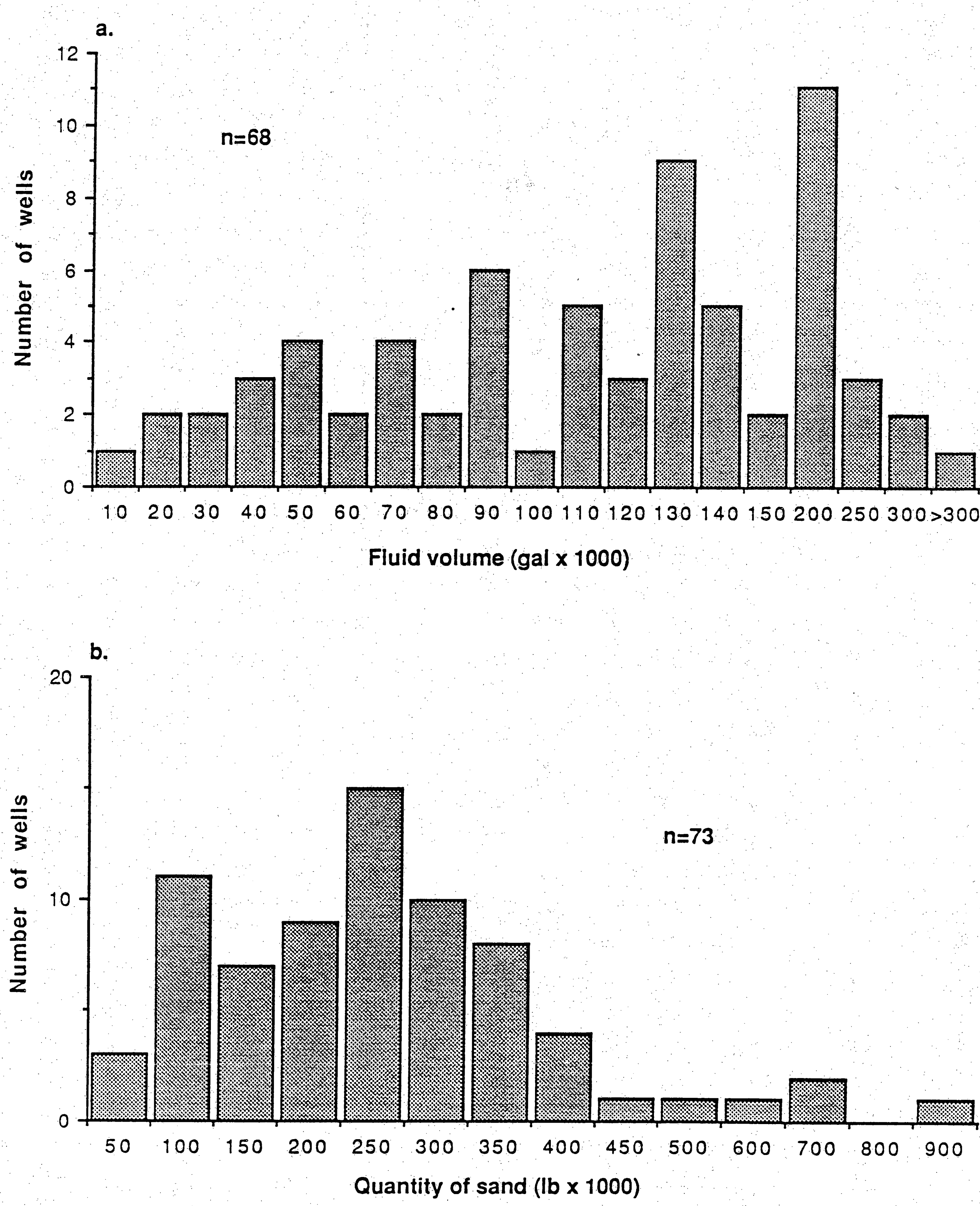


Figure 20. Amount of material used in well completion between January 1983 and April 1988. (a) Volume of fluids used in hydraulic fracture jobs in Frontier Formation. (b) Quantity of sand used in fracture jobs. No acid usage is shown because only 12 wells were treated with acid as part of the stimulation, and 10 of those used less than 5,000 gal. One well was acidized (68,000 gal) but not fractured.

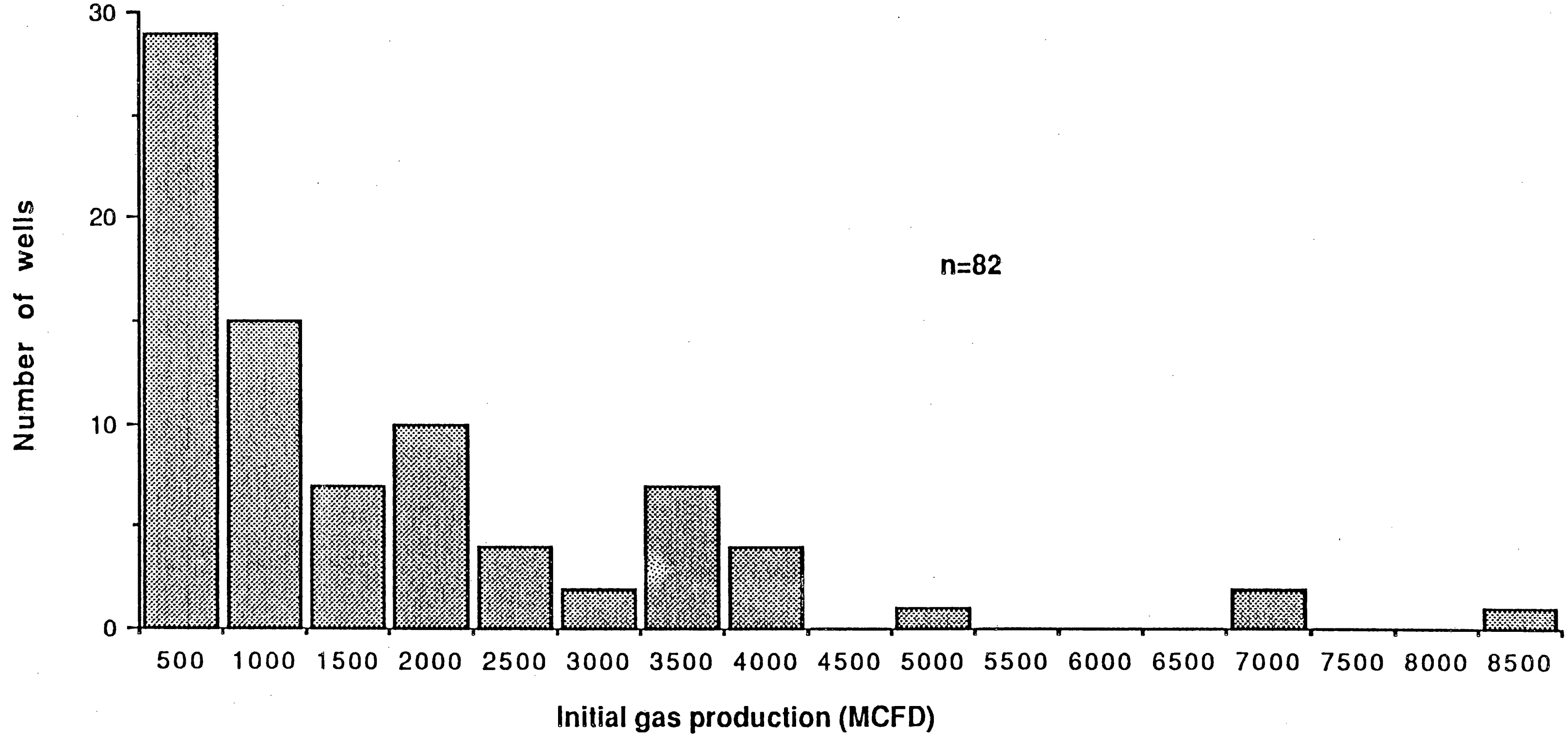


Figure 21. Daily gas production in the Frontier Formation (January 1983 to April 1988) ranged from 48 to 8,240 MCFD. Most wells produced less than 1,500 MCFD.

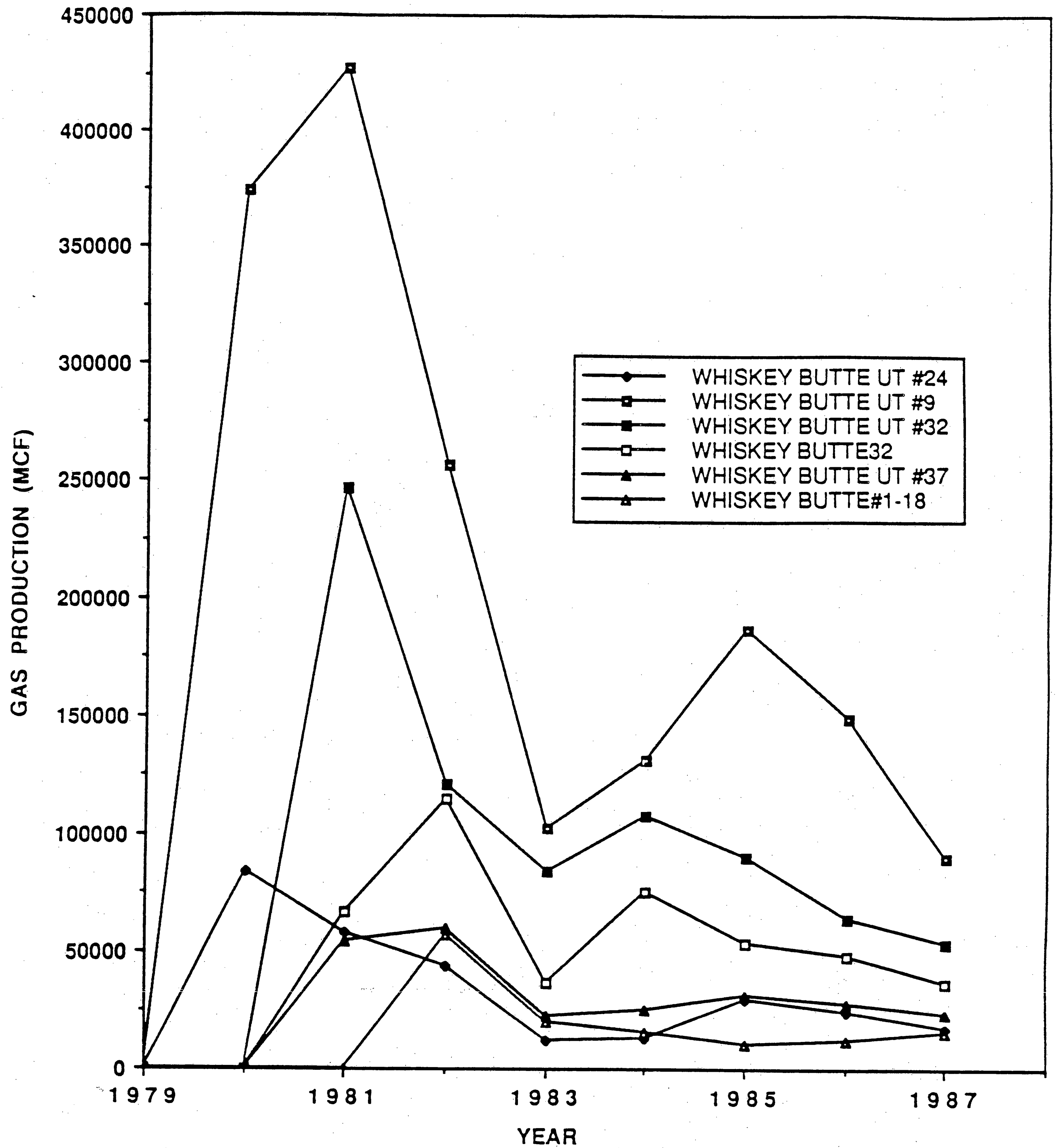


Figure 22. Production decline curves for selected wells in the Whiskey Buttes field, Frontier Formation. From ICF-Lewin Energy Division (1988c).

Whiskey Buttes field (Amoco): Water-gel and sand fracture; typically 700,000 lb of 20/40 mesh sand with a 30-lb/1,000-gal chemical concentration in a total of over 350,000 gal of fluid. Average completion depth of 11,000 ft with post-stimulation production of greater than 450 MCF/day

Fontenelle field (Natural Gas of California): Typically acidized; sand-water fracture; 80,000 lb of sand (20,000 lb of 10/20 mesh plus 60,000 lb of 20/40 mesh sand) in 140,000 gal of fluid. Average completion depth is 8,800 ft.

Pine Canyon Field (Terra Resources): Sand-foam fracture with CO2 additive (165,000 lb of sand in 55,000 gal). Post-stimulation production rate of more than 800 MCF/day.

Bird Canyon field (General Atlantic Energy, formerly Energetics): Water-gel fracture using 47,000 gal of Alcogel and 60,000 lb of 20/40 mesh sand. Completion depth is 9,300 ft. Post-stimulation production rate of more than 600 MCF/day.

The Frontier Formation in the Greater Green River Basin in western Wyoming is well served by pipelines and nearby markets. Principal pipeline access to the east is provided by Wyoming Interstate and to the west and south by Northwest Pipeline. One of several proposed pipelines (WyCal or Kern River) will also serve the west. The growing demand in California and north central states will allow exports to increase as fast as pipeline capacity does, but competing supplies in the Rockies will hinder widespread development of new resources. The 1986 and 1987 reserves-to-production ratios in Wyoming are 25 to 1, indicating a large surplus of gas waiting for export. Summer 1988 spot prices reflected this market. At $1.12/Mcf, they were about the lowest in the United States. Because demand for cost-competitive supplies is expected to continue, a major emphasis of technology development in the Frontier is reduction of production costs.

Ground access in the Greater Green River Basin is hampered locally by steep terrain. Local relief reaches 1,000 ft in some areas.

Core from 44 wells in the Frontier Formation is available for study at the U.S. Geological Survey (fig. A1, table A5). Length of core ranges from 5 to 134 ft per well.

Technical Challenges for Fracture Treatment

The technical challenges posed by the Frontier Formation of the Green River Basin are representative of many low-permeability gas reservoirs. Well stimulation can be improved by advances in pretreatment geologic and engineering analysis and design, fracture treatment monitoring, and post-treatment evaluation. Representatives of producing and service companies familiar with the Green River Basin recognize the potential for improvement in all these areas, but four main needs are cited frequently by these workers: (1) improved interpretation of complex Frontier Formation stratigraphy and analysis of rock properties from logs, (2) prediction of fluid loss, abnormal treatment pressures, and fracture propagation direction in naturally fractured Frontier reservoirs, (3) prediction and evaluation of reservoir fluid pressure variations, and (4) prediction, control, and post-treatment evaluation of fracture height growth.

Understanding the depositional facies patterns of the Frontier Formation is a technical challenge because the success of completion techniques and reservoir stimulation varies with sedimentary facies (M. Doelger, Barlow and Haun, Inc., personal communication, 1988). And yet despite data to the contrary from several hundred wells drilled in the Moxa Arch area, the depositional setting is considered to be "very interpretive." Some of the uncertainty concerns the distribution of marine and shoreline deposits. The distribution of clay-rich sandstone, which may depend on diagenetic patterns as well as depositional facies, was also mentioned as an important uncertainty. Information on the amount of gas production by facies and the success of fracture treatment by facies could help guide drilling programs and fracture treatment design. Principles derived from GRI-sponsored research in the Travis Peak Formation can be applied to these questions in the Moxa Arch area.

Many fields in the Moxa Arch area contain natural fractures and are considered to be fractured reservoirs (P. Warenburg, Dowell-Schlumberger, personal communication, 1988), and natural fractures must be considered in a design of Frontier fracture treatments. Problems have been encountered with fluid loss into natural fractures during emplacement of proppant, especially in the deep Frontier Formation (W. Renner, Halliburton Co., personal communication, 1988). Some natural fractures are open, and some are closed, but they open at a critical pressure. The distribution and character of natural fractures cannot be adequately predicted at present. Minifracs are necessary to determine leakoff but currently are not performed routinely. A related problem is abnormal treating pressure resulting from fracture branching (Medlin and Fitch, 1988); such branching can be expected in fractured Frontier reservoirs. This phenomenon is described in the section on technical challenges in the Mesaverde Group, Piceance Basin. A combination of reservoir modeling and geologic analysis of fractures could help meet this challenge, and results can be compared to results from SFE No. 2 in the Travis Peak Formation.

Variable fluid pressure and local overpressure in Frontier reservoirs contribute to uncertainty in reservoir evaluation and fracture treatment design (W. Renner, Halliburton Company, personal communication, 1988). Because of uncertainties in reservoir pressure and reservoir stresses, it is difficult to predict what type of treatment will be required (M. Doelger, Barlow and Haun, Incorporated, personal communication, 1988). A related technical concern is that casing string designs in the Frontier are commonly not appropriate for the required fracture treatment (W. Renner, Halliburton Company, personal communication, 1988). Casing is often not heavy enough to sustain pressures required for fracture treatment.

Uncontrolled fracture height growth was also cited as a major problem in the Frontier Formation. Aspects of this problem that were mentioned include assessing stress differences between reservoir and potential barriers, determining the minimum amount of stress data required to design a treatment, development of pre-fracture stress logs, design and control of fracture fluid viscosity, and post-fracture evaluations of fracture shape (M. Doelger, Barlow and Haun, Incorporated, personal communication, 1988; P. Warenburg, Dowell-Schlumberger, personal communication, 1988). A related problem is low fluid recovery after fracture treatment. Fluid recovery of 20 percent or less was cited for some Frontier examples (P. Warenburg, Dowell-Schlumberger, personal communication, 1988). Low fluid recovery may interfere with post-fracture reservoir evaluation.

Typical well completion data and economic factors are listed in the Appendix (tables A3 and A4).

CLEVELAND FORMATION, ANADARKO BASIN

Structural Overview of the Anadarko Basin and Adjacent Areas

The Anadarko Basin is a west-northwest-trending, axially asymmetric structural basin of Paleozoic age in western Oklahoma and the Texas Panhandle. It is bordered on the south by the Amarillo-Wichita Uplift and the Marietta Basin, on the southeast by the Ardmore Basin and the Arbuckle Uplift, on the east by the Nemaha Ridge, and on the north and west by the Kansas shelf and the Hugoton Basin (figs. 23 and 24, table A6). The narrow, steeply dipping, and structurally complex south flank of the basin contrasts with the broad, gently dipping, structurally simple north flank. The deepest part of the basin is adjacent to, and parallel with, the Amarillo-Wichita Uplift. Exploratory wells and gas-producing wells in the deep basin have reached depths as great as 26,000 ft (Kennedy and others, 1982).

The northern shelf of the basin in Oklahoma is distinguished from the main basin by a hinge line separating the steeper dips of the inner basin (90 to 140 ft/mi) from the more gentle dips of the shelf (50 to 80 ft/mi) (fig. 25). In Oklahoma and the northeastern Panhandle of Texas, the south-southeasterly regional dip of the shelves is less than about 50 to 80 ft per mile (fig. 25). The northwestern margin of the Anadarko Basin is marked by a change to north and northwest strikes. Open, northwest-trending anticlines and synclines strike parallel to the axis of the Dalhart Basin (fig. 24).

The Anadarko Basin is part of the southern Oklahoma aulacogen (Walper, 1976, 1977; Webster, 1977, 1980; see Ham and others, 1964 for alternative terminology). Aulacogens are thick sedimentary basins extending at high angles from orogenic belts (Hoffman and others, 1974; Burke, 1977). Crustal extension occurred in the southern Oklahoma aulacogen during the Cambrian, probably as a failed rift arm of the opening proto-Atlantic Ocean (Burke and Dewey, 1973; Rankin,

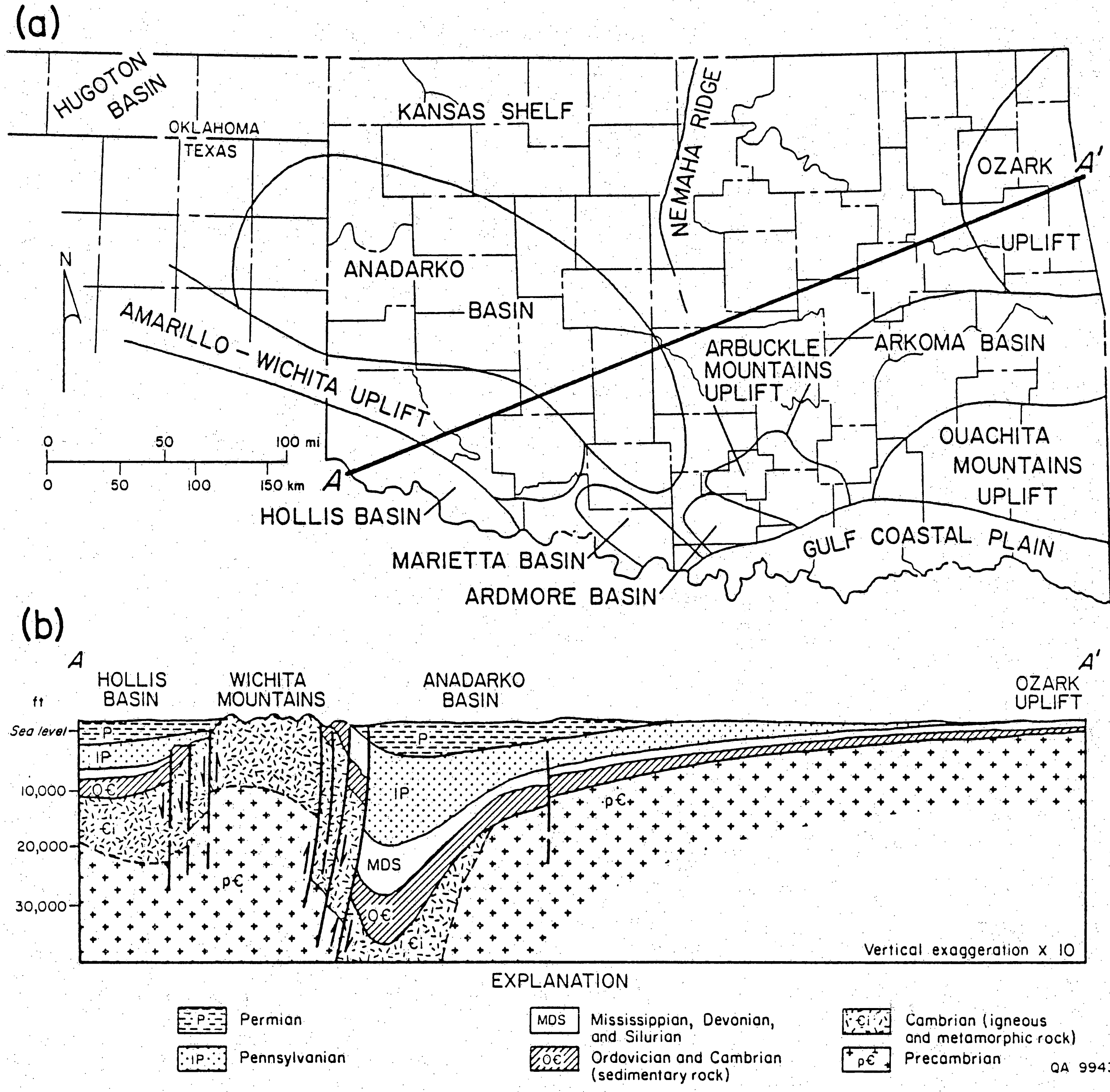


Figure 23. (a) Major geologic and tectonic provinces of Oklahoma. (b) Schematic cross section (A-A') illustrates the asymmetry of the Anadarko Basin and the thick Paleozoic sedimentary rocks in the Anadarko Basin. Modified from Cardott and Lambert (1985, fig. 1).

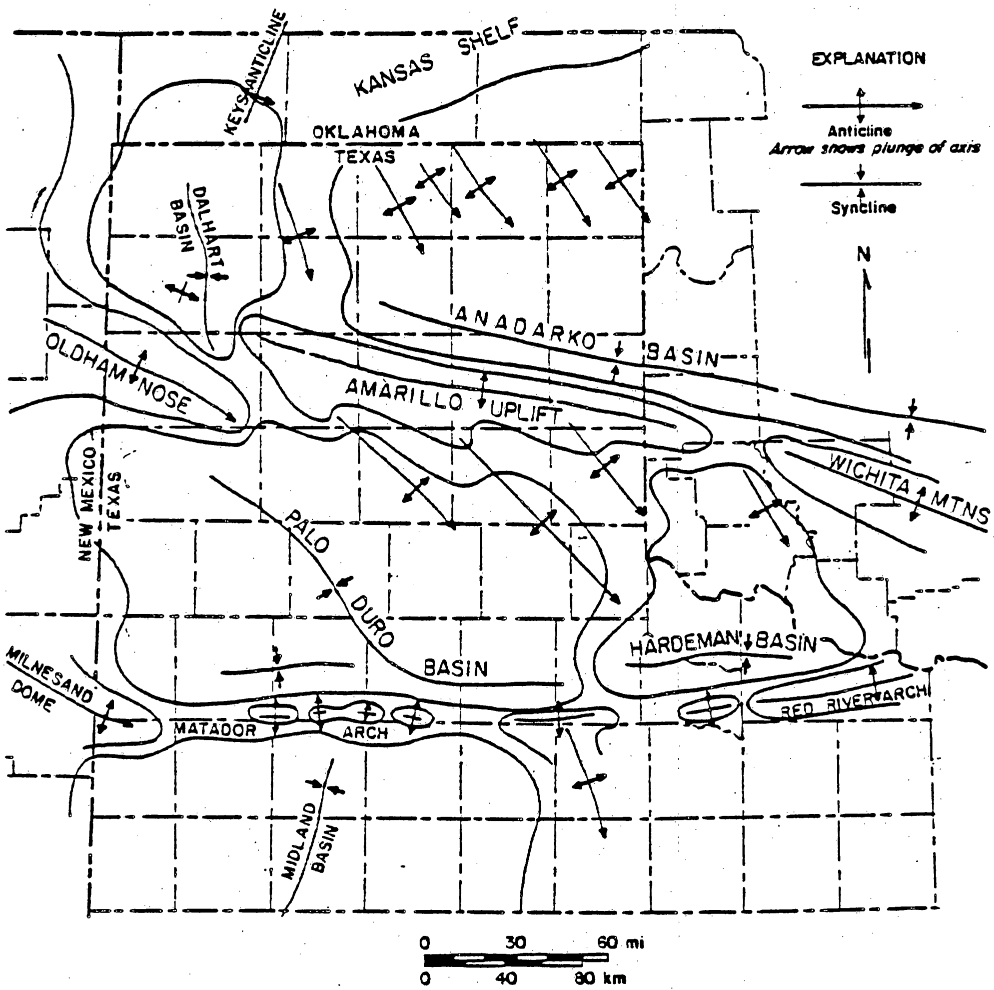


Figure 24. Major structural elements of the Texas and Oklahoma Panhandles. From Gustavson and others (1980, fig. 2).

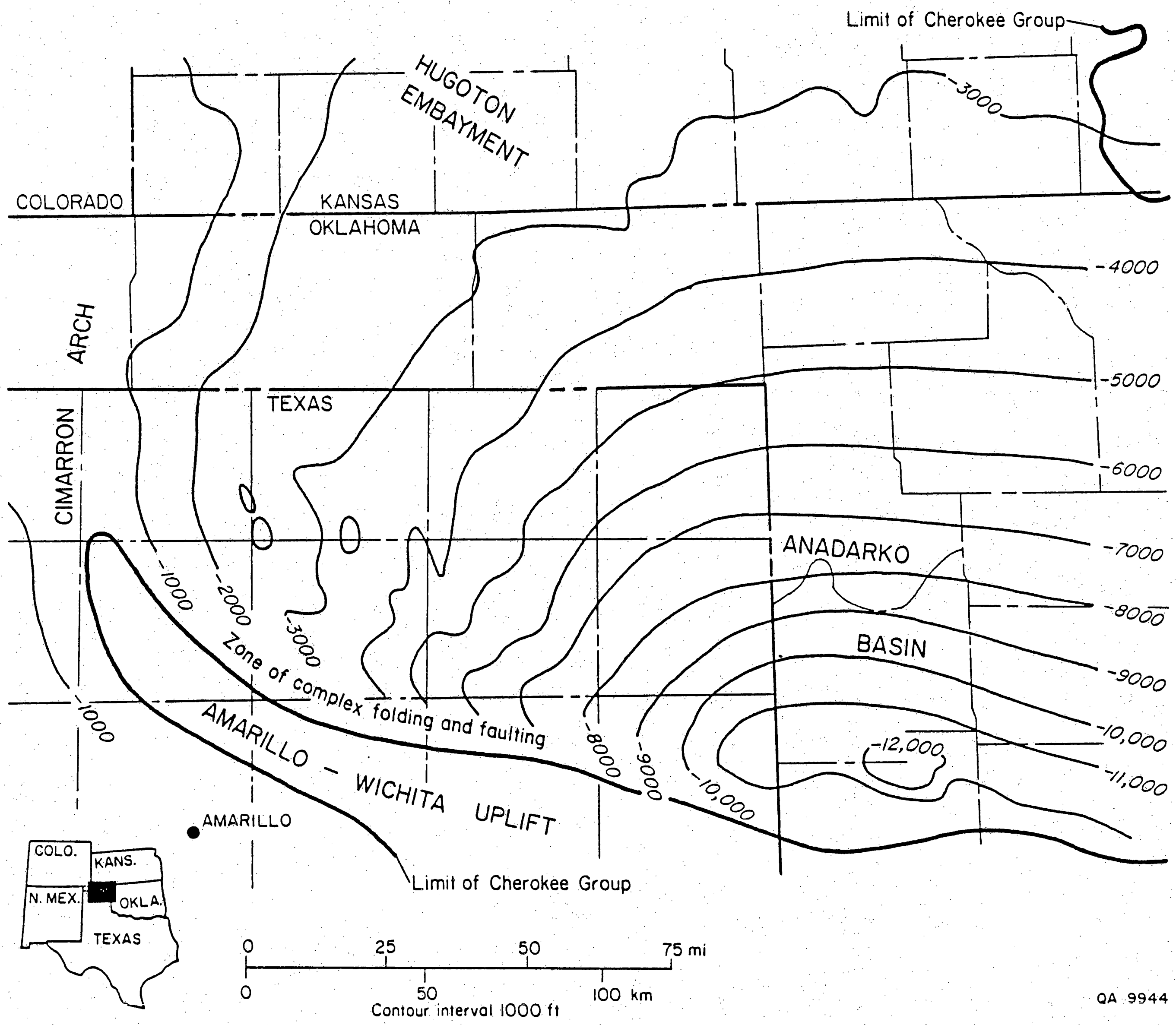


Figure 25. Structure on top of the Mississippian, northwestern Anadarko Basin and surrounding area. Modified from Rascoe (1962, fig. 3).

1976; Keller and others, 1983). The frontal fault zone of the Amarillo-Wichita Uplift was active during Cambrian rifting, but was quiescent during Late Cambrian through Early Mississippian time, when stable shelf conditions prevailed (Amsden, 1983).

Several phases of subsidence characterized the basin from the Late Cambrian through the Early Pennsylvanian (Hoffman and others, 1974; Brewer and others, 1983). Post-rifting cooling and thinning of the crust were responsible for subsidence that formed the Anadarko Basin (Feinstein, 1981; Denison, 1982; Garner and Turcotte, 1984). Subsidence accelerated in Late Mississippian and Early Pennsylvanian time (Dickinson and Yarborough, 1977; Donovan and others, 1983). Maximum rates of subsidence occurred during Morrowan and Atokan times (Early Pennsylvanian) (Evans, 1979). The axis of maximum subsidence coincided with, or was just north of, the present Wichita Uplift (Gilbert, 1982).

The Amarillo-Wichita Uplift may have been a positive feature as early as Middle Devonian time (Cardott and Lambert, 1985). Significant uplift occurred during Late Mississippian through Early Pennsylvanian time (Eddleman, 1961; Ham and Wilson, 1967; Webster, 1977, 1980). By the Early Pennsylvanian (Morrowan-Atokan) intense north-south crustal shortening in the region (Wichita orogeny) raised vertical blocks in the Amarillo-Wichita Uplift. Although large faults and folds are absent in the gently dipping rocks of the Kansas shelf, this deformation event could have influenced fracture patterns in the study area. During Permian time, sediments were deposited over the older, deformed rocks of the Amarillo-Wichita Uplift. In Late Permian time, another episode of movement, less intense than that of Pennsylvanian time, faulted the Permian rocks (Brewer and others, 1983).

The deformation of the Amarillo-Wichita Uplift and the Wichita orogeny, which occurred during late Paleozoic, is part of the Wichita Structural Belt, a zone of deformed rocks that stretches from south-central Oklahoma to Utah (figs. 26 and 27). Intraplate deformation along the northern margin of the Anadarko Basin resulted from continental collision during the Paleozoic. This collision was the convergence of North America and South America-Africa across the Ouachita orogenic belt (Kluth and Coney, 1981; Budnik, 1986).

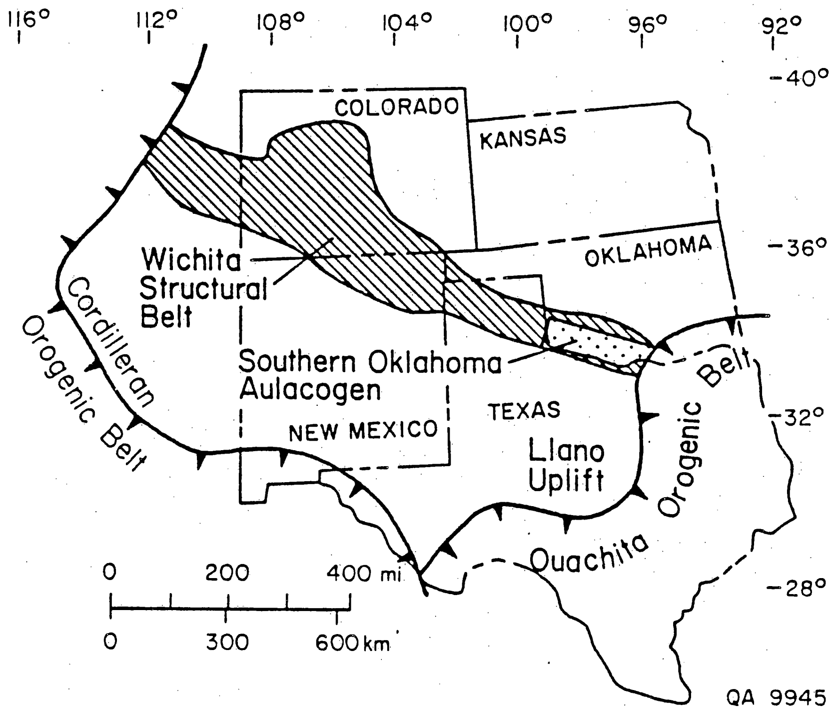


Figure 26. Location of the Southern Oklahoma aulacogen in the Wichita Structural Belt (Wichita Megashear of Budnik, 1986). Modified from Budnik (1986, fig. 1).

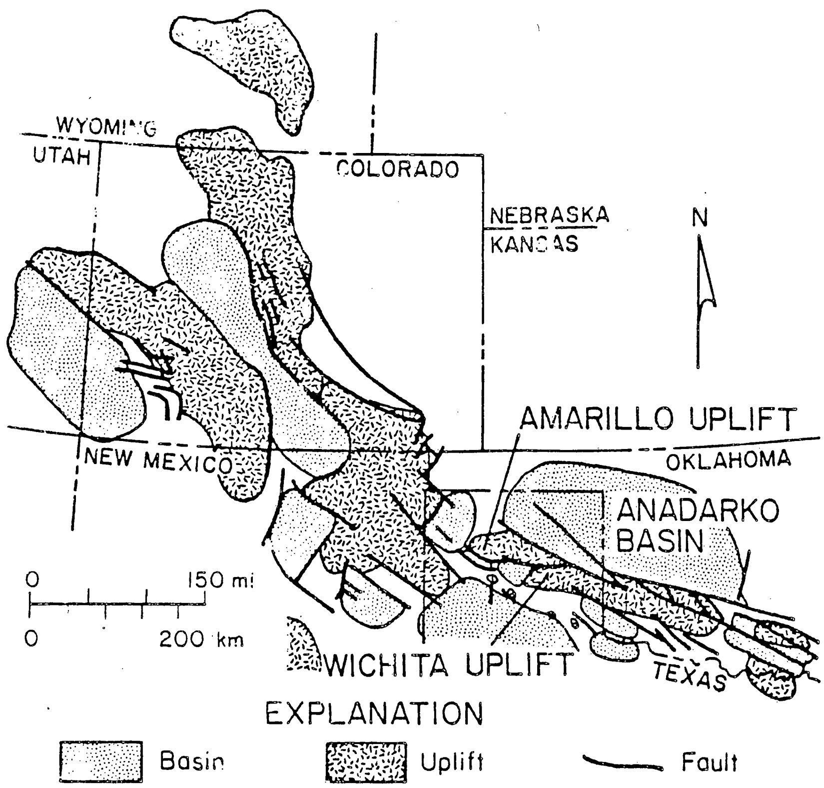


Figure 27. Location of the Anadarko Basin and Amarillo-Wichita Uplift in the Wichita Structural Belt. Modified from Budnik (1986, fig. 2).

After the Wichita orogeny, large quantities of arkosic sediment (granite wash) were deposited along the rapidly subsiding axis of the Anadarko Basin adjacent to the Amarillo-Wichita Uplift. A broad, stable platform north and northwest of the basin axis received carbonates, thin shales, and fine sands (Eddleman, 1961), including sediments of the Cleveland Formation.

The Cleveland Formation occurs in the subsurface of the northeast Texas Panhandle and extends into northwestern Oklahoma and the Oklahoma Panhandle (Finley, 1984). At present, structural dip of the Cleveland Formation north of the Amarillo Uplift is to the east and southeast. The top of the formation is less than 10,000 ft below the surface everywhere in the northeast Texas Panhandle (fig. 28).

Eastward tilting during Late Cretaceous time was the most recent major structural event that occurred in the Anadarko Basin (Eddleman, 1961). Mild east-northeast compression probably affected the area during Late Cretaceous to early Tertiary time as a result of deformation and changes in plate-wide stress systems in the Cordilleran orogenic belts to the west (Jackson and Laubach, in press). However, evidence of these events has not been recognized in the Anadarko Basin because late Mesozoic and early Tertiary rocks are not widespread there. The surficial expression of structural features in the Texas and Oklahoma Panhandles is largely obscured by recent sediments, but remote sensing data suggest that some northwest-trending faults cut Permian rocks (Nielsen and Stern, 1985). As described below, some faults in the Amarillo-Wichita Uplift displace Quaternary alluvium (Crone and Luza, 1986) and subdued modern seismic activity occurs in southwestern Oklahoma.

Stress orientation

The study area is on the northern and western margins of the Anadarko Basin, in the Midcontinent stress province of Zoback and Zoback (1980) (fig. 7). This stress province is a large, tectonically quiescent region characterized by east-northeast striking maximum horizontal compressive stress. The uniform northeast-southwest compressive stress here has been defined by

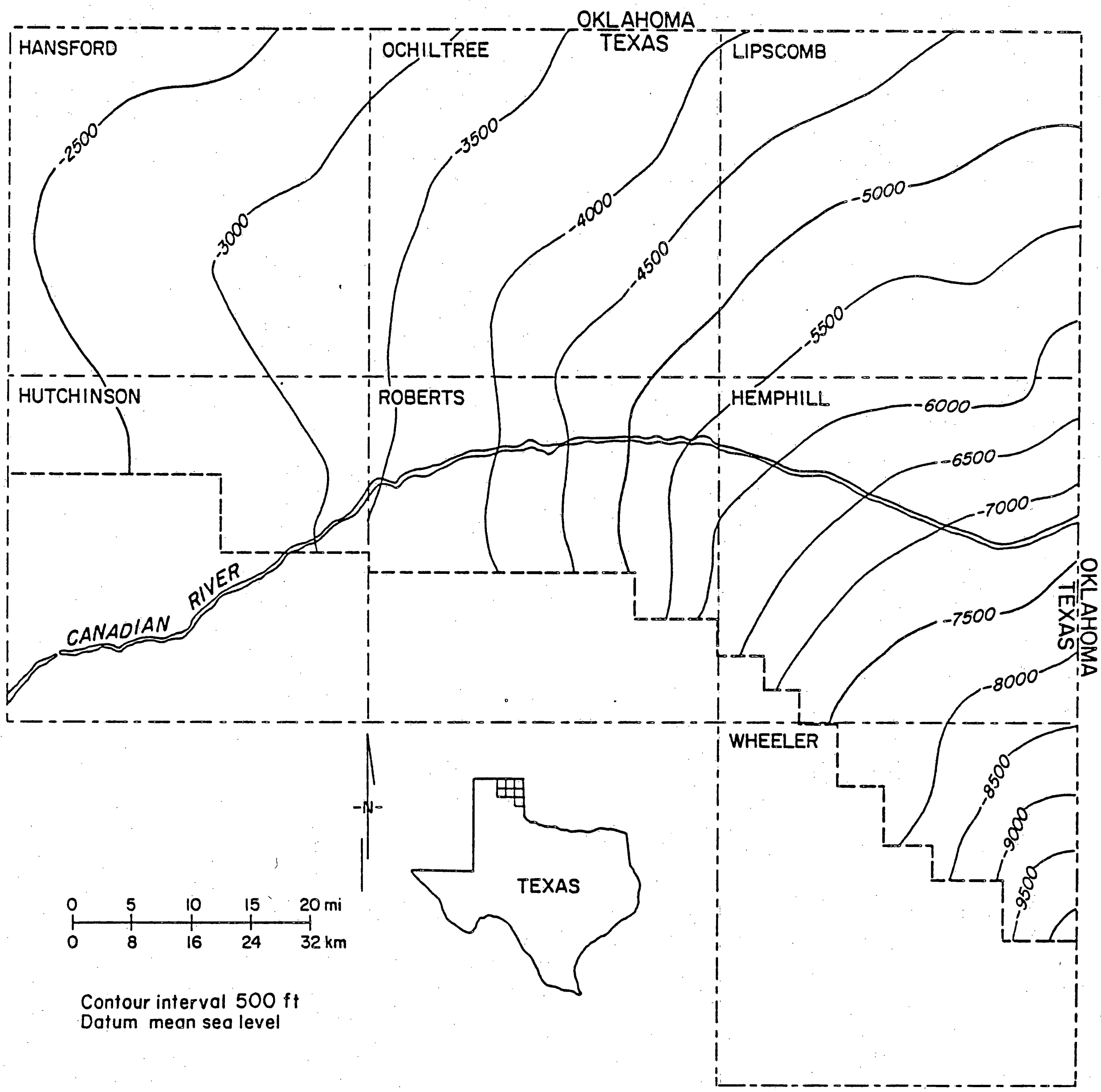


Figure 28. Structure contours on top of the Cleveland Formation, northeast Texas Panhandle. From Finley (1984, fig. 43).

hydraulic fracture measurements (Haimson, 1977) and by earthquake focal mechanisms (Herrmann, 1979). The orientation of least principal horizontal stress indicated by hydraulic fracture treatment in the Anadarko Basin is N25°W (von Schonfeldt and others, 1973). The northwest-trending boundary between the Midcontinent stress province and the Southern Great Plains stress province is west of the study area. The least principal horizontal stress direction in the Southern Great Plains province is north-northeast-south-southwest, oblique to that in the Midcontinent province (fig. 7). In the poorly defined transition zone between these two provinces, stress orientations may rotate (Zoback and Zoback, 1980).

One of the most prominent young tectonic features in the Midcontinent stress province is the northwest-trending Meers fault in the Amarillo-Wichita Uplift. The fault is coincident with a pre-Permian fault, but scarps in alluvium indicate the fault is Quaternary age (Gilbert, 1983a,b). The fault displays reverse sense-of-motion and a component of left-lateral slip (Ramelli and Slemmons, 1986; Myers and others, 1987). Recent studies indicate that movement occurred on this fault during late Holocene time (Madole, 1988). Movement on the Meers fault suggests that significant east-northeast-directed tectonic compressive stress may exist in this potential SFE No. 4 study area.

Reservoir-scale structures

Tectonic fractures and stylolites can be expected in the Cleveland Formation, given the history of tectonic activity in adjacent areas. Fractures and tectonic stylolites may enhance permeability and reservoir anisotropy (Nelson, 1985). Fractured reservoirs are recognized in carbonate units in the Anadarko Basin (Landes, 1970), and fractures contribute to reservoir permeability in some Cleveland Formation wells (Bradshear, 1961).

Stratigraphy

General stratigraphy

Gray to black shale, siltstone, arkosic red beds, sandstone, coal, and limestone constitute the Middle Pennsylvanian Missourian (Canyon) Series of the Anadarko Basin in the Texas Panhandle (Roth, 1955; Totten, 1956). The Cleveland Formation contains the thickest and best-sorted sandstones and is considered part of the basal Missourian Pleasanton Group (fig. 29) by Nicholson and others (1955). Its stratigraphic position is somewhat uncertain, however, because the Cleveland has been placed in the Missourian Kansas City Group (Railroad Commission of Texas, 1981) and in the Des Moinesian Marmaton Group (Best, 1961). Most studies have followed the terminology of Nicholson and others (1955), which places the Pleasanton Group unconformably above undifferentiated carbonates of the Marmaton Group (Des Moines). Overlying the Pleasanton Group are undifferentiated limestones and shales of the Kansas City, Lansing, and Pedee Groups. Cunningham (1961) noted that in the western Anadarko Basin, the Pleasanton and Kansas City Groups are generally inseparable sequences of calcareous shale, arenaceous limestone, and dolomite.

Deposition of terrigenous-clastic sediments of the Cleveland Formation represents an interruption of carbonate sedimentation in the Marmaton and Lansing-Kansas City Groups. The change in sedimentation may have resulted from renewed subsidence (Rascoe, 1962) and/or source area rejuvenation in the Anadarko Basin during late Des Moinesian and early Missourian time. Thickness of Missouri Series sediments ranges from 3,000 ft in southwest Oklahoma to 250 ft in central Kansas (fig. 30). This isopach trend reflects the asymmetric paleobathymetry of the Anadarko Basin during Missourian time.

In the northern Texas Panhandle, the Cleveland Formation dips gently (68 ft/mile) to the southeast and ranges in depth from 2,500 ft to more than 9,500 ft (fig. 28) (Railroad Commission of Texas, 1981). As it extends into the deeper part of the Anadarko Basin it thickens from 78 to 170 ft (Finley, 1984). A generalized isopach map of the Cleveland shows an arcuate, northwest-southeast

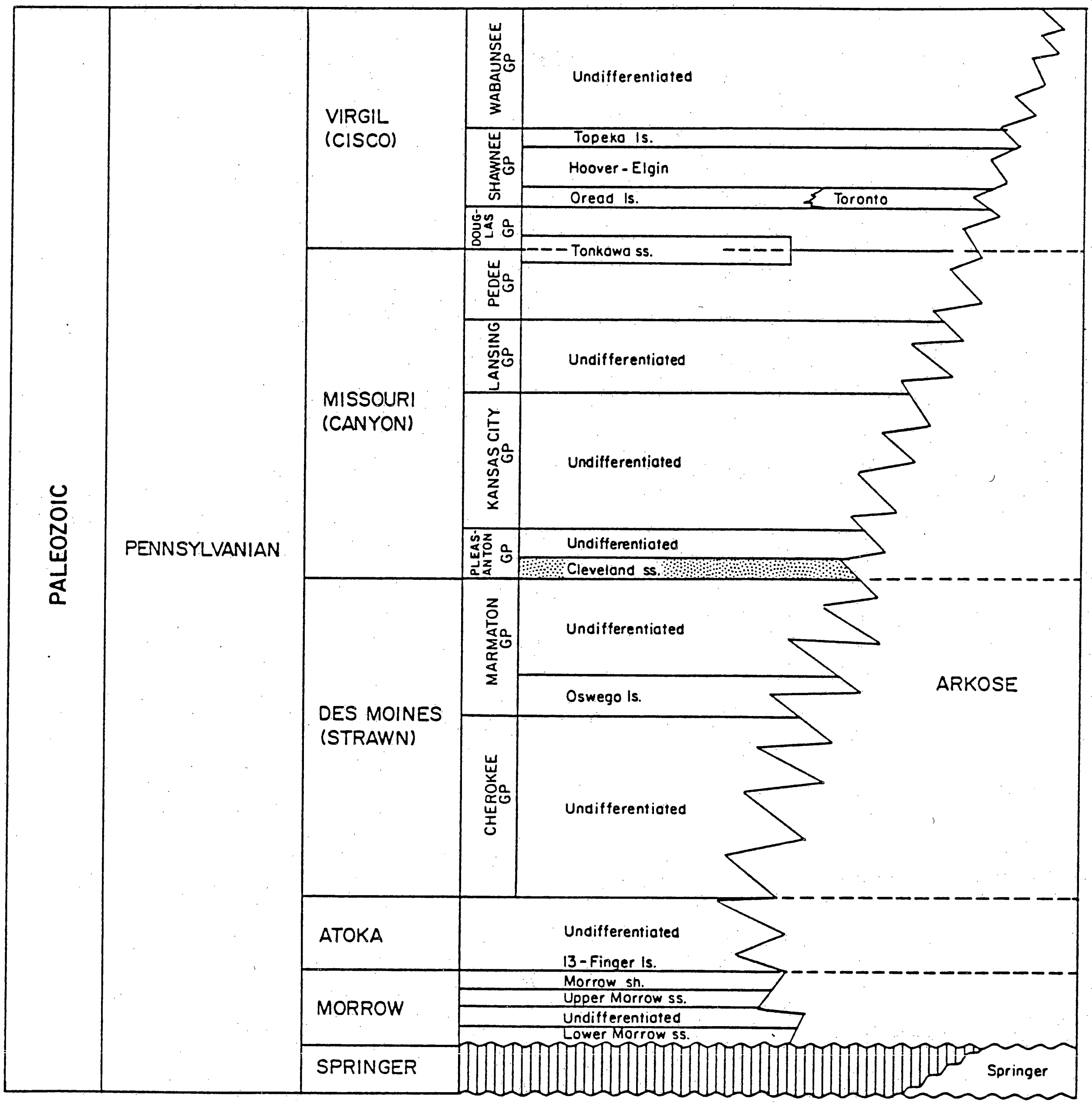


Figure 29. Stratigraphic column of the Pennsylvanian System in the Anadarko Basin, Texas. From Finley (1984, fig. 42).

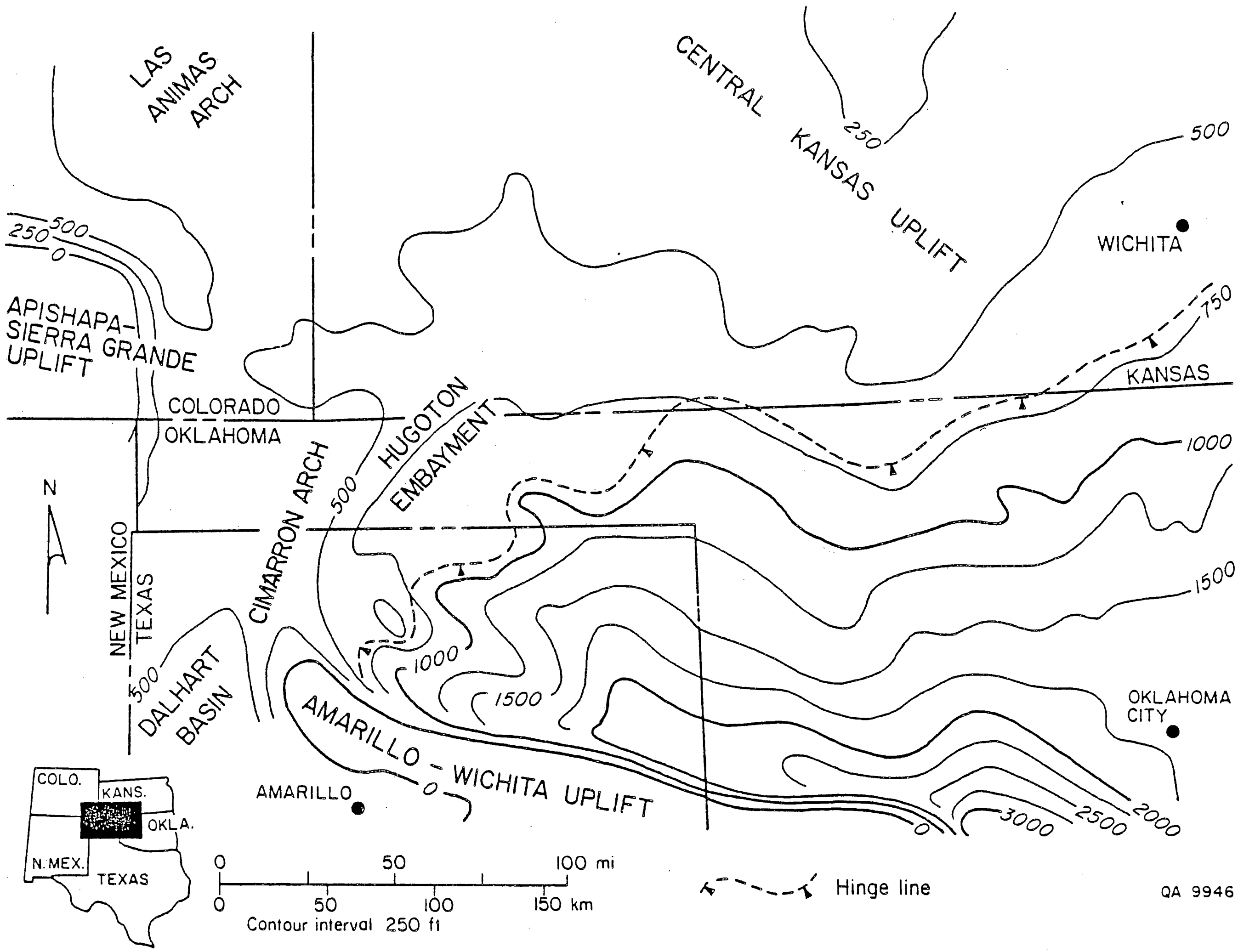


Figure 30. Isopach map of the Missouri Series of the Anadarko Basin, Colorado, Kansas, Oklahoma, and Texas. Modified from Rascoe (1962, fig. 10).

trending thick zone north of the Amarillo Uplift (fig. 31). The thick zone divides and extends to the northeast into Lipscomb County (fig. 31). To the south, the Cleveland pinches out into shales associated with granite wash that was shed from the Amarillo-Wichita Uplift. It grades basinward (north) into silty calcareous shale (fig. 32) (Railroad Commission of Texas, 1981).

Most studies describe the Cleveland as angular fine- to medium-grained, micaceous, glauconitic, and calcareous sandstone (Best, 1961; Bevan, 1961; Bradshear, 1961; Britt, 1961; Cunningham, 1961). In Oklahoma, the Cleveland is divided locally into upper (Jones) and lower (Douglas) sandstones by a coal/shale section (Kousparis, 1978). In the Ellis Ranch field, Ochiltree County, Texas, three sandstones designated as the Upper, Middle, and Lower Cleveland are present in a 270-ft-thick interstratified sandstone and shale interval (Britt, 1961). Poorly developed, upward-coarsening sandstones are typical of the Cleveland Formation in Lipscomb and Ochiltree Counties, Texas (fig. 33). Thin shale laminations and shale interbeds are common at the base of the sandstones (Best, 1961; Cunningham, 1961), and thicker (30 to 100 ft) shale sections separate the individual Cleveland sandstones from one another (fig. 33). Vertical growth of hydraulically induced fractures in the Cleveland Formation is likely to be inhibited by carbonates and shales of the Lansing-Kansas City and Marmaton Groups.

Depositional environments

Few detailed stratigraphic and sedimentologic studies of the Cleveland Formation in the Texas Panhandle exist, and no core descriptions were available for this study. Therefore, attempts to define the environments of deposition of sediments in the Cleveland Formation were based on the formation's stratigraphic position, electric-log character, isopach map patterns, and texture and composition of sediments (figs. 31, 32, and 34) (Railroad Commission of Texas, 1981; Finley, 1984). Previous workers proposed that fluvial/deltaic and marine shelf sand-ridge environments developed as distal equivalents to alluvial fans that prograded northward into the Anadarko Basin (table A7) (Railroad Commission of Texas, 1981; Finley, 1984). Finley (1984) concluded that

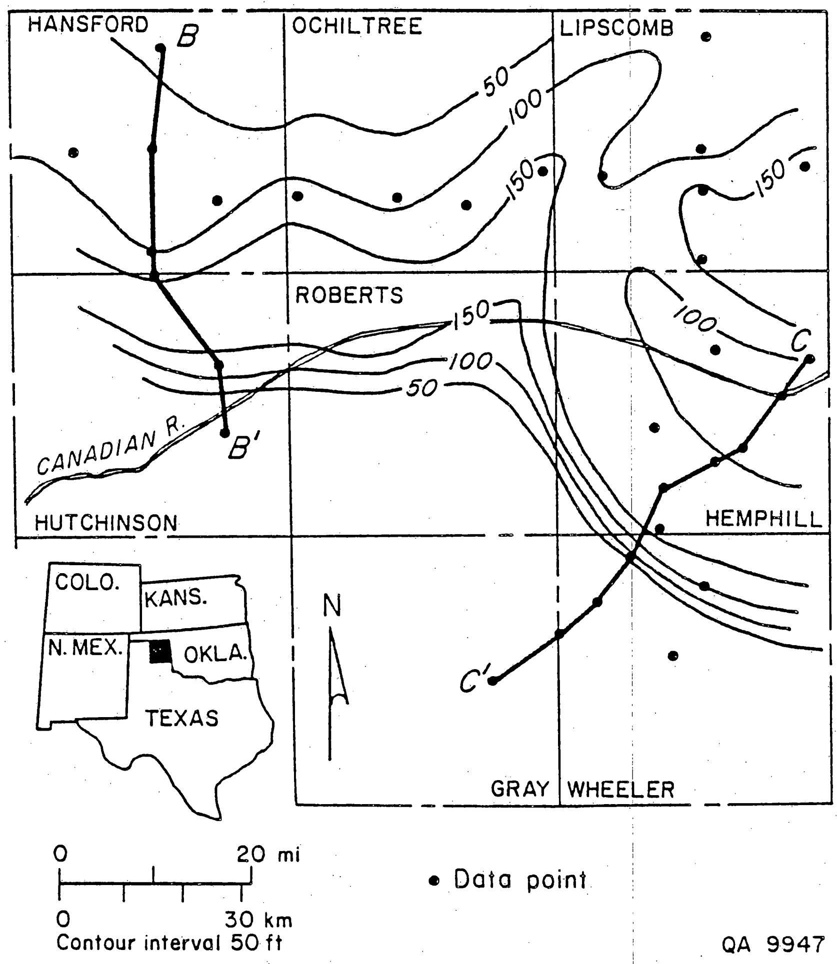


Figure 31. Isopach map of the Cleveland Formation, northeast Texas Panhandle. Cross section B-B' shown in figure 32. Cross section C-C' shown in figure 34. Based on data from Railroad Commission of Texas (1981).

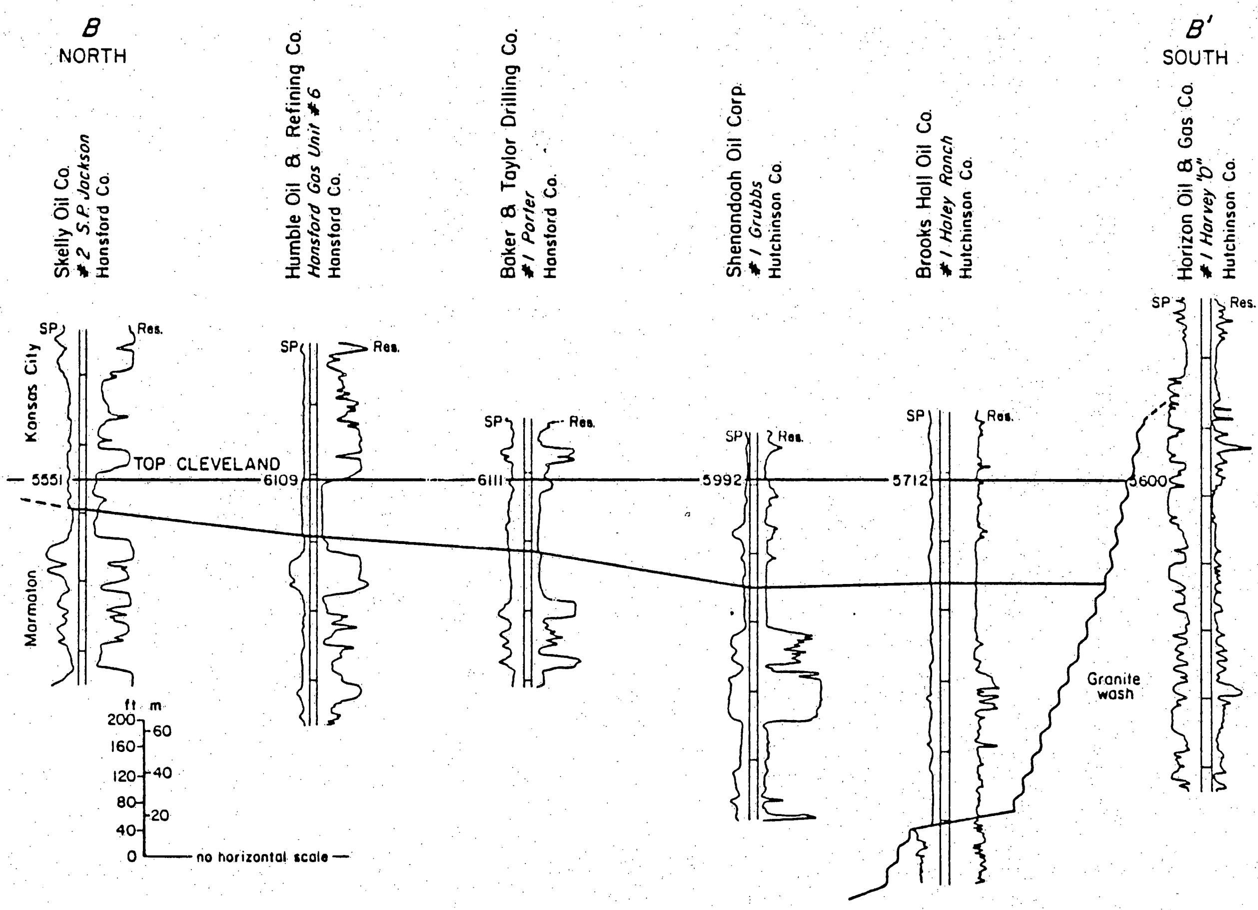


Figure 32. North-south stratigraphic cross section B-B' through the Cleveland Formation, Anadarko Basin, Texas. Cross sections are based on spontaneous potential (SP) and resistivity (Res) logs. From Finley (1984, fig. 45). Location of section shown in figure 31.

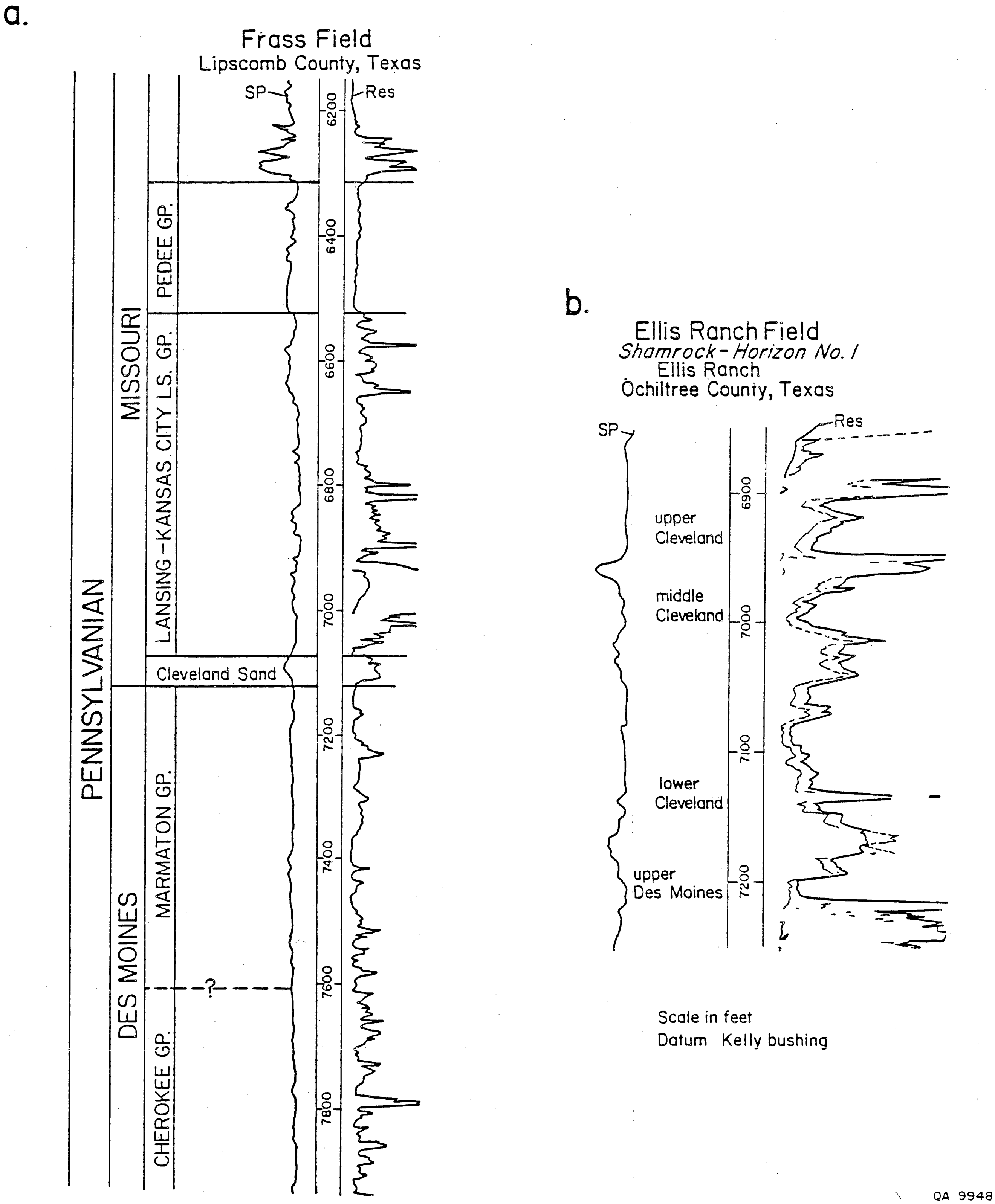


Figure 33. (a) Representative spontaneous potential (SP) and resistivity (Res) logs for the Missourian Series of the Anadarko Basin, Lipscomb County, Texas. (b) SP and Res logs illustrate the character of the Upper, Middle, and Lower Cleveland Formation sandstones in the Ellis Ranch field, Ochiltree County, Texas. Note scale change between logs. Modified from Bevan (1961) and Britt (1961).

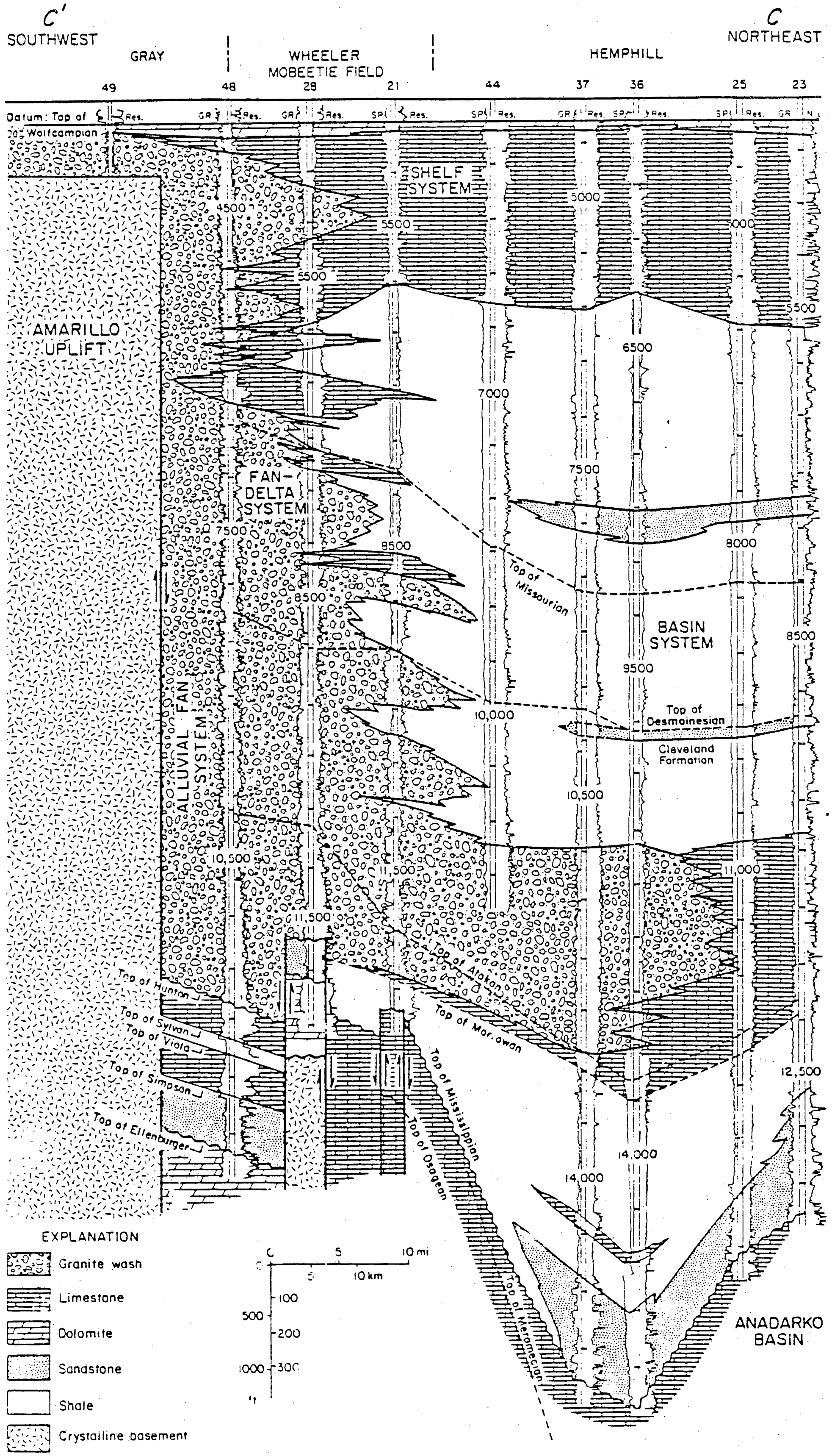


Figure 34. Northeast-southwest stratigraphic cross section C-C' showing facies of the Cleveland Formation, Anadarko Basin, Texas. Logs are gamma ray (GR), resistivity (Res), and spontaneous potential (SP). Location of cross section shown in figure 31. Modified from Finley (1984, fig. 48; modified from Dutton, 1982)

stacked upward-coarsening and upward-fining sequences on SP logs might represent delta-front progradation and abandonment followed by deposition of marine-reworked delta deposits.

A study of the Missourian Virgilian strata in west-central Oklahoma (Kumar and Slatt, 1984) indicates that the entire Pennsylvanian System consists of basin to shelf terrigenous clastic sediments separated by regionally extensive thin limestones. Sandstone and shale accumulated in the basin as submarine-fan and basin-slope deposits during low sea-level stands. Then, during the ensuing rise in sea level, the clastic sediments were capped by transgressive limestones. Kumar and Slatt (1984) suggested a northern source for these sandstones, and on the basis of regional seismic data, they interpreted and mapped two southward-prograding submarine-fan complexes in the Cleveland Formation.

Although located basinward of the Amarillo-Wichita Uplift, the source of Cleveland sediments may have been located to the north, east, and west of the basin (Railroad Commission of Texas, 1981). Depositional setting of the Cleveland Formation in Texas is interpreted as low-energy shelf to basin based on three factors: (1) interbedded association of sandstone, shale, and limestone, (2) textural immaturity of the sandstone, and (3) presence of glauconite. However, a thorough sedimentologic study of the Cleveland Formation based on cores would be essential for reconstructing paleoenvironments and defining their relationships to the Amarillo-Wichita Uplift and to the Anadarko Basin.

Reservoir characteristics

The principal hydrocarbon produced from the Cleveland Formation is gas derived from sandstones with low permeabilities (less than 0.1 to 0.5 md) and variable porosity values (9 to 18 percent). Ten fields in Texas have produced more than 10 billion cubic ft (BCF) of gas. Four have produced more than 30 BCF, and one (Ellis Ranch) has produced more than 100 BCF. Cumulative production values for Cleveland reservoirs range from 15,317 MMCF in Northrup field to 152,000 MMCF in Ellis Ranch field (C. M. Garrett, Jr., Bureau of Economic Geology, written communication, 1988). Small volumes of oil are produced from Bradford field, Lipscomb County (202 barrels of oil per day [BOPD]; Best, 1961), Ellis Ranch field, Ochiltree County (58 BOPD; Britt, 1961), and Frass field, Lipscomb County (28 BOPD; Bevan, 1961).

Net pay in the Cleveland Formation varies from 10 to 45 ft (C. M. Garrett, Jr., Bureau of Economic Geology, written communication, 1988), and most fields are described as combination stratigraphic and structural traps (sandstones draped over an anticlinal nose). Totten (1961), however, stressed that porosity pinchouts and/or facies changes are more important than structural closure in trap formation. Although most Cleveland fields were completed in the 1950's (an early period of heightened exploration in the Anadarko Basin [Totten, 1961]), Pate's (1959) overview of stratigraphic traps in the Anadarko Basin does not mention Cleveland production. This absence suggests that the Cleveland was generally considered a "secondary" target, especially during the period from 1935 to 1954, prior to the use of methods for acidizing and artificially fracturing wells (Rogatz, 1961). Few details are available on completion practices for the Cleveland, but Best (1961) reported that Bradford field was acidized and pumped, whereas Lips field (Bradshear, 1961) was acidized and fractured (20,000 gal acid, 20,000 to 40,000 lb sand) to enhance permeability along existing natural fractures.

Lithology and Diagenesis

Core samples of the Cleveland Sandstone from the Diamond Shamrock Carl Ellis No. B-1 well, Ochiltree County, Texas, were described as fine-grained subarkose (Railroad Commission of Texas, 1981). The following discussion is based on those samples and a thin section made from a core chip from 7,151 ft depth. Average grain size of the sand and silt fraction is 0.14 mm; grains are subangular and elongate to subelongate. The sandstones contain horizontal, parallel laminations that are defined by thin layers of mica and clay.

Quartz is the most abundant framework grain; it is reported as comprising 65 percent of the total sample volume (Railroad Commission of Texas, 1981), but this figure apparently includes the volume of quartz overgrowths. Detrital feldspar volume is 10 percent, with plagioclase more abundant than orthoclase. Many feldspar grains are extensively altered to clay; those feldspar grains that are described as fresh and unaltered may be albitized. Three percent of the sample is mica, primarily muscovite. Some of the muscovite has altered to sericite, and some biotite has altered to chlorite. Heavy minerals, including zircon, sphene, and ilmenite, comprise 1 percent of the sandstone. Trace amounts of chert and glauconite are present.

The thin section contains 15 percent clay matrix, which surrounds grains and fills pore throats (Railroad Commission of Texas, 1981). The clay is described as sericitic and was interpreted as being diagenetic in origin. Based on the description of the clay, however, it seems likely that much of the clay was originally detrital. It probably was altered during burial by neomorphism (precipitation of overgrowths and/or recrystallization). Some of the clay probably is authigenic cement that formed as a result of feldspar alteration and dissolution. The presence of relatively abundant detrital clay has contributed to low depositional porosity in these sandstones.

The most abundant cement is reportedly quartz (Railroad Commission of Texas, 1981), although authigenic quartz was not counted separately from detrital quartz. Petrographic relationships indicate that quartz was the first cement to precipitate, followed by calcite, which comprises 6 percent of the sandstone volume. Minor authigenic siderite is found parallel to bedding planes, and it may have precipitated preferentially in the clay-rich layers.

Only 1.0 percent porosity was observed in the thin section; primary and secondary pores were not distinguished. Porosimeter porosity reported from this depth was 13.0 percent. At least some of the discrepancy between porosimeter and thin-section porosity is caused by microporosity, which cannot be seen in thin section but is measured by a porosimeter. However, a difference of 12 percent between porosimeter and thin-section porosity seems unusually high. The porosity in the core chip that was used to make the thin section may not be representative of the entire interval that was measured by porosimeter.

X-ray diffraction of two core samples of Cleveland sandstones from Lipscomb County, Texas, and Ellis County, Oklahoma, indicates that chlorite, illite, and kaolinite are present, and that chlorite is the most abundant clay mineral. Photomicrographs suggest that the illite and chlorite in these samples are authigenic. Treating wells with HCl could cause partial dissolution of chlorite, leaving a residue that could plug pores and reduce permeability (King, undated). The Ellis County sample also contained 5 percent ankerite, another iron-rich mineral that could cause completion problems if the well were treated with HCl.

Production, Resource Potential, Logistics

This discussion of the Cleveland Formation's production history and resource potential is based primarily on well completion data from Petroleum Information Services (undated). Gas is currently produced from the Cleveland Formation in eight fields in the FERC-designated area of the Anadarko Basin. Estimated gas-in-place is 70 TCF (table A6). Between 1981 and March 1988, more than 80 wells were spudded and completed, most of these in 1984 (fig. 35). Nineteen operators have drilled the Cleveland since 1982 (fig. 36). Most wells drilled between January 1983 and March 1988 are in Lipscomb and Ochiltree Counties (fig. 37). Depth to the top of the perforated interval ranges from 6,250 to 9,550 ft (fig. 38, table A6). Most of the 83 wells for which completion information was available were hydraulically fractured using either sand/gel or sand/water treatments (fig. 39, table A8). Typically, a well was acidized with 1,500 to 3,000 gal of 7.5 percent HCl (fig. 40a), then fractured with 40,000 to 80,000 gal of water or cross-linked gel (fig. 40b) and 60,000 to 180,000 lb sand (fig. 40c). Well and reservoir properties for a fracture design study of a well in Lipscomb Field (King, undated) are shown in table 3. Production rates were often too small to measure prior to stimulation of the formation (table A8). Post-stimulation rates ranged widely, from a minimum of 60 MCFD to a maximum of 12,250 MCFD. Average post-stimulation rate for 83 wells was 3,018 MCFD, but most of those wells produced less than 3,000 MCFD (fig. 41). Figure 42 shows production decline curves for the Cleveland.

ICF-Lewin Energy Division (1988c) reports that in the 1960's and 1970's, the standard treatment for Diamond Shamrock (Maxus Exploration) wells was 20,000 lb of sand with a 3-percent

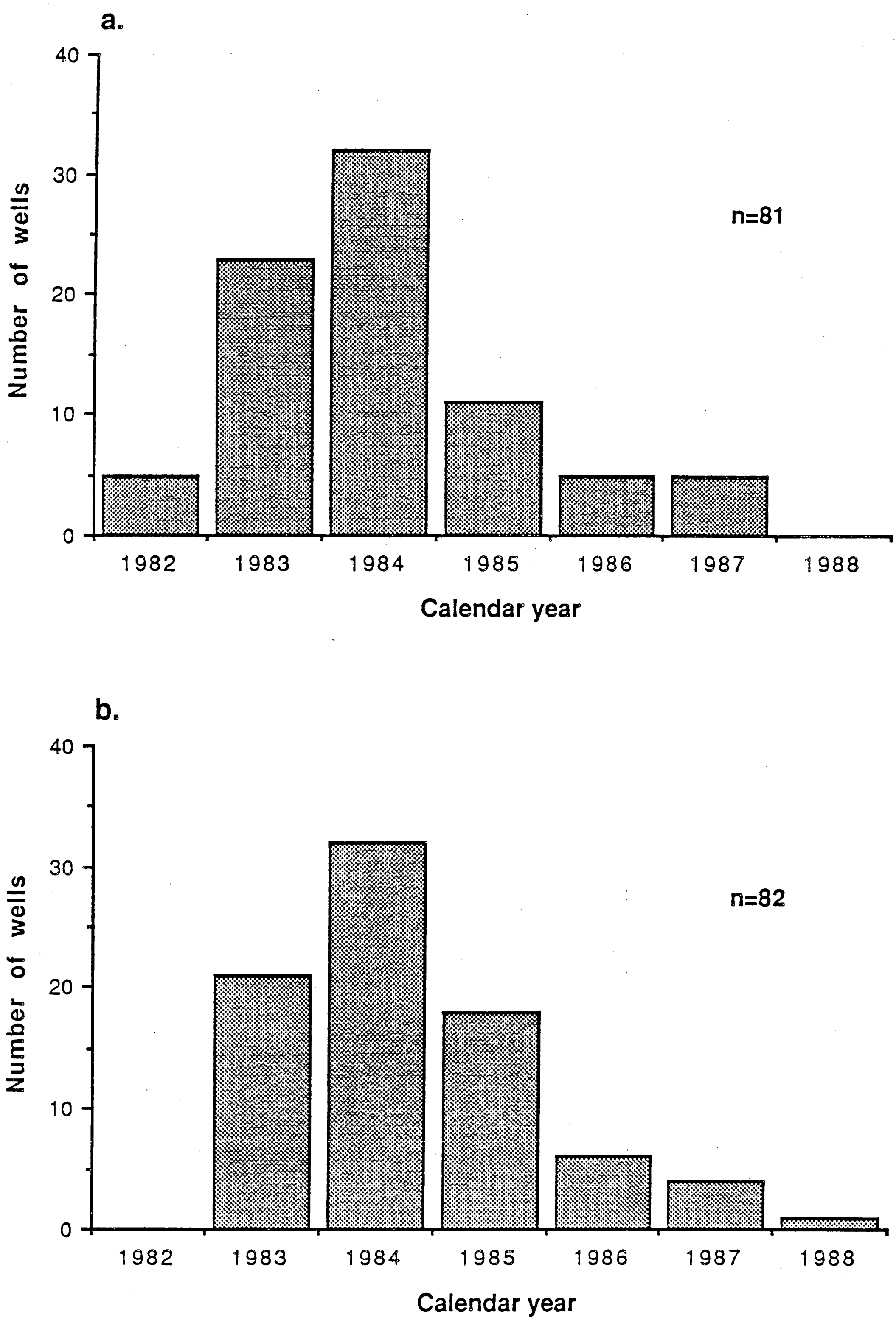


Figure 35. Number of successful gas wells (a) spudded and (b) completed in the Cleveland Formation between September 1982 and April 1988 that had IPF less than 5 BOPD.

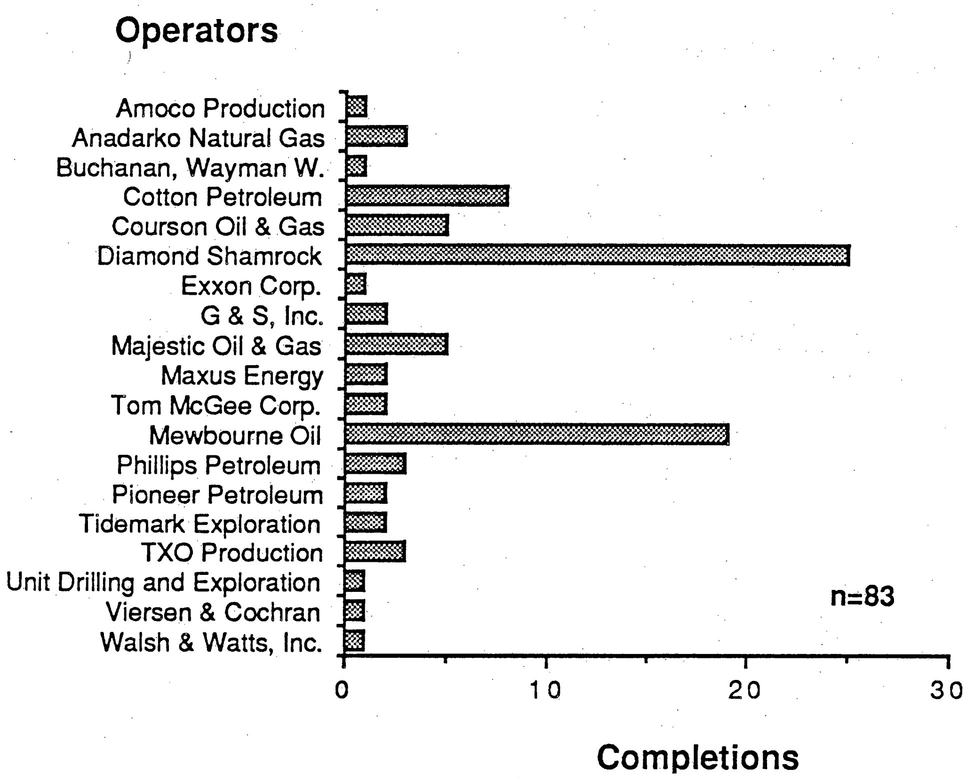


Figure 36. Operators that completed successful gas wells in the Cleveland Formation between January 1983 and April 1988.

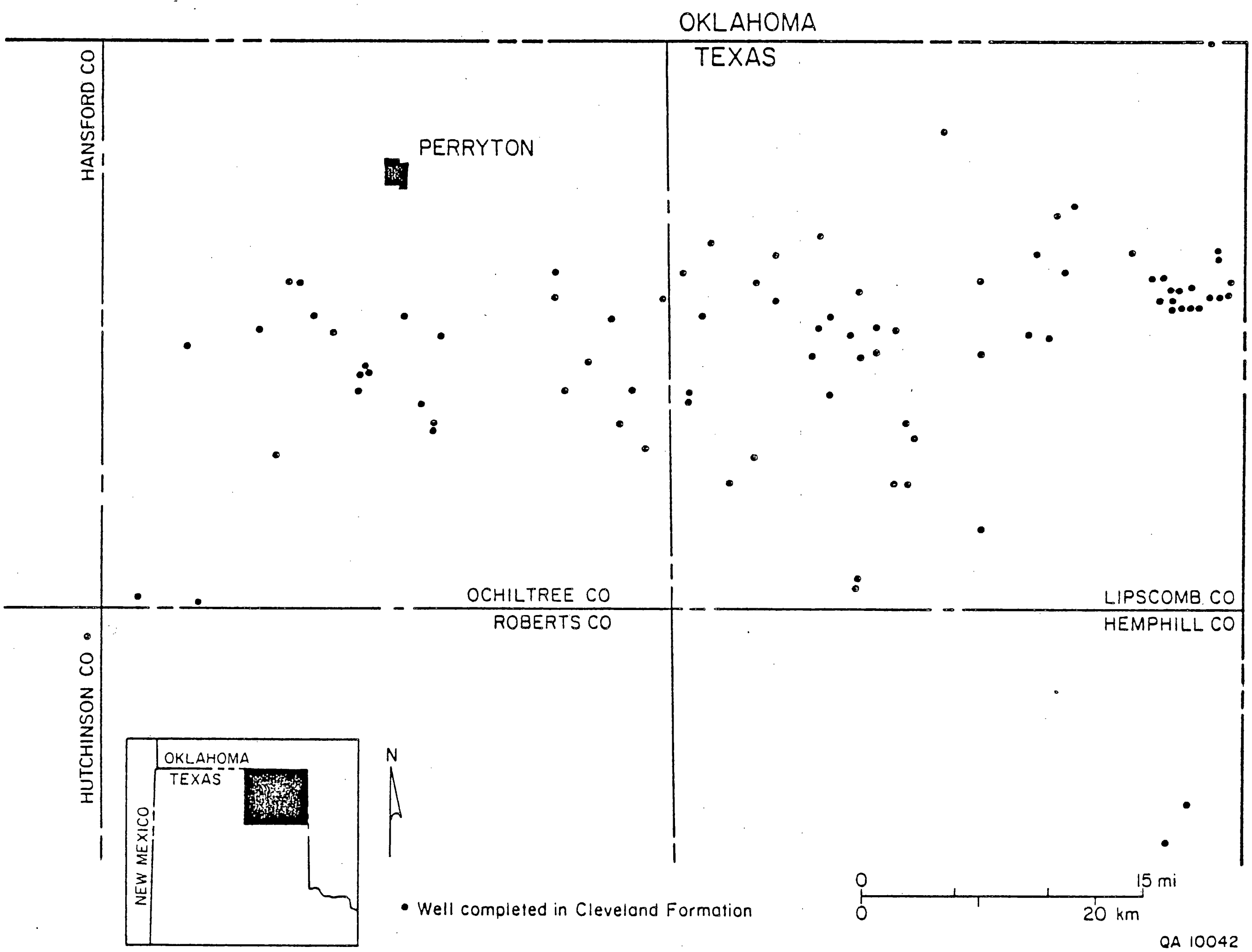


Figure 37. Map of wells completed in the Cleveland Formation between January 1983 and April 1988.

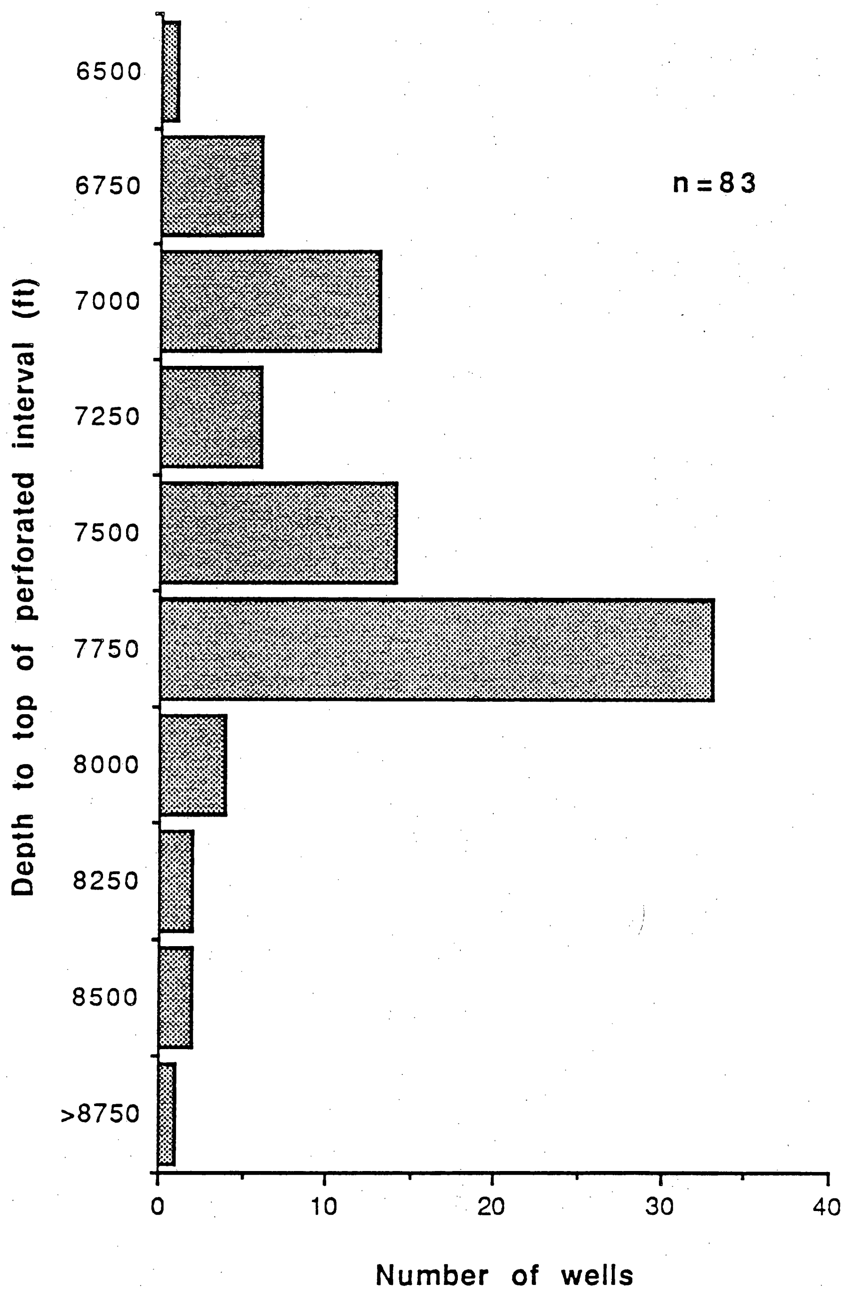


Figure 38. Depth to top of the perforated interval in the Cleveland Formation ranges from 6,250 to 9,550 ft.

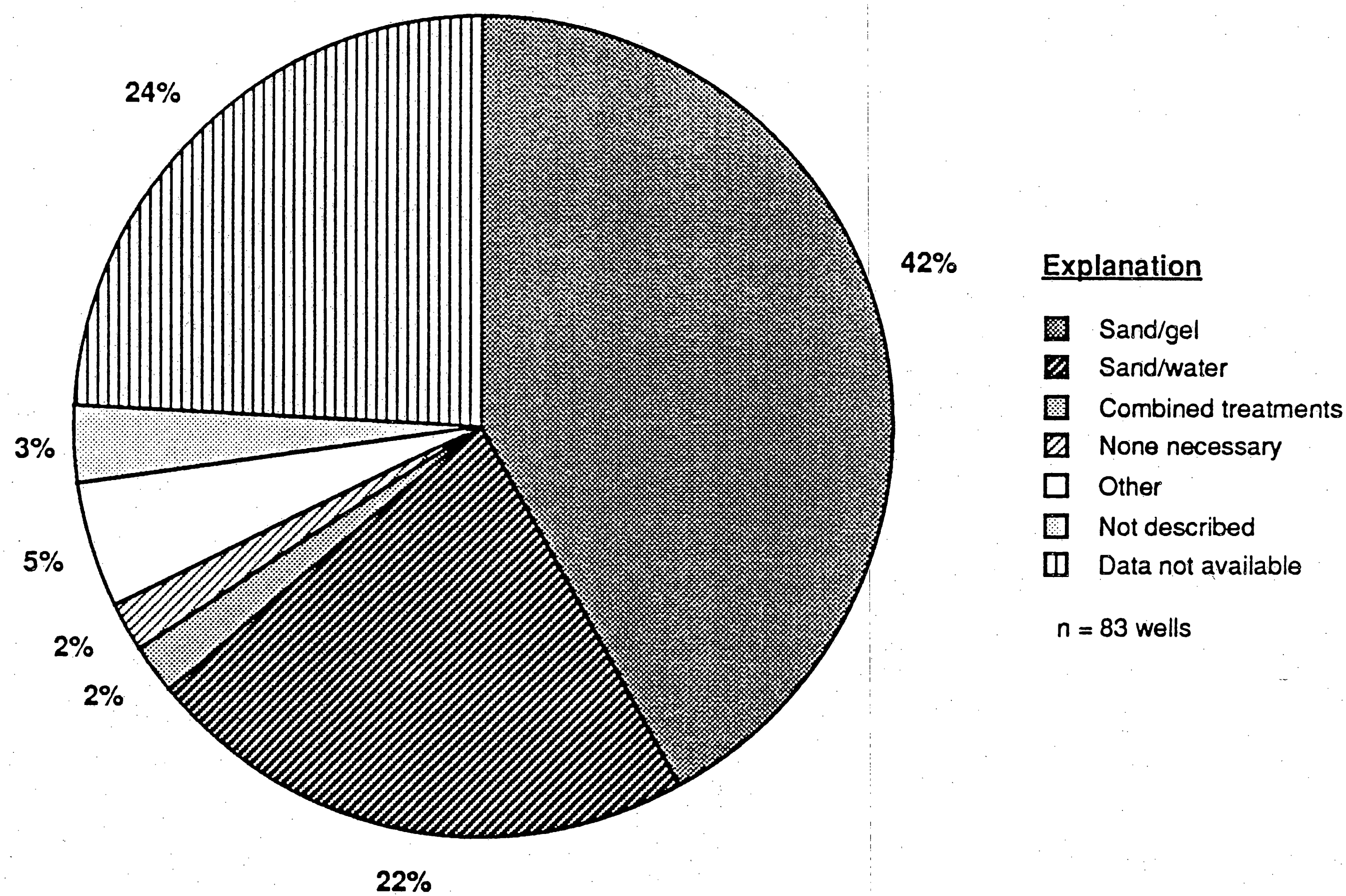


Figure 39. Stimulation methods used on successful gas wells completed in the Cleveland Formation between January 1983 and April 1988. All wells produced less than 5 BOPD. "Combined treatments" include only wells that were treated with different techniques, not those that were treated more than once with the same technique. Fracture techniques "not described" include wells that were fractured, but for which no further information was available. Wells designated as "data not available" are wells for which no information of any sort was provided.

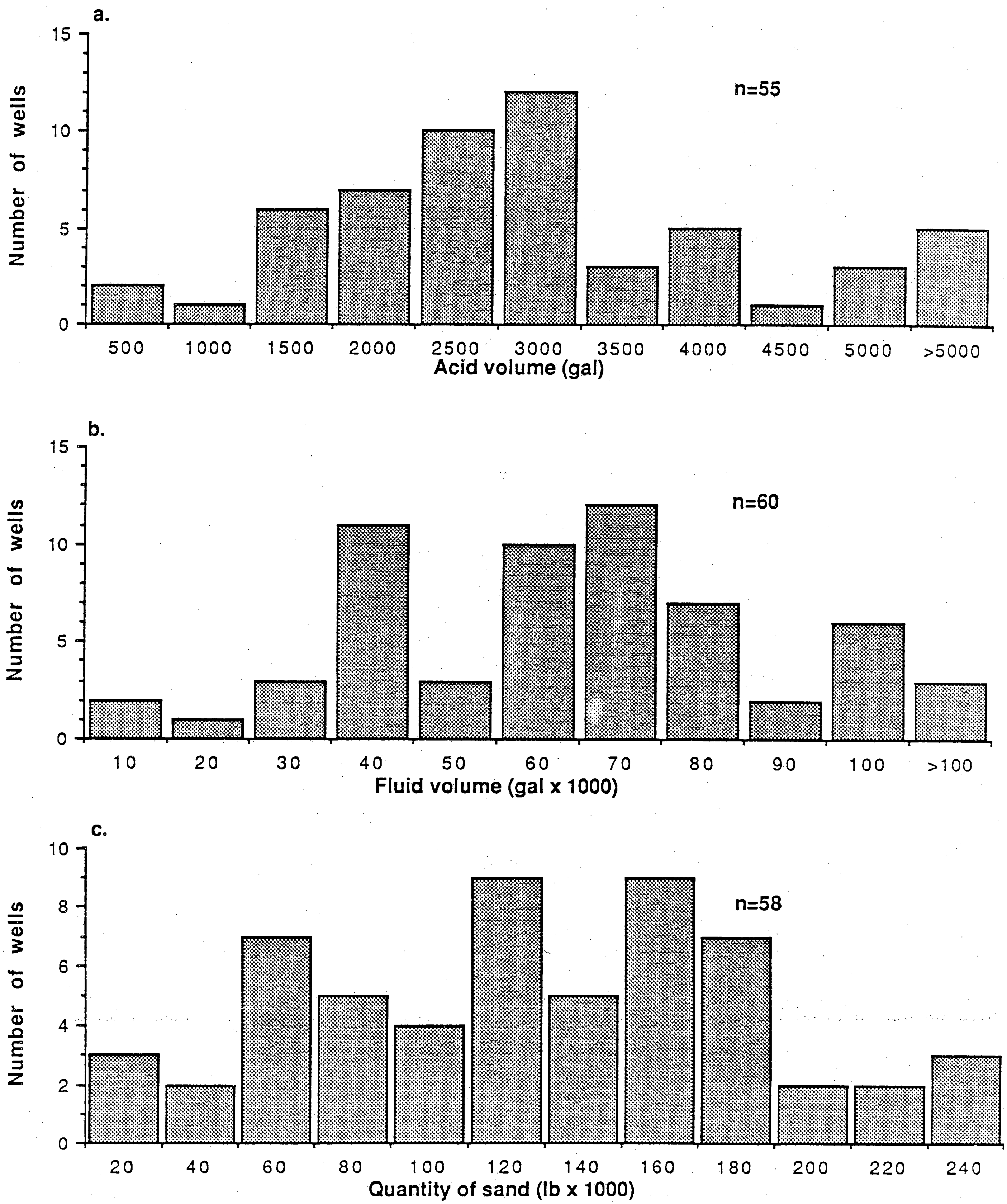


Figure 40. Amount of material used during stimulation of successful gas wells completed in the Cleveland Formation between January 1983 and April 1988. (a) Volume of acid used. (b) Total fluid volume used in hydraulic fracturing jobs. (c) Quantity of sand used in hydraulic fracturing jobs.

Table 3. Well and reservoir properties for a fracturing design study of a well in Cleveland Formation, Lipscomb Field, Lipscomb County, Texas.

Depth = 7,600 ft	Casing/tubing diameter = 5.5 inches
Drainage radius = 1,867 ft	Fracture height = 50 ft
Wellbore radius = 5.5 inches	Viscosity = 0.02 cps
Porosity = 12.5%	Compressibility = 3.2×10^{-4} l/psi
Permeability = 0.30 md	Young's modulus = 6.0×10^{6} psi

Temperatures: surface = 70°F; fluid = 70°F; formation = 160°F

Bottom hole pressure: static = 2,300 psi; fracturing = 4,250 psi

Overburden pressure: 1,950 psi

Source: S. King, undated.

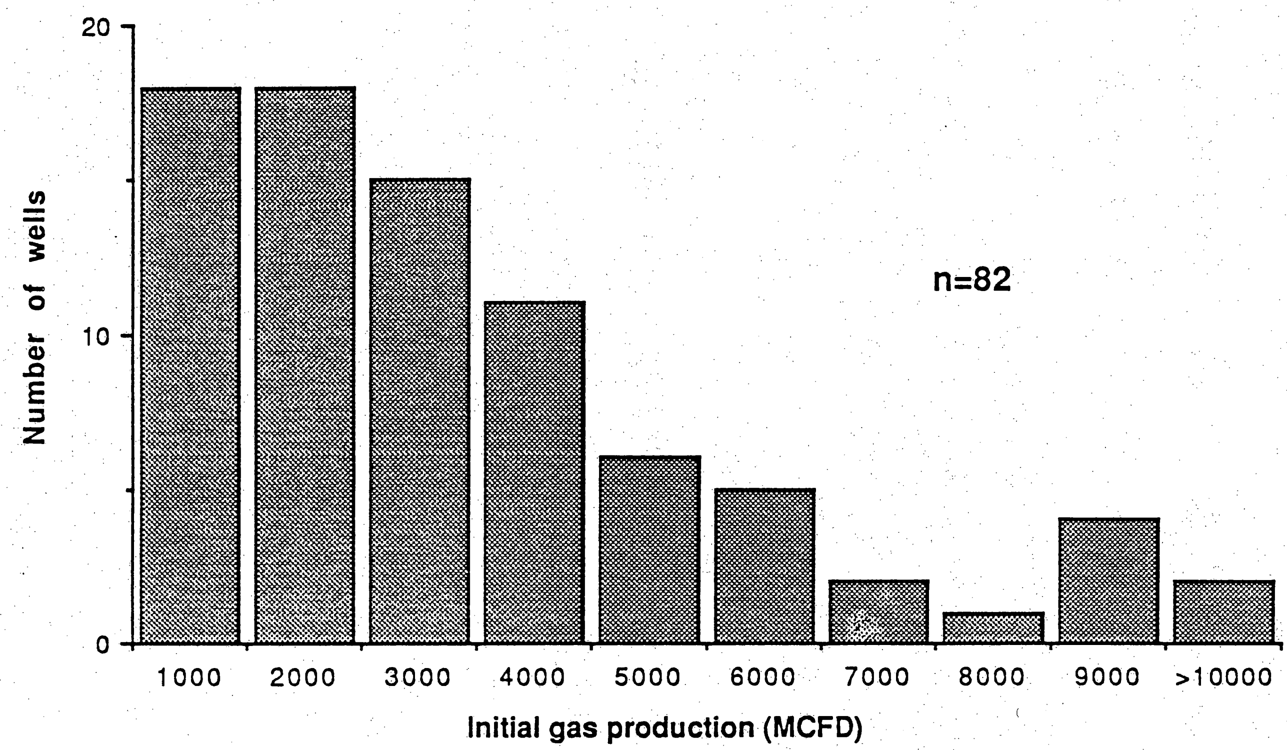


Figure 41. Daily gas production from 82 wells in the Cleveland Formation that had IPF less than 5 BOPD. Most wells produced less than 4,000 MCFD, which was, however, more than the amount produced by the majority of wells in each of the other three basins.

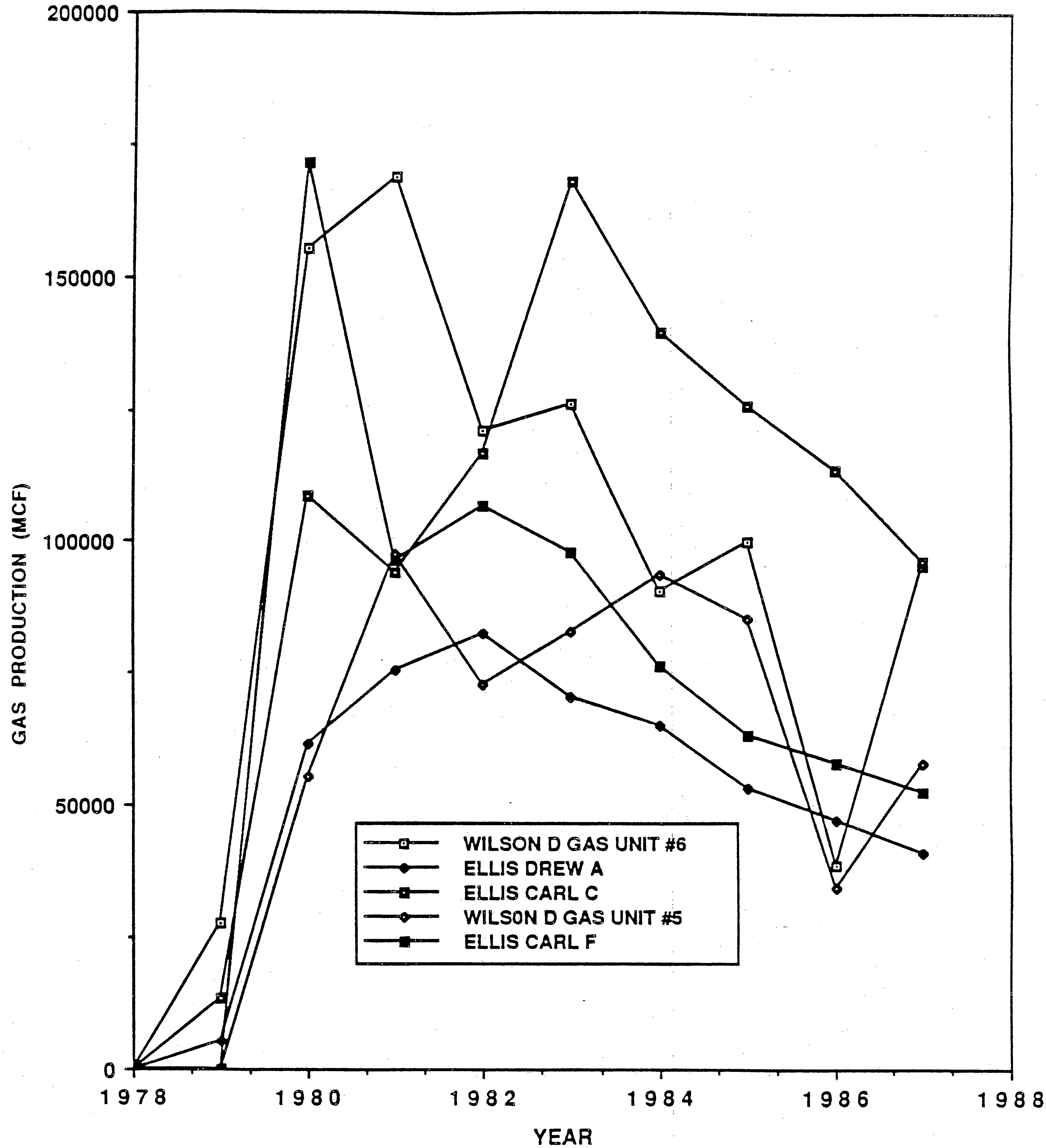


Figure 42. Production decline curves for selected wells in the Cleveland Formation, Ellis Ranch field. From ICF-Lewin Energy Division (1988c).

gelled acid. In the early 1980's, the composition of the injected fluid was altered to a cross-linked polymer gel (30 to 40 lb/1000 gal). More recently, foam fractures (70 percent foam, 30 percent fluid) have been applied with up to 150,000 lb of sand. (Another major Cleveland operator, Mewbourne, uses significantly less sand, 50,000 lb, in treatment of its wells.) Diamond Shamrock reports post-stimulation production rates of 500 to 1000 MCFD, a significant increase over pre-stimulation rates of 100 to 150 MCFD. See table A9 for survey of drilling and stimulation costs in the Cleveland Formation.

ICF-Lewin Energy Division (1988c) also reports that the Cleveland Formation in the Anadarko Basin in Texas Railroad Commission District 10 and in parts of Oklahoma is currently well-served by pipelines and nearby markets. It lies in the midst of a major gas-producing region, which exports gas to the North-Central United States. Despite the current projected surplus of 6.5 TCF (Woods, 1987) in the South-Central region (Texas, Oklahoma, Louisiana, Arkansas), export capacity is expected to decline rapidly. Total supplies are expected to decline from 12.4 TCF in 1985 to 7.7 TCF in 2020, leaving only a 1.5 TCF surplus in the South-Central region. This presents an opportunity for the Cleveland to capture an increasing share of remaining South-Central supplies and growing exports to the North-Central and Atlantic regions. June 1988 spot prices were $1.27/MCF, about average for the country, and slightly below mid-1987 levels. Given the expected availability of export potential and declining local supplies, a major emphasis for technology development in the Cleveland is likely to be improved recovery per well.

Ground access in the Anadarko Basin is not hampered by local relief. Paved roads cross the area at 15- to 20-mi intervals, and unpaved section roads are present at 1- to 2-mi spacing.

No cores from the Cleveland Formation are known to be available for study by the public.

Technology Challenges

The principal difficulty in producing gas from the Cleveland Formation is its very low permeability. Seventy-eight percent of permeability values from 391 wells in the Cleveland were below 0.1 md (Railroad Commission of Texas, 1981); the median value was 0.028 md. Massive fracturing is therefore required to produce gas economically from the Cleveland Formation, and so virtually all Cleveland wells are fractured prior to testing and production (Railroad Commission of Texas, 1981). The drainage area of each well is small, only 40 to 80 ac, and the reservoir is not drained effectively beyond the fracture (P. Lancaster, Mewbourne Oil Co., personal communication, 1988). The Cleveland drains very slowly; pressure in wells that were temporarily shut-in has increased for as long as 90 days (P. Lancaster, Mewbourne Oil Co., personal communication, 1988). As a result of such low pressure, the gas must be compressed before being placed in pipelines.

Significant problems may be encountered during fracture-stimulation of low-permeability gas wells in the Anadarko Basin: lost circulation, difficulty with formation evaluation, and an incomplete understanding of the relationship between injected sand volume and well productivity. Additionally, the amount of sand used in fracture jobs varies from 50,000 to 150,000 lb (ICF-Lewin Energy Division, 1988c). However, one operator reports no significant fracture-containment problems in the Cleveland Formation when the target zone in the wellbore has been effectively isolated with cement (P. Lancaster, Mewbourne Oil Co., personal communication, 1988). Vertical fracture containment is necessary to avoid intercepting non-productive shales above or below the target zone.

Wells in the Cleveland Formation are commonly stimulated with acid. However, treatment with a binary fluid of HCl and HF is generally regarded as the best system, owing to the chlorite content of the formation (King, undated) because iron liberated by partial dissolution of chlorite can plug pores. The binary fluid dissolves the chlorite more readily, and pore-plugging is minimized. Iron control agents are often used to prevent precipitation of the iron in the formation.

Important technical challenges presented by the Cleveland Formation are (1) containing vertical fracture growth and confining fractures to productive zones, (2) increasing the area drained by each well, and (3) maintaining enough pressure to put the gas in pipelines.

ABO FORMATION, PERMIAN BASIN

Structural Overview of the Northwest Permian Basin and Adjacent Area

The Pecos slope of eastern New Mexico is a region of gentle eastward dip (50 to 100 ft/mi) east of the Pedernal Uplift (fig. 43) between the late Tertiary Basin and Range province to the west and the relatively undeformed High Plains to the east (table A10) (Kelley and Thompson, 1964, p. 110). Depth to the top of the Abo ranges from approximately 1,800 ft in the western part of the study area to approximately 4,500 ft at the southeastern edge (Broadhead, 1984b). Current Abo production is in the northwestern part of the Northwest shelf of the Permian Basin (Broadhead, 1987). The Permian Basin, Northwest shelf, and Pedernal Uplift were created by late Pennsylvanian-Permian deformation, and they existed as topographic features during deposition of the Permian Abo Formation. Gentle folds and small faults in the Abo Formation and in overlying units reflect Late Cretaceous through Tertiary episodes of compression and extension. The Pecos buckles are the most prominent of the minor folds and faults that are superimposed on the Pecos Slope (Kelley, 1971; Foster and others, 1972; Broadhead, 1984b). The Pecos buckles are northeast-trending right-lateral, transpressive strike-slip faults and associated folds (figs. 44 and 45) (Kelley, 1971).

The depositional paleogeography of the Abo Formation was established by structural movements during the Paleozoic (fig. 43) (Kluth, 1986). The southern Rocky Mountain region underwent at least five changes in patterns of basin sedimentation in the Paleozoic that can be broadly related to major patterns of Paleozoic tectonic activity. Paleozoic movement patterns are inferred from sedimentary thickness variations. Throughout early Paleozoic time, the region formed part of the tectonically stable North American craton (Hayes, 1975). Lower Paleozoic rocks are generally thin and are mainly eroded remnants of blanketlike deposits and a south- and southwestward-thickening wedge of marine carbonates (Ross and Ross, 1986). Unconformities mark epeirogenic uplift in the Middle Ordovician, Early Silurian, and Late Silurian-Middle Devonian;

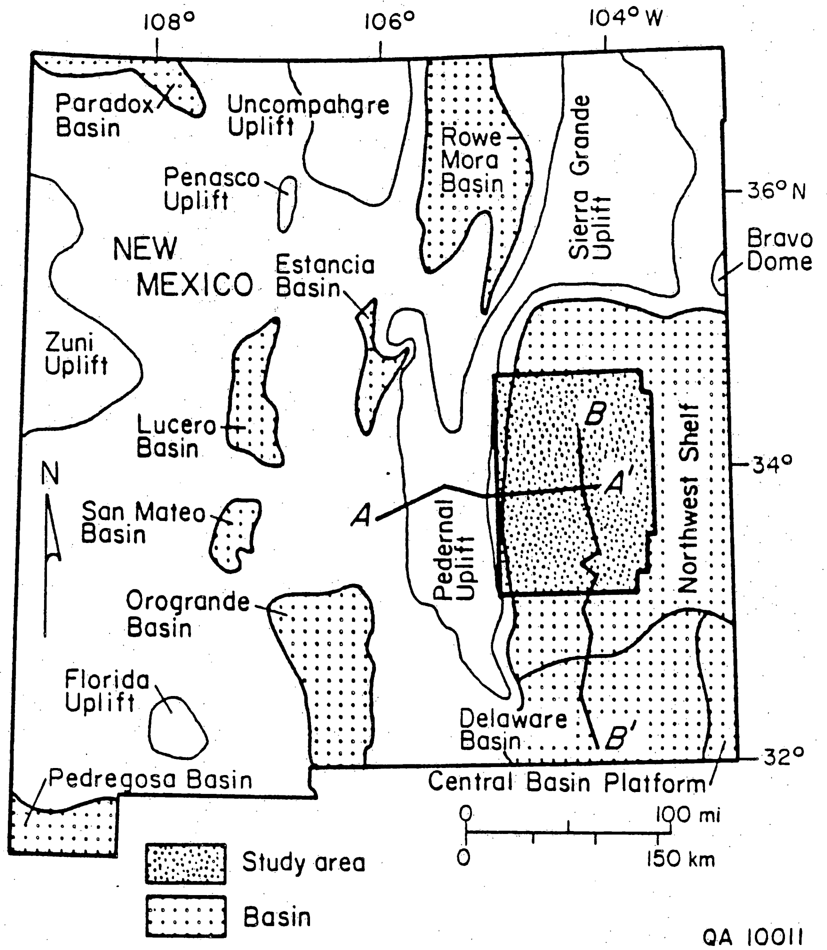


Figure 43. Map of Paleozoic-age uplifts and basins in New Mexico. Stippled box depicts the region of productive Abo sediments and locations of figures 46, 52, and 53. Cross sections are shown in figure 51. From Broadhead (1984b, fig. 1).

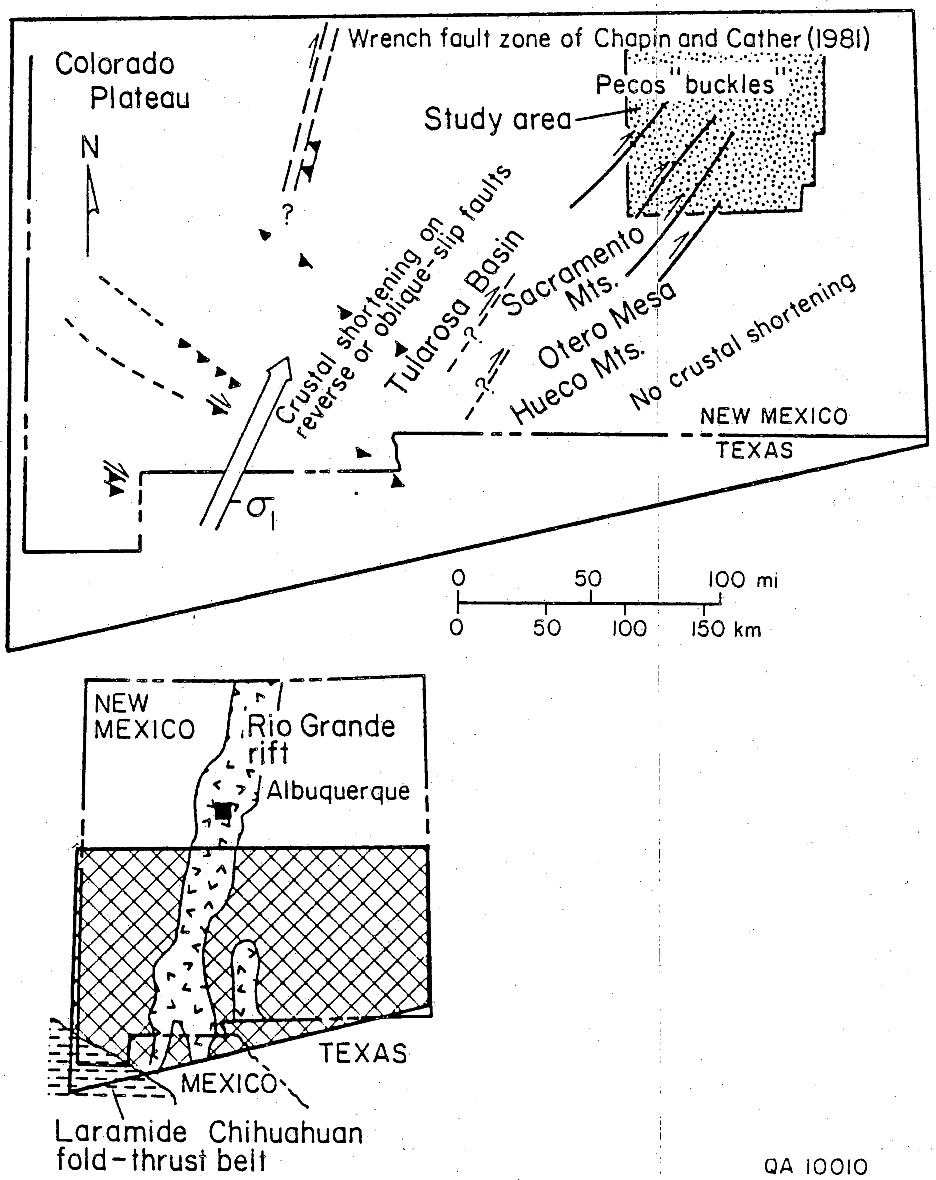


Figure 44. Tectonic map of southern New Mexico in Laramide time, illustrating an interpretation of the Pecos Slope buckles as strike-slip faults separating compressed and shortened crust of southwest New Mexico from less compressed and less shortened crust of southeast New Mexico. Maximum horizontal stress direction indicated by σ_1. From Seager (1983, fig. 10).

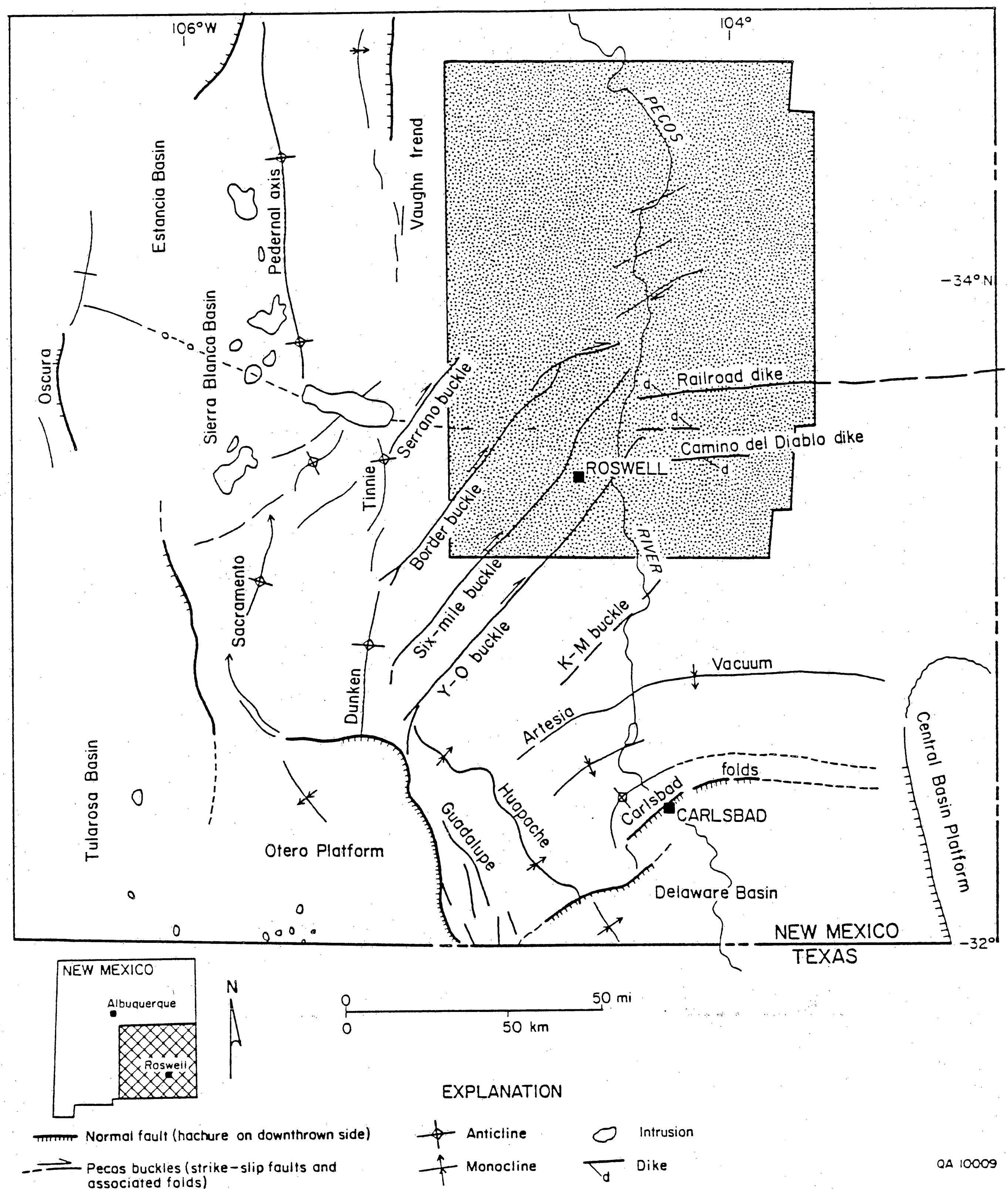


Figure 45. Structural map of southeastern New Mexico. Modified from Kelley (1971, fig. 12). Stippled box shows location of figures 46, 52, and 53.

these unconformities are partly responsible for the regional northward thinning of Paleozoic strata (Greenwood and others, 1977).

The Permian Basin of West Texas and eastern New Mexico began to develop in association with the late Paleozoic Ancestral Rocky Mountains and as a result of the collision of Gondwana with the southeastern and southern margins of Euramerica (Windley, 1984). Sediment patterns in the basin changed from carbonate-shelf environments in the early Paleozoic to reefs in the Pennsylvanian and Permian. Shales were deposited along the margins of the north-trending Central Basin Platform along the Texas-New Mexico border (Masters and Mast, 1987). The Pedernal Uplift is a buried north-trending paleotopographic high created by late Pennsylvanian-Permian deformation. Uplift began in early Pennsylvanian time (Thompson, 1942; Meyer, 1966; Kottlowski, 1969) and continued into early Permian (Wolfcampian) time (Broadhead, 1984b). In southern Chaves County, flat-lying Permian strata cover late Pennsylvanian anticlines and faults (Black, 1976).

The Pecos Slope is an east-dipping homocline of Late Cretaceous to Tertiary age (Kelley, 1971; Eaton, 1988), part of a suite of gentle, low-amplitude folds and minor faults developed in the southern New Mexico foreland of the Laramide thrust belt (fig. 44) (Chapin and Cather, 1981; Chapin, 1983; Seager, 1983). Permian rocks in the Pecos Slope generally strike north to northeast and dip gently eastward at approximately 50 ft/mile (fig. 46). The western limit of the slope is the structural divide formed by the Mescalero, Sacramento, and Guadalupe arches and the Tertiary Tularosa and Estancia graben to the west (fig. 45) (Kelley and Thompson, 1964). Small folds and faults, primarily of early Tertiary age, and dikes are superimposed on the Pecos Slope (Kelley, 1971; Broadhead, 1984b). Faulting is minor both in density per unit area and in the amount of throw; the largest faults have throws of less than 1,000 ft (Kelley, 1971). Folds on the Pecos Slope include long, open anticlines and synclines, monoclines, circular domes, and, locally, overturned and fan folds (Kelley, 1971).

The Pecos buckles are the most distinctive structures on the Pecos Slope. They are northeast-trending, linear folds and faults (Broadhead, 1984b). The upthrown side of faults alternates along strike. The buckles are primarily right-lateral strike-slip fault zones with little displacement (Kelley,

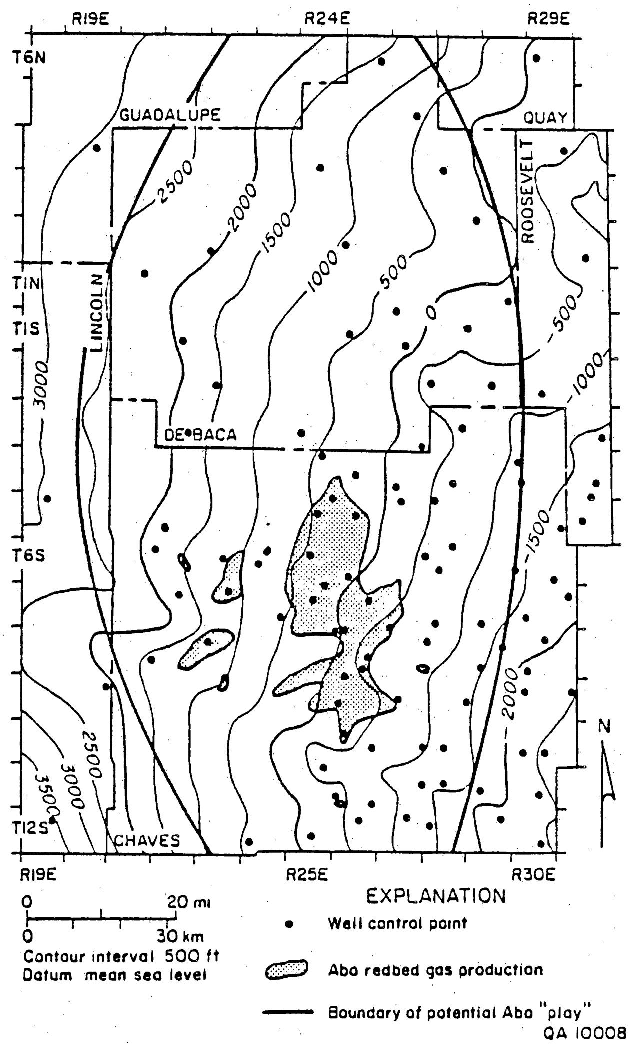


Figure 46. Structure-contour map of the Abo Formation in the Chaves/De Baca County area shows the gentle eastward dip of the formation. Location shown in figure 43. Modified from Broadhead (1984b, fig. 23) and Wheatley (1981).

1971). Buckles plunge northeastward across the regional dip of the Pecos Slope, about 8 to 20 mi apart. They are exposed for distances of 40 to 80 mi. Adjacent to buckles, bedding is tilted sharply upwards in a zone that ranges from a few tens of feet to 4,000 ft in width (fig. 47). Commonly, this narrow zone of intense deformation is within a wider zone of uplift. For example, the zone of uplift is as wide as 4 mi along the Six-mile buckle west of Roswell (fig. 48). Within the buckle, the style of folds, faults, and fractures may change along strike (fig. 47). The en echelon pattern of minor folds and faults associated with the buckles and within inter-buckle domains is characteristic of strike-slip fault zones (fig. 49) (Hancock, 1985). Buckles are associated with steeply plunging subsidiary folds and faults that have more easterly trends and branch away from the main buckle zone (fig. 48).

Tertiary volcanic and intrusive rocks on the Pecos Slope constitute another structural feature that could create fractures and increase heat flow locally (Broadhead, 1984b). Most of the Tertiary igneous rocks are in Lincoln County, west of the area of Abo production, but a few east-trending dikes have been mapped in eastern Chaves County (fig. 48) (Kelley, 1971; Broadhead, 1984b).

The Pecos Slope is adjacent to two major tectonic features of the southwestern United States. The west-northwest-trending Laramide Chihuahuan fold-thrust belt in southern New Mexico, West Texas, and Mexico (Chapin and Cather, 1981) is less than 200 mi southwest of the study area (fig. 44, inset). The north-trending Rio Grande rift in central New Mexico (Woodward and others, 1978; Rieker, 1979) is approximately 100 mi west of the area of Abo production (fig. 44, inset). Development of these structures probably caused compressional and extensional stresses and higher heat flow in rocks in east-central New Mexico (Coney, 1971; Coney and Harms, 1984; Eaton, 1988). Uplifts and basins southwest of the study area reflect the Laramide Orogeny, which occurred between 80 and 40 mya (Coney, 1971). In southwestern New Mexico, Laramide deformation was marked by movement on large-scale, northeast-directed thrusts (Corbitt and Woodward, 1973; Drewes, 1982). Northeast of the thrusts, in the foreland region of the thrust belt, a belt of west-northwest- to northwest-trending basement-cored block uplifts and complementary basins formed (Seager, 1981; Brown and Clemons, 1983). Laramide deformation in the foreland area of the fold-thrust belt in

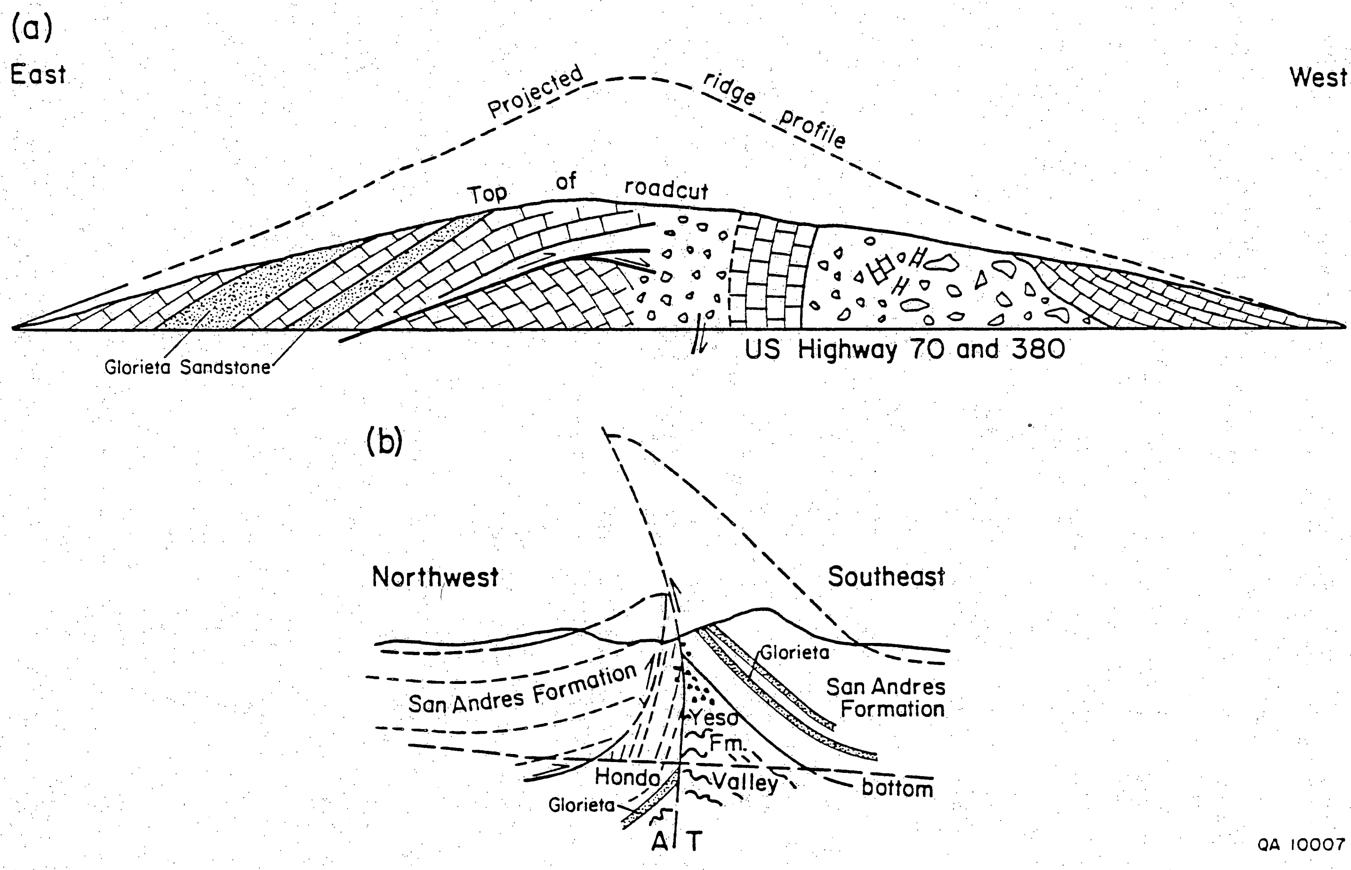


Figure 47. Structural sketches of cross sections through Pecos Slope buckles. (a) Border buckle at roadcut of U.S. Highway 70 and 380, (b) Border buckle at Hondo Canyon. From Kelley (1971, fig. 18). See figure 48 for approximate location of exposures.

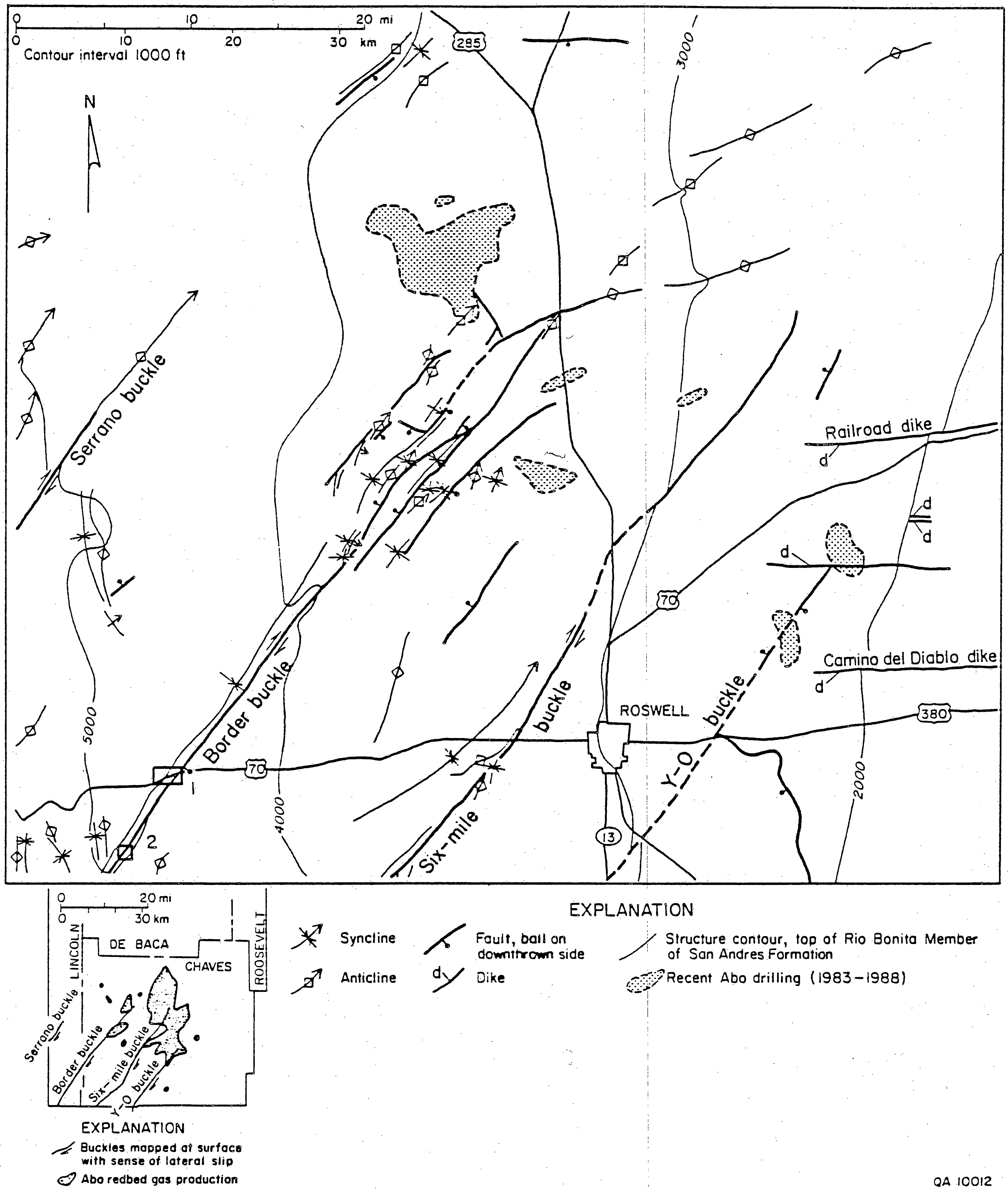


Figure 48. Structural map of buckle terminations. 1 = Location of figure 47a. 2 = Location of figure 47b. From Kelley (1971, plate 5). Inset shows major surface structures (Pecos Slope buckles) mapped by Kelley (1971) and their relation to Abo gas production. Inset from Broadhead (1984b, fig. 24).

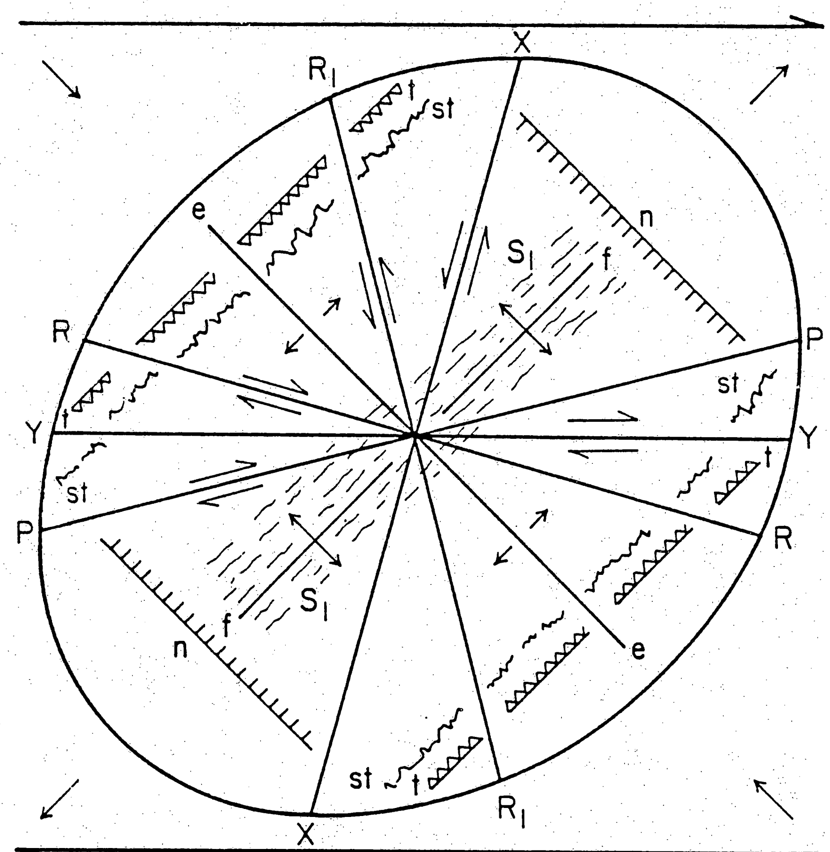


Figure 49. Compilation diagram illustrating en echelon structures characteristic of strike-slip fault zones evolving during simple shear. R and R_1, Reidel and conjugate Reidel shears; P, X and Y, P- X- and Y-shears; e, extension fracture, fissure, or vein; n, normal fault; t, thrust; st, stylolite; f, fold; S_1, foliation. From Hancock (1985, fig. 9).

south-central and southwestern New Mexico was characterized by uplift of simple basement blocks similar in style, but smaller than uplifts of the central Rocky Mountains. Uplifts are asymmetric, with steep, southwest-dipping, reverse-faulted northeast flanks and broad, less deformed southwest flanks. Basins adjacent to these uplifts are filled with lower Tertiary clastic rocks 3,000 to 7,000 ft thick (Seager, 1983). According to Baltz (1965, p. 2042 and 2066) epeirogenic uplift occurred throughout the region during the early Tertiary. Many of the present ranges in central New Mexico resulted from Tertiary tectonism (Eaton, 1988).

Stress orientation

Eastern New Mexico is in the Southern Great Plains stress province, an extensional province characterized by uniform north-northeast-trending least principal horizontal stress (fig. 7) (Zoback and Zoback, 1980). Evidence for stress directions comes from hydraulically fractured wells in the Permian Basin of West Texas (Zemanek and others, 1970) and from alignment of post-5-m.y. volcanic feeders in northern New Mexico (Zoback and Zoback, 1980). The probable extensional regime is inferred from earthquake focal mechanisms and post-5-m.y. basaltic volcanism. Least principal horizontal stress directions in the Southern Great Plains province are oblique to stress directions in the adjacent Midcontinent stress province. Epicenters of sparse earthquakes on the High Plains of southeastern New Mexico are on the western edge of a region of seismic activity that extends southward and eastward into Texas; most earthquakes are centered on the Central Basin Platform (Rogers and Malkeil, 1979; Sanford and others, 1981), a fault-bounded Early Permian structure. Seismicity is spatially associated with faults, but because the old buried faults show no evidence of recent movement at the surface, Sanford and others (1981) suggested that hydrocarbon recovery practices such as water injection for secondary recovery may be responsible for some seismic activity.

Reservoir-scale structures

The Pecos buckles and associated folds, faults, and fractures could affect Abo reservoir characteristics. According to Scott and others (1983) and Broadhead (1984b), Abo production is not directly controlled by surface or subsurface structures, and production is not limited to fractures in the buckles (Broadhead, 1984b). Abo production is spatially associated with the terminations of the Border, Six-mile, and Y-O buckles (fig. 48, inset). However, the role of fractures in Abo production has not been established (Broadhead, 1984b). Fractures and, locally, brecciation are evident in the central parts of some buckles (fig. 47). Core data suggest that the upper unit of the Abo is fractured in De Baca and Guadalupe Counties (Broadhead, 1984b). The buckles are primarily strike-slip fault zones, and a range of natural fractures and minor faults can be expected in areas of strike-slip faulting (fig. 49). Fractures associated with regional tilting during formation of the Pecos Slope, and fractures associated with Tertiary extension may affect production and stimulation. Broadhead (1984b) concluded that detailed surface and subsurface studies of fracture trends within areas of favorable source and reservoir rocks would delineate potentially productive fairways within the Abo.

Stratigraphy

General stratigraphy

Dark-red arkosic sandstones, conglomerates, and mudstones of the Abo Formation were first described by Lee and Girty (1909). Needham and Bates (1943) redescribed the type section in Abo Canyon, Manzano Mountains of southeastern New Mexico, and those authors' formational boundaries are still accepted. The Abo is the basal formation of the Permian (Wolfcampian to Leonardian) Manzano Group (fig. 50) (Otte, 1959; Pray, 1961). Its age and terrestrial origin are inferred from the

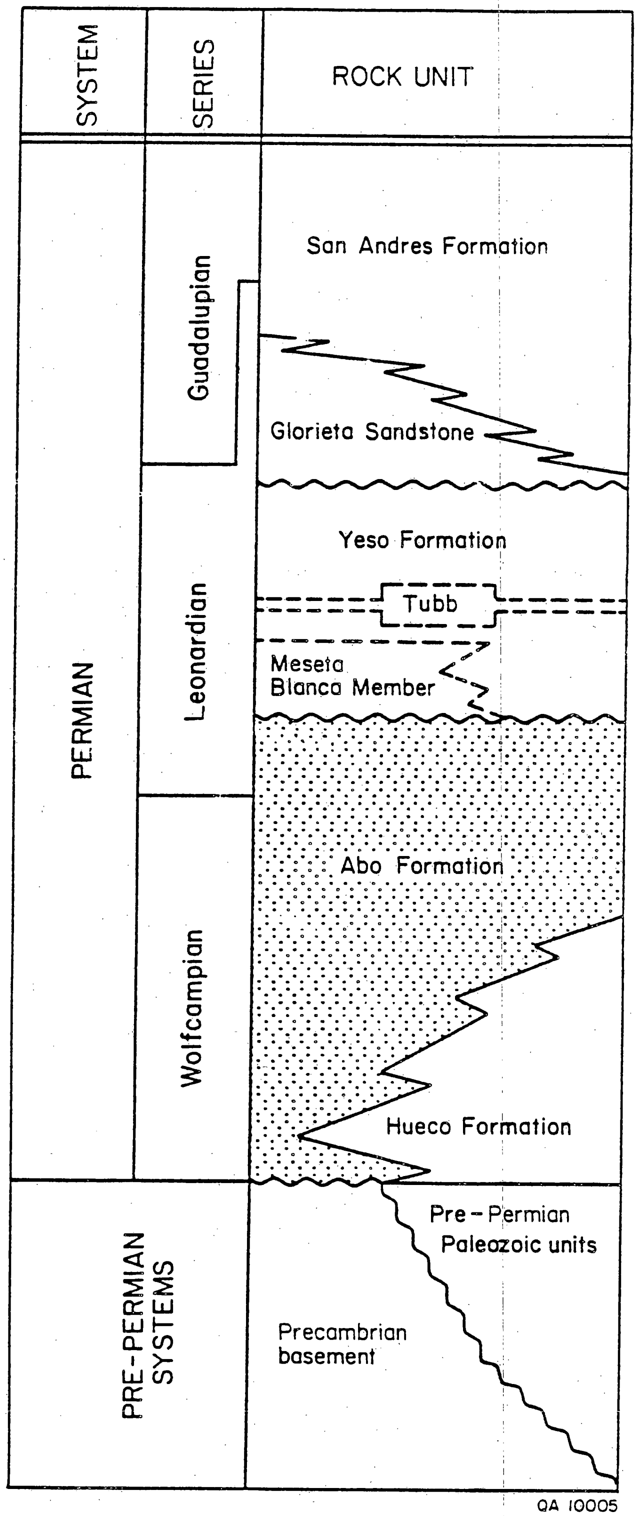


Figure 50. Generalized stratigraphic column of Permian (Wolfcampian to Guadalupian) sediments on the Northwest Permian Basin shelf, New Mexico. Modified from Broadhead (1984b, fig. 4).

presence of Permian vertebrate and trace fossils (Baars, 1962; Myers, 1982), plant and wood fragments, and the red hematite cement that pervades the sequence.

Abo sediments crop out in the Sacramento, Manzano, Nacimiento, Zuni, and Sandia Mountains and in other small uplifts in southeastern New Mexico. East of the Pedernal Uplift (fig. 43), depth to the Abo ranges from 1,800 to 4,500 ft (Broadhead, 1984b). The north-south oriented Pedernal Uplift (fig. 43) of Pennsylvanian to Permian age was a positive feature during Abo deposition. Different depositional environments existed on the east and west sides of the uplift during Abo time. As a result, Abo sections exposed in outcrop and preserved in the subsurface have different stratigraphic sequences.

Outcrop stratigraphy has been studied by Bachman and Hayes (1958), Baars (1962), Delgado (1977a), Hatchell and others (1982), Myers (1982), and Speer (1983a,b). Since discovery of Abo gas in 1977, Broadhead (1982, 1983, 1984a,b) has correlated Abo stratigraphy from the surface to subsurface. On either side of the uplift, the Abo is divided into upper, middle, and lower lithostratigraphic units (fig. 51), each composed of varying percentages of conglomerate, arkosic sandstone, siltstone, and mudstone (Broadhead, 1983, 1984b; Speer, 1983a,b). To the west, the Abo disconformably overlies terrigenous clastics and marine limestones of the Bursum Formation and/or Paleozoic sedimentary rocks. Lower Abo sediments thin and onlap the Pedernal Uplift. The lower and upper Abo units can be correlated west of the uplift. The middle Abo onlaps the lower Abo unit and pinches out east of the Pedernal Uplift (fig. 51a). On the Northwest Permian Basin shelf, east of the Pedernal Uplift, the lower Abo interfingers with shallow marine terrigenous-clastic sediments and limestones of the Hueco Formation. The middle and upper Abo interfinger to the south with Abo "reef and backreef" dolostones and limestones. These limestones interfinger with the Bone Spring Limestone in the Delaware Basin (fig. 51b). Unconformably overlying the Abo Formation are sandstones, siltstones, limestones, and evaporites of the Yeso Formation (Needham and Bates, 1943; Broadhead, 1984b).

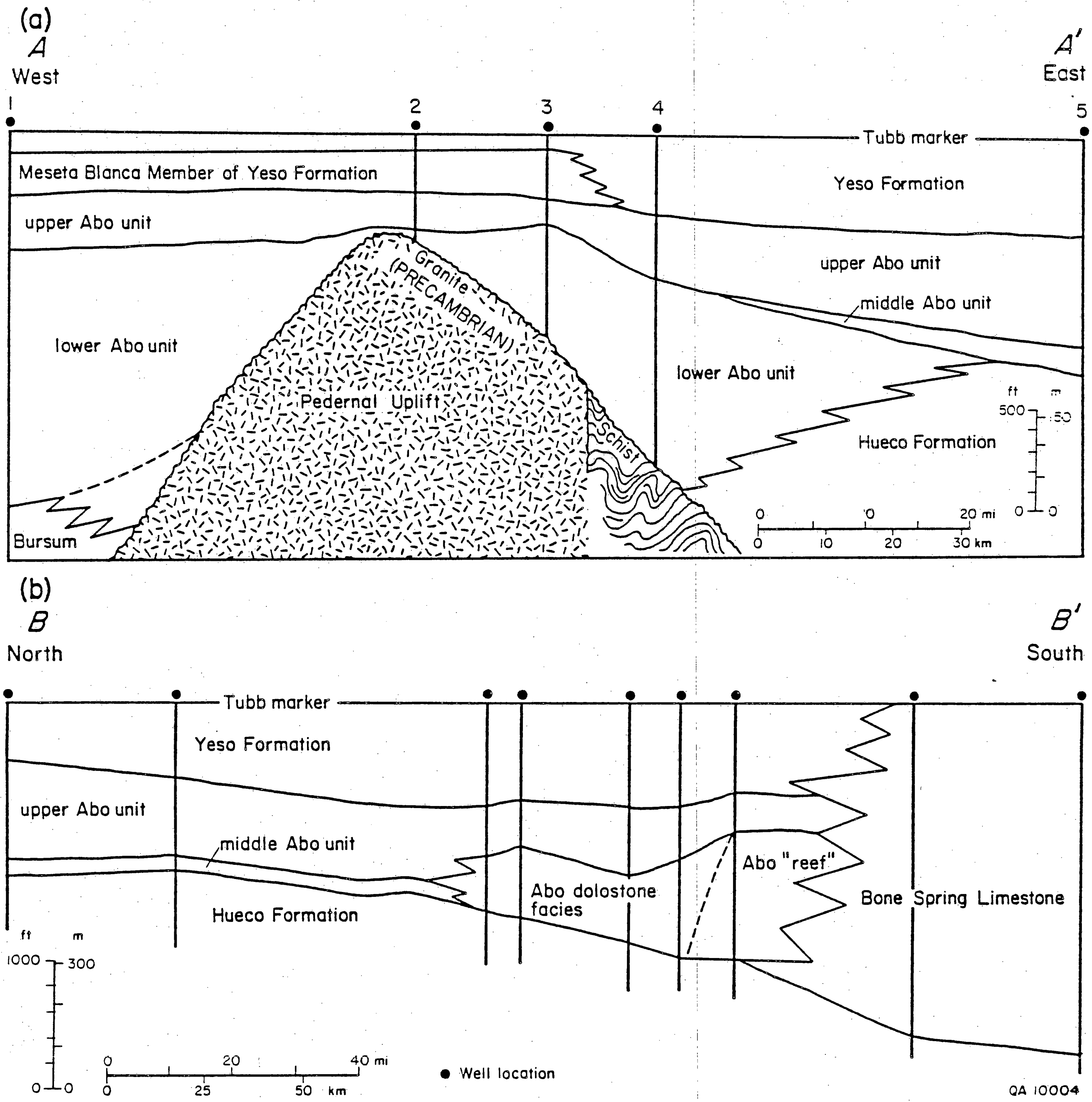


Figure 51. (a) West-east (A-A') and (b) north-south (B-B') cross sections through the Abo Formation show draping of the Abo over the Pedernal Uplift, and southward interfingering of the Abo terrigenous-clastic sediments with "reef and backreef" carbonates. Locations given in figure 43. Modified from Broadhead (1984b, figs. 5 and 6).

Abo stratigraphy on the Northwest Permian Basin shelf

Because this study is concerned with the part of the Abo Formation in Chaves and De Baca Counties that produces hydrocarbons (fig. 46), this discussion is restricted primarily to the stratigraphic and depositional nature of Abo sediments east of the Pedernal Uplift on the Northwest shelf of the Permian Basin (table A11). An Abo isopach map indicates that the thickness of terrigenous-clastic Abo sediments ranges from less than 400 to 1,400 ft in the Chaves/De Baca County region (fig. 52a). The upper Abo ranges from less than 100 to 900 ft in thickness, and generally thins to the south (fig. 52b). As noted above, Broadhead (1983, 1984a,b) divided the Abo Formation into three lithostratigraphic units. Brief sedimentologic descriptions of each unit follow:

Lower Abo Unit: A "granite wash" unit of interbedded conglomerate and coarse- to medium-grained arkosic sandstone. Some red mudstone interbeds are present. The lower unit correlates to the east with limestones and mudstones in the Hueco Formation (fig. 51a) and thins to the west as it unconformably overlies the Pedernal Uplift. On the east flank of the Pedernal Uplift, the lower unit is 870 ft thick (well 4, fig. 51a); it thins to 80 ft over the crest of the uplift (well 2) then thickens to 1,250 ft in well 1.

Middle Abo Unit: Middle Abo sediments consist of 90 percent red mudstone and 10 percent red, very fine grained, silty sandstone. The middle unit is about 130 ft thick in well 5 (fig. 51a). It pinches out to the west and is absent west of the Pedernal Uplift. To the east and south, it conformably overlies the Hueco Formation and grades into mudstones and dolostones of Abo "reef" and "backreef" facies (fig. 51b). Sandstone beds vary from 1 to 10 ft in thickness and are commonly massive, burrowed, or cross-laminated. Broadhead (1983) reports a sparse marine fauna in middle Abo marine mudstones.

Upper Abo Unit: The upper Abo lies conformably on the middle and lower Abo units and is lithologically similar on both sides of the uplift. It contains 10 to 30 percent red, very fine grained sandstone and 70 to 90 percent red mudstone. Sandstones occur as multiple sharp-based, upward-fining sequences 1 to 4 ft thick in channel scours 20 ft deep and 150 ft wide. Individual beds exhibit planar laminations, crossbeds, ripples, and soft-sediment deformation (Broadhead, 1983). Thickness of the upper unit varies from 550 ft in well 5 to 250 ft in wells 1 and 2 (fig. 51a).

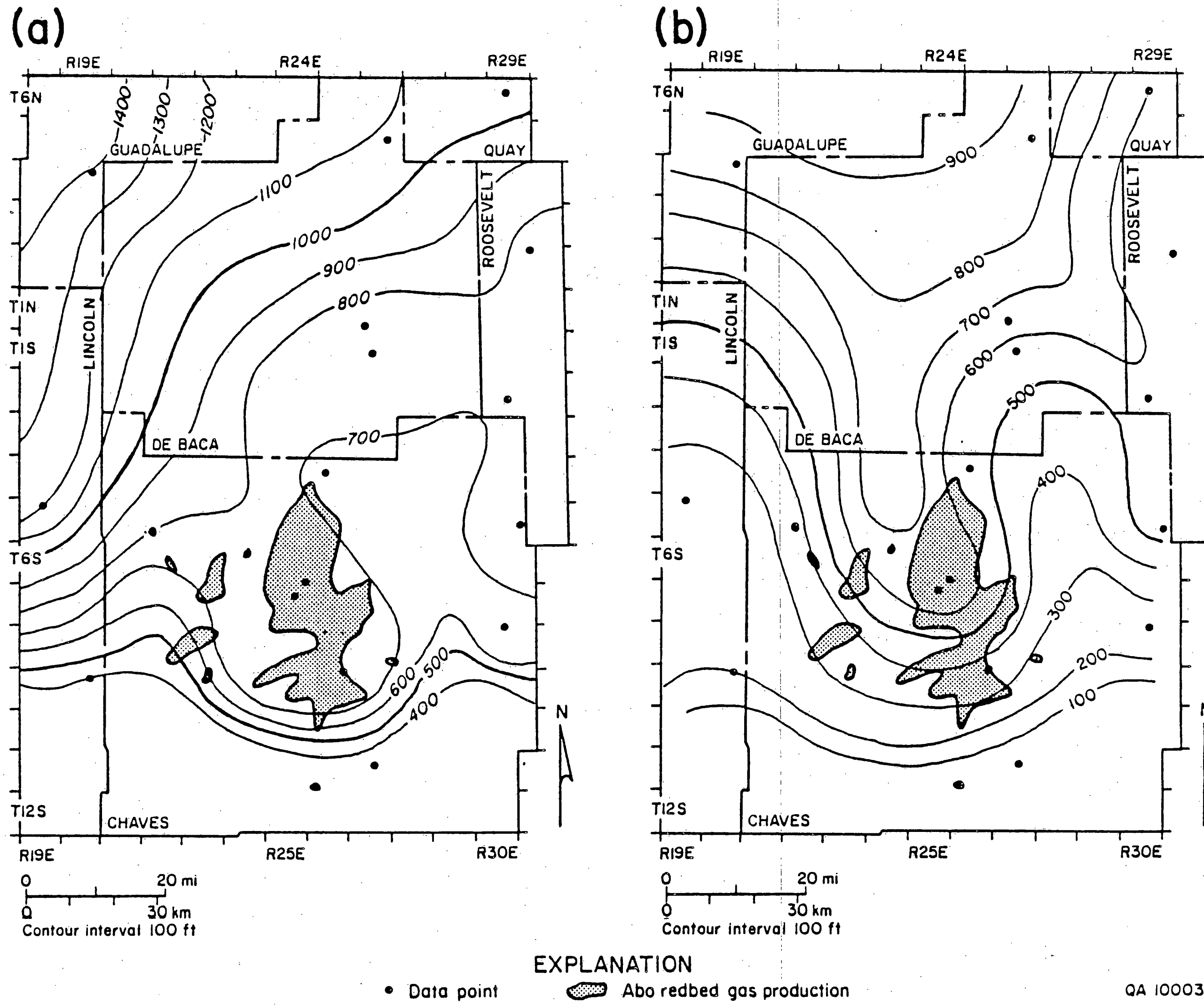


Figure 52. Isopach map of terrigenous-clastic sediments in (a) the Abo Formation and (b) the upper Abo on the Northwest Permian Basin shelf. Note the strong south-to-southeast trend in decreasing sediment thickness. Area of Abo production is highlighted. Location of figures shown in figure 43. Constructed from data in Broadhead (1984b).

Depositional environments

Speer (1983a,b) summarized the depositional environments of the Abo Formation west of the Pedernal Uplift. A wedge of fluvially deposited, terrigenous-clastic basin-fill sediments was deposited in response to the uplift and erosion of the uplift. This interpretation of fluvial deposition under arid to semiarid climatic conditions (Delgado, 1977b; Speer, 1983a) also pertains to the area east of the Pedernal Uplift, but the presence of an additional sediment source for the eastern Abo resulted in the deposition of finer grained sediments in alluvial-fan, marginal marine/deltaic, and meandering-stream environments. Middle and upper Abo Formation sediments deposited on the Northwest shelf were derived primarily from source areas to the north (Curry County; Broadhead, 1984b). The Pedernal Uplift supplied sediment to the lower Abo unit to the east and was the major source of Abo sediments deposited in the Orogrande Basin west of the uplift (fig. 43). Dispersal patterns measured by Bachman and Hayes (1958) and by Speer (1983b), and inferred by Broadhead (1984b) from isopach maps, indicate that Abo sediment was transported to the east, south, and west. A strong southward decrease in thickness of the entire Abo Formation and thinning of the terrigenous-clastic component of the upper Abo (fig. 52a) support a southerly transport direction for Abo sediments east of the Pedernal Uplift.

Lower Abo "granite wash" was shed off the Pedernal Uplift and other Wolfcampian-age positive granitic features. Alluvial-fan systems onlapped the uplift and graded eastward into shallow Paleozoic seas where fossiliferous mudstone and limestone (Hueco) deposits accumulated (Broadhead, 1984b). Lower Abo alluvial-fan sediments east of the uplift are poorly understood due to lack of outcrop exposure and sparse core information. However, Speer (1983b) described the lower Abo exposures in the Sacramento Mountains as lenses and beds of clast-supported cobble conglomerate interbedded with medium- to fine-grained sandstone. Conglomerate beds are 2 to 60 ft thick and extend up to 8.5 mi. Planar-laminated to cross-stratified sandstone beds range from 2 to 25 ft in thickness and are as much as 0.6 mi wide. The transition from conglomerate to sandstone and the stratification of these sediments suggest deposition on the middle to outer parts of small alluvial fans in stream-channel, braided-stream, and overbank environments (Speer, 1983b). Rare, thin limestones and micrite beds in the lower Abo were either deposited in shallow lakes or they interfinger with the Hueco Limestone (Bachman and Hayes, 1958).

The lithologic change from lower Abo "granite wash" to overlying mudstone-rich middle Abo sediments was interpreted by Broadhead (1984b) as a change in depositional environment from alluvial-fan to marginal marine and fluvio-deltaic settings. Alluvial fans adjacent to the Pedernal Uplift probably were transgressed by the Paleozoic seas in the Permian Basin and were buried by muddy shallow-shelf deposits. Broadhead (1984b) cites the presence of marine fauna, high calcareous content of the mudstones, swelling clay minerals, and absence of roots and desiccation features as support for a marine origin. Crossbeds in the uncommon sheet-like shelf sandstones imply that shelf sediments were periodically reworked by waves and/or tides.

Overlying the fine-grained middle Abo unit are mudstones and sandstones deposited in fluvial and deltaic depositional environments (Broadhead, 1984b). A deltaic depocenter elongated north-south through De Baca and Chaves Counties (fig. 53) was mapped by Broadhead (1984b). Precise sandstone geometries are not known, but based on data from cores and well logs, a low-gradient meandering stream (point bar sandstones) depositional setting can be invoked for parts of the upper Abo Formation. The upper Abo fluvial plain grades southward into deltaic deposits. Sandstones thicker than 5 ft observed in cores generally exhibit sharp bases and gradational upper contacts with overlying mudstones. Thinner sandstones are interpreted as crevasse-splay deposits because of their gradational upper and lower contacts, common soft-sediment deformation structures, and the presence of root traces. Mudstones were deposited in adjacent floodplains.

Abo play development and reservoir characteristics

Before 1977, no petroleum had been produced from the Permian Abo red beds on the Northwest shelf of the Permian Basin. In 1977, Yates Petroleum Corporation drilled the discovery

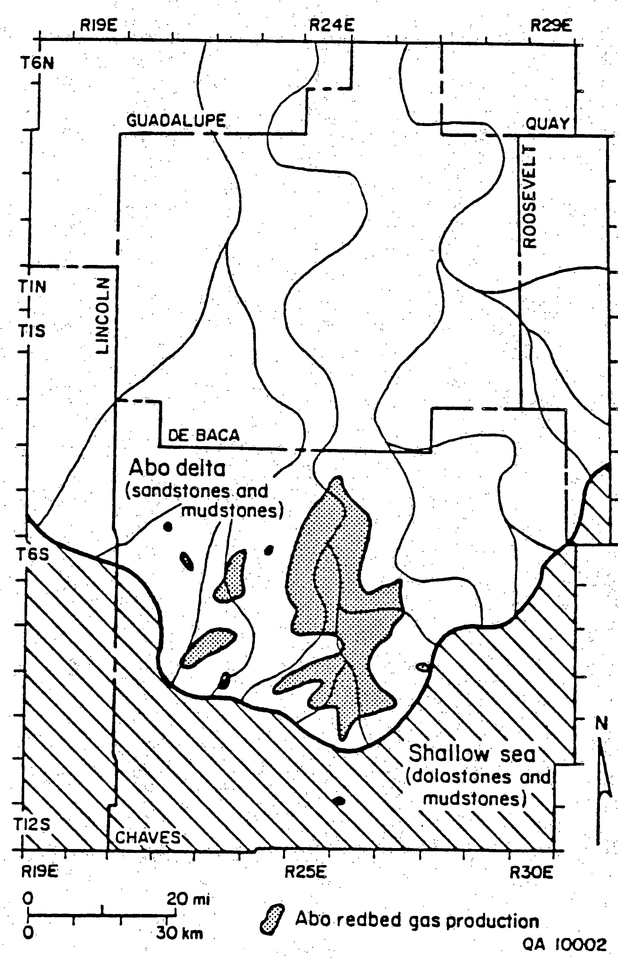


Figure 53. Proposed reconstruction of fluvial and deltaic depositional environments of the upper Abo Formation. Location shown in figure 43. Modified from Broadhead (1984b, fig. 22).

well, the Yates No. 1 McConkey, of the Pecos Slope Abo gas field in north-central Chaves County (Broadhead, 1984b). An 18-ft-thick sandstone was acidized and artificially fractured to generate an IP of 2,550 MCFD and 1 barrel of condensate per day (BCPD) through perforations at depths of 4,764 to 4,782 ft (Broadhead, 1983; 1984a). Drilling activity soared in 1981 following the designation of the Abo Formation as a 'tight' sandstone by the Federal Energy Regulatory Commission (FERC). Approximately 400 gas wells were drilled and completed in the Abo between 1980 and 1983. Wheatley (1981) proposed that the ultimate Abo play area could include most of Chaves, all of De Baca, and the southern half of Guadalupe County, and that the Abo would have multiple pay zones. These predictions were strengthened by gas shows in De Baca County (Broadhead, 1982), but Scott and others (1983) concluded that water production in De Baca County might be excessive for economic gas recovery.

All Abo production from the Pecos Slope Abo gas field (Pecos Slope, West Pecos Slope, and South Pecos Slope fields) has come from upper Abo fluvial/deltaic sandstones. Sandstone/mudstone ratios are low, but thick channel sandstones form reservoirs, and interbedded mudstones provide seals for stratigraphic traps. Structural position has no apparent control on trapping of gas or influence on gas or water production (Scott and others, 1983; Broadhead, 1984a). Present field limits are defined by a facies change into muddy and dolomitic sediments to the west, east, and south, whereas to the north, reservoirs are less developed because of a lack of mudstone seals (Broadhead, 1984b).

Scott and others (1983) mapped individual reservoir sandstones up to 40 ft thick with porosities as high as 14 percent. These sandstones, interpreted as channels, have southerly oriented, sinuous to branching patterns. However, Broadhead (1984b) stresses the difficulty and uncertainty in correlating channel sandstones using wells on 160-acre spacing. Most channel sandstones are in the upper 450 ft of the Abo Formation. A regional network of horizontal and vertical fractures may comprise all the permeability in the Abo because bottom-hole pressures (1,000 to 1,200 psi) are equal among numerous sandstone reservoirs throughout an area with 2,400 feet of structural dip

(Scott and others, 1983; Broadhead, 1984b). Fractures in the sandstones and healed fractures in the mudstones have been documented by Broadhead (1984b).

Lithology and Diagenesis

The lithology and diagenesis of low-permeability, gas-producing sandstones and mudstones of the Abo Formation in the subsurface in east-central New Mexico have been described by Broadhead (1984b), and the following discussion is based on his work. The oldest part of the Abo Formation, the lower granite wash unit, consists of interbedded red sandstone, conglomeratic sandstone, conglomerate, and mudstone. The coarser deposits are fine sandstones to pebble conglomerates that are moderately to poorly sorted and well indurated; they are classified as arkoses. Framework grains are mainly quartz, potassium feldspar, and granite fragments. Detrital clay matrix occurs in some of the granite wash, but the clay minerals have not been identified. The most common authigenic cements are anhydrite, calcite, and dolomite. Thin-section porosity ranges from 0 to 10 percent. Mudstones in the lower Abo are silty and sandy and about 10 percent are calcareous.

The middle Abo unit consists mainly of red mudstones (90 percent), with interbedded calcareous sandstones (10 percent). Clay minerals in middle Abo mudstone have not been identified, but some mudstones swell in water, indicating that they contain smectite.

The upper unit of the Abo Formation consists of red sandstones that are fine to very fine grained, well-indurated to friable arkoses. Natural fractures are common. Framework grains are mainly quartz, averaging 60 percent, and feldspar, averaging 20 percent. Potassium feldspar is more abundant than plagioclase, and most feldspars are unweathered. Feldspar content decreases toward the south away from the sediment source area. Most upper Abo sandstones in the north are arkoses, but to the south they are quartzarenites. Most sandstones are well sorted and contain little detrital clay matrix.

Authigenic cements include anhydrite, calcite, dolomite, quartz, clay, and hematite. Anhydrite is an early cement that fills primary porosity and replaces framework grains. It is generally present in volumes of 0 to 10 percent. Dolomite is the most abundant carbonate cement; both dolomite and calcite were relatively late cements that precipitated in sandstones that had already been compacted during burial. Quartz overgrowths are rare and volumetrically minor. Clay rims stained by hematite are common around framework grains; the clay rims probably formed in the vadose zone by mechanical infiltration of clay particles carried into the sand by downward-percolating rainwater or floodwater. They are stained red by finely disseminated hematite.

Porosity in upper Abo sandstones was reduced by development of clay rims, compaction, and precipitation of cements; thin-section porosity is rare. The visible pores, which are about 0.04 mm x 0.01 mm, are interpreted to be relict primary pores, not secondary pores formed by dissolution. Porosity determined from neutron logs ranges from 6 to 18 percent, and porosity determined from density logs ranges from 2 to 15 percent. The lack of visual porosity suggests that most pores indicated by logs are micropores that probably occur in the clay rims. Permeability is low, averaging 0.0067 md in situ. The low permeability is caused by the presence of abundant clay-hematite matrix and authigenic cements that occluded the primary depositional porosity.

The percentage of mudstones in the upper Abo decreases to the north. Most mudstones are red, but about 10 percent are gray. The upper Abo mudstones contain about 60 percent clay and 40 percent silt and sand-size grains of quartz. Because of the high percentage of coarser grain sizes in the mudstones, they may not act as fracture barriers within the Abo. Some mudstones swell in fresh water, particularly in the south, and thus probably contain smectite. Fractures filled by anhydrite or carbonate cement are common. Anhydrite also occurs as birdseye lenses, concretions, and in rare, thin beds. Many mudstones in the lower part of the upper Abo unit are burrowed and contain fragments of fusulinids, brachiopods, and ostracodes.

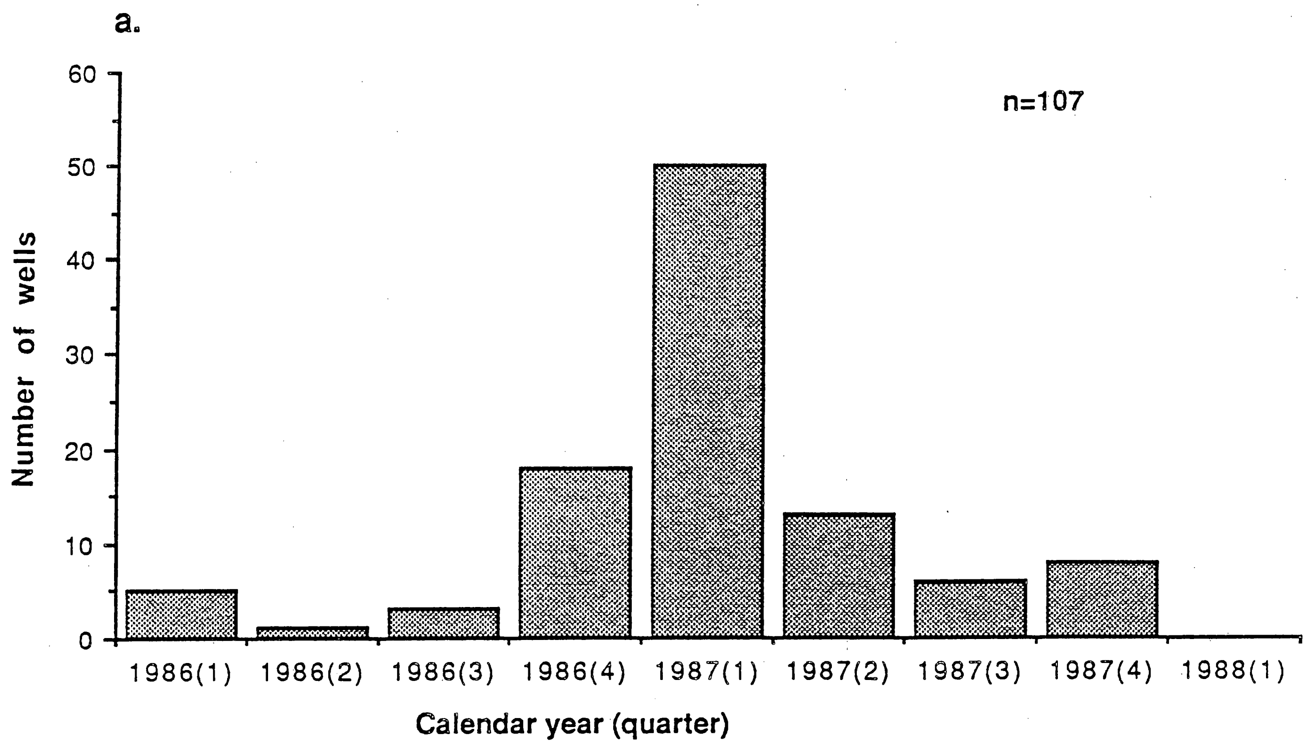
Production, Resource Potential, Logistics

Gas is produced from upper Abo sandstones located in Chaves County. Despite very recent (June 1988) problems of arsenic production in the gas at levels of 500 micrograms/m^3 (Slaton,

1988) that resulted in a shut-in of 60 MMCFD from 600 wells, industry interest in the Abo Formation has remained at moderate to high levels (Stephen Speer, Yates Petroleum, Artesia, New Mexico; Keith Williams, Texaco, Incorporated, Midland, Texas, personal communications, 1988). The Abo is, and will continue to be, mostly an independent's play, although Texaco (Getty) participates in farm-out arrangements. Large acreage blocks are being held, and even marginally productive wells (few 10's MCFD produced from one zone instead of multiple pay zones) are being completed. Activity should pick up as gas prices increase (Keith Williams, Texaco, Incorporated, Midland, Texas, personal communication, 1988).

The area currently covered by the FERC designation is 11,411 mi^2 (ICF-Lewin Energy Division, 1988a). Broadhead (1983) reported a 90-percent drilling success rate for the region. In post-1982 activity, the number of wells targeting and completed in the Abo Formation peaked with more than 60 completions in the first six months of 1987 (fig. 54). In 1985, 31,198 MMCF of gas were produced from Abo red beds in New Mexico (Broadhead, 1987). On-line production per well averages 400 MCFD (Scott and others, 1983) and primary reserves average 500 MMCF per well (Boneau and others, 1983). Therefore, the combined reserves reported by Broadhead (1984a) for 400 wells were about 200 BCF. ICF-Lewin Energy Division (1988a) have estimated that the ultimate Abo resource base is 3 TCF.

Only six operators have drilled the Abo since 1986 (fig. 55). Most wells are north of Roswell, in townships T6S, R21 and R22 (fig. 56). Depth to the top of the perforated zone ranges from 2,000 ft to 4,750 ft (fig. 57, table A10). Three-fourths of the 94 wells for which information is available were hydraulically fractured using sand/water treatments (fig. 58, table A12). One percent of the wells were acidized only. Among the wells that were acidized, the volume of acid used was from 750 to 10,250 gals. (fig. 59a) with an average of 3,310 gals. Hydraulic fracturing of wells used between 13,000 and 181,000 gals of fluid (fig. 59b) with an average of 60,000 gals, and between 19,000 and 292,000 lbs of sand (fig. 59c) with an average of 87,000 lbs. No information is available on pre-stimulation production from the Abo. For 104 wells completed between January 1, 1983 and April 1, 1988, post-stimulation rates range from 54 to 11,494 MCFD



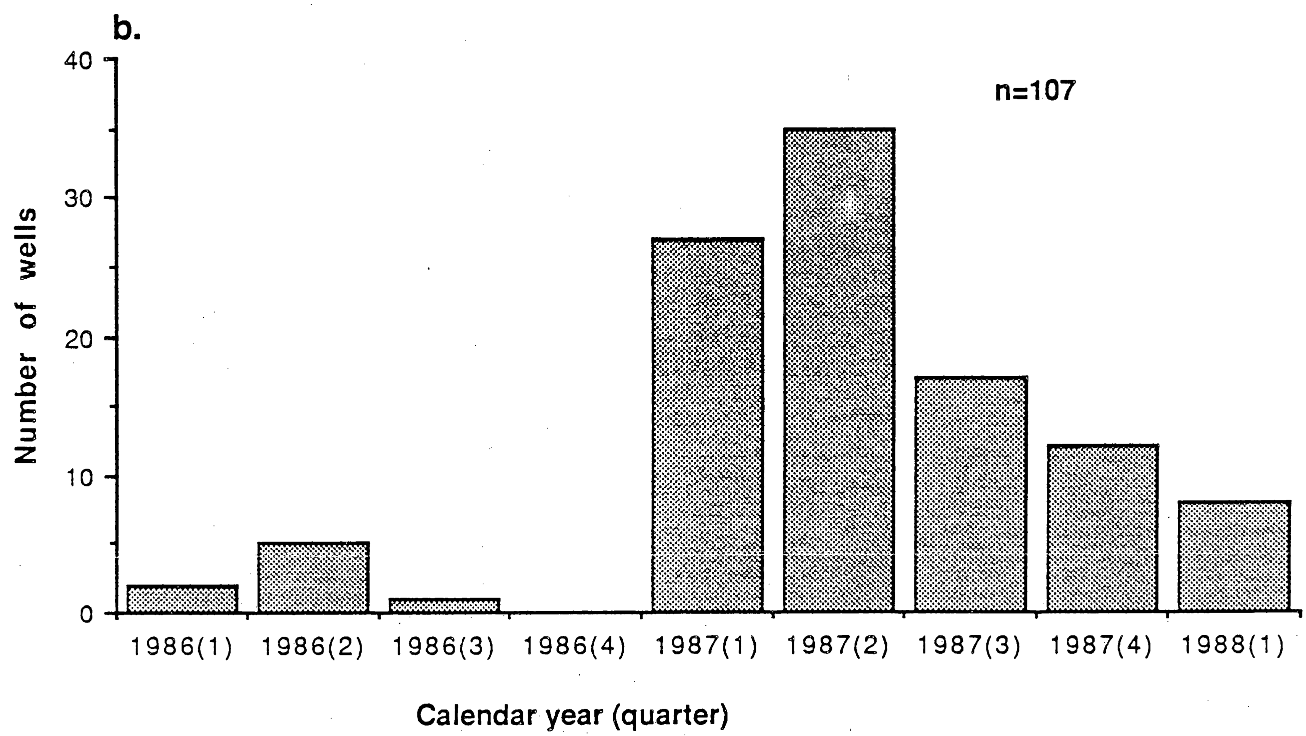


Figure 54. (a) Wells spudded in the Abo Formation January 1986-December 1987. In addition to the wells shown here, three wells were spudded between August 1984 and December 1985. (b) Successful gas wells completed in the Abo Formation January 1986-April 1988.

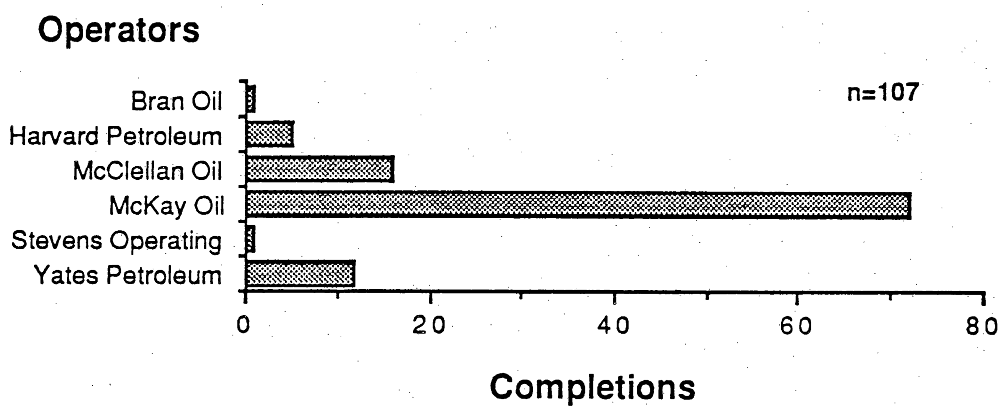


Figure 55. Graph of operators that completed successful gas wells in the Abo Formation between January 1986 and April 1988.

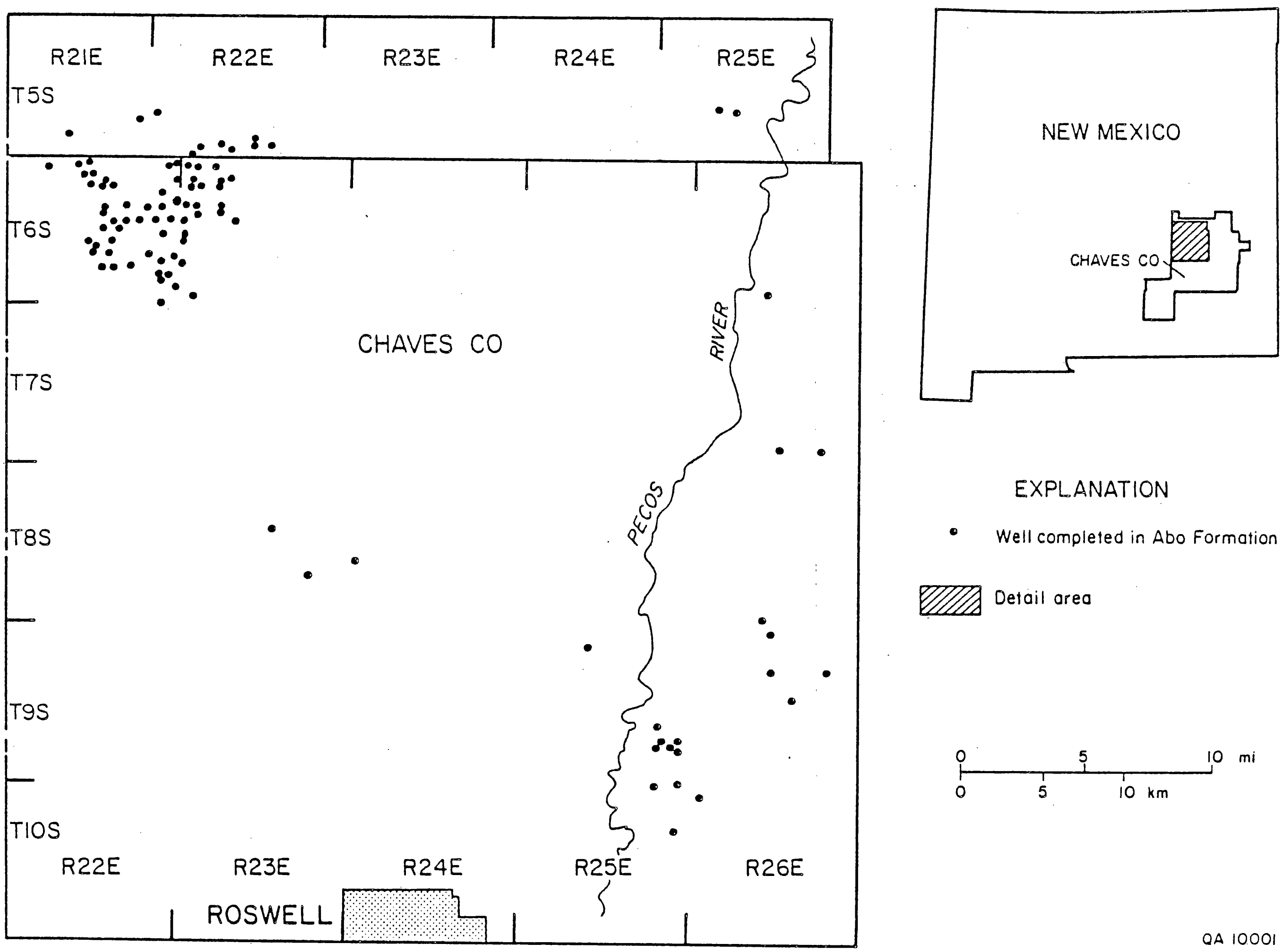


Figure 56. Map of wells completed in the Abo Formation between January 1983 and April 1988.

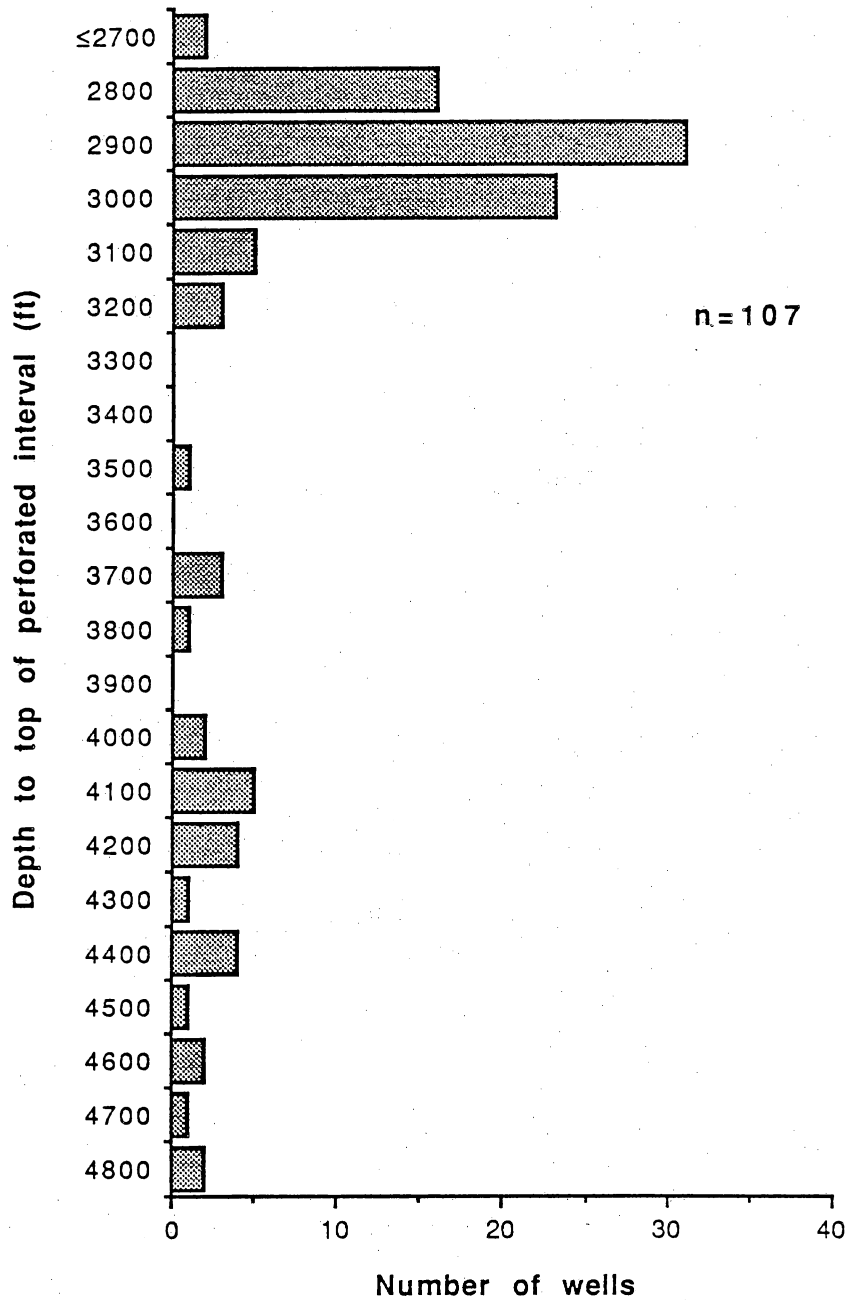


Figure 57. Depth to top of the perforated interval in wells completed in the Abo Formation ranges from 2,000 to 4,750 ft.

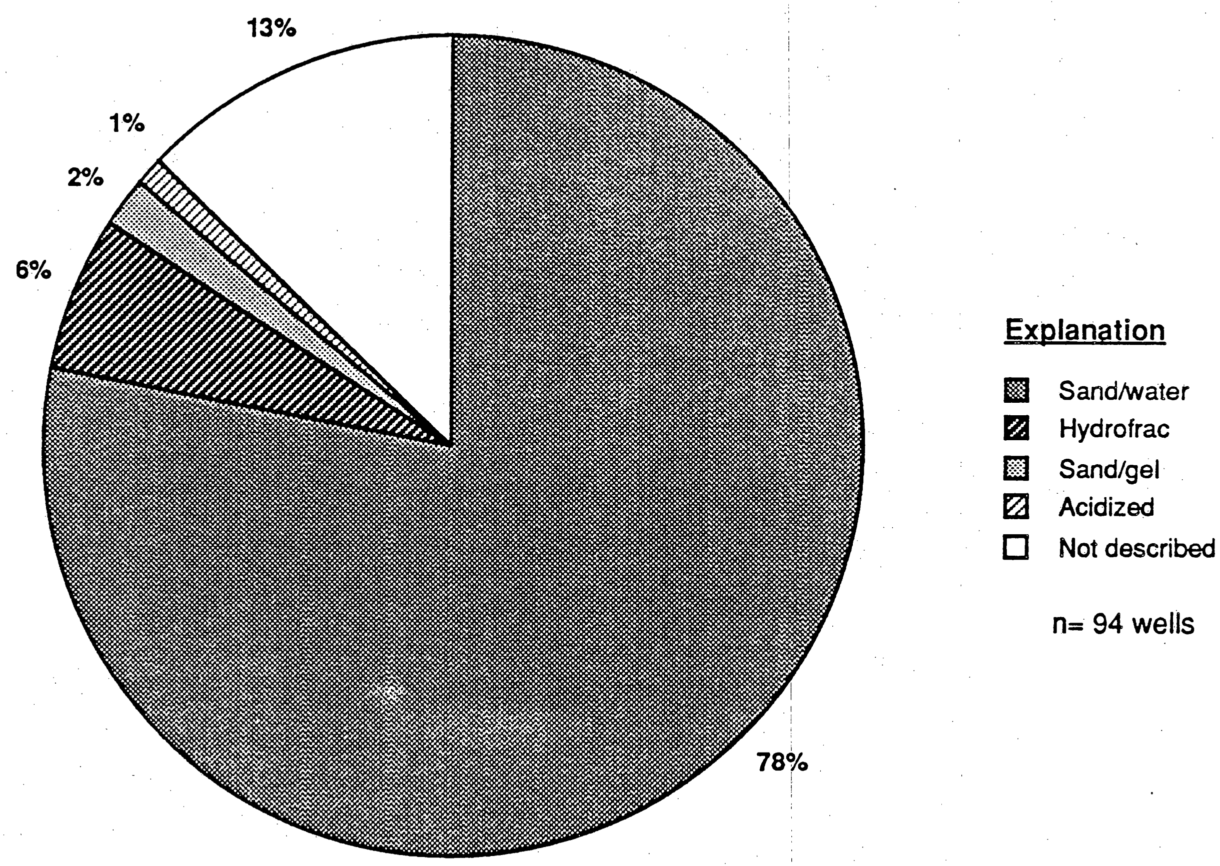


Figure 58. Stimulation methods used on successful gas wells in Abo Formation between January 1986 and April 1988. No wells were completed in the Abo Formation in the period from January 1983 to December 1985. Fracture techniques "not described" include wells that were fractured, but for which no further information was available.

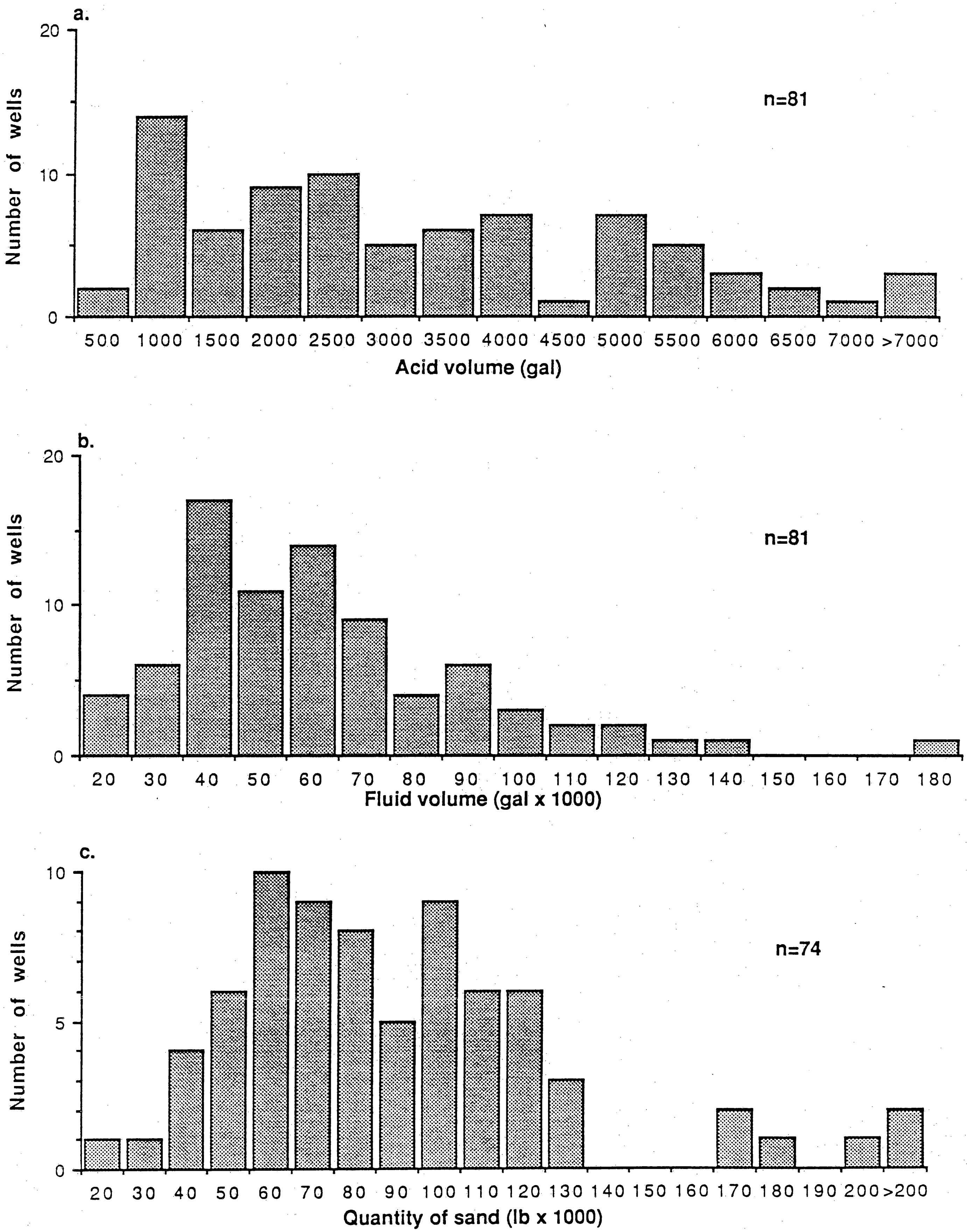


Figure 59. Amount of material used in well stimulation, Abo Formation. (a) Volume of acid. (b) Volume of fluid. (c) Quantity of sand.

with an average of 1,890 MCFD (fig. 60, table A12). Table A13 shows costs for drilling and stimulation. In 1985, 31,198 MMCF of gas were produced from Abo red beds in New Mexico (Broadhead, 1987). Figure 61 gives production decline curves for nine wells in the Abo Formation.

Markets for Permian Basin gas are generally good. Abo gas would compete with gas from the San Juan Basin for the growing California cogeneration and EOR markets. Most of the contracts are long-term and would require demonstrated sustained production to justify transportation costs (El Paso and Transwestern have pipelines to the West through Gallup, New Mexico). Current (June 1988) Permian Basin spot prices for the interstate markets are about $1.20/MCF, slightly lower than in June 1987.

Ground access is generally unhampered by local terrain in the area of the Abo fields.

No cores from Abo wells are known to be available for study by the public.

Technology Challenges

The producing interval of the upper Abo Formation is depositionally, and to a lesser degree lithologically, quite similar to the Travis Peak Formation of East Texas, which has been the subject of intense GRI-sponsored research on low-permeability gas sandstones. Channel sandstones that form reservoirs were deposited in braided-to-meandering-stream depositional systems, and the associated abandoned-channel plugs and floodplain mudstones separate and seal the reservoirs. As in the Travis Peak Formation, mudstones in the Abo Formation may not be thick enough or strong enough to act as barriers to hydraulic fractures. Because no empirical data are available, the ability of the overlying Yeso Formation (sandstones, mudstones, and evaporites) and the basal Hueco Formation (limestone) to contain hydraulic fractures can only be postulated. Abo wells typically are completed in two phases (Wheatley, 1981): (1) treating the formation with acid, and (2) fracturing the formation with jelled water and sand (CO_2 and nitrogen are also used; Broadhead, 1984b). Sand/water and hydrofrac treatments were the primary processes used to stimulate 81 wells completed between January 1, 1983 and April 1, 1988 (fig. 58) (Petroleum Information, undated).

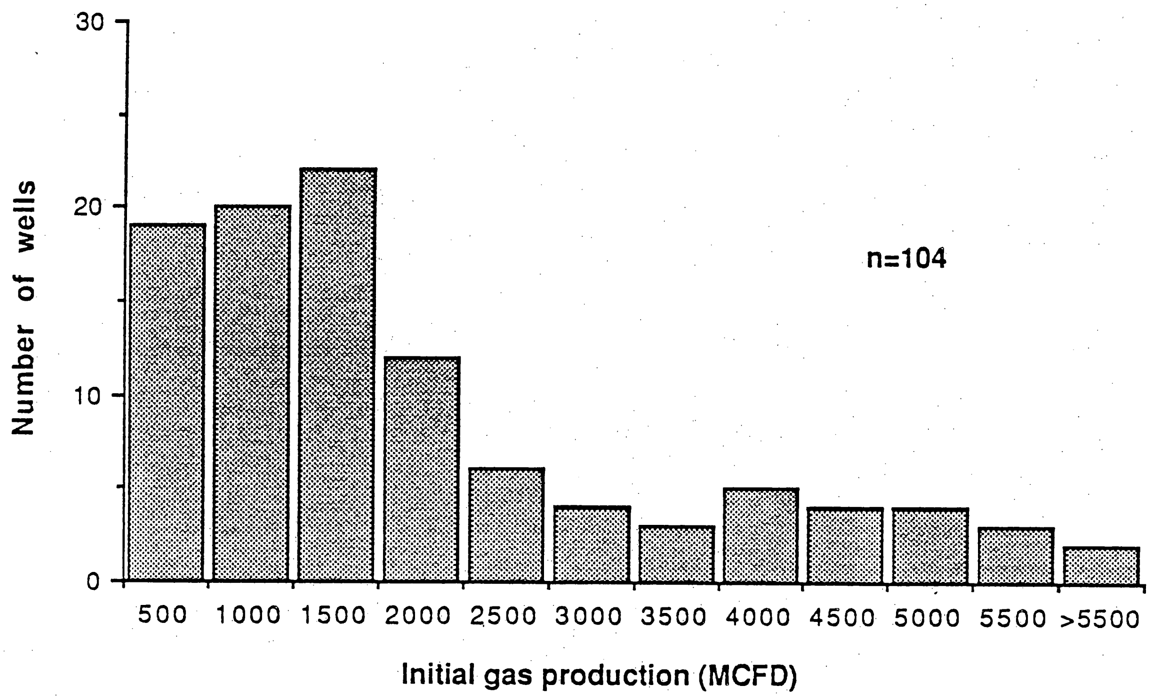


Figure 60. Daily gas production in the Abo Formation between January 1983 and April 1988. Most wells produced less than 2,000 MCFD.

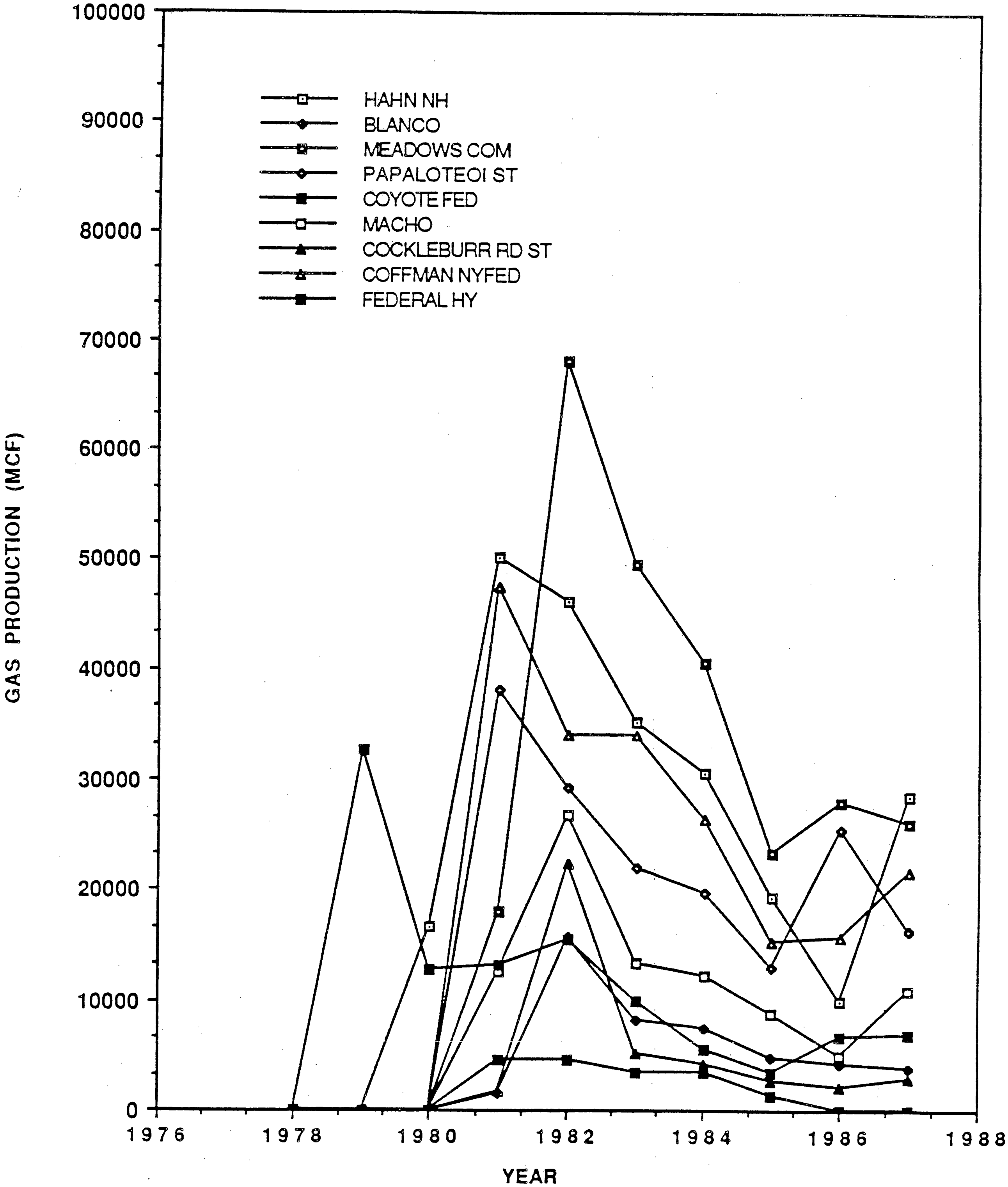


Figure 61. Production decline curves for wells in the Pecos Slope field, Abo Formation. From ICF-Lewin Energy Division (1988c).

In 1981, a year of historically high costs, average drilling and completion costs per well were $400,000 to $500,000 (Wheatley, 1981) (table A13). No data are available on current drilling and completion costs, but average costs were lower for the entire period from 1983 to 1988.

Formation evaluation problems arise from high irreducible water saturation caused by bound water in the hematite-clay matrix and anomalously high radioactivity induced by uranium and unweathered potassium feldspar in the sandstones (Scott and others, 1983; Broadhead, 1984b). Comparing visual porosity estimates with measurements made by logs reveals that the density log generally understates porosity and the neutron log overstates it (Broadhead, 1984b). Dual induction lateral logs, compensated neutron density logs, and microspherically focused logs are most commonly run to characterize the formation (Petroleum Information, undated; Keith Williams, Texaco, Incorporated, Midland, Texas, personal communication, 1988). Fewer litho-density/special density logs and natural gamma-ray/spectroscopy/spectrometry logs, and only one sonic log were reported (Petroleum Information, undated). Only in a few wells have core samples (conventional or side-wall) been taken for geologic or petrophysical analysis (Broadhead, 1984b; Keith Williams, Texaco, Incorporated, Midland, Texas, personal communication, 1988). These cores were not available for study in this report.

Broadhead (1984b) states that the few sandstone samples available from Abo reservoirs do not contain porosity visible in thin section, but he asserts that if more samples were available some would contain relict primary macroporosity. However, these reservoirs have 8 percent porosity indicated by the neutron log and 15 percent porosity indicated by the formation-density log. The porosity indicated by these logs is most likely microporosity within the hematite-clay matrix, but the true volume of microporosity is probably lower than either log indicates. The higher porosity reading by the formation-density log is caused by the presence of gas, and the neutron porosity reading is probably too high because of the presence of clay minerals mixed with the hematite cement (Broadhead, 1984b).

Broadhead (1984a, 1984b) does not think that either the micropores or the relict primary pores serve as the primary gas reservoir or contribute significantly to production, although he mentions that micropores could act as "a secondary storage space for gas and contribute to long-term production" (Broadhead, 1984b, p. 31). Instead, he believes that the Abo gas is stored in, and produced from, natural fractures. Broadhead (1984a) states that the presence or absence of fractures is not controlled by "any single structural element", but he speculates that individual structures could influence the intensity of fracturing and, hence, the volume of gas production. However, no relationship between structure and gas production has been observed to date.

A potential technical challenge in the Abo Formation is improved understanding of the depositional systems and burial history of the Abo Formation. Additional sedimentologic and diagenetic studies of the producing and underlying sandstones would be part of the research effort. Geologic maps of discrete stratigraphic sequences, productive and non-productive sandstones, and potential mudstone fracture barriers could enhance reservoir and field delineation as well as expose by-passed productive horizons, indicate the presence of deeper potentially productive zones, and/or extend current field and play limits. In addition, it must be determined if the Abo is a fractured reservoir. If it is, the nature of the fracture system (areal extent, stratigraphic occurrence, and geometry), and the most effective exploration and production methods for this type of reservoir should be determined. If well-history analyses reveal that the Abo is not a fractured reservoir, then the current completion practices may not be achieving optimal recovery from these low-permeability reservoirs. It is possible that the micropores and relict primary macropores actually are acting as the main gas reservoir in the Abo. Support for this hypothesis comes from the few Abo wells that produce without artificial stimulation. It is believed that the gas in these wells is produced from primary porosity and not from natural fractures (Stephen Speer, Yates Petroleum, Artesia, New Mexico, personal communication, 1988).

MESAVERDE GROUP, PICEANCE BASIN

Structural Setting

The Piceance Basin is an asymmetric, northwest-trending Late Cretaceous to early Tertiary sedimentary and structural basin in the northeastern part of the Colorado Plateau province. The basin is defined by a series of early Tertiary (Laramide) uplifts (fig. 62). The basin is bounded on the north by the Uinta Mountain Uplift, on the east by the Grand Hogback monocline (which forms the western flank of the White River Uplift), on the southeast by the Sawatch Range, on the southwest by the Uncompahgre Uplift, and on the west by the Douglas Creek Arch (figs. 62 and 63, table A14). The Douglas Creek Arch is a mildly positive feature that separates the Piceance Creek Basin from the Uinta Basin in Utah. During Mesaverde Group deposition, there was little or no relief on the Douglas Creek Arch and the Uncompahgre Uplift; Laramide structural elements generally had little influence on Cretaceous depositional patterns (Murray and Haun, 1974; Johnson and Keighin, 1981). The deepest part of the basin is on the northeast side (fig. 62). Depth to the top of the Mesaverde ranges from ground surface to 8,600 ft.

During the Cretaceous, the area that would later form the Piceance Basin was part of a larger, rapidly subsiding, elongate, north-trending, asymmetric foreland basin that covered much of the central part of the United States and Canada (Kauffman, 1977; Lawton, 1986; Merewether and Cobban, 1986; Weimer, 1986). The basin was bounded on the west by the Sevier orogenic belt or Overthrust Belt, a fold and thrust belt that is exposed west of the Piceance Basin in Utah (Harris, 1959; Armstrong, 1968; Royse and others, 1975). The Overthrust Belt consists of large-scale east-vergent thrust faults and folds that lie between the metamorphic hinterland to the west and the less-deformed foreland to the east. An epicontinental seaway occupied the foreland basin during much of the Cretaceous. A major episode of subsidence in the foreland basin during middle Cretaceous (Aptian-Cenomanian) time is interpreted as recording the initiation of thrust-loading

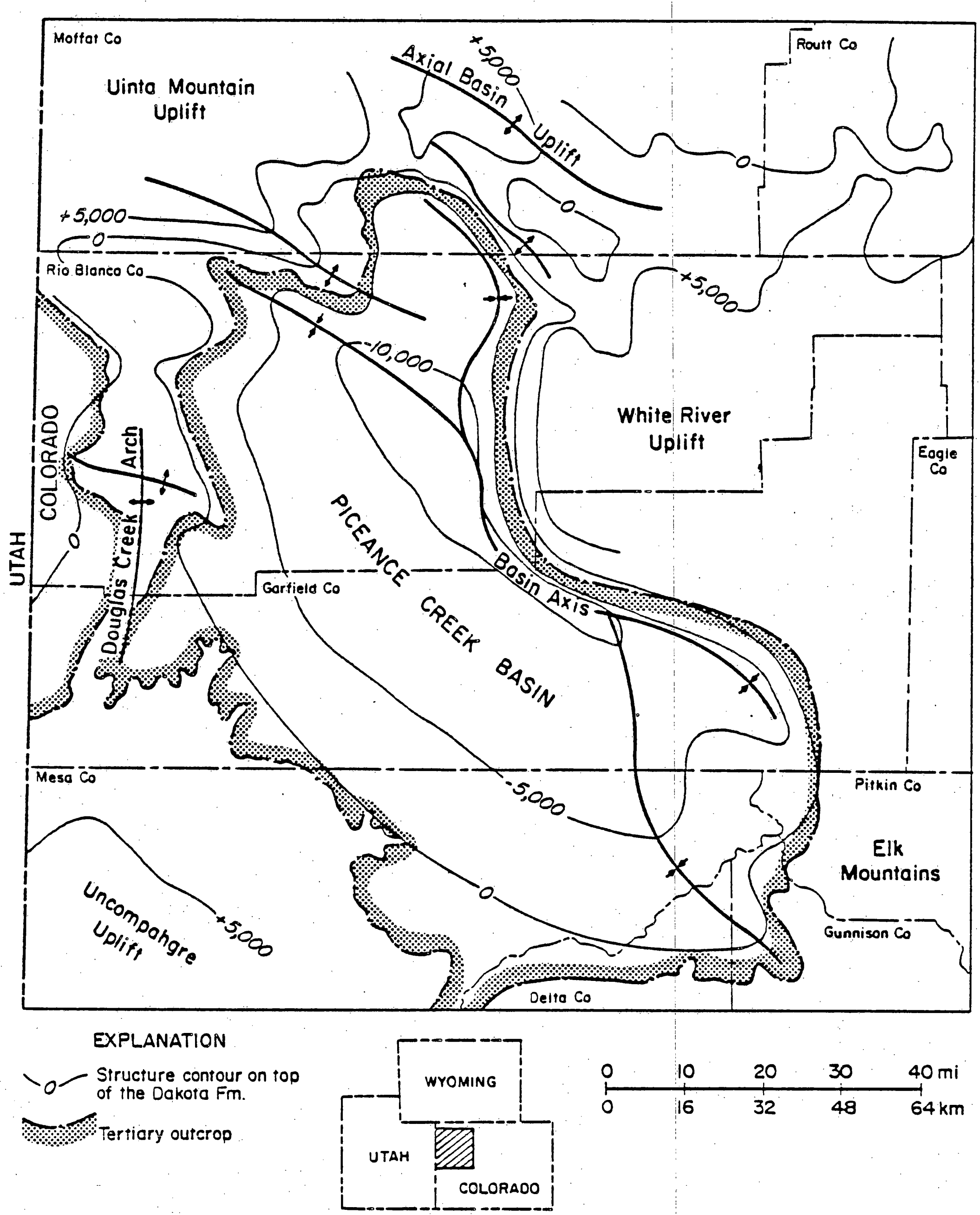


Figure 62. Location and generalized structure map, Piceance Creek Basin. From Finley (1984, fig. 73; modified from Dunn, 1974).

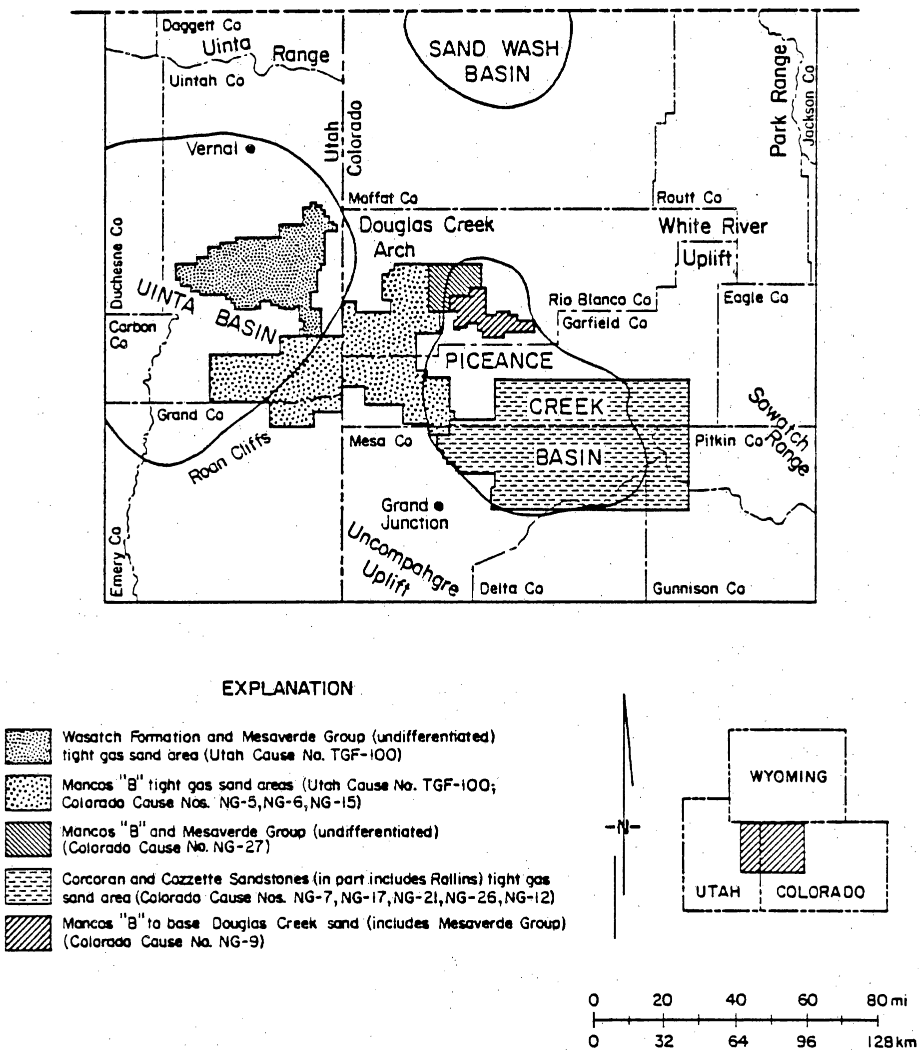


Figure 63. Areas covered by tight gas sand applications, Piceance Creek and Uinta Basins (Colorado Oil and Gas Conservation Commission, 1980a,b,c,d,e, 1981, 1982; Utah Board of Oil, Gas, and Mining, 1981). From Finley (1984, fig. 74).

deformation in the adjacent Overthrust Belt (Heller and others, 1986). The correlation of transgressions and regressions of the Upper Cretaceous shoreline with episodic thrust faulting and uplift in the Sevier orogenic belt shows that basin subsidence was accelerated by thrust-loading deformation (Jordan, 1981).

In northwest Colorado, the Sevier orogeny (160 to 72 mya) caused east-west horizontal compression during the time of Mesaverde Group deposition (Lorenz, 1985b), and sediments derived from erosion of the orogenic highlands of the Overthrust Belt contributed to filling the basin. East-west folding contemporary with the Sevier orogeny is marked in the Piceance Basin by low amplitude flexures in the area of the Douglas Creek Arch (Quigley, 1965) and the Uncompahgre Uplift (MacQuown, 1945). Some east-trending natural fractures in the basin may record this event (Lorenz, 1985b).

The Piceance Basin was delimited by movement of uplifts that formed in the foreland basin of the Overthrust Belt during the Laramide orogeny approximately 72 to 40 mya (Dickinson and Snyder, 1978; Tweto, 1980). The Laramide uplifts are bounded by reverse and thrust faults (Berg, 1962; Gries, 1983a). The regional stress regime during the Laramide was primarily one of east-west compression, but the northwest trend of some folds within the Piceance Basin and northeast-trending fractures in the Rangely dome (Peterson, 1955) suggest either (1) that an episode of northeast-directed compression occurred during part of the Laramide, such as the late Laramide reorientation of stresses proposed by Chapin and Cather (1981), or (2) the fold trends resulted from reactivation of northwest-trending anisotropy in the crystalline Precambrian basement (Tweto, 1980; Lorenz, 1985b). During Laramide deformation of the foreland, the adjacent Overthrust Belt became inactive (Hamilton, 1978). The change in the location and style of deformation is possibly due to changes in subduction angle of the Pacific Plate (Cross and Pilger, 1978; Dickinson and Snyder, 1978).

Onset of Laramide deformation is recorded by an unconformity at the top of the Mesaverde (Johnson and Nuccio, 1986). The upper part of the Mesaverde was deeply weathered during the interval represented by the unconformity (Johnson and May, 1980). Local relief on the unconformity in the Piceance Basin is slight, but thousands of feet of Mesaverde rocks may have been removed (Johnson and Nuccio, 1986). Initial subsidence of the Piceance Basin is recorded by thickening of early Eocene strata of the upper member of the Wasatch Formation toward the present basin axis (Merriam, 1954). The Laramide orogeny marked the end of Mesaverde deposition and a change from thin-skinned (Overthrust Belt) to thick-skinned (Laramide) deformation in the foreland region and the development of separate sedimentary basins (Lawton, 1986).

Four episodes of regional uplift have occurred since the end of the Laramide (40 mya). Post-Laramide uplift events occurred during the early Eocene (Hansen, 1984; Lorenz, 1985b), early Miocene to Pliocene (Scott, 1975), and between 8 and 10 m.y. and from 1.5 m.y. to the present (Larsen and others, 1975). Pliocene tectonism reactivated Laramide faults, and some new folds and faults formed, but apparently, there was little differential movement between the basin and the adjacent White River Uplift (Johnson and Nuccio, 1986). The southeastern part of the basin was intruded by plutons in the Oligocene, and the Divide Creek, Wolf Creek, and Coal Basin anticlines may be, in part, the result of doming over plutons (Collins, 1977). The central and northern parts of the basin were apparently not intruded by Oligocene plutons (Larsen and others, 1975). The Colorado River system has removed as much as 5,000 ft of overburden from the center of the basin (Larsen and others, 1975; Johnson and Nuccio, 1986).

Folds within the basin (fig. 64) are doubly plunging (periclinal), open, asymmetric folds with southwest limbs steeper than northeast limbs (Pitman and Johnson, 1978; Pitman and Sprunt, 1986). Cretaceous rocks also are cut locally by high-angle normal faults and minor reverse faults. Throws of normal faults are typically 100 ft or less at the surface (Pitman and Sprunt, 1986). Faults locally parallel anticlinal hinges. The Divide Creek anticline is cut by several normal faults transverse to the fold trend, as well as by a northwest-trending reverse fault parallel to the fold hinge (Berry, 1959). The asymmetry of the Rangely and Piceance Creek domes suggests that reverse and thrust faults may underlie these folds at depth (Gries, 1983a; Lorenz, 1985b). With the exception of faults with minor displacement along the Grand Hogback, thrust faults do not cut Late Cretaceous through Eocene rocks (Johnson and Nuccio, 1983, 1986).

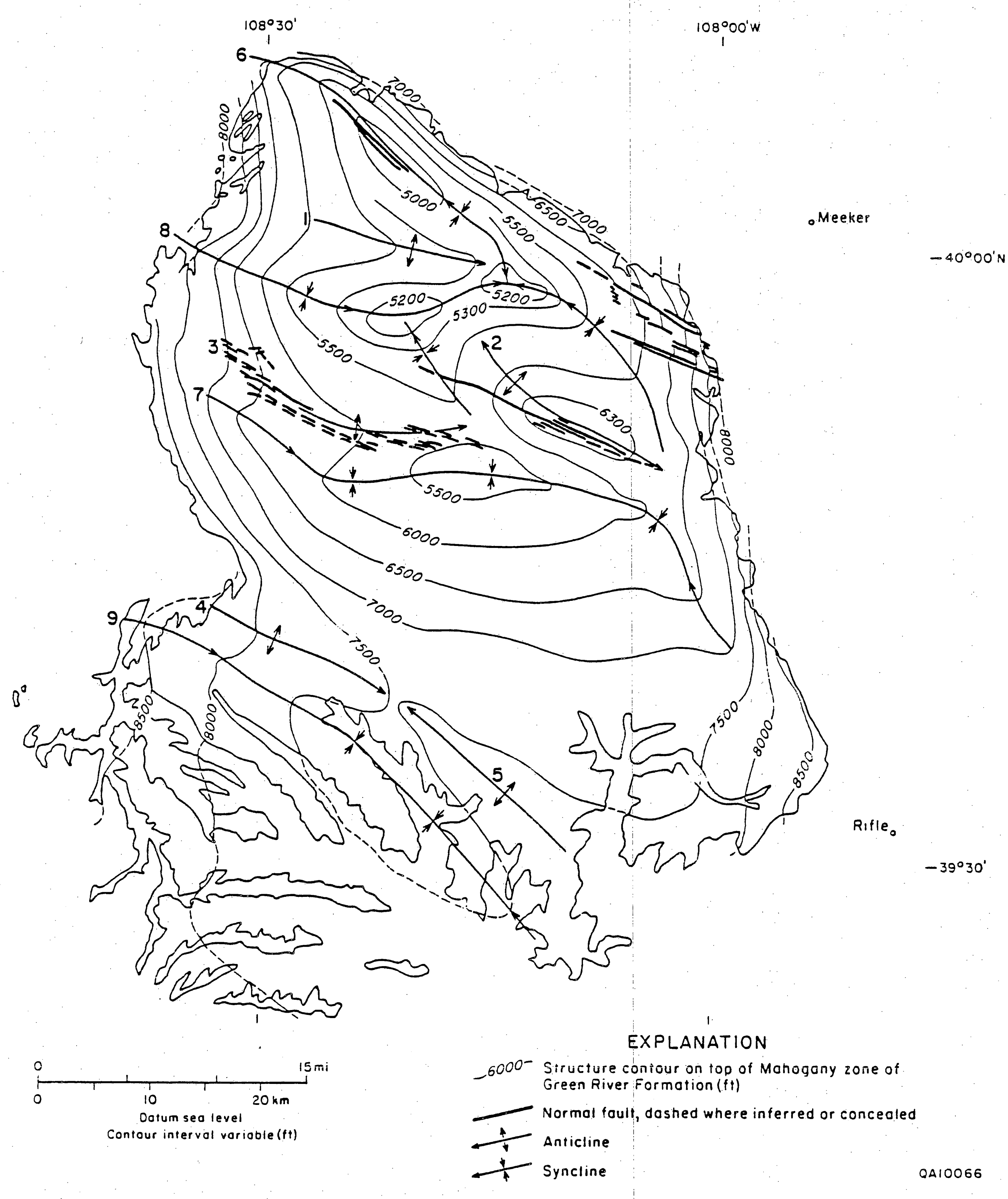


Figure 64. Internal structural configuration of the northern part of the Piceance Basin. 1, Yellow Creek anticlinal nose; 2, Piceance Creek anticline; 3, Sulphur Creek anticlinal nose; 4, Douglas Creek anticline; 5, Crystal Creek anticlinal nose; 6, Red Wash syncline; 7, Hunter Creek syncline; 8, Rangely syncline; 9, Clear Creek syncline. Structure is the top of Mahogany zone of Green River Formation. See figure 67 for location. From Pitman and Sprunt (1986, fig. 2).

Natural fractures

Two types of natural fracture systems are present on the Colorado Plateau: (1) regional fracture sets and (2) fracture sets associated with specific folds or faults (Kelley and Clinton, 1960; Lorenz and Finley, 1987a). Regional fracture sets can be caused by small regional stresses in conjunction with high fluid pressures (Warpinski, 1986), and they can occur in flat-lying, unfaulted rocks (Hancock, 1985). Fractures associated with folds and faults may have regular geometric patterns, but they commonly cut across lithologic boundaries (Hancock, 1985). Several regional fracture sets of different age are present in the Piceance Basin (Murray, 1967; Amuedo and Ivey, 1978; Smith and Whitney, 1979; Smith, 1980; TRW, 1980; Jamison and Stearns, 1982; Grout and Verbeek, 1983; Verbeek and Grout, 1983, 1984a, 1984b).

Subparallel, west-northwest-striking vertical fractures are common in the relatively undeformed rocks of the Mesaverde Formation in the subsurface (Lorenz and Finley, 1987a) (fig. 65). Fractures are typically mineralized with quartz, carbonate minerals, and clay minerals (Pitman and Sprunt, 1986), and they are locally open in core (Lorenz and others, 1986). Well test and core data from the Department of Energy's Multiwell Experiment (MWX) site suggest that these fractures have unidirectional west-northwest strike (fig. 66). Abundance of regional fractures in the Mesaverde correlates with diagenetic and depositional characteristics (Lorenz and Finley, 1987a). Subvertical extension fractures are predominantly in sandstone. The natural fracture systems at the MWX site are not well-interconnected vertically or laterally (Lorenz and others, 1986); nevertheless, they have a significant effect on well tests, reservoir stimulation, and gas production (Lorenz and others, 1986; Branagan and others, 1987).

Observations of open fractures in core and the contrast between high in situ permeabilities measured with well tests and low permeabilities measured in core show that fractures are an important component of reservoir permeability locally in the Piceance Basin (Pitman and Sprunt, 1986; Lorenz and Finley, 1987a; Branagan and others, 1987). Production in the Piceance Basin has been most successful in structurally closed areas where the reservoir rocks are naturally fractured

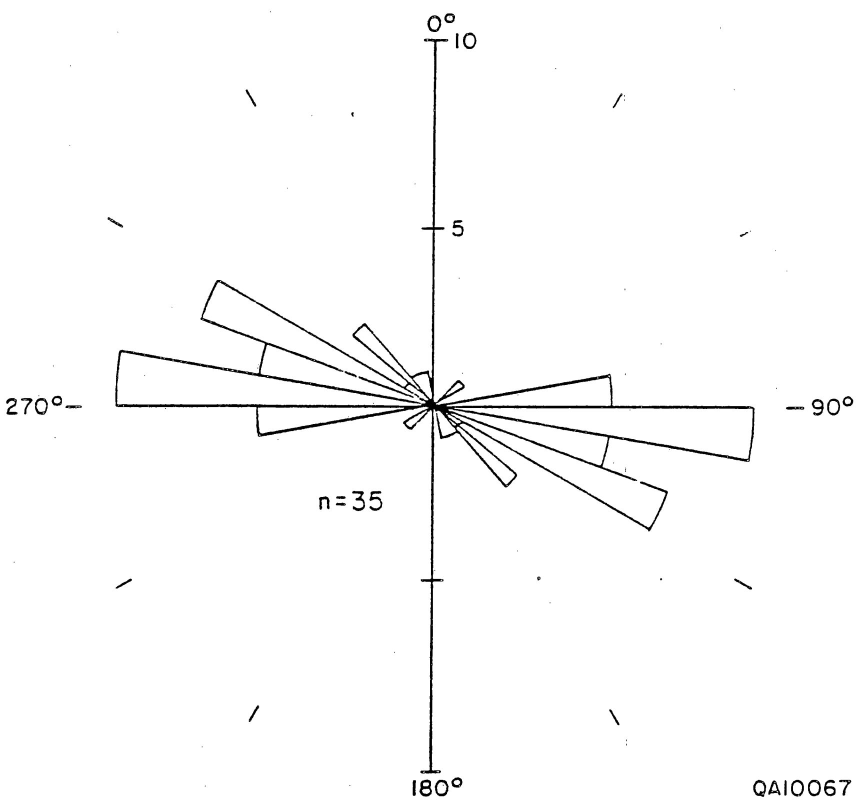


Figure 65. Rose diagram of fracture strikes in oriented core from the Department of Energy's (DOE) Multiwell Experiment (MWX). Fractures from all zones are combined. MWX is a DOE field laboratory research project designed to advance development of low-permeability reservoirs. For location of MWX site see figure 67. From Lorenz and Finley (1987a, fig. 2).

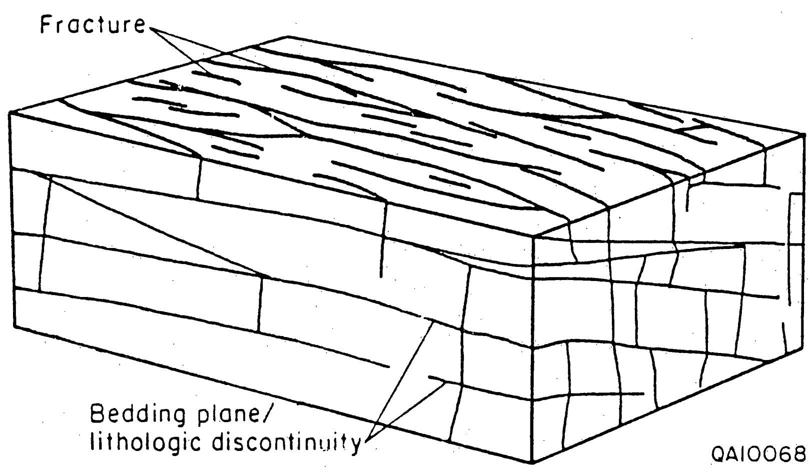


Figure 66. Unidirectional, subparallel fracture model developed for MWX. For location of MWX site see figure 67. From Lorenz and others (1986, fig. 1).

(Pitman and Sprunt, 1986, p. 221). The most productive field in the Piceance Basin, Piceance Creek field (fig. 67), is on the Piceance Creek anticline, a closed structure with extensive natural fractures (Millison, 1962; Ritzma, 1962; Mallory, 1977). Some of the best producing wells in this field are within a high-angle fault zone (Pitman and Sprunt, 1986). Core analysis indicates intense fracture development on the eastern side of the basin adjacent to the White River Uplift (Pitman and Sprunt, 1986). Core from MWX wells indicates that pervasive fractures occur in the Rulison field (Lorenz and Finley, 1987a). Well records also reveal fractured reservoirs in the White River, Baldy Creek, Divide Creek, Wolf Creek, and Mamm Creek reservoirs (fig. 67) (Pitman and Sprunt, 1986). Data from the MWX wells indicate anisotropic fracture permeability throughout the Mesaverde, commonly with ratios 100:1 of Kh_{max} to Kh_{min} (Branagan, 1987; Branagan and others, 1987).

Fluid pressure

The Mesaverde is generally normally pressured throughout the Piceance Basin, except in deep wells such as the lower part of the MWX wells, where intervals with high pore pressure exist (Pitman and Sprunt, 1986). Overpressured, hydrocarbon-bearing reservoirs are present in deeper parts of the Piceance Basin in Cretaceous Dakota Sandstone, sandstone and siltstone in the Mancos Shale (Mancos B), and sandstones in the Mesaverde Group (Spencer, 1987). The areal extent of overpressuring in the basin is not well defined because few wells have been drilled deeper than 10,000 ft.

Overpressuring commonly occurs where bottom-hole temperatures exceed 200°F. Some wells in the Piceance Basin that were drilled with normal mud weights and have bottom-hole temperatures greater than 200°F may have been overpressured in the past. According to Spencer (1987, p. 377), normal pressures can be accounted for in these wells by (1) pressure decline due to gas migration in vertical fractures, and by (2) low rates of gas generation compared to gas loss. Moreover, overpressure may be masked in these rocks by permeability that is too low to require heavy

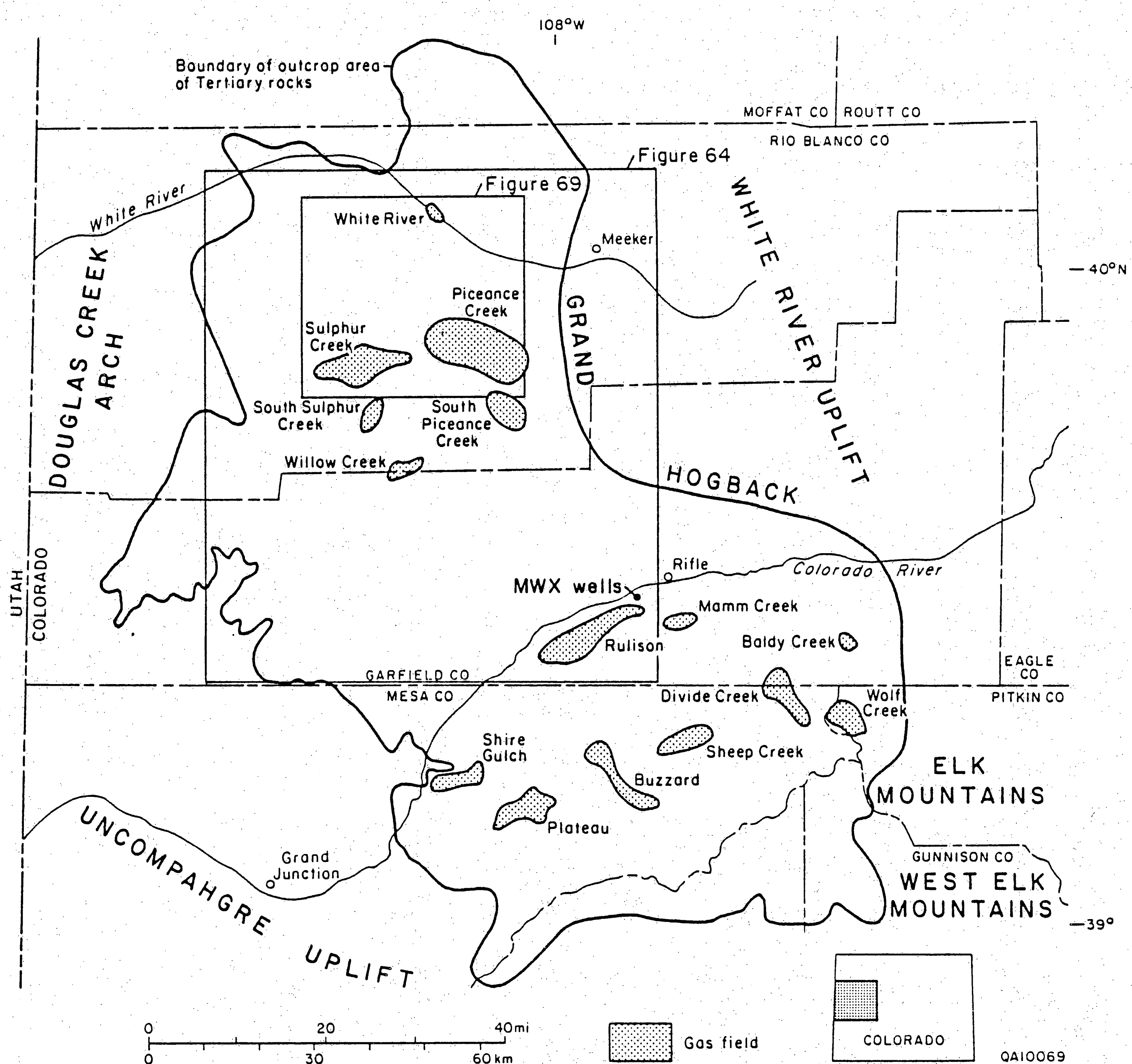


Figure 67. Location of selected gas fields in the Piceance Creek Basin. MWX is in NW 1/4, Section 34, T6s, R94W, Garfield County, within Rulison field. From Pitman and Sprunt (1986, fig. 1).

mud. Subnormal to normal pressures are present in most of the gas fields producing from reservoirs with temperatures less than 160°F.

Law and others (1986), McPeak (1981), Law (1984), and Spencer (1987) conclude gas is the pressuring fluid phase in Rocky Mountain basins. Law and Dickinson (1985) and Spencer (1987) suggest that overpressured and underpressured gas accumulations in the centers of basins and down-dip from water-bearing rocks are the result of thermal generation of gas in low-permeability rocks where gas accumulation rates are higher than rates of gas loss. Regional or local uplift, or temperature fluctuations, cause overpressured gas accumulations to evolve into underpressured gas accumulations if gas is lost from the system faster than it is replaced.

Stress

The Piceance Basin is in the Colorado Plateau stress province (Zoback and Zoback, 1980), but it is near the junction of three other stress provinces that have uncertain boundaries with the Colorado Plateau stress province (fig. 7). The other stress provinces near the Piceance Basin are the Basin and Range-Rio Grande rift province, the Southern Great Plains province, and the Midcontinent province.

The Colorado Plateau stress province is characterized by north-northeast-trending regional least principal stress direction, perpendicular to the minimum stress direction in the adjacent Basin and Range-Rio Grande rift province (Thompson and Zoback, 1979). The occurrence of strike-slip and thrust focal mechanisms indicates a compressional stress regime for the Colorado Plateau province, but the absence of major faulting and seismicity suggests generally low differential stresses (Smith, 1978; Zoback and Zoback, 1980). This interpretation is consistent with in situ stress measurements in the Piceance Basin that indicate all three principal stresses are approximately equal to lithostatic pressure (Wolff and others, 1974; Bredehoeft and others, 1976). Data from MWX wells show that fracture gradient is lowest in sandstones and high, but variable, in shales and mudstones (fig. 68) (Warpinski and others, 1985a,b; Warpinski and Teufel, 1987). Table 4 shows examples of in situ

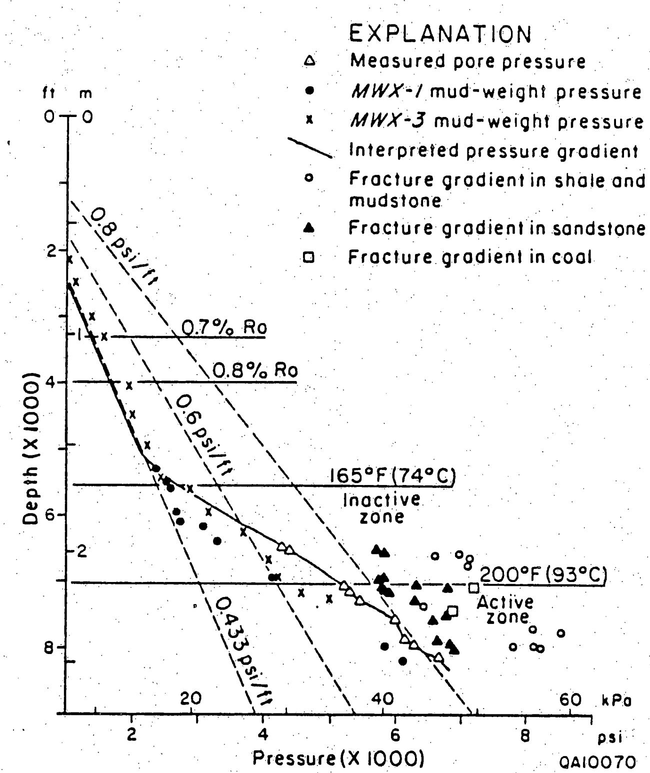


Figure 68. Interpreted pressure profile for MWX site wells, Piceance Basin. Fracture-gradient data for various lithologies are also shown. Generally shales and mudstones have higher fracture gradients than do sandstones. From Spencer (1987, fig. 10).

Table 4. Summary of in situ stress and mechanical properties data, as a function of depth, well MWX-2, Rifle, Colorado. From Warpinski and others (1983, table 4).

Depth (m)	Lithology	σ_{Hmin} (MPa)[d]	Estimated error (MPa)	P_i (MPa)	ν	E (GPa)	σ_v (MPa)	σ_{Hmin} (calculated) (MPa)	Fracture gradient (psi/ft)
2457	Shale	56.7	0.14	46.9[a]	0.229	20	58.4	50.3	1.02
2443	Shale	56.2	0.21	46.9[a]	0.245	20	58.0	50.5	1.02
2430	Sand	47.5	0.21	43.4	0.194	35	57.7	46.9	0.86
2415	Silt/shale	47.2	0.34	43.4	0.226	29	57.4	47.5	0.86
		53.8	0.34						0.98
2406	Silt	47.1	0.21	43.4	0.220	35	57.2	47.3	0.86
2393	Sand	45.8	0.34	42.4[b]	0.162	37	56.8	45.2	0.85
2367	Shale	59.2	0.69	43.4[a]	0.260	19	56.2	47.9	1.11
2336	Shale	56.2	0.69	43.4[a]	0.265	NA	55.5	47.8	1.06
2317	Silt	52.5	0.14	33.2[c]	0.224	NA	55.0	39.5	1.00
2295	Sand	45.5	0.14	32.9[c]	0.225	NA	54.5	39.2	0.875
2276	Sand	46.9	0.21	32.6[c]	0.195	NA	54.1	37.8	0.91
2263	Coal	47.3	0.52	32.5[c]	NA	NA	53.7	NA	0.925
2254	Sand	46.3	1.00	32.3[c]	0.201	NA	53.5	37.7	0.91
2226	Mudstone	44.3	0.21	31.9[c]	0.237	NA	52.9	38.4	0.88

[a]Estimates of shale pore pressure may be unreliable.

[b]Measured after several months of production.

[c]Estimated from mud weight.

[d]1 MPa = 145.03 psi.

stress and mechanical properties data from the MWX experiment (Towse and Heuze, 1983; Warpinski and others, 1983). In the Piceance Basin, horizontal stress orientations have been determined by several methods in the MWX wells, where natural fractures and high-permeability anisotropy trend west-northwest (fig. 65) (Clark, 1983; Towse and Heuze, 1983; Johnson, 1985; Lorenz and others, 1986; Lorenz and Finley, 1987a,b; Branagan and others, 1987; Lin and Heuze, 1987), consistent with the regional stress pattern. Local deviations of minifrac strike from the expected average regional fracture azimuth have been reported from the Piceance Basin (fig. 69) (Towse and Heuze, 1983). Warpinski (1986) modeled the stress history of the Piceance Basin with results that compare favorably with present-day stress data at the MWX site. These results suggest that the geologic history of the basin has had an influence on current stress magnitude and orientation. Present-day in situ stress anisotropy may reflect remnant strains from the Sevier and Laramide east-west compressive stress fields (Wolff and others, 1974; Warpinski and Teufel, 1987).

Stratigraphy

General stratigraphy

The Mesaverde Group (fig. 70) was first named by Holmes (1877) for Upper-Cretaceous age exposures of interbedded sandstone, shale, and coal in the San Juan Basin of the Four Corners area of Colorado, Utah, Arizona, and New Mexico. Mesaverde strata exposed in the Piceance Creek Basin, northwest Colorado, are lithologically similar to, but younger than the Mesaverde at its type section (Weimer, 1960; Collins, 1976). The Mesaverde in northwest Colorado ranges from 1,000 to 8,200 ft in thickness (fig. 71) and was deposited in the Eagle Basin of Utah and Colorado. The Eagle Basin was destroyed by the Late Cretaceous-Early Tertiary Laramide Orogeny that formed the Uinta, White River, Sawatch, and Uncompahgre Uplifts, and the Douglas Creek Arch, which define the margins of the Piceance Creek Basin (figs. 62 and 63) (Quigley, 1965; Kauffman, 1977; Johnson and Keighin, 1981).

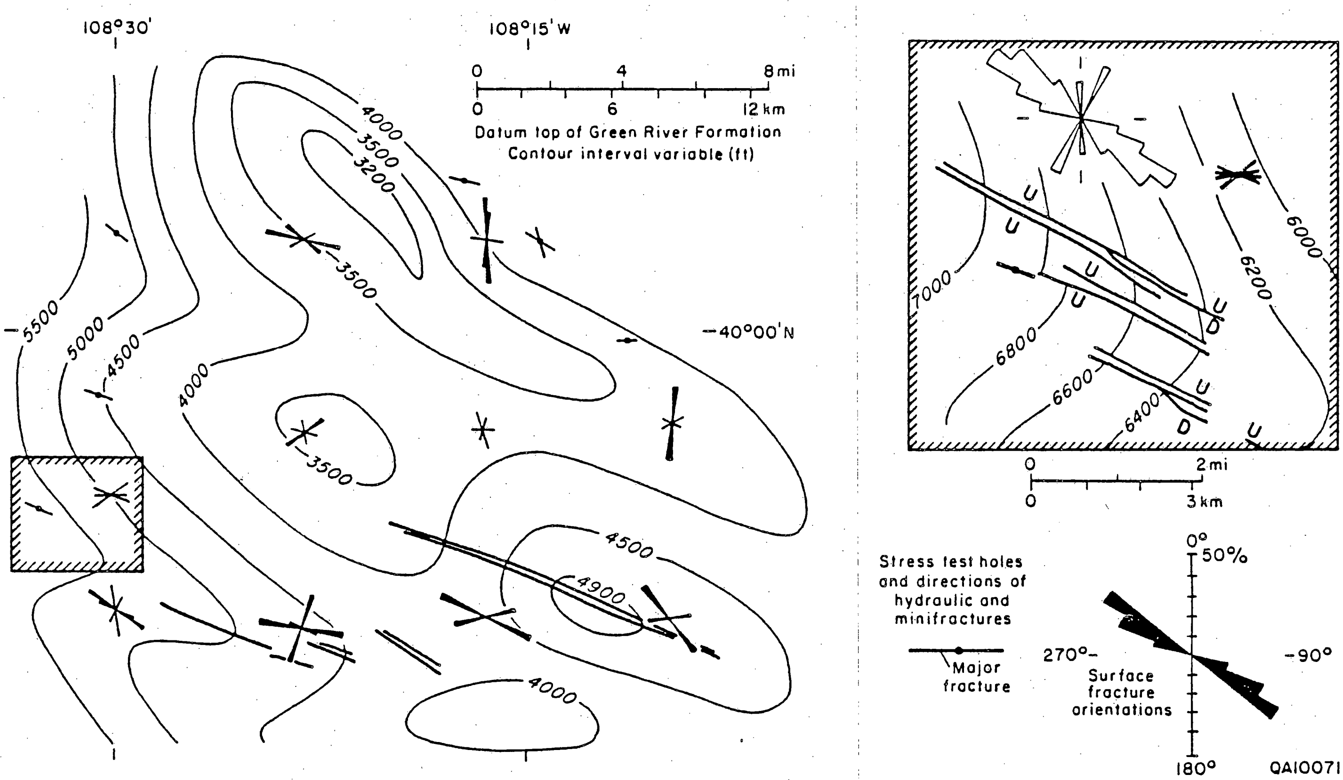


Figure 69. Surface joints, structure, and hydrofracture directions in the northern Piceance Basin. See figure 67 for location. From Towse and Heuze (1983, fig. 10).

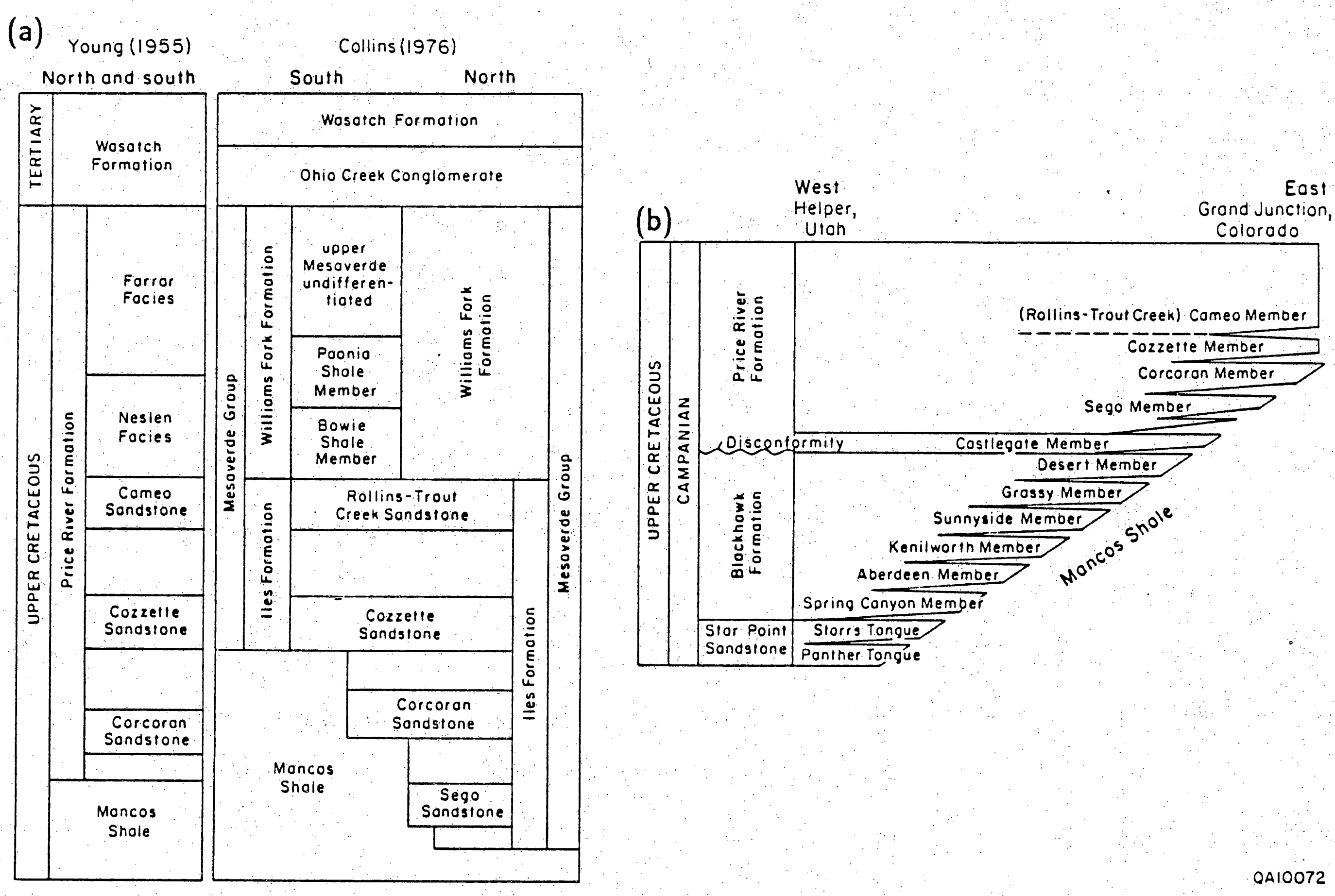


Figure 70. (a) Stratigraphic columns for the Upper Cretaceous Mesaverde rocks, Piceance Creek Basin, Colorado. Note the discrepancies between the classification of Young (1955) and that of Collins (1976). (b) Graphic depiction of the stratigraphic occurrence of the sandstone members in the Price River Formation of Young (1955; same as in the Iles Formation of Collins, 1976). Young (1955) demonstrated the southeastward progradation and termination of the Castlegate and younger sandstone members from Utah to Colorado. Locations of Helper, Utah, and Grand Junction, Colorado, shown in figure 71. Modified from Young (1955, fig. 2) and Collins (1976, fig. 4).

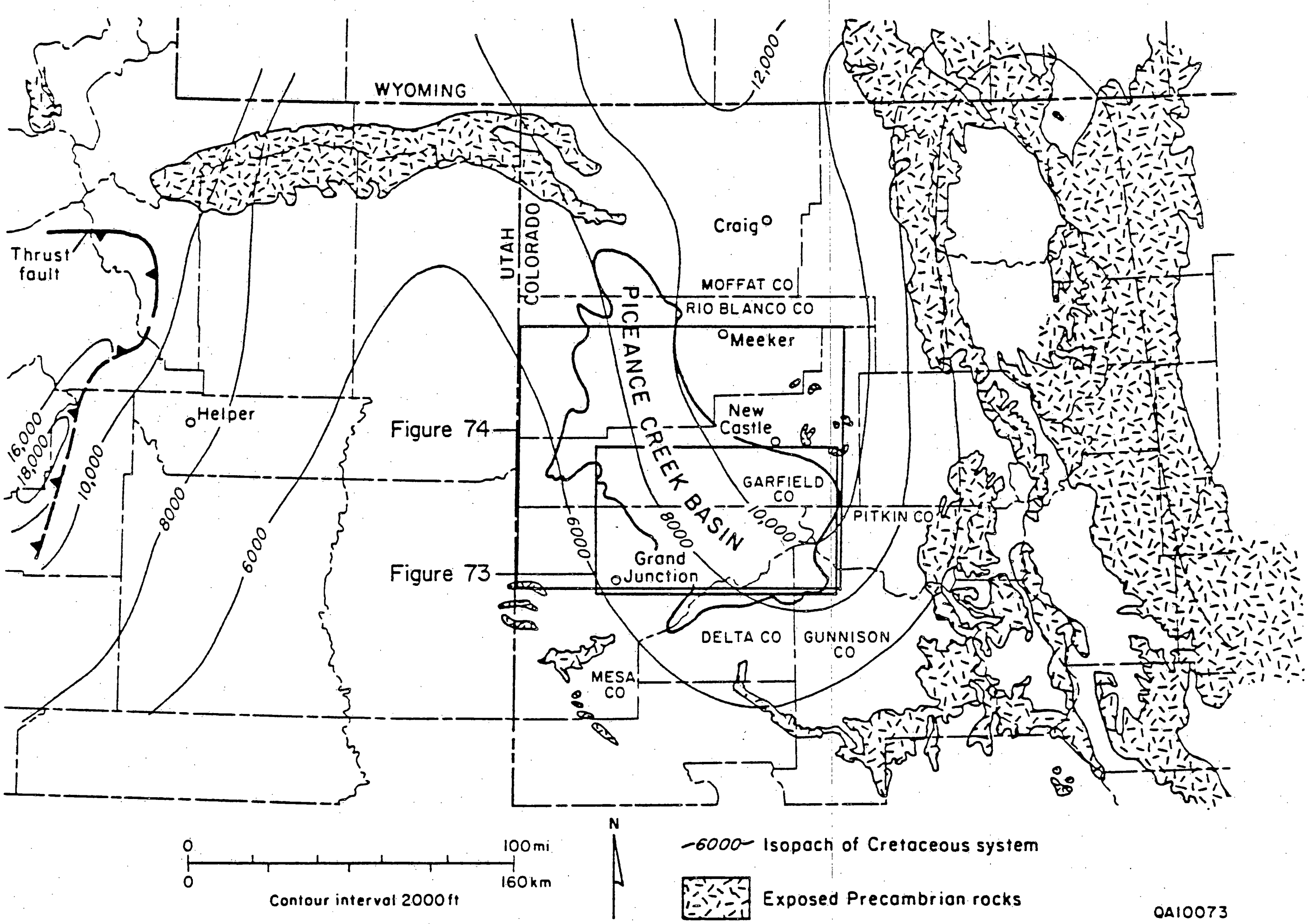


Figure 71. Isopach map of the Cretaceous System in the vicinity of the Piceance Creek Basin, Colorado. Note that isopach values include the rocks from the Dakota Sandstone through the Mesaverde Group. Modified from Sanborn (1977, fig. 6).

During the Cretaceous Period, the region now occupied by the Piceance Creek Basin was covered by the Cretaceous Interior Seaway (Quigley, 1965; Kauffman, 1977). Mesaverde sediments document the overall eastward withdrawal of the sea, and the deposition of fluvial, paludal, littoral/deltaic, and paralic environments (Young, 1955; Warner, 1964; Quigley, 1965; Collins, 1976; Lorenz and Rutledge, 1987). This overall regressive package overlies and intertongues with the Mancos Shale and is overlain by the Lance Formation, the Ohio Creek Conglomerate, or the Lewis Shale (Collins, 1976; Boyles and others, 1981).

Stratigraphic nomenclature for the Mesaverde Group in the Piceance Creek Basin has undergone numerous revisions (Lee, 1909; Johnson, 1948; Hanks, 1962). The cause for much of the confusion and ambiguity in terminology is the complex interrelationship between the continental, marginal marine, and marine rocks (Young, 1955). The constraints of this study require a detailed discussion of the stratigraphy and depositional setting of the gas-bearing sandstones of the lower Mesaverde Group. Therefore, to include all intervals of interest, two stratigraphic schemes for the Mesaverde must be discussed. The reader is referred to the discussions by Young (1955), Warner (1964), and Collins (1976), and to figure 70 for a fuller explanation of the stratigraphic terminology.

Young (1955) modified the terminology of Spieker and Reeside (1925) and Fisher (1936) by substituting the name Price River Formation for the relatively coarser-grained rock sequence overlying the Mancos Shale (the Mesaverde Group as discussed in this study), and he divided the lowest part of the Price River Formation into several sandstone members (fig. 70). In ascending order, these members are: the Castlegate, Sego, Corcoran, Cozzette, and Cameo. Two lithofacies, defined by the presence or absence of coal (the Neslen and the Farrar), constitute the landward equivalent section to these sandstone members and form the upper Price River Formation. This classification is important in that Young (1955) included the Castlegate sandstone as the basal regressive interval of the Mesaverde. It unconformably overlies the Blackhawk Formation to the west and interfingers eastward with the Mancos Shale. Additionally, Young (1955) demonstrated that deposition of the Sego, Corcoran, and Cozzette members represents multiple episodes of shoreline regression separated by transgressive tongues of the marine Mancos Shale (signifying periods of rapid subsidence or low sediment input). He also defined the youngest regressive sandstone as the Cameo Member, which includes the lithologically equivalent Rollins/Trout Creek sandstones (Warner, 1964; Collins, 1976).

Collins (1976) retained the name Mesaverde at Group status as it was first proposed by Hancock (1925) and followed the division of the Mesaverde into two formations, the basal Iles Formation and the overlying Williams Fork Formation. Collins (1976) shows the interfingering relationships between the Sego, Corcoran, Cozzette, and Rollins-Trout Creek (Young's Cameo) sandstones of the Iles Formation with the Mancos Shale (fig. 70). The Williams Fork Formation is divided into the Bowie Shale and Paonia Shale Members. The uppermost 2,000 to 4,000 ft of the Williams Fork Formation is undifferentiated. Descriptions of all the formations and their component members follow.

Iles Formation

Interbedded sandstones, siltstones, and shales with a combined thickness ranging from 890 to 1,600 ft comprise the Iles Formation (Collins, 1976). These sediments are nonmarine in the northwest. As they grade southward into marine sediments, they become fine grained. Sandstones generally thin and pinch out to the east, whereas the Mancos Shale wedges pinch out to the west (fig. 70). Although Collins (1976) does not include the Castlegate or Cameo Members within the Iles, and Dunn and Irwin (1977) place the Castlegate in the Mancos, they will be included in this discussion.

Castlegate Member: The Castlegate consists of cross-bedded to massive, coarse- to fine-grained sandstone that unconformably overlies the Blackhawk Formation of the Mancos Shale. It is 500 ft thick at Castlegate, Utah, and becomes finer grained and thins to a wedge-edge just east of the Utah/Colorado state line (Young, 1955).

Sego Member: Three sandstone lenses that are interbedded with shale and coal and form the Sego Member can be traced into Colorado. A tongue of the Mancos Shale (Buck tongue) separates the Sego from the Castlegate, and the disconformable upper boundary of the Sego is placed at the contact between coal-bearing rocks and the Mancos Shale. Thickness of the

Sego averages 200 ft, with individual sandstones attaining maximum thicknesses of 50 ft (Young, 1955).

Corcoran Member: The third major Mancos Shale wedge separates the Corcoran Member from the underlying Sego Member. The Corcoran ranges from 0 to 180 ft in thickness (Collins, 1976; Warner, 1964), but where the Mancos tongue is missing, the combined thickness of the Sego and Corcoran can be 300 ft. Siltstone, shale, and coal are interbedded with the Corcoran Sandstone.

Cozzette Member: The Cozzette Member is a shale- and coal-bearing sandstone similar to the Corcoran. Its thickness can range from 0 to 220 ft (Warner, 1964), and it contains two prominent sandstones that may have a combined thickness of 130 ft (Young, 1955).

Cameo Member: The Cameo Member consists of coal-bearing rocks and a basal sandstone (called the Rollins-Trout Creek by Collins, 1976) that overlies the fifth major transgressive tongue of the Mancos Shale (Young, 1955). This member is 350 ft thick in northwestern Mesa County (Dunn and Irwin, 1977), and the basal sandstone (Rollins-Trout Creek) can reach 125 ft in thickness (Warner, 1964).

Williams Fork Formation

A series of nonmarine conglomerates, sandstones, siltstones, mudstones, claystones, and rare algal limestones form the Williams Fork Formation (Collins, 1976). Rocks in this lithologically variable formation are divided into two members, the Bowie Shale Member and the Paonia Shale Member, and an upper interval of undifferentiated sediments (fig. 70). The total Williams Fork Formation ranges from 4,600 to 6,400 ft in thickness, and it is overlain by conglomerates in the Ohio Creek Formation that grade eastward into the Lewis Shale (Collins, 1976; Dunn and Irwin, 1977; Boyles and others, 1981).

Bowie Shale Member: The Bowie Shale Member comprises the lowermost 680 ft of the Williams Fork Formation. It generally consists of basal nonmarine sandstone, siltstone, shale, coal, and shell beds that grade upward into marine siltstone and shale (Mancos Shale). The rocks are grouped into two regressive packages separated by a marine shale wedge of the Mancos. Each regressive sequence consists of a basal marine sandstone that is overlain by nonmarine coal-bearing rocks.

Paonia Shale Member: Nonmarine sandstone, siltstone, shale, and coal overlie the second sandstone of the Bowie Shale Member and form the Paonia Shale Member. This member has a gradational upper contact with the overlying, undifferentiated sediments and averages 560 ft in thickness (Collins, 1976). Sandstone bedding is variable; the thickest sandstones are lenticular in cross section and are associated laterally with thin-bedded sandstone and siltstone. Coal deposits are typically thin but thicken locally (Collins, 1976).

Upper Williams Fork Formation (undifferentiated): Upper Williams Fork strata consist of lithologically variable sediments (conglomerate, sandstone, siltstone, shale, coal) that range from 2,000 to 4,000 ft in thickness. Lenticularly bedded sandstones and thin-bedded coals are common.

Depositional environments

Mesaverde strata record deposition in coastal-plain, swamp, lagoon, delta, beach, and shelf environments during a major Upper Cretaceous regressive event (table A15) (Young, 1955; Weimer, 1960; Warner, 1964; Masters, 1967; Collins, 1976; Lorenz, 1983b; Finley, 1985; Lorenz and Rutledge, 1987). During Campanian to Maastrichtian time, fluvial, deltaic, and shoreline environments prograded to the south-southeast from a source in the Wasatch Mountains, filling the Eagle Basin on the western margin of the Cretaceous Interior Seaway (Quigley, 1965; Collins, 1976; Kauffman, 1977).

Young (1955) postulated that coastal plains with associated mainland beaches prograded into the Cretaceous Sea, and that episodic periods of basin subsidence and termination of sediment supply account for the interfingering wedges of marine shale. Collins (1976) refined this depositional scenario, and stated that the Mesaverde Group closely resembles a large deltaic complex similar to the Niger Delta, in that it displays multiple cycles of deposition in the same way. This depositional setting includes the fluvial, paludal, deltaic, and littoral facies represented in the Mesaverde Group, but Collins (1976) concluded that beach deposition was not dominant in the Mesaverde. In contrast, Boyles and others (1981) interpreted the Lower Mesaverde Iles Formation as marine-influenced (storm processes) progradational shoreface sequences cut by distributary channels and tidal inlets. They did not differentiate between deltaic and strandline deposition. Lorenz (1983b, 1987) used outcrop, well log, and core analyses to divide the Mesaverde sequence into four intervals that represent deposition under differing environmental conditions (fig. 72). His divisions will be discussed in this report. They encompass—from base to

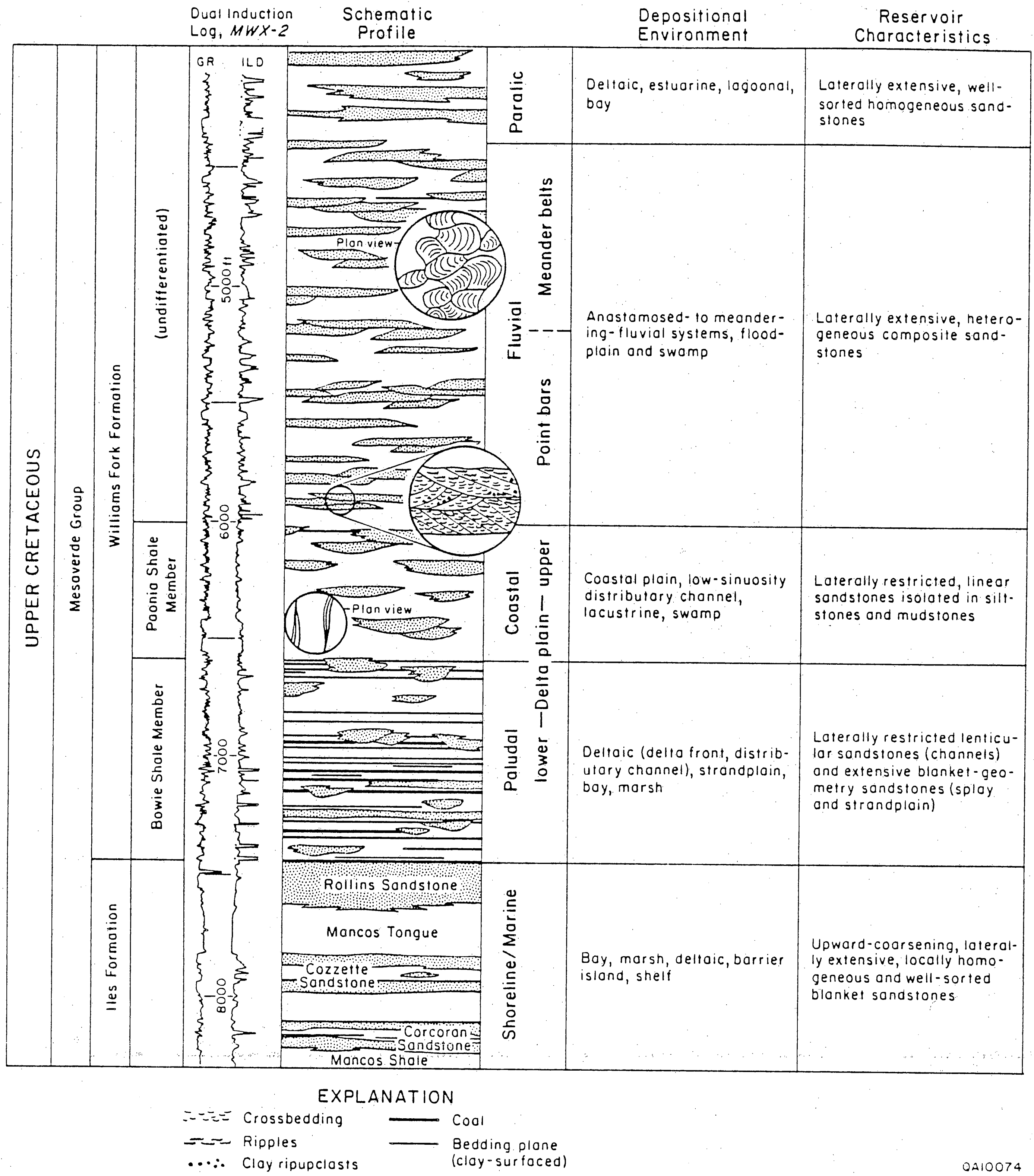


Figure 72. Generalized stratigraphic and lithologic column emphasizing the depositional attributes of the Mesaverde Group. Modified from Lorenz (1983b, fig. 1).

top—shoreline/marine, coastal/paludal (lower and upper delta plain), fluvial, and paralic environments.

Shoreline/marine

Shoreline/marine deposits include the basal Mesaverde section from the Mancos Shale to the top of the Rollins sandstone (fig. 72) (Lorenz, 1983b). Intricate intertonguing of these deposits with Mancos Shale implies that the general progradational pattern of the Mesaverde was periodically interrupted by transgressive incursions of the Cretaceous Interior Seaway. The Castlegate, Sego, Corcoran, Cozzette, and Rollins sandstones represent transitional littoral/marine environments (barrier islands, wave-dominated deltas, offshore bars) that occupied the strandline between fluvial coal-bearing rocks to the northwest, and marine shale to the southeast (Young, 1955; Collins, 1976; Boyles and others, 1981; Finley, 1985). The littoral deposits are thin-bedded, medium- to fine-grained, well-sorted, upward-coarsening sandstones that exhibit wave-generated sedimentary structures (oscillation ripples, horizontal laminations, hummocky-cross stratification) and marine trace and body fossils (<u>Ophiomorpha</u>, <u>Inoceramus</u>) (Young, 1955; Warner, 1964; Boyles and others, 1981; Finley, 1985; Lorenz and Rutledge, 1987). Sandstones thicken locally where two or more upward-coarsening sequences are superimposed, or where sand-filled channels (distributary channels and tidal inlets) have cut the blanketlike shoreline deposits (fig. 73) (Boyles and others, 1981; Palmer and Walton, 1984; Lorenz and Rutledge, 1987). Finley (1985) subdivided the Corcoran and Cozzette sandstones into four and three divisions, respectively, on the basis of their depositional characteristics (deposition under transgressive or regressive conditions).

As shown in figures 70 and 74, the Corcoran and Cozzette sandstones made the farthest basinward advances. Additionally, Finley (1985) documented that due to their regressive depositional nature, the Corcoran and Cozzette (and most likely the Castlegate, Sego, and Rollins) sandstones are time-transgressive (they rise stratigraphically), become younger in age to the southeast, and have basinwide continuity. These strandplain sandstones display upward-coarsening

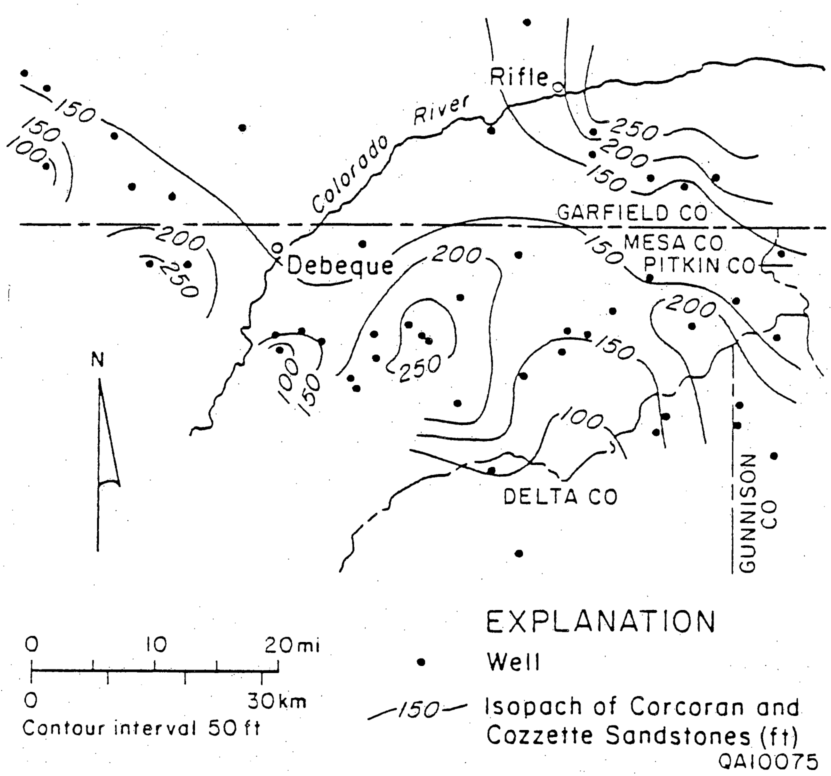


Figure 73. Isopach map of combined Corcoran and Cozzette sandstone thicknesses. Location shown in figure 71. From Lorenz (1983a, fig. 3).

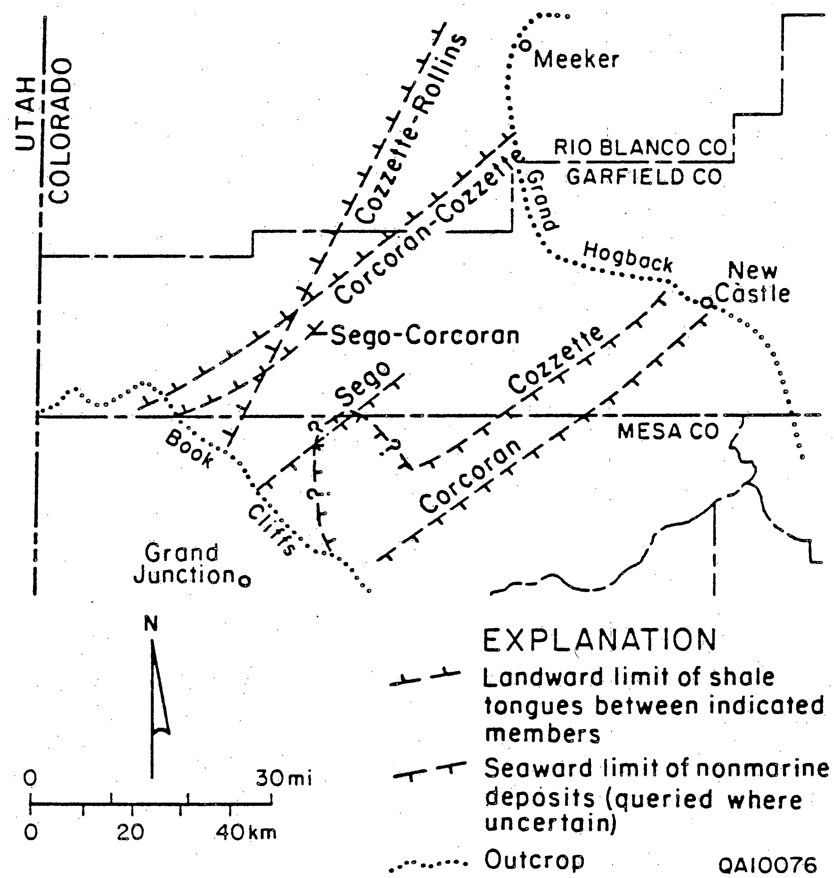


Figure 74. Shoreline trends depicting the farthest basinward progradations of the Corcoran through Rollins Members. Also note the positions of the farthest landward deposition of the marine Mancos Shale tongues. Location shown in figure 71. From Warner (1964, fig. 11).

to blocky log patterns (fig. 75) and grade up paleoslope (NW) through a fluvial, coal-bearing facies into their source area (Young, 1955; Warner, 1964; Boyles and others, 1981). They commonly interfinger with, and are overlain by, rooted mudstones and coals (swamp), whereas they pinch out into marine shale southeast toward the basin (figs. 70 and 74) (Young, 1955; Warner, 1964; Finley, 1985).

Coastal/paludal

The Bowie Shale and Paonia Shale Members define the interval of coastal/paludal sediments that overlie the Iles Formation (fig. 72). Stratigraphic and sedimentologic evidence (lithology, structures, facies associations) indicate that these sediments represent continued progradation of the Mesaverde and were deposited in lower and upper delta-plain environments. Lower delta-plain distributary-channel sandstones display cross bedding, rippling, and soft-sediment deformation. They have high thickness/width ratios (widths 120 to 175 ft; Lorenz, 1983b, 1987). Restricted lateral continuity is due to low rates of lateral migration, rapid subsidence rates, and confinement by floodplain mudstones (fig. 72). Some thin, rippled to rooted, upward-coarsening, laterally persistent sandstones of probable crevasse-splay, levee, and strandplain origin are interbedded with the carbonaceous shales and coals.

In the upper delta plain, channel sandstones form more continuous lenses within the floodplain mudstones as a result of higher lateral migration rates. Thin, interbedded crevasse-splay deposits are not as common in the upper delta plain. Strandplain deposits formed by marine reworking of crevasse-splay and distributary sandstones are absent (Lorenz, 1983b, 1987).

Fluvial

Sandstones in the fluvial (undifferentiated) Mesaverde section are dominantly sharp-based, upward-fining to blocky trends formed by the deposition and amalgamation of fluvial point bars

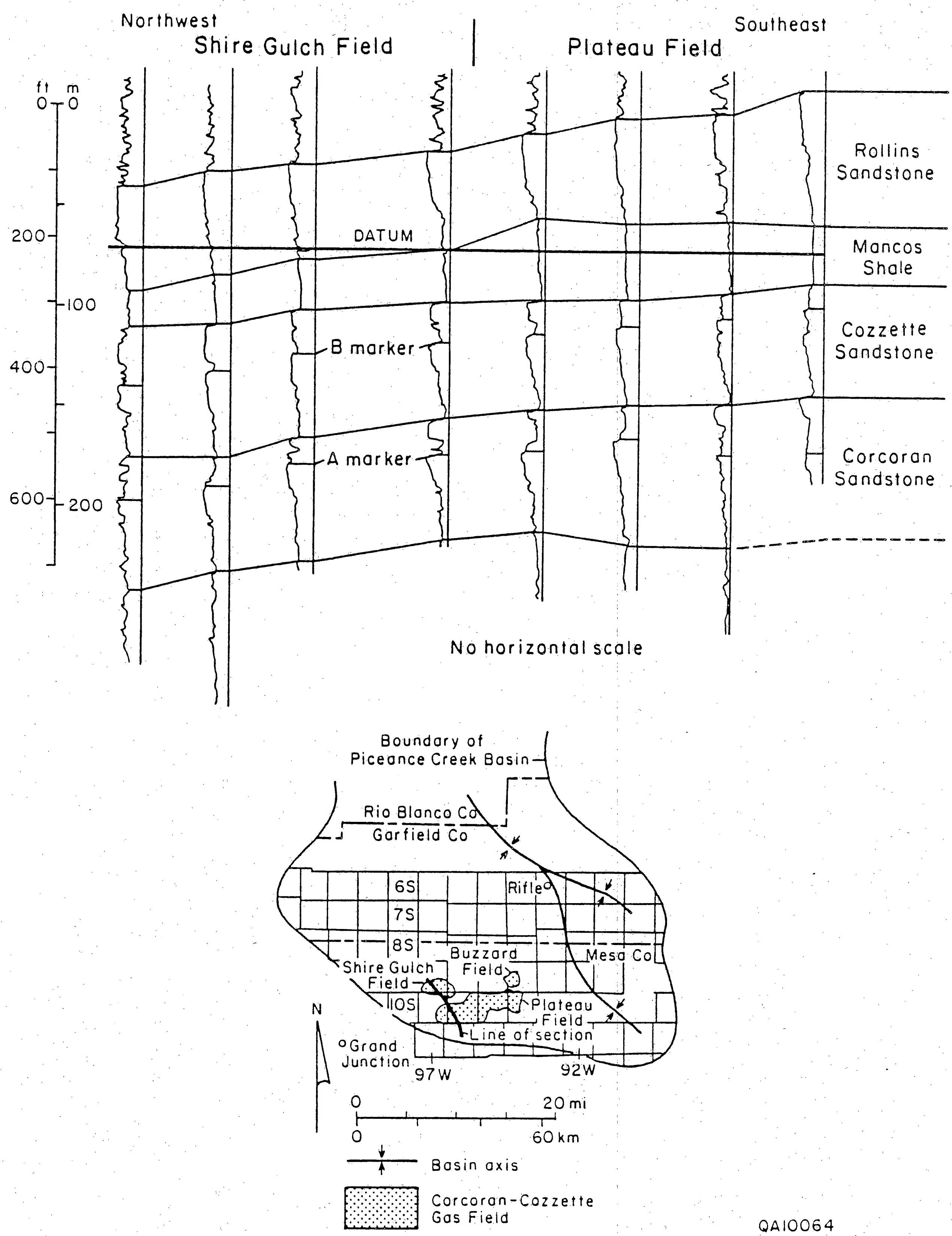


Figure 75. Stratigraphic cross section through Shire Gulch and Plateau fields using a bentonite marker in the lower Rollins as a datum. Modified from Finley (1985, fig. 3).

(Lorenz, 1983b, 1985a). Meandering streams deposited arcuate point bars 2 to 13 ft thick and up to 750 ft wide. One cycle of point bar deposition is characterized by a sharp-based, medium- to fine-grained, cross-bedded sandstone fining upward into very fine grained sand, silt, and clay. Preservation of the upper point-bar fine-grained cap is tenuous because subsequent channel erosion commonly removes the muddy section, leaving only a sharp sand-sand contact highlighted by mud rip-up clasts.

Multiple episodes of fluvial (point bar) deposition in conjunction with delta-plain subsidence created composite sandstone deposits or meanderbelts interbedded with floodplain and swamp mudstones in the fluvial section (fig. 72). Vertically and laterally superimposed point-bar and meanderbelt sandstones reach thicknesses of 60 ft and widths of 1,700 ft (Lorenz, 1983b, 1987). Payne and Scott (1982) described meandering-stream depositional facies in the Mesaverde, but in addition, they interpreted some of the fluvial deposits as having been deposited by anastomosing fluvial systems. This difference is significant because anastomosing fluvial systems deposit laterally confined sandstones within a mud-rich floodplain (Rust and Legun, 1983; Smith, 1983). The anastomosing channel deposits they described formed lenses 240 to 400 ft wide and 60 ft thick, whereas the meandering-channel deposits occur in broad belts 2,000 ft wide and 10 to 20 ft thick. Additionally, Payne and Scott (1982) interpret the presence of lacustrine and Gilbert-type deltas within the anastomosing stream systems tract.

Paralic

Lorenz (1983b, 1987) mentions a fourth but minor sedimentologic division consisting of sediments deposited in paralic (lagoonal-shallow neritic) environments. Deltaic, estuarine, lagoonal, and bay environments likely formed in response to the marine transgression that deposited the overlying Lewis Shale. Sandstone deposits are laterally continuous, well-sorted, and homogeneous.

Reservoir characteristics

According to ICF-Lewin Energy Division (1988a) the Corcoran and Cozzette Sandstones contain 21.4 TCF of gas, and the rest of the Mesaverde holds 65 TCF. Gas occurs in naturally fractured sandstones that possess low porosity and permeability (Western Oil Reporter, 1981a; Lorenz, 1983b; Finley, 1985), but the gas can be economically produced after sandstones in the lower two-thirds of the Williams Fork Formation and in the Iles Formation (Chancellor and Johnson, 1986) have been hydraulically fractured. The nonmarine section of the Mesaverde Group contains the greatest gas reserves, but the nonmarine reservoirs are of low quality and discontinuous. Stratigraphic traps predominate in this basin; structure has no apparent influence on trap formation, although porosity, permeability, reservoir quality, and fracture intensity are generally greater on structural highs or closures (Johnson and Keighin, 1981; Brown and others, 1986; Johnson and Nuccio, 1986).

Fluvial reservoirs are composite bodies formed by the juxtaposition of point-bar and meanderbelt sandstones (Lorenz, 1983b; Lorenz and others, 1985). They are arcuate in plan geometry, elongate parallel to paleoslope, and generally isolated by mudstones (except where two meanderbelts are in erosive contact) (Lorenz, 1985a; Lorenz and others, 1985); they attain thicknesses of 2 to 60 ft. Reservoir width may reach 1,700 ft, and their lateral terminations can be of two types, either abrupt, as a result of sandstone/mudstone contacts forming by channel scour of the floodplain, or gradational, due to the interfingering of the point-bar and levee deposits with the floodplain (Lorenz, 1983b). Fluvial sandstones can be internally heterogeneous (variable lithology, grain size, sorting, sedimentary structures), thus affecting reservoir quality and water saturation. Localized, randomly occurring impermeable zones arise from the preservation of "mud plugs" at the top of abandoned channels (Lorenz, 1983b). Chancellor and Johnson (1986) report the occurrence of discrete gas/water contacts and high formation water values in the upper 1,000 to 1,700 ft of the Williams Fork Formation (fluvial zone; fig. 72) that hinder well completions.

Discrete gas/water contacts are not noted in the lower producible part of the Mesaverde Formation; therefore, their origin is likely related to the channel "mud plugs".

Although they do not have gas reserves as large as the fluvial section does, sandstones in the Iles Formation form the best quality and most prolific reservoirs in the Mesaverde Group (Warner, 1964; Quigley, 1965; Johnson and Keighin, 1981; Johnson and Nuccio, 1986). Marine processes responsible for deposition of shoreline sandstones created blanket-geometry, internally homogeneous reservoirs (Lorenz, 1983a; Finley, 1985). Finley (1985) summarized the reservoir characteristics of the Corcoran and Cozzette Members (figs. 70 and 72). Sandy, upward-coarsening shoreface intervals and blocky, regressive barrier-island sandstones (fig. 75) show no strong trends in porosity and permeability. However, although erratic, porosity and permeability values generally increase and water saturation decreases in the coarser grained and better-sorted deposits. Porosities range from 5 to 15 percent, and unstressed permeabilities range from 0.152 to 0.045 md, indicating that in situ permeabilities are less than 0.1 md. Porosity and permeability decrease with, and resistivity increases with, an increase in the content of carbonate cement and in silty burrowed intervals.

Net pay in the Corcoran and Cozzette Members is distributed among multiple depositional units (four in the Corcoran; three in the Cozzette), and each has distinct sand percent values and areal geometries (Finley, 1985). In the Corcoran 63 percent of net pay is sandstone (Finley, 1985), and its maximum thickness reaches 62 ft. Sandstone percent ranges from 27 to 75 percent in the Cozzette Member. No direct correlation exists between the amount of proppant used to artificially fracture these sandstones and their initial potential flowing (IPF) values, although thicker perforated intervals deliver higher flow rates (Finley, 1985; Chancellor and Johnson, 1986). Most common fracture treatments in the littoral sandstones use between 70,000 and 130,000 lb sand, yielding resultant IPF values ranging from 200 to 1,200 MCFGPD.

Lithology and Diagenesis

Several petrographic studies of Mesaverde Group sandstones in the Piceance Basin have been conducted, many as part of the DOE-sponsored MWX test. This discussion of lithology and diagenesis of Mesaverde sandstones is subdivided into the five zones defined by the MWX project (Lorenz, 1983b), from bottom to top as follows: (1) shoreline/marine; (2) paludal, or lower delta plain; (3) coastal, or upper delta plain; (4) fluvial; and (5) paralic (fig. 73). The marine/shoreline sandstones of zone 1, which are the Corcoran, Cozzette, and Rollins sandstones, are in the Iles Formation. Sandstones in zones 2 through 5 are generally unnamed, but they are all in the Williams Fork Formation of the Mesaverde Group.

Shoreline/Marine

Petrographic studies of Mesaverde marine sandstones in the Iles Formation have been reported by Palmer (1984), Pitman and Spencer (1984), Brown and others (1986), and Sandia National Laboratories and CER Corporation (1987). Corcoran and Cozzette sandstones generally are very similar to one another in mineral composition (Brown and others, 1986). The framework minerals are primarily quartz (55 to 65 percent), chert (14 to 16 percent), detrital dolomite (5 to 10 percent), metamorphic rock fragments (5 to 15 percent), plagioclase (8 to 10 percent), mica (2 to 5 percent), sedimentary rock fragments of mudstone, shale, and siltstone (1 to 8 percent) and volcanic rock fragments (trace to 2 percent) (Pitman and Spencer, 1984; Brown and others, 1986). These sandstones are classified as "feldspathic litharenites to litharenites" by Palmer (1984) and Brown and others (1986), but Corcoran and Cozzette sandstones from the MWX wells are subarkoses (Pitman and Spencer, 1984). Detrital clays identified by X-ray diffraction are mixed-layer illite/smectite, illite, and chlorite (Brown and others, 1986). Authigenic cements are quartz (1 to 5 percent); carbonates (1 to 14 percent), including calcite, siderite, dolomite, and ankerite; and clay minerals, including kaolinite (0 to 2 percent), illite, mixed-layer illite/smectite, and chlorite

(Palmer, 1984; Pitman and Spencer, 1984; Brown and others, 1986). Marcasite has been observed in some samples in volumes of 4 to 5 percent.

Rollins sandstone samples were somewhat more quartz-rich than the Corcoran or Cozzette sandstones and are classified as sublitharenites and feldspathic litharenites. Fossil fragments are present in all samples studied by Brown and others (1986), and calcite cement is common because the fossils provided an internal source of $CaCO_3$.

The general diagenetic sequence for Corcoran, Cozzette, and Rollins sandstones is (1) precipitation of calcite cement, (2) compaction, (3) alteration of feldspars to authigenic clays, (4) precipitation of quartz cement, (5) precipitation of a second generation of calcite cement, (6) generation of secondary porosity by dissolution of carbonate cement and feldspars, (7) precipitation of authigenic clays, and (8) dolomitization of calcite cement (Sandia National Laboratories and CER Corporation, 1987). With minor variations, this same sequence of diagenetic events was observed in sandstones from all zones of the Mesaverde Formation (Pitman and Spencer, 1984).

Porosity in Corcoran and Cozzette sandstones consists of microporosity, associated with detrital and authigenic clays, and macroporosity, primarily secondary pores that formed by dissolution of feldspars and carbonate cements. Porosimeter porosity ranges from 2.6 to 18 percent; in situ permeability calculated from short-term transient pressure analysis and long-term pressure-production history matching ranges from 0.002 to 0.08 md (Brown and others, 1986). Laboratory-measured permeability at surface pressure conditions varies from less than 0.01 to 0.03 md. Most of the porosity in Rollins sandstones is microporosity associated with mixed-layer illite/smectite and kaolinite. Porosimeter porosity ranges from 11 to 22 percent, and in situ permeability was calculated to range from 0.0002 to 0.04 md. In Corcoran, Cozzette, and Rollins sandstones, natural fractures may contribute to early production from a well, but reservoir simulation and short-term transient test analyses indicate that matrix porosity is the primary control on productivity (Brown and others, 1986).

Paludal zone

Pitman and Spencer (1984) summarize the petrography of sandstones in zones 2 through 5, and the discussion of these zones is based on their work. Sandstones in the paludal zone (fig. 72) are commonly interbedded with coals and carbonaceous shales and mudstones. Paludal sandstones cored in the MWX wells are fine to very fine grained and moderately to well sorted. In general, the paludal sandstones are similar to the underlying marine sandstones but contain more rock fragments. They are classified as feldspathic litharenites and sublitharenites; coal fragments, ripped-up clay clasts, and sedimentary rock fragments are common.

The sequence of diagenetic events in paludal sandstones is similar to that in the marine sandstones, but the relative abundance of authigenic minerals varies. Calcite and quartz cements are rare. Dolomite and ankerite are the most abundant carbonate cements, with combined volumes of 7 to 19 percent. Detrital dolomite grains commonly have overgrowths of dolomite and ankerite. Mixed-layer illite/smectite and fibrous illite are the most abundant authigenic clays.

Porosimeter porosity is low in most paludal sandstones, 2.9 to 12.2 percent, and permeability ranges from less than 0.1 to 2.2 md. The low porosity may be caused by the presence of abundant ductile rock fragments that compacted early in the burial history, reducing primary porosity. Abundant authigenic clay contributes to the low permeability.

According to Pitman and Spencer (1984), geophysical log interpretation in paludal sandstones is complicated by the abundant ripped-up mud clasts and detrital coal. Clean sandstones that contain mud clasts can be misinterpreted as being shaley. Furthermore, the presence of a large volume of low-density mud clasts and coal fragments will cause neutron and density logs to show anomalously high porosity.

Coastal zone

Sandstones in the coastal zone (fig. 72) contain somewhat higher percentages of feldspar and rock fragments than do the marine sandstones; they are classified as feldspathic litharenites. Illite and mixed-layer illite/smectite fill primary and secondary pores and coat detrital grains. Authigenic calcite is the most abundant cement, ranging in volume from 4 to 20 percent. The calcite does not appear to be leached, so significant secondary porosity did not develop. Porosimeter porosity ranges from 2.9 to 8.7 percent, and permeability varies from less than 0.1 to 0.37 md. According to Pitman and Spencer (1984), the abundant clays cause high irreducible water saturation and low permeability. They recommend the use of hydraulic fracture fluids containing KCl for stimulating this interval.

Fluvial zone

Sandstones in the fluvial zone (fig. 72) are interbedded with shales, mudstones, and siltstones (Lorenz, 1983b). Open, vertical natural fractures were recovered in many of the fluvial sandstones cored in the MWX wells. The composition of fluvial sandstones is more variable than that of other Mesaverde sandstones, ranging from lithic arkoses to feldspathic litharenites. Quartz is the most abundant framework constituent. Both orthoclase and Na-rich plagioclase feldspar are present, and chert is the most common rock fragment. Other lithic grains include mudstone, shale, siltstone, dolomite, and rare metamorphic and volcanic rock fragments. Detrital grains of mudstone, shale, and siltstone are difficult to identify because they have been deformed by compaction to form pseudomatrix between framework grains. In addition to compaction, these grains have undergone diagenetic reactions, and many are now sericitized. As a result of these chemical and mechanical changes, much of the original primary porosity was lost during early diagenesis.

Authigenic minerals include quartz, calcite, dolomite, ankerite, illite, mixed-layer illite/ smectite, iron-rich chlorite, and kaolinite. Quartz overgrowths are rare in most fluvial sandstones because of abundant detrital clay matrix and pseudomatrix. Calcite cement occurs in large, poikilotopic patches, as a grain replacement, and filling natural fractures. Secondary porosity has developed by partial dissolution of feldspar grains, particularly orthoclase, and by dissolution of early calcite cement. Many secondary pores are filled by authigenic clay minerals.

Porosimeter porosity in fluvial sandstones varies from 1.3 to 11.1 percent. Permeability is highly variable, ranging from less than 0.01 to 0.67 md. Matrix permeability is highest in sandstones with abundant open natural fractures (Pitman and Spencer, 1984).

Paralic zone

The paralic zone forms the uppermost part of the Mesaverde Group (fig. 72). Sandstones in the paralic zone are classified as litharenites and feldspathic litharenites. Sedimentary rock fragments of mudstone, siltstone, and shale are particularly abundant in this zone and constitute 5 to 26 percent of the framework grains. These ductile fragments are typically deformed between more rigid framework grains to form pseudomatrix.

Authigenic minerals are quartz, calcite, rare dolomite, illite, mixed-layer illite/smectite, chlorite, and kaolinite. Iron-rich chlorite lines primary pores, with crystals oriented perpendicular to framework grains. Kaolinite books occur in both primary and secondary pores; kaolinite was a late cement that precipitated after dissolution of calcite cement.

Porosity in paralic sandstones ranges from 0.7 to 9.5 percent. Much of the porosity is secondary and formed by dissolution of calcite cement. Those sandstones with low porosity typically either contain abundant authigenic kaolinite or retain high volumes of calcite cement. Permeability is controlled primarily by the volume of authigenic clay (Pitman and Spencer, 1984). Most sandstones have permeability values of about 0.1 md, but samples with little authigenic clay have permeability of 0.3 md or greater (Pitman and Spencer, 1984).

It can be difficult to interpret logs in the low-permeability zones accurately. Geophysical logs through the paralic zone indicate that most sandstones have low porosity and high apparent water saturation (60 to 100 percent), but abundant clays coating detrital grains may reduce formation resistivity and cause apparent high water saturation.

Summary

Mesaverde sandstones are mainly feldspathic litharenites. Detrital quartz is the most abundant constituent, comprising about 60 percent of the framework grains. Feldspars compose about 5 to 10 percent of the framework grains, with Na-plagioclase more abundant than orthoclase. Sedimentary rock fragments, which constitute most of the remainder of the framework grains, include detrital fragments of shale, mudstone, siltstone, chert, and dolomite. Many of the rock fragments are ductile and were deformed by compaction into pseudomatrix during early burial.

Authigenic cements include quartz, calcite, dolomite, ankerite, illite, mixed-layer illite/smectite, iron-rich chlorite, and kaolinite. In most zones calcite is the most abundant carbonate cement, but it is commonly extensively dissolved, leaving secondary porosity. Authigenic clays typically line primary pores and fill secondary pores.

The main reason for low-permeability in Mesaverde sandstones apparently is the presence of abundant clay in the form of authigenic clay, detrital clay, and clay in pseudomatrix formed from sedimentary rock fragments. The presence of the clays results in a complex micropore network that is poorly interconnected. Fluid flow is significantly restricted by the complex, tortuous pore geometries (Pitman and Spencer, 1984). Soeder and Randolph (1987) have concluded that most Mesaverde sandstones contain a dual-porosity system of large secondary solution pores connected by narrow slot pores. Most primary porosity has been lost by compaction or cementation.

Production, Resource Potential, Logistics

Well completion data from Petroleum Information Services indicate that between 1974 and 1988, the year having the most wells spudded and completed was 1983 (fig. 76). Twenty-six

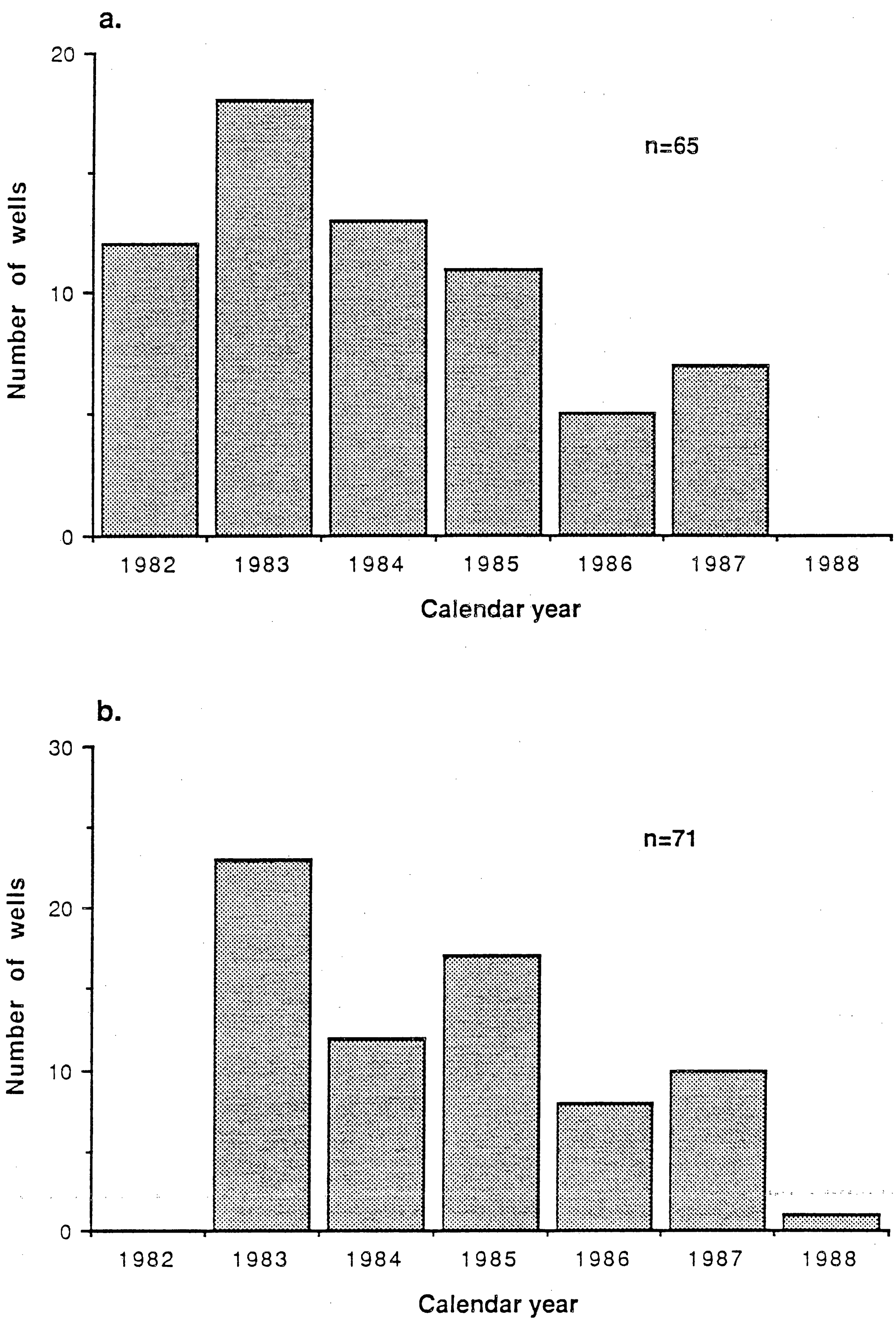


Figure 76. (a) Wells spudded in the Mesaverde Group, 1982-1987. (b) Wells completed in the Mesaverde Group, 1982-1988. Five wells spudded between 1974 and 1977 were completed after August 1983.

operators have completed successful gas wells in the Mesaverde since 1982 (fig. 77). Most wells drilled since 1983 are northeast of Grand Junction, Colorado, in southern Piceance Creek Basin (fig. 78). Depth to the top of the perforated interval ranges from 552 to 8,560 ft (fig. 79, table A14). One-fourth of the 71 wells for which information is available were fractured using sand/water and one-fourth were fractured using sand/foam (fig. 80). Fifteen percent of the wells required no treatment and four percent were only acidized. Of the wells that were treated with acid, half used 1,000 gal of acid or less (fig. 81a). A typical fracture treatment used between 2,266 and 985,245 gal of fluid (fig. 81b) (average of 141,180 gal) and between 3,550 and 1,328,000 lb of sand (fig. 81c) (average of 288,200 lb). Post-stimulation rates range from a minimum of 3 to a maximum of 6,475 MCFD with an average of 764 MCFD (fig. 82, table A16). Average production decline curves for four fields in the Mesaverde Group are shown in figure 83. Estimated gas in place is 65 TCF for the Mesaverde and 21.4 TCF for the Corcoran and Cozzette.

A survey by ICF-Lewin Energy Division (1988c) of stimulation treatments focused on Logan Wash field, Plateau field, Shire Gulch field and Sulphur Creek field. Their survey of drilling and completion costs is given in table A17.

Logan Wash field: Logan Wash field is a relatively small field with 6 producing wells and 1 shut-in well; see figure 83 for production decline curve. The average completion depths are 4,000 to 5,000 ft with typical completions consisting of casing, perforating, and stimulating by acid, CO_2, or gel-water.

Plateau field: This field produces from several low-permeability sand intervals in the Mesaverde Group. During 1987 the field contained 64 producing wells, 26 shut-in wells, and 12 abandoned wells; see figure 83 for a production decline curve. Completion depth was typically from 4,000 to 5,000 ft with wells commonly cased, perforated, and stimulated. Stimulation types included acidizing, and water-, nitrogen/sand-, or emulsion/sand-fracturing. Fluid volumes range from 1,100 to 112,000 gal and sand used ranges from 50,000 to 170,000 lb.

Shire Gulch field: The Shire Gulch field is a moderate size field that produces from several low-permeability sands in the Mesaverde Group. In 1987, the field contained 18 producing wells, 7 shut-in wells, and 1 abandoned well; see figure 83 for a production decline curve. The average completion depth ranges from 3,000 to 4,000 ft, and wells are typically cased, perforated, and stimulated. Stimulation types are nitrogen/sand-, sand/foam-, and gel-water/sand-fracturing.

Sulphur Creek field: This field produces only from the Mesaverde Group. During 1987, 8 wells were producing and 1 well was shut-in. Figure 83 shows a production decline curve. The

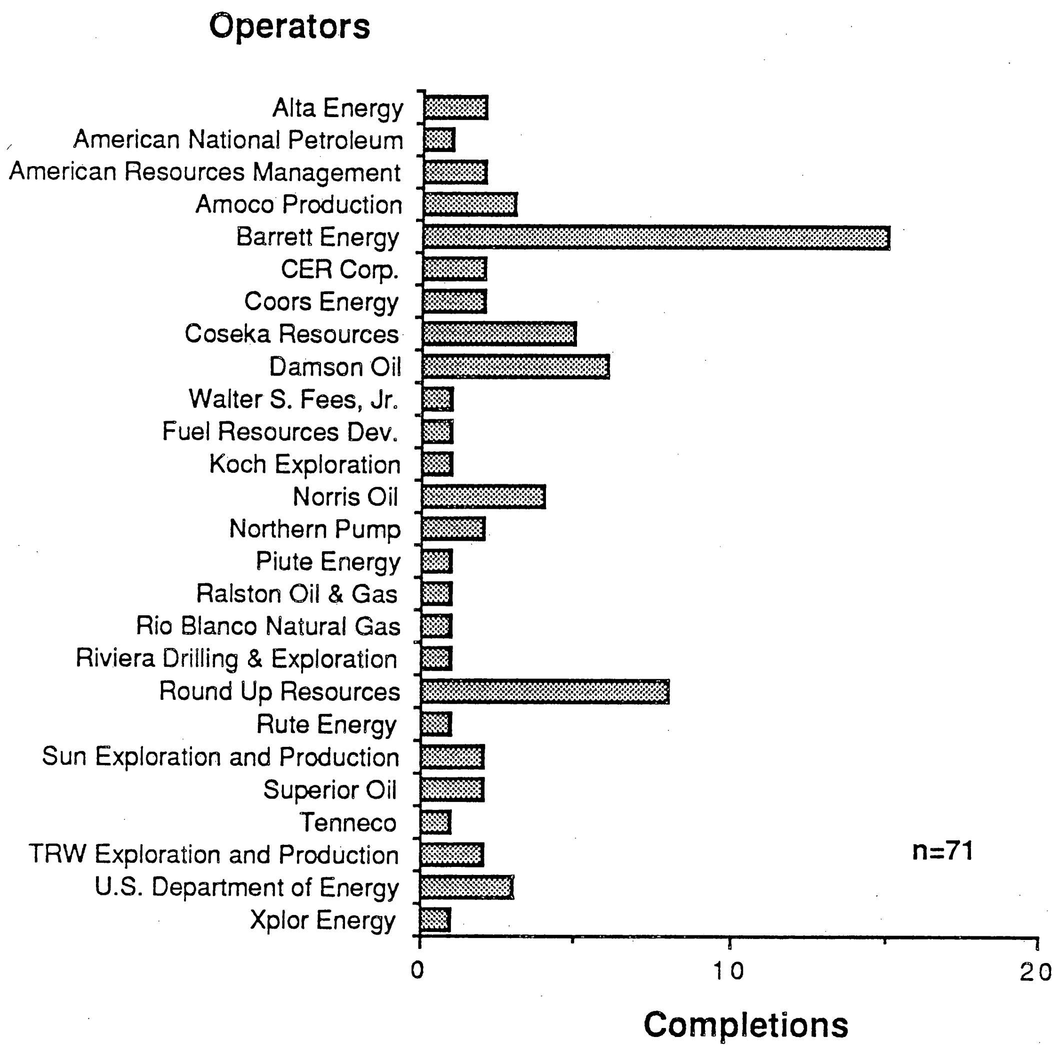


Figure 77. Graph of operators that completed successful gas wells in the Mesaverde Group between January 1983 and April 1988.

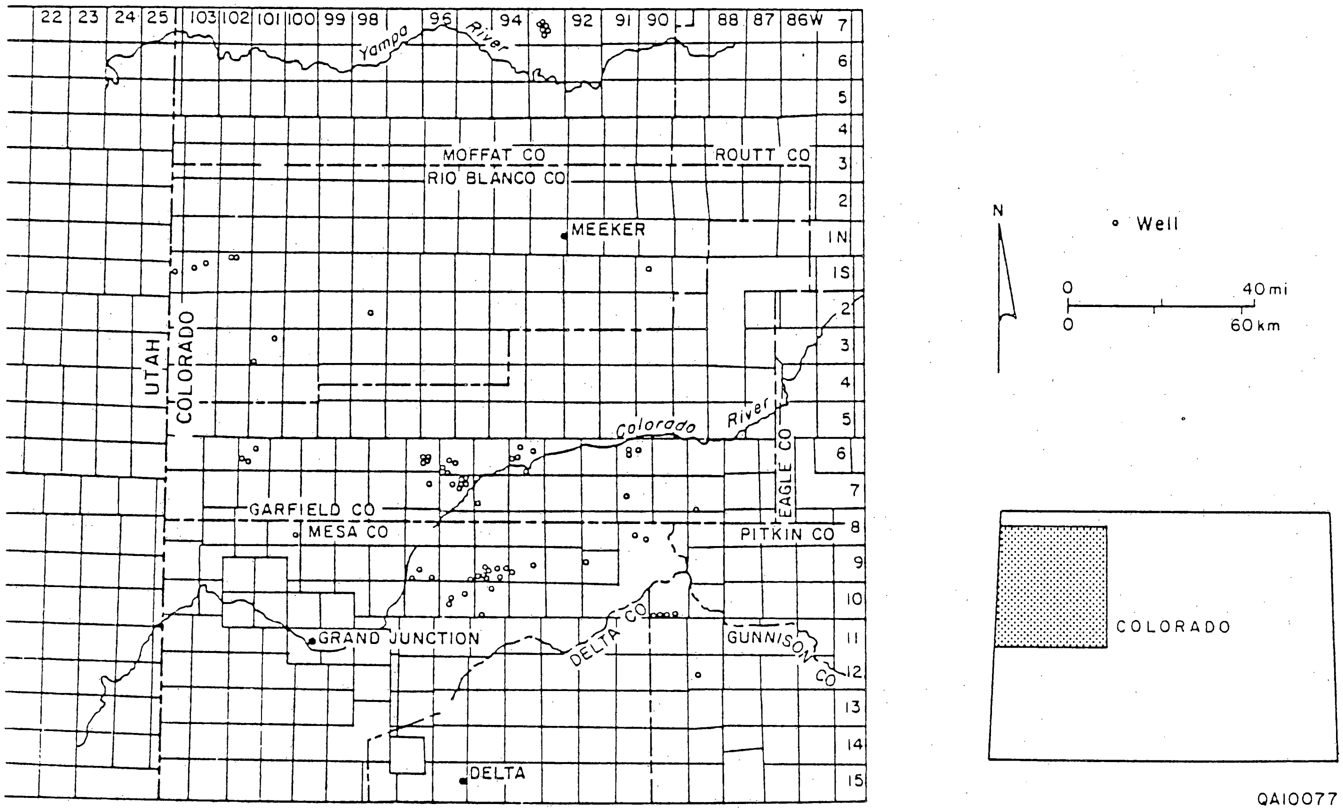


Figure 78. Map of wells completed in the Mesaverde Group between January 1983 and April 1988.

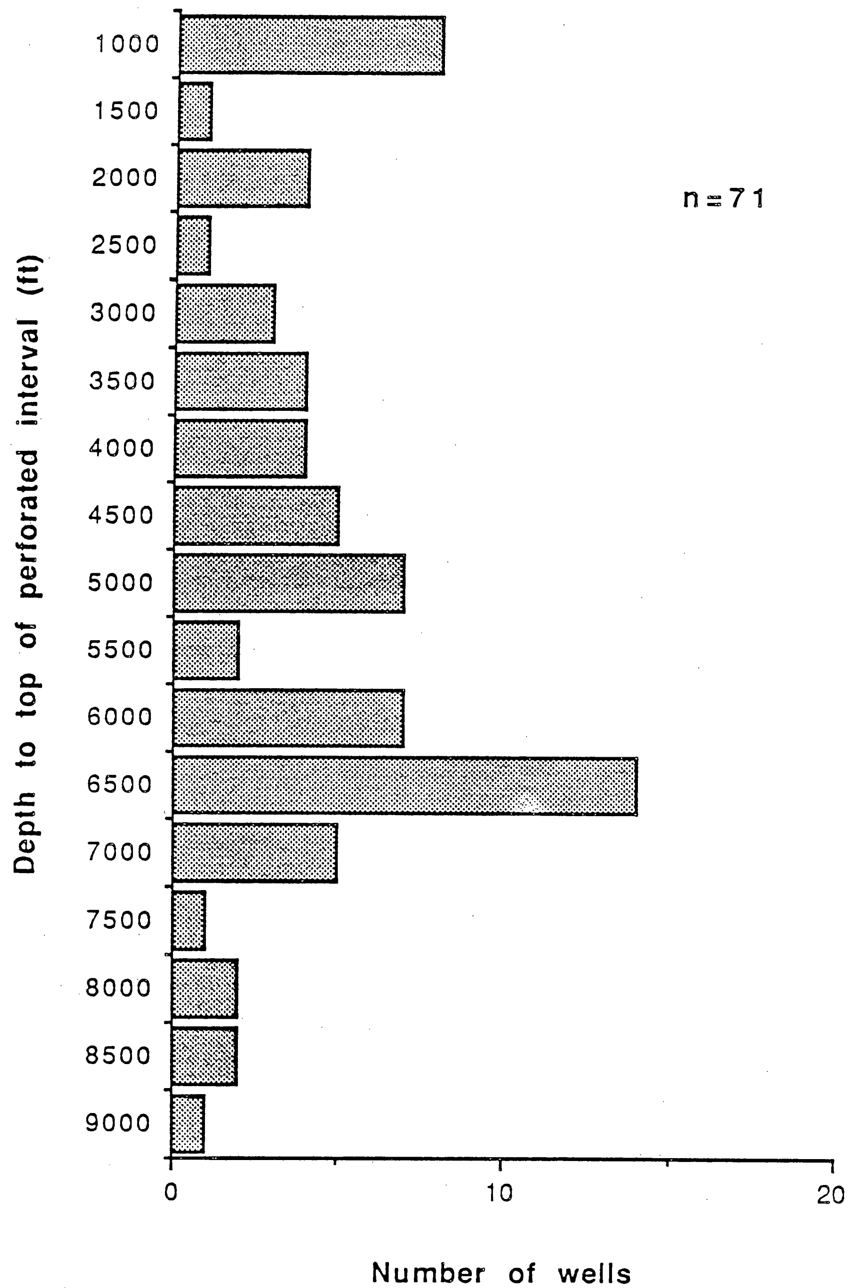


Figure 79. Depth to perforated interval in the Mesaverde Group ranges from 552 to 8,560 ft in successful gas wells completed between January 1983 and January 1988.

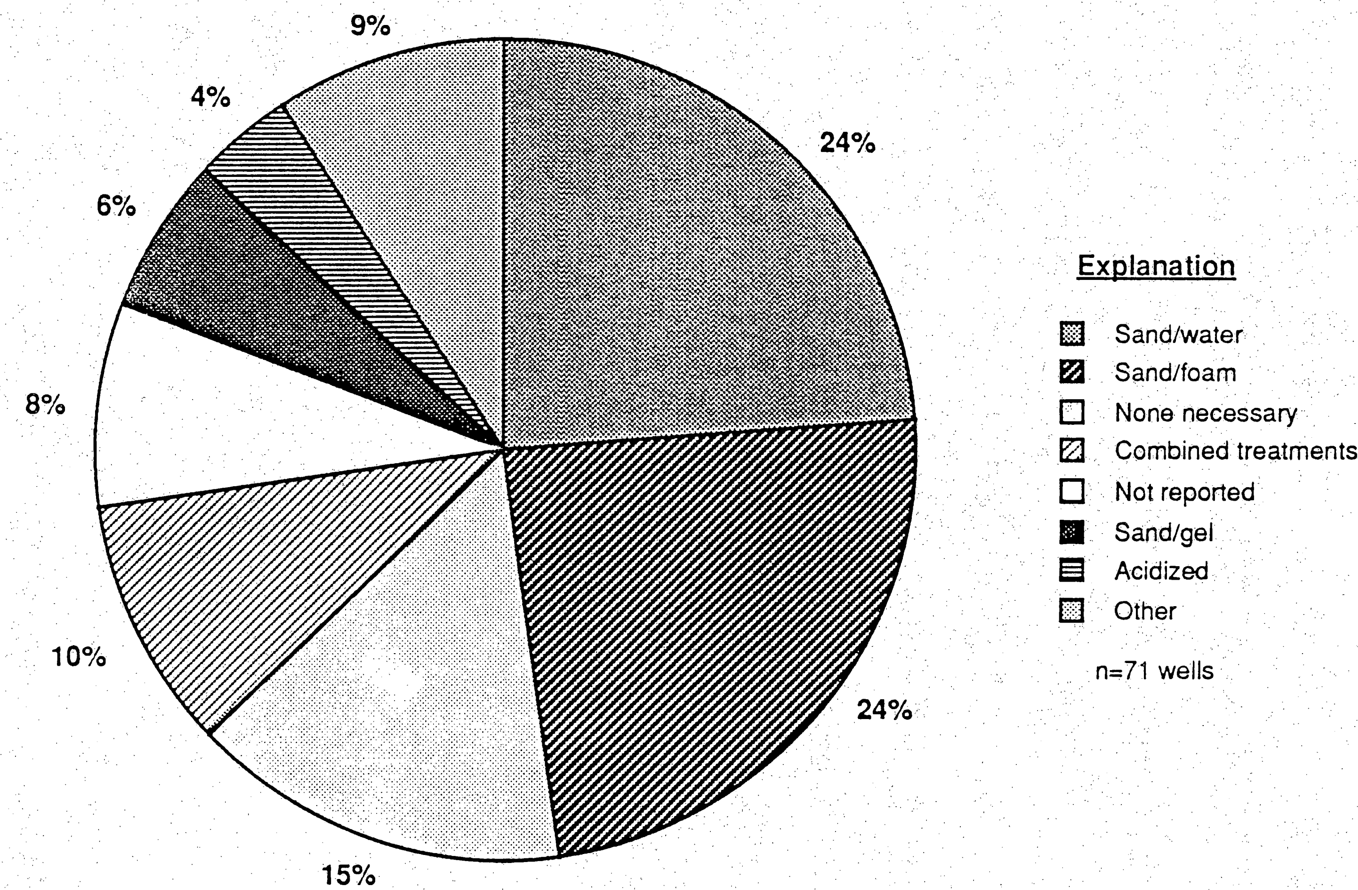


Figure 80. Stimulation methods used in successful gas wells completed in the Mesaverde Group between January 1983 and April 1988. "Combined treatments" include only wells that were treated with different techniques, not those that were treated more than once with the same technique. Wells designated "data not available" are wells for which no information of any kind was provided.

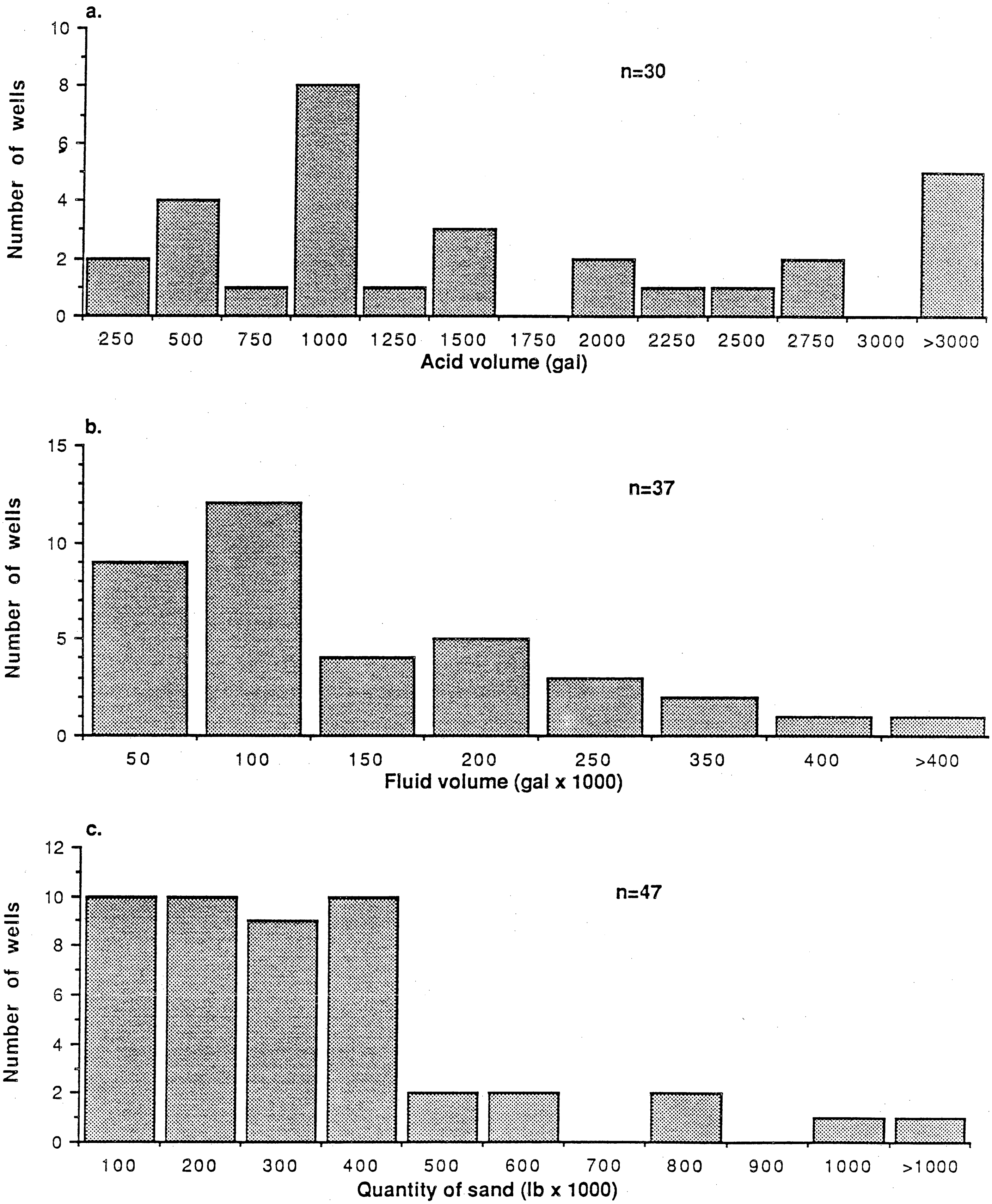


Figure 81. Amount of material used for stimulation of wells completed in the Mesaverde Group between January 1983 and April 1988. (a) Volume of acid. (b) Total fluid volume. (c) Total quantity of sand used.

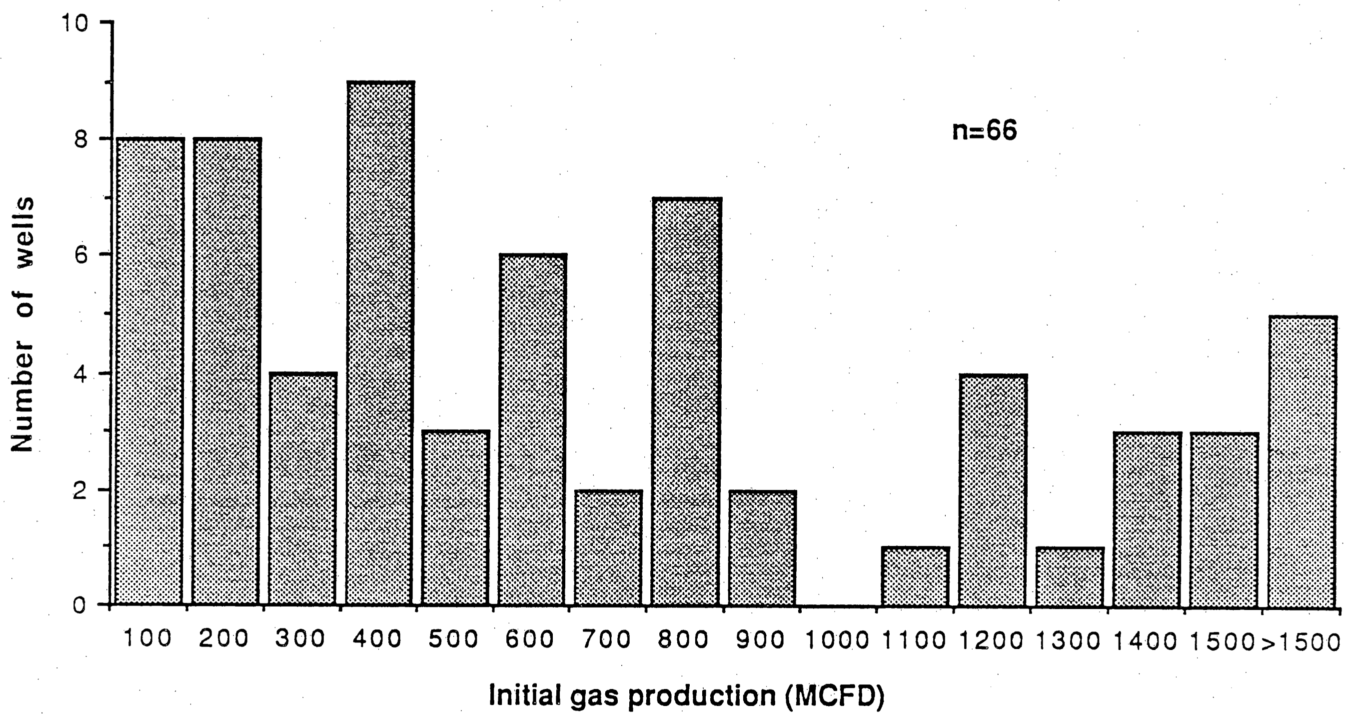


Figure 82. Daily gas production from the Mesaverde Group between January 1983 and April 1988. Most wells produced less than 700 MCFD.

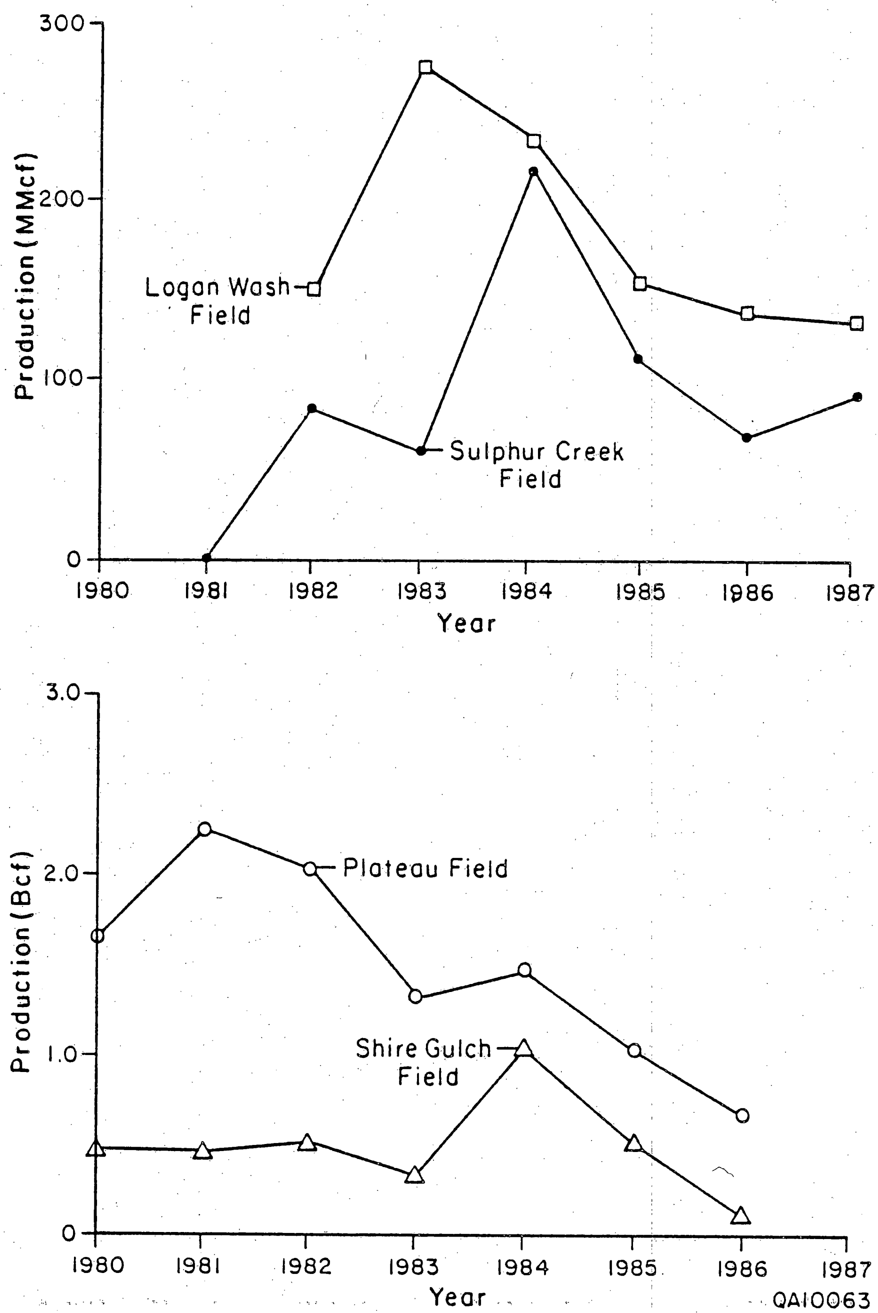


Figure 83. Average production decline curves for four fields in the Mesaverde Group. From ICF-Lewin Energy Division (1988c).

average completion depth ranged from 8,000 to 10,000 ft. Most wells were stimulated with acid and water-gel/sand-fracturing.

Markets for gas are extremely limited in the Rocky Mountains, particularly in the Piceance Basin. Regional oversupply, combined with the high cost (about $0.50/MCF) of transportation to the east, reduces the marketability of new supplies. One potential for renewed demand in the region is the application for the Kern River pipeline from the Colorado-Wyoming area to California to serve the growing EOR markets. Until this market opens up, spot interstate prices will remain as low as those in any region in the country. June 1988 prices were $1.12/MCF, slightly lower than those for June 1987.

Well costs (in 1981) including a fracture treatment ($200,000 to $500,000) approached $1 million. However, a massive hydraulic fracture treatment can increase production by a factor of four (Western Oil Reporter, 1981b). Chancellor and Johnson (1986) describe completion and production statistics for five wells that were completed over a 3,000-ft interval in the Mesaverde (marine/paludal sections). Flow for these wells stabilized at 30 to 125 MCFD/well with minor water and condensate production.

Chancellor (1977) outlined the completion program for the Rio Blanco Natural Gas Company #498-4-1 Government well that bottomed in the Williams Fork Formation. A 130-ft interval flowed 55 MCFD through 16 perforations prior to stimulation. It was treated with 7,000 gal of gelled KCL water and 775,000 lb of sand. Post-fracture production was initially 800 MCFD; it leveled off at 130 MCFD plus three barrels per day each of oil and water. Cost for the fracture treatment was $260,000. Total payout of the well costs ($800,000) was expected after eight years.

Most development in the Piceance Basin is limited to bottoms of river valleys because of rugged terrain. Local relief ranges from 1,000 to 3,000 ft.

Core from 36 wells in the Mesaverde Group is available for study at the U.S. Geological Survey (table A18; fig. A2). Length of core ranges from 2 to 832 ft per well.

Technology Challenges

The low-permeability sandstones of the Mesaverde Formation in the Piceance Basin are depositionally similar to those of the Travis Peak Formation of East Texas. Both units consist of lenticular fluvial and deltaic sandstones that are interbedded with floodplain siltstones and shales.

Sanborn (1977) concluded that any technological advances made in producing Mesaverde reservoirs would substantially increase reserves. Brown and others (1986) state that undeveloped resources exist in the southern Piceance Creek Basin in non-structural, low-reserve accumulations. Most production from the Mesaverde Group in the Piceance Creek Basin has been from naturally fractured, marginal-marine, deltaic, and strandplain sandstones (Castlegate, Sego, Corcoran, Cozzette, and Rollins) of the Iles Formation. Reservoir quality is best on closed structures (Brown and others, 1986; Johnson and Nuccio, 1986). However, the nonmarine upper section of the Mesaverde, because of its greater thickness and abundant gas shows, is believed to contain more gas in place, even though it has lower permeability and porosity (Johnson and Nuccio, 1986). Owing to reservoir discontinuities (especially in the Williams Fork Formation), Mercer and Frohne (1986) suggest well spacings of 160 acres to optimize reservoir drainage.

Although the reservoirs of the Iles Formation are classified as "tight" in Mesa and Garfield Counties (Western Oil Reporter, 1981a), their permeabilities are greater than those described in the FERC guidelines and defined there as "tight" in parts of the Piceance Creek Basin (J. C. Lorenz, Sandia National Laboratory, personal communication, 1988). Most reservoirs respond favorably to stimulation because interbedded marine shales, floodplain mudstones, and coals create high stress intervals that contribute to fracture-growth containment. However, Warpinski and others (1985b) reported a fracture treatment (75,000 gal and 193,000 lb) of paludal sandstones whose permeability was a function primarily of interconnected natural fractures, where production decreased after the fracture treatment. The decline was attributed to (1) reservoir damage, (2) damage to the natural fracture system, and (3) short fracture/reservoir intersection that resulted from the small lateral extent of the reservoir. Warpinski and others (1985b) advise overdesigning fracture proppant to avoid crushing, and Roundtree (1981) suggests using a high-temperature cross-linked gel.

A primary problem with completions in the Mesaverde is the abnormal treating pressure that is commonly observed during massive hydraulic fracturing (MHF). This increase in treating pressure decreases fracture effectiveness by producing undesirable width/length ratios, by limiting the size of hydraulic fractures, by causing premature sand-outs, and by increasing pumping horsepower required by as much as a factor of two (Medlin and Fitch, 1988).

The pressure growth (Δp) begins with the first injection of fluid into fractures, continues throughout the treatment, and ranges from 0.1 to 1.0 psi/bbl of fluid pumped. Sand-outs do not begin before the pressure increase exceeds 2,300 psi, but always begin before Δp exceeds 2,500 psi. In addition, Medlin and Fitch (1988) noted that Δp is matched by a corresponding 1:1 increase in instantaneous shut-in pressure (ISIP) that is semi-permanent, lasting at least 12 days. Field data suggested that the pressure increase in at least some instances developed before the first sand reached the perforations. The data pointed to the conclusion that "sand transport within the fracture was not a contributing factor" and that "pressure growth occurs only above some critical injection rate that depends on the type of fluid used" (Medlin and Fitch, 1988 p. 637). Thin fluids pumped at low rates seemed least likely to cause pressure growth.

Tracer and temperature logs indicated that pressure growth produced little vertical fracturing and that, in general, the fractures were well contained within the perforated intervals. The bounding shales are as brittle as the sandstones (Medlin and Masse, 1986), and fracture containment is believed to be primarily due to stress variations between the sandstones and the shales. During pressure growth, actual fracture lengths as determined by production data were shorter than the predicted ideal theoretical lengths.

Fracture branching at points of formation heterogeneity is proposed as the cause of pressure and ISIP growth (Medlin and Fitch, 1988). Slip motion along the branch faces generates friction that increases the energy needed to sustain crack growth. A geologic challenge is to identify and predict the occurrence of inhomogeneities that lead to fracture branching. These inhomogeneities could be depositional, due to the lenticular nature of the Mesaverde, or diagenetic, reflecting variation in cementation, or structural, such as the presence or absence of natural fractures or stress variations. Most likely, all of these factors are interrelated and play a role in causing fracture branching.

Medlin and Fitch (1988) suggested that pressure growth and resulting sand-out could be avoided by a two-stage treatment that makes use of a process whereby thin fluid is pumped at low rates to fracture the rock, followed by a thick-gel treatment pumped with sand. This procedure might be an appropriate experiment for SFE No. 4. Medlin and Fitch (1988) also suggested that pressure growth could be an effective way to fracture multiple Mesaverde sands in a single treatment. Initially, fractures would be expected to propagate in zones with the lowest fracture gradient, and as pressure growth developed in these zones, fluid would be diverted to zones with the next highest fracture gradient where fracturing and subsequent pressure growth would occur. The process would continue until all zones were receiving fluid in proportion to their fracture gradients.

Determining the correct values of elastic properties to use in hydrofracture design is another important technology challenge. This challenge is illustrated by mechanical and sonic tests that were conducted on shales and sandstones from four gas wells in the Mesaverde Group (Lin and Heuze, 1987). Field dynamic moduli were derived from velocity logs and compared with values of static and dynamic moduli obtained from laboratory testing. Differences between dynamic and static stiffness coefficients as large as 600 percent were obtained. The difference between dynamic moduli obtained by field and laboratory tests was as high as 200 percent (Lin and Heuze, 1987).

The moderate occurrence of siderite concretions in the sandstones, especially in the coastal/paludal section, should preclude use of fluids that liberate iron and induce pore plugging (Lorenz, 1983b, 1987). Apparently, there are more iron-bearing minerals in the Mesaverde Group than in the Travis Peak Formation. Hunt (ResTech Corporation, personal communication, 1988) recommends careful study of the geochemistry of the Mesaverde to avoid pH problems that might lead to formation of chemical gels. These gels could cause abnormal pressure growth during hydraulic fracturing. In addition, salinities of formation waters need to be studied because they probably are not homogeneous and are neither understood nor documented as well as salinities in the Travis Peak Formation.

SUMMARY OF OBSERVATIONS

The purpose of this report is to provide a basis for comparing candidate low-permeability formations, one of which will be selected as the target of SFE No. 4. Three general criteria are important for selecting the target formation: current operator activity, high resource potential, and potential scientific challenge posed by the chosen formation (table 1).

A review of table 5 shows that there are significant differences between the formations with regard to these criteria. For example, for the same time period, January 1986 to April 1988, 107 wells were completed in the Abo Formation, whereas fewer than 20 wells were completed in each of the other formations. Drilling activity since 1982 is less disparate, but still varies by as much as 25 percent from one basin to another.

The amount of resource potential varies considerably from one formation to another. The average production from wells in each formation ranges from 764 to 3,018 MCFD. Estimates of gas-in-place vary by more than an order of magnitude.

As a measure of constrained development of gas resources, the proportion of successful wildcat wells is quite low. No wildcats have been drilled in the Abo recently. Nine of 71 successful wells in the Mesaverde were wildcats (table 5).

The most common quantifiable geological difficulty related to gas production in these formations is low permeability, despite the presence of fractures in these formations. The vast majority of wells require stimulation to produce gas. The Mesaverde Formation has the highest proportion of successful wells not requiring stimulation: 15 percent. However, for all other formations in this study the ratio is less than 2 percent. Conversely, the Mesaverde requires relatively large amounts of fluid and sand in fracturing jobs: up to 250,000 gal and 400,000 lb, respectively, or about five times as much as is required to fracture the Cleveland Formation.

Another important consideration for siting SFE No. 4, not covered by the criteria in table 1, is extending the technology developed during SFE's 1 through 3 to a new area. This would suggest

Table 5. Summary of formation characteristics applicable to selection criteria. Period covered is 1983-1988, except as noted.

Formation name	Wells completed (1986-88)	Average production (MCFD)	Estimated Resource G-I-P (TCF)	Estimated Resource Recoverable (TCF)	Wildcats in new fields	Market access	Industry interest
Frontier	10	1,496	20.3	4.9	2	Good	High
Cleveland	11	3,018	70.0	?	1	Good	Mod-High
Abo	107	1,890	3.0	?	0	Good*	Mod-High
Mesaverde	19	764	86.4	2.3	9	Good	High

*Abo is temporarily shut-in due to arsenic in the gas.

that the target formation of SFE No. 4 should be similar enough to the Travis Peak Formation that the fracture analysis techniques developed there could be tested in this formation, but that the problems encountered should be different enough to require extrapolation.

Each of the four rock units examined in this report presents different conditions that would present new challenges for the location of SFE No. 4. The units will be discussed below in order of increasing complexity and of increasing data availability.

The Cleveland Formation is in perhaps the simplest structural environment for artificial fracture development. The formation dips gently, at depths of less than 10,000 ft, and is not strongly faulted. Although natural fractures contribute to reservoir permeability in some Cleveland wells, almost no wells produce without fracture stimulation. Sandstone beds within the formation are separated by 30- to 100-ft-thick shales that may contain vertical fracture growth. Shales and limestones overlying the formation may also confine vertical fractures to the Cleveland.

The Frontier Formation presents slightly more complex problems. It occurs at depths down to about 15,000 ft, and overpressuring in deep wells may be common. Fractures, stylolites, and faults can be expected in Moxa Arch reservoirs. The reservoir is compartmentalized, shown by lack of communication between wells on 360-acre spacing. Channel sandstones are the most frequently perforated facies type, but they are laterally discontinuous. Historically, production from the Second Frontier has benefitted from improved fracture technology, suggesting that there may be further potential for enhanced gas production. Reservoir seals are present as 50- to 150-ft-thick shales.

A different set of geological challenges is present in the Abo Formation. Regional tectonics and local structure may be affecting production. Natural fractures associated with regional tilting, Tertiary extension (and possibly with dike emplacement) may enhance reservoir permeability. Although production is spatially associated with ends of some Pecos Slope buckles (strike-slip fault zones), the role of fractures in Abo production has not been established. Broadhead (1984a) concluded that gas was stored and produced from fractures, and he further speculated that structure might enhance the intensity of fracturing and thereby increase the volume of gas produced.

Detailed fracture studies in areas of favorable source and reservoir rock would delineate potentially productive fairways (Broadhead, 1984b). An improved understanding of the interaction between structure, depositional systems, and fracture permeability could lead to improved production from this formation.

The Mesaverde Group presents complex problems related to fracture characterization and control. MWX studies have shown that natural fractures affect permeability in this formation. Anisotropic permeability, present throughout the Mesaverde, commonly has ratios of 100:1 between maximum and minimum values (Branagan, 1987). There are at least two sets of fractures in the Mesaverde: regional fractures developed in flat-lying rocks and fractures associated with local folds and faults. Although vertical fractures are commonly mineralized, gas production at the MWX site is reportedly enhanced by natural fractures. Stratigraphic traps predominate, but permeability is greater on structural highs or closures. Throughout the Piceance Creek Basin production is most successful in areas of structural closure where rocks are fractured. Gas present in naturally fractured sandstones with low porosity and permeability can be economically produced after hydraulic fracturing, but because the difference between maximum and minimum horizontal stresses is low, the direction that a hydraulic fracture propagates may be difficult to predict. Well costs may reach $1 million, in part because of the massive hydraulic fractures that are necessary. Treatment pressure increases ascribed to fracture branching commonly occur. Improvements in treatment procedure (including multiple-stage treatments) could solve these problems, and might present the opportunity for multiple fracture treatments during the same fracture job in different target horizons with different fracture gradients.

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APPENDIX

Each of the formations examined in this report presents slightly different problems in generalizing, quantifying, and displaying production and engineering data. Data summarized in the Appendix were compiled from Petroleum Information completion cards (January 1, 1983 through April 1, 1988), Finley (1984), and formation summary sheets prepared by ICF-Lewin Energy Division (1988a).

Production and engineering data were compiled primarily from successful gas wells completed since 1983; no data were taken from dry holes in the areas of interest. Where no up-to-date information was available, information was taken from either Finley (1984) or ICF-Lewin Energy Division (1988a) formation summary sheets. With the exception of three wells in the Mesaverde Group, all production information is for wells completed in the formation in question; wells producing from multiple horizons (commingled production) were omitted. In the Mesaverde Group, commingled production is significant, so information from these wells was incorporated into the database.

Information about fracture techniques and materials includes only data directly applicable to the producing horizon. Locally, horizons that did not produce were treated with various fracture techniques, but this information was not included in characterization of fracture methods or materials. Spud dates include new well spuds as well as old well workovers (or re-entries).

Information supplied below provides specific details about the subset of well data assembled to prepare summary tables for each formation.

Frontier Formation

Eighty-two successful gas wells were completed in the Frontier Formation in the Moxa Arch area between January 1983 and April 1988. No gas wells were completed between May 1987 and April 1988. Production and engineering data provided here represent information from wells completed in the First, Second, Third, and Fifth Frontier ``benches." Almost half (45 percent) of the wells were completed in the Second Frontier. Commonly, however, the producing horizon was not specifically named and was noted only as "Frontier Formation."

Cleveland Formation

One hundred ninety wells were completed in the Cleveland Formation between January 1983 and March 1988. Gas production data, formation fluid data, and data concerning materials used in well stimulation were prepared from a subset of 87 wells producing 5 BOPD or less. Data from four wells producing from the Cleveland Formation and one or more overlying and underlying formations (commingled production) were omitted from the database.

Abo Formation

One hundred seven successful gas wells were completed in the Abo Formation between August 1984 and March 1988. Information provided represents data from all 107 wells.

Mesaverde Group

Seventy-one successful gas wells were completed in the Mesaverde Group between January 1983 and April 1988. Production and engineering information provided in this report represent data from the Mesaverde Group (undifferentiated), the Castlegate, Corcoran, Cozzette, and Rollins Formations, and the Cameo Member. Information also includes data from gas wells producing from multiple horizons within the Mesaverde Group, as well as three wells producing from formations within the Mesaverde Group and the Emery Formation (one well) or the Fort Union Formation (two wells).

Gross perforated interval for these wells was calculated by summing gross perforated intervals from each producing horizon. Depth to top of perforated interval in wells producing from multiple horizons is the depth to the first perforations in the stratigraphically highest producing formation; depth to base of perforated interval is the depth to the deepest perforations in the stratigraphically lowest producing horizon.

Table A1. General Attributes--Frontier Formation (Moxa Arch).

Stratigraphic Unit/Play

Frontier Formation, Upper Cretaceous.

Area

Greater Green River Basin. FERC-designated area on the Moxa Arch is approximately 1,760 mi^2.

Thickness

In the northern Moxa Arch area, ranges from 1,200 ft (northwest) to 300 ft (south). Average thickness is 450 ft in the southern Moxa Arch area.

Depth

In the Moxa Arch area, depth to the top of the First Frontier ranges from 5,700 ft (NW) to 10,900 ft (S). Average depth is 7,820 ft (N=47 log picks). Depth to top of the Second Frontier ranges from 6,300 ft (NW) to 12,200 ft (S) (N=61 log picks).

Depth to perforations varies from 6,040 to 12,198 ft (fig. 18). Average is 9,012 ft. Deepest production depth is 12,198 ft (Second Frontier).

Estimated Resource Base

Gas in place: 20.3 TCF. Maximum recoverable gas: 4.921 TCF (ICF-Lewin Energy Division, 1988a).

Formation Attitude/Other

Generally, the formation dips from basin margins toward basin center.

Geologic Parameters/Basin-Trend

Structural/Tectonic Setting

The Moxa Arch lies in the western part of the Greater Green River Basin. The Moxa Arch is bounded on the north by the Wind River Range, on the east by the Rock Springs Uplift, on the south by the Uinta Mountains, and on the west by the Wyoming Overthrust Belt. The present structural setting is primarily a result of Late Cretaceous--Early Tertiary Laramide tectonism.

Thermal Gradient

1.2° to 1.6°F/100 ft.

Pressure Gradient

Pressure gradient is approximately 0.54 psi/ft in area of Docket No. 189-80 application.

Stress Regime

Colorado Plateau stress province, characterized by north-northeast-trending least horizontal stress. Generally low differential stresses. High horizontal compressional stresses may exist locally.

Table A2. Geologic Parameters--Unit/Play--Frontier Formation (Moxa Arch).

Depositional Systems/Facies

Deposited as several distinct progradational units of a large, wave-dominated deltaic system. These units are commonly referred to as the First, Second, Third, Fourth, and Fifth Frontier sandstones. Of these, the First, Second, and Third Frontier are of primary economic interest in the area; the Second Frontier is the most laterally consistent and productive unit. The Frontier was deposited as an eastward-prograding deltaic complex that includes prodelta muds, delta-front sands, interdeltaic shoreline sands, and delta-plain sands, muds, and coals. The most laterally continuous sandstone within the Second Frontier, known as the second bench, represents regressive strandplain and barrier island deposition.

Texture

Very fine grained to medium-grained and coarse-grained sandstone having some silty and shaly intervals. Poorly to moderately sorted, subangular to subrounded sandstone.

Mineralogy

Litharenites to sublitharenites that contain subequal amounts of quartz and rock fragments, and minor feldspar, dominantly plagioclase. The rock fragments are mainly chert. Framework grain composition varies with depositional environment; marine sandstones contain fewer rock fragments and proportionally more quartz than do fluvial sandstones. Detrital clays are mixed-layer illite/smectite.

Diagenesis

Cements include quartz, chlorite, and kaolinite. Quartz cement is most abundant in clean, quartzose sandstones and less abundant in poorly-sorted or chert-rich sandstones. Detrital mixed-layer illite/smectite appears neomorphosed.

Typical Reservoir Dimensions

No data on size of individual reservoirs.

For all benches within the Frontier, gross perforated interval ranges from 8 to 919 ft, with an average of 157 ft (N=81).

For the Second Frontier only, gross perforated interval ranges from 8 to 382 ft, with an average of 65 ft (N=37).

Pressures/Temperatures in Reservoir

Initial shut-in pressure ranges from 224 to 6,789 psi, and averages 3,211 psi. Temperature range is from 161° to 242°F.

Natural Fracturing

Structural setting suggests natural fractures are likely to be common. However, only one well out of 84 examined (post-1983) did not require stimulation.

Data Availability

Three cores reported for wells completed since January 1983. Eighty-six cores from a total of 555 completions (through December 1983).

Compensated neutron, gamma ray, and dual induction-spherically focused logs are the most common types of logs from wells completed since January 1983.

Table A3. Engineering Parameters--Frontier Formation (Moxa Arch).

Reservoir Parameters

For the Frontier Formation (overall) in the northern Moxa Arch area: Porosity ranges from 5.7 percent to 25 percent with an average of 13.4 percent. Permeability ranges from <0.0001 to 1.3 md, with an average of 0.007 md.

For the Frontier Formation on the southern Moxa Arch, porosity ranges up to 18 percent, with an average of 12 percent. In situ permeability ranges from 0.171 md, with an average of 0.0308 md.

Net Pay Thickness

For the Second Frontier only, range is from 9 to 90 ft. Average is 36 ft (northern Moxa Arch), to 21 ft (southern Moxa Arch).

Production Rates

Pre-Stimulation

TSTM to 2,630 MCFD.

Post-Stimulation

For Frontier Formation overall, range is from 48 to 8,240 MCFD, with an average of 1,496 MCFD (N=82) (fig. 21).

For the Second Frontier only, range is from 48 to 4,000 MCFD, with an average of 1,066 MCFD. Thirty-eight of 82 wells (46 percent) produce >1,000 MCFD (average=2,782 MCFD).

Decline

See figure 22.

Formation Fluids

Since January 1983, 13 of 82 wells have produced an average of 29 BPD of condensate. Range is from 0 to 113 BPD. Twenty-two of 82 wells produce an average of 25 BPD of water. Range is from 0 to 181 BPD.

Water Saturation

Average is 51 percent. Range is from 36 percent to 68 percent.

Well Stimulation Techniques

Seventy-two of 75 wells (96 percent) for which completion methods were reported were hydraulically fractured by some technique. Sixty-five of these 75 wells (87 percent) were hydraulically fractured using sand/foam, sand/gel, or sand/water treatments (fig. 19). Typical stimulations use between 100,000 to 300,000 lb of sand; fluid volume is more variable than in other formations, but 50 percent of the operators used between 100,000 and 200,000 gal (fig. 20). Wells are generally not acidized (86 percent), but two wells were acidized only. Twenty-three percent of the wells were stimulated in two or more steps (maximum of five treatments). The largest treatment recorded consisted of nearly 400,000 gal fluid and nearly 900,000 lb sand.

Success Ratio

Thirty-four of 35 (97 percent) of fracture treatments resulted in improved flow in the southern Moxa Arch. No data for the northern Moxa Arch.

Well Spacing

640 acres.

Table A4. Economic Factors--Frontier Formation (Moxa Arch).

FERC Status

Approved by Wyoming Oil and Gas Conservation Commission. Certain parts have FERC approval.

Attempted Completions

Eighty-four successful gas well completions in the Moxa Arch area (January 1983 to May 1987) (fig. 15). One hundred four attempted completions in the Moxa Arch area (to December 1983).

Success Ratio

In the Greater Green River Basin as a whole, 22.7% of all wildcat wells were successful in 1970-1977 (ICF-Lewin Energy Division, 1988a). No data specific to the Frontier.

For the period January 1983 to May 1987, two of 84 successful wildcat gas wells were new field discoveries, and two of 84 were successful wildcat outposts.

Drilling/Completion Costs

Drilling costs: $250,000 for a 9,000-ft well; $450,000 for an 11,000-ft well.
Completion costs: $160,000 to $250,000.
Equipment costs: $50,000.
Stimulation costs: $90,000 to $100,000.
Operating costs: No data.
(1988 dollars)

Market Outlets

Pipelines in place to serve established production on the Moxa Arch, especially on the northern end of the arch near Big Piney, Dry Piney, and La Barge East fields. Northwest Pipeline Corporation and FMC Corporation operate pipelines in this area.

Industry Interest

High. Six applications have been filed for designation of the Frontier as a tight gas sand in different parts of the Greater Green River Basin.

Operating Conditions

Physiography

In the Wyoming-Big Horn Basins physiographic subdivision. Local relief of 300 to 500 ft in most areas, 500 to 1,000 ft toward the western margin of the basin; greater relief is encountered along the Overthrust Belt.

Climatic Conditions

Semiarid to arid. Most areas receive 8 to 16 inches mean annual precipitation at higher elevations. Mild summers, cold winters. Exploration and development drilling are conducted all year.

Accessibility

Access is by unimproved roads and may be locally limited by significant relief.

Extrapolation Potential

Good to very good. The Frontier is a widespread deltaic system present in several subbasins of the Greater Green River Basin and in the Wind River and Big Horn Basins. Best blanket geometry is in the Second Frontier, which would be analogous to other delta-front, barrier, and strandplain facies in other less areally extensive deltaic and interdeltaic deposits.

Comments

Mileage charges may be high for service to remote areas. Selected services based at Rock Springs, Wyoming.

Table A5. Wells in Moxa Arch area, Green River Basin, with cores from the Frontier Formation available for study at the U.S. Geological Survey. Forty-four wells are listed in order of increasing township and range numbers. Fifteen townships are covered by this list.

County (Field)	Location*	Operator	Well Name	Depth (ft)	Length (ft)
Lincoln (OSC)	23N 112W 26	Belco Pet Corp	4 Emigrant Springs Unit	10624 - 10652	28
Lincoln (OSC)	23N 112W 32	Amoco	1 Shute Creek Unit	10755 - 10855	100
Sweetwater (SS)	24N 111W 3	C & K Petroleum	2 Lincoln Road	9560 - 9679	119
Sweetwater (SS)	24N 111W 4	C & K Petroleum	3 Lincoln Road	9465 - 9524	59
Sweetwater (SS)	24N 111W 5	C & K Petroleum	4 Lincoln Road	9287 - 9315	28
				9355 - 9450	95
				9472 - 9506	34
Sweetwater (SS)	24N 111W 9	C & K Petroleum	1 Lincoln Road	9560 - 9668	108
Sweetwater (SS)	24N 111W 10	C & K Petroleum	7 Lincoln Road	9660 - 9745	85
Sweetwater (SS)	24N 111W 15	C & K Petroleum	12 Lincoln Road	9814 - 9868	54
Sweetwater (SS)	24N 111W 16	C & K Petroleum	6 Lincoln Road Unit	9906 - 9928	22
				9945 - 10009	64
Sweetwater	24N 113W 11	FMC Corp	1-11 Pomeroy Draw	9842 - 9894	52
Sweetwater	25N 107W 30	American Hunter	A-1 Enterprise	15925 - 16059	134
Sweetwater	25N 108W 17	American Hunter	1 Faraway	15230 - 15267	37
Sweetwater	25N 110W 22	Energetics Inc	32-22 Federal	5251 - 5305	54
Sweetwater	25N 110W 27	Energetics Inc	32-27 Federal	10487 - 10521	34
Sweetwater/Lincoln	25N 111W 5	Natural Gas Corp	13-5-F N Anderson Canyon	8747 - 8808	61
Lincoln	25N 111W 7	Natural Gas Corp	23-7F Federal	8722 - 8782	60
Lincoln	25N 111W 19	Natural Gas Corp	3-19 Federal	8737 - 8788	51
				8813 - 8872	59
Lincoln	25N 111W 19	Natural Gas Corp	2-19 Federal	8941 - 8982	41
Lincoln	25N 112W 3	Pacific Trans Supply	12-3 Federal	8307 - 8345	38
				8390 - 8454	64
Lincoln	25N 112W 3	Pacific Trans Supply	34-3 Federal	8495 - 8551	56
Lincoln	25N 112W 7	Pacific Trans Supply	23-7 Pts-Fontenel	8536 - 8650	114
Lincoln	25N 112W 8	Pacific Trans Supply	32-8 Federal	8252 - 8286	34
				8302 - 8328	26
Lincoln	25N 112W 9	Pacific Trans Supply	41-9 Federal	8650 - 8671	21
				8708 - 8753	45
Lincoln	25N 112W 11	Pacific Trans Supply	43-11 Federal	8604 - 8712	108
Lincoln	25N 112W 14	Natural Gas Corp	41-14-E Federal	8613 - 8640	27
				8652 - 8710	58
Lincoln	25N 112W 21	Natural Gas Corp	34-21-E Federal	8850 - 8910	60
Lincoln	25N 113W 13	Pacific Trans Supply	23-13 Federal	8830 - 8855	25
				8875 - 8935	60
Sweetwater/Lincoln	26N 111W 18	Southland Royalty Co	1 East Stead Canyon	8521 - 8558	37
Sweetwater/Lincoln	26N 111W 19	Pacific Trans Supply	32-19 PTS Federal	8303 - 8335	32
				8347 - 8353	6
Sweetwater/Lincoln	26N 111W 19	Pacific Trans Supply	32-19 Federal	8295 - 8354	59
Sweetwater/Lincoln	26N 111W 31	Natural Gas Corp	32-31 Federal	8541 - 8572	31
Lincoln	26N 112W 14	Belco Pet Corp	13 East LaBarge Unit	7827 - 7882	55
Lincoln	26N 112W 22	Natural Gas Corp	43-22 Federal	7668 - 7710	42
Lincoln	26N 112W 22	Natural Gas Corp	22-22B Fontenelle	7600 - 7660	60
Lincoln	26N 112W 28	Pacific Trans Supply	34-28 Eubank Cattle Co	7572 - 7638	66
Lincoln	26N 112W 31	Pacific Trans Supply	14-31 Fontenelle	8385 - 8464	79
Lincoln	26N 112W 32	Pacific Trans Supply	42-32 Buck	7838 - 7895	57
Lincoln (BPL)	26N 113W 13	Belco Pet Corp	42 Green River Bend Unit	7441 - 7458	17
Lincoln (BPL)	26N 113W 15	Belco Pet Corp	30 Green River Bend Unit	7408 - 7451	43
				7454 - 7469	15
				7476 - 7500	24

Table A5 (cont.)

County (Field)	Location*	Operator	Well Name	Depth (ft)	Length (ft)
Lincoln (BPL)	26N 113W 23	Belco Pet Corp	32 Green River Bend Unit	7829 - 7836	7
				7855 - 7860	5
				7878 - 7896	18
				7913 - 7925	12
Lincoln (BPL)	27N 113W 36	Belco Pet Corp	14 Chimney Butte	7399 - 7435	36
Lincoln (BPL)	27N 114W 4	Belco Pet Corp	41 Green River Bend Unit	6311 - 6332	21
				6680 - 6713	33
				6755 - 6819	64
Lincoln (BPL)	28N 113W 29	Mountain Fuel Supply	3 Unit	6930 - 7013	83
				7673 - 7749	76
Lincoln (BPL)	28N 113W 36	Mobil Oil Corp	44-29 Unit	6172 - 6214	42
				6672 - 6721	49

* Location given as Township-Range-Well Number

Field names:
OPS: Opal-Shute Creek
SS: Storm Shelter
BPL: Big Piney-LaBarge

Source: Thomas C. Michalski, U.S. Geological Survey, written communication, 1988.

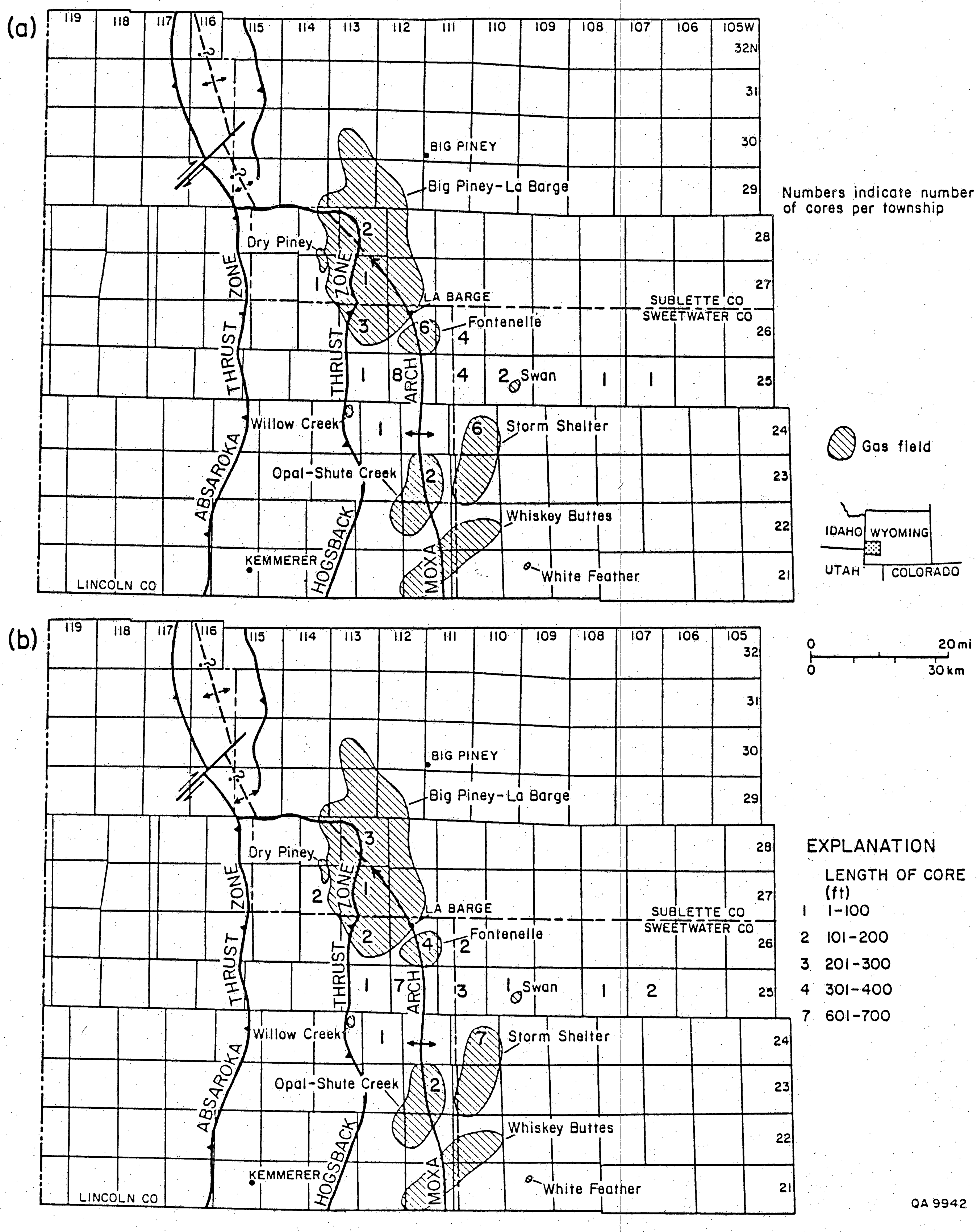

Figure A1. Cores from Frontier Formation, Moxa Arch area, Green River Basin available for study at U.S. Geological Survey. (a) Number of cores per township. (b) Total length of cores per township.

Table A6. General Attributes--Cleveland Formation.

Stratigraphic Unit/Play

Cleveland Formation, Kansas City Group, Pennsylvanian (Missourian)

Area

Anadarko Basin. Total FERC-designated area is 5,051 mi^2 in Texas and Oklahoma. Approximately 4,500 mi^2 in all or part of seven counties in the Texas Panhandle.

Thickness

Across Hansford, Ochiltree, and Lipscomb Counties, Texas, range is 80 to 170 ft. Average is 120 ft.

Depth

Depth to top of Cleveland ranges from 6,300 ft (WNW) to 9,500 ft (ESE), with an average of 7,400 ft (N=81).

Depth to top of perforations ranges from 6,250 to 9,550 ft, with an average of 7,400 ft (N=83) (fig. 38). Deepest production depth is 9,580 ft.

Estimated Resource Base

Gas in place: 70 Tcf.

Formation Attitude/Other

Strike is north to northeast; dip averages about 1° east-southeast.

Trapping mechanism is stratigraphic.

Geologic Parameters/Basin-Trend

Structural/Tectonic Setting

Northern (Kansas) Shelf of the Anadarko Basin. Bounded to the south by the Amarillo-Wichita Uplift. Minor structures include low-amplitude folds. Potentially complex burial and natural fracture history, but no data available on subsurface fractures in the Cleveland.

Thermal Gradient

Less than 1.2° to 2.2°F/100 ft, mostly 1.4° to 2.0°F/100 ft.

Pressure Gradient

0.375 psi/ft. Mud weights suggest normal hydrostatic gradients.

Stress Regime

Midcontinent compressional stress regime. East-northeast-trending maximum horizontal stress. Bounded on the south by high-angle reverse fault of the Amarillo Uplift.

Table A7. Geologic Parameters--Unit/Play

Depositional Systems/Facies

Marine-shelf environment having sources to the west, north, and east other than the Amarillo Uplift. Thin (20- to 40-ft) deltaic unit possible at the base of the formation in some areas, represented by upward-coarsening (possibly deltaic front) to blocky (possibly distributary bar) log characters. Rest of unit may be shelf-dispersed sands near or at storm-wave base.

Texture

Fine- to very fine grained, well-sorted sand, tending to be tightly packed in diagenetic and detrital clay.

Mineralogy

Information is available from one thin section of a fine-grained subarkose containing 15 percent clay matrix. Major framework minerals are quartz, weathered feldspar (plagioclase more abundant than orthoclase), and mica.

Diagenesis

Authigenic minerals include quartz overgrowths, calcite, and siderite. Some authigenic clay (probably illite) formed as a result of feldspar alteration and dissolution.

Typical Reservoir Dimensions

Areal extent is usually 25 to 75 mi^2; however, operators have developed smaller reservoirs. Average thickness is 120 ft. For wells completed since January 1983, gross perforated interval ranges from 8 to 106 ft, with an average of 46 ft (N=82).

Pressures/Temperatures in Reservoir

Typically, original pressure range is 2,200 to 2,700 psi. Temperature range is 135° to 160°F.

For wells completed since January 1983, shut-in bottom hole pressure ranges from 581 to 4,610 psi, and averages 2,200 psi (N=61).

Natural Fracturing

No definite evidence of natural fracturing. Two wells out of 84 completed since January 1983 did not require stimulation.

Data Availability

Estimated that <1 percent of the Cleveland wells in the Texas Panhandle have been cored, and no cores have been reported from wells completed since January 1983. Logs typically include dual induction, induction, compensated neutron, and gamma-ray logs. No sonic logs (January 1983-March 1988).

Table A8. Engineering Parameters--Cleveland Formation.

Reservoir Parameters

Median in situ permeability for 391 wells is 0.028 md, representing an unknown mixture of pre- and post-stimulation well tests. Bulk porosity is 10 percent.

Net Pay Thickness

Average is 10 to 45 ft; maximum is estimated to be 75 ft.

Production Rates

Pre-Stimulation

Commonly TSTM.

Post-Stimulation

For wells completed after January 1983, and which produce ≤5 BOPD, the range is from 60 to 12,250 MCFD. Average is 3,018 MCFD (N=83).

Sixty-five of 83 wells (78 percent) produce >1,000 MCFD (Average=3,688 MCFD). Forty-six of 83 wells (55 percent) produce >2,000 MCFD (Average=4,575 MCFD).

See figure 41.

Decline

Approximately 56 percent in the first year, followed by 11 percent/year for the life of the well. See figure 42.

Formation Fluids

Two wells out of 83 produced measurable condensate (3 bbl, 27 bbl). For 396 wells completed prior to 1981, condensate production is low, and none produced more than 5 BPD.

Three wells out of 83 produced measurable water (≤7 BPD).

Water Saturation

Thirty percent to 40 percent for the usual pay zone. Calculated values range from 30 percent to 50 percent, and up to 100 percent.

Well Stimulation Techniques

Sixty-one of 63 wells (97 percent) for which completion techniques were reported were hydraulically fractured by some method. Fifty-three of these 63 wells (84 percent) were hydraulically fractured using either sand/gel or sand/water treatments.

Typical treatment includes acidizing with 1,500 to 3,000 gal of 7.5 percent HCl, and fracturing with 40,000 to 80,000 gal of water and/or cross-linked polymer gel, and from 60,000 to 180,000 lb sand. Pressures of 4,500 to 5,000 psi are used.

See figures 39 and 40.

Success Ratio

Stimulation is commonly successful.

Well Spacing

Six hundred forty acres, 320 acres optional. Operators are interested in lowering this to 320 acres, 160 acres optional.

Table A9. Economic Factors--Cleveland Formation.

FERC Status

Approximately 4,500 mi^2 in northeast Texas Panhandle approved by state on November 30, 1981.

Approximately 550 mi^2 in Oklahoma also FERC-approved.

Attempted Completions

Eighty-two successful completions and old well workovers from January 1983 to March 1988 (fig. 35).

Five hundred seven total in 6 counties in Texas (to December 1983).

Success Ratio

Since January 1983, only one successful wildcat discovery has been made in the area of interest. Seventy-nine of 82 successful gas well completions (96 percent) have been infill wells.

For infill wells drilled prior to December 1983, success ratio was 80 percent to 90 percent, dropping toward the edges of a field.

Drilling/Completion Costs

Total costs for a 7,500-ft well range from $422,000 to $547,000.
Drilling and completion costs: $260,000 to $370,000.
Equipment costs: $80,000.
Stimulation costs: $75,000 to $90,000.
Operating costs: $1,500/month.
Additional expenditures: $7,000.
(1988 dollars)

Market Outlets

Many pipelines in place and healthy competition exists for the available gas. Gas is purchased for interstate sale, agricultural irrigation pumps, fertilizer plants, power generation, and residential use.

Industry Interest

Moderate to high. One FERC application prepared by Diamond Shamrock and supported by 22 other companies (data as of 1981).

Operating Conditions

Physiography

Terrain generally flat-lying to low, rolling hills. Local relief 100 to 200 ft along the "Canadian Breaks" (eroded slopes of the Canadian River valley). Numerous internally-drained depressions (playas) on the Southern High Plains.

Climatic Conditions

Subhumid to semi-arid continental climate, with most rainfall occurring as a result of convective-cell thunderstorms between April and September. Mean annual rainfall ranges from 18 to 23 inches. At Amarillo, normal daily minimum temperature in January is 22.5°F. Normal daily maximum temperature in July is 91.4°F. Weather usually does not prevent drilling activity.

Accessibility

Paved highways cross the area at intervals of 15 to 20 mi. Unpaved section roads on 1- to 2-mi spacing.

Extrapolation Potential

Fair. Very thin deltaic package has no good analogy. Shelf sand having abundant clay matrix has analogy in the Mancos "B" (Piceance and Uinta Basins), and Sanostee Member (San Juan Basin), although the Mancos "B" is much thicker, and the Sanostee is a calcarenite- and calcite-cemented sandstone. A possible engineering extrapolation would be the Mancos "B" shale in the Uinta Basin.

Comments

All drilling and completion services readily available in the Oklahoma and Texas Panhandle areas.

Table A10. General Attributes--Abo Formation.

Stratigraphic Unit/Play

Abo Formation, Lower Permian (Wolfcampian to Lower Leonardian).

Area

Permian Basin.

Total FERC-designated area is 11,411 mi^2 in east-central to southeast-central New Mexico.

Thickness

Thickness ranges from 535 to 818 ft. Average is 700 ft.

Depth

Depth to top of Abo Formation ranges from 1,800 to 5,500 ft, with an average of 3,100 ft.

Depth to top of perforations ranges from 2,000 to 4,750 ft, with an average of 3,200 ft (N=107) (fig. 57).

Deepest production depth is 4,750 ft.

Estimated Resource Base

Gas in place: >3TCF (Estimate of recoverable gas, ICF-Lewin Energy Division, 1988a).

Formation Attitude/Other

Strike is north-northeast; dip is east-southeast. Structural and stratigraphic traps exist in the area of interest. Local steep dips and faults occur adjacent to Pecos Slope buckles. Most production from the Abo (after January 1983) appears to be associated with the terminations of the Border, Six-mile, and Y-O buckles.

Geologic Parameters/Basin-Trend

Structural/Tectonic Setting

Within relatively undeformed southern Great Plains Stress Province and adjacent to late Tertiary Basin and Range extended terrain and Laramide thrust belt of Southwest New Mexico. Laramide Pecos Slope "buckles," which are strike-slip faults and associated folds, are present in area of Abo production.

Thermal Gradient

No data.

Pressure Gradient

0.35 psi/ft.

Stress Regime

Southern Great Plains stress province. Least principal horizontal stress direction is north-northeast and uniform over a large area. Extensional regime.

Table A11. Geologic Parameters--Unit/Play--Abo Formation.

Depositional Systems/Facies

Lower Abo: "Granite wash" alluvial fan deposits drape the Pedernal Uplift and interfinger basinward with limestone.

Middle Abo: East of Pedernal Uplift, marine shelf mudstones and sandstones grade upward into distal deltaic deposits. The middle Abo onlaps the lower Abo and pinches out to the west.

Upper Abo: Southward progradation of meandering-stream and delta-plain environments, upper Abo sediments drape the Pedernal Uplift and interfinger with "reef and backreef" carbonates.

Texture

Principally an upward-fining sequence of interbedded cobble conglomerates, coarse- to fine-grained sandstone, and mudstone. Some dolostones and limestones are present.

Mineralogy

Variable. Lower Abo sandstones are arkoses containing quartz, potassium feldspar, and granite fragments. Upper Abo sandstones are subarkoses, arkoses, and quartzarenites. Feldspar content is highest in the north and decreases southward. Detrital clays are present, but the minerals have not been identified. Some mudstones swell in fresh water and probably contain smectite.

Diagenesis

Authigenic cements in the Upper Abo include anhydrite, calcite, dolomite, quartz, and clay; and hematite clay rims stained red by hematite are common around detrital grains. The rims probably formed by mechanical infiltration of clay into the sand shortly after deposition.

Typical Reservoir Dimensions

No data on areal extent of individual reservoirs. For wells completed since January 1983, gross perforated interval ranges from 3 to 1,305 ft, with an average of 245 ft. More than 50 percent of the wells have gross perforated intervals $\leq$ 200 ft (N=107).

Pressures/Temperatures in Reservoir

Initial pressure ranges from 1,000 to 1,200 psi. Temperatures range from 102° to 115°F (sparse data). For wells completed since January 1983, shut-in bottom hole pressure ranges from 520 to 1,343 psi and averages 878 psi (N=69).

Natural Fracturing

Very limited data on natural fracturing. Natural fractures are generally believed to be closed or filled with secondary minerals. All wells successfully completed since January 1983 required some type of stimulation.

Data Availability

Limited core data. Four cores are reported in the literature (Broadhead 1984b). No cores reported from 107 wells completed since January 1983.

Seventy-five percent of the wells examined were mechanically logged. Dual latero-log, compensated neutron, acoustic cement bond, and microspherically focused logs are the most common types. No sonic logs reported.

Table A12. Engineering Parameters--Abo Formation.

Reservoir Parameters

Permeability ranges from 0.03 to 0.05 md. Average in situ permeability is 0.0067 md. Bulk porosity ranges from 5 to 15 percent.

Net Pay Thickness

Ranges from 38 to 45 ft, with an average of 40 ft.

Production Rates

Pre-Stimulation

A few tens of MCFD per well reported.

Post-Stimulation

Range is from 54 to 11,494 MCFD. Average is 1,890 MCFD (N=104).

65 of 107 wells (61 percent) produce >1,000 MCFD. (Average=2,708 MCFD) (fig. 60).

Decline

See figure 61.

Formation Fluids

No hydrocarbon liquids, condensate, or water were produced from any successful gas wells completed since 1983 (N=107).

Water Saturation

No data.

Well Stimulation Techniques

Ninety-three of 94 wells (99 percent) for which completion methods were reported were hydraulically fractured by some technique. Eighty-four of 94 wells (89 percent) were treated using a sand/water mixture or conventional hydraulic fracturing (fig. 58).

Typical treatment includes acidification (variable quantities of acid), and fracturing with 40,000 to 70,000 gal of fluid (generally water), and from 60,000 to 180,000 lb sand. Treatments using 180,000 gal fluid and 240,000 lb sand have been reported (fig. 59).

Success Ratio

Flow from most wells increases from a few tens of MCFD (pre-fracture) to a flow of a few thousand MCFD (post-fracture). Data reported for 92 wells (Broadhead, 1984a, time period not specified) indicate average initial calculated open flow of 2,172 MCFD after fracturing, with a range of 18 to 15,500 MCFD.

Well Spacing

One hundred sixty acres.

Table A13. Economic Factors--Abo Formation.

FERC Status

FERC approved 11,411 mi^2 in Chaves and DeBaca Counties, New Mexico. Nine fields are affected.

Attempted Completions

One hundred seven successful completions from January 1983 to March 1988 (fig. 54). Five hundred fifty-five attempted Abo completions to December 1983.

Success Ratio

Success ratio is 90 percent for 300 wells drilled since FERC designation in 1983. All wells were drilled in known producing areas of the Abo.

Drilling/Completion Costs

Total costs for a 4,000-ft well range from $330,000 to $442,000.
Drilling and completion costs: $250,000 to $350,000.
Equipment costs: $20,000 to $32,000.
Stimulation costs: $60,000.
Operation costs: $600/month.
(1988 dollars)

Market Outlets

Transwestern Pipeline Company purchases and distributes Abo gas. Pipeline system is connected with a 24-inch Panhandle line.

Industry Interest

Interest in the Abo Formation remains at moderate to high levels despite the recent (June 1988) shut-in of approximately 600 wells. One major (Texaco) and four independents (Yates, Sequoia, Mesa, Nortex) optimistically anticipate that a solution to the arsenic production problem by the end of 1988 and increased gas prices will stimulate activity in the Abo play.

Operating Conditions

Physiography

The area straddles the boundary between two physiographic provinces--the Southern High Plains and the Pecos Plain. Except in the vicinity of the Western Caprock Escarpment, topography is flat to gently rolling.

Exposed rocks range from Permian to Recent in age, and include Triassic, Jurassic, and Cretaceous rocks.

Climatic Conditions

Semiarid climate. Most rainfall occurs during convective-cell thunderstorms between April and September. Daytime high temperatures in summer can exceed 100°F. Daytime lows in winter in 20's. Weather conditions usually do not limit drilling activity.

Accessibility

Major north-south and east-west roads intersect in Roswell. Unpaved section roads on 1- to 2-mile spacing.

Extrapolation Potential

Good. Abo Formation production is derived from stratigraphic traps formed by the isolation of braided and meandering stream channel sandstones and deltaic sandstones by floodplain mudstones. Experience and knowledge gained from research conducted in the Abo Formation would be directly applicable to exploration and exploitation of similar facies in other formations (for example, the Oriskany Sandstone, the Medina Group, and the Travis Peak Formation). In addition, natural fracture studies in the Abo would be widely applicable to other low-permeability gas sandstones in western basins.

Comments

All drilling and completion services are available in the Permian Basin.

Table A14. General Attributes--Mesaverde Group (Piceance Basin).

Stratigraphic Unit/Play

Mesaverde Group. Upper Cretaceous.

Production and engineering data are compiled from the following formations/wells:

Castlegate Formation/6 wells
Corcoran Formation/8 wells
Cozzette Formation/1 well
Rollins Formation/1 well
Cameo Member/14 wells
Mesaverde (Undifferentiated)/23 wells
Commingled production/18 wells

Total=71 successful gas wells completed between January 1983 and January 1988.

Area

Piceance Basin.

FERC-designated area in the Piceance Basin is:

2,512 mi^2 (Corcoran-Cozzette)
2,689 mi^2 (Castlegate, Sego, Rollins, Coaly)

Estimated tight gas productive area: 4,500 mi^2.

Thickness

Corcoran-Cozzette: 325 ft.

Mesaverde (Castlegate, Sego, Rollins, Coaly): 2,000 to 5,000 ft.

Depth

Depth to top of Mesaverde Group varies from 0 to 8,600 ft, with an average of 3,984 ft.

Depth to top of perforated interval ranges from 552 to 8,560 ft, with an average of 4,524 ft (fig. 79).

Depth to base of perforated interval ranges from 563 to 8,831 ft, with an average of 4,862 ft (N=71).

Greatest production depth is 8,831 ft.

Estimated Resource Base

Total estimated gas in place: 86.4 TCF.

Corcoran-Cozzette: 21.4 TCF.

Mesaverde (Castlegate, Sego, Rollins, Coaly): 65 TCF.

Maximum recoverable gas (Corcoran-Cozzette only): 2,294 TCF (ICF-Lewin Energy Division, 1988a).

Formation Attitude/Other

Strike is generally to the northwest, dip to the northeast at 2° to 3° (T5-11S, R93-100W).

Much steeper and more varied dips on northwest-trending, open periclinal folds in eastern Mesa, western Pitkin, and southeastern Garfield Counties (T6-9S, R90-92W).

Geologic Parameters/Basin-Trend

Structural/Tectonic Setting

Northwest-trending Late Cretaceous to Early Tertiary sedimentary and structural basin is bounded on the north by the Uinta Uplift, on the east by the White River Uplift, on the southeast by the Sawatch Range, on the southwest by the Uncompahgre Uplift, and on the west by the Douglas Creek Arch.

Thermal Gradient

Mostly 2.6° to 2.9°F/100 ft (Cozzette only).

Pressure Gradient

0.42 psi/ft (Corcoran-Cozzette).

0.3 psi/ft (Castlegate, Sego, Rollins, Coaly).

Locally higher (overpressured) in deep wells.

Stress Regime

In Colorado Plateau compressional stress province, which has north-northeast-trending least horizontal stress. Natural fractures, permeability anisotropy and fracture created in hydraulic fracture treatment strike west-northwest at MWX site.

Table A15. Geologic Parameters--Unit/Play--Mesaverde Group (Piceance Basin).

<u>Depositional Systems/Facies</u>

Regressive shoreline sandstones (prograding shoreface, barrier island, wave-dominated delta) intertongue with transgressive marine deposits of the Mancos Shale in the basal Mesaverde Group (Iles Formation). Strandplain facies interfinger updip with, and are often overlain by, coal-bearing fluvial/paludal (coastal plain) sediments deposited in lower and upper delta-plain environments (Williams Fork Formation). Upper undifferentiated Mesaverde rocks represent deposition in fluvial systems (meandering to anastomosed). The fluvial sequence is capped by paralic (estuarine, bay, lagoon) deposits that represent the onset of the Lewis transgression.

<u>Texture</u>

Shoreline/Marine sandstones:

Upward-coarsening, poorly to well-sorted, very fine grained sandstones with detrital silt and clay.

Paludal/Coastal Sandstones:

Internally homogeneous to upward-fining, poorly to well-sorted, fine-grained sandstone. Detrital silt and clay, and siderite-rich, mud rip-up clasts common.

Fluvial Sandstones:

Internally heterogeneous, blocky to upward-fining, poorly to moderately sorted, medium- to fine-grained sandstone. Conglomerate rarely present.

Paralic:

Homogeneous, poorly to well-sorted, very fine to fine-grained sandstone.

<u>Mineralogy</u>

Mesaverde sandstones are mainly feldspathic litharenites. Average composition is 60 percent quartz, 5 to 10 percent feldspar, and 30 percent rock fragments. Lithic grains are chert, dolomite, shale, mudstone, and siltstone.

Detrital clays are mixed-layer illite/smectite, illite, and chlorite.

Diagenesis

Authigenic cements include quartz, calcite, dolomite, ankerite, mixed-layer illite/smectite, chlorite, illite, and kaolinite. In most zones calcite is the most abundant carbonate cement. Dissolution of calcite formed secondary porosity.

The main reason for low permeability is presence of abundant authigenic clay, detrital clay, and pseudomatrix formed from compacted sedimentary rock fragments.

Typical Reservoir Dimensions

No data on size of individual reservoirs. Number of new wildcat field discoveries and wildcat outposts suggests that areal extent of individual fields is commonly not well-constrained.

For wells completed since January 1983, gross perforated interval ranges from 4 to 1,563 ft, with an average of 248 ft (N=71).

Forty-five of 71 wells (63 percent) have gross perforated intervals $\leq$ 200 ft.

Pressures/Temperatures in Reservoir

In T7-8S, R90-91W, 3,200 psi at 250°F at approximately 7,500 ft.

In T8-10S, R97-100W, 1,019 psi at 107°F at approximately 2,550 ft.

(Average parameters for undifferentiated lower Mesaverde).

Natural Fracturing

Locally, natural fractures are an important component of reservoir permeability. Eleven out of 71 successful gas wells (15 percent) completed since January 1983 did not require stimulation.

Data Availability

For wells completed since January 1983, 17 cores from five wells, plus nine sidewall cores from one well.

Compensated neutron, dual induction, gamma-ray, and cement bond logs are most common.

Table A16. Engineering Parameters--Mesaverde Group (Piceance Basin).

Reservoir Parameters

Porosimeter porosity ranges from 2.6 to 22 percent. In situ permeability ranges from 0.0002 to 0.08 md.

Corcoran-Cozzette: porosity ranges from 2.6 to 18 percent.
In situ gas permeability ranges from 0.003 to 0.05 md.

Rollins: porosity ranges from 11 to 22 percent.
In situ gas permeability ranges from 0.0002 to 0.04 md.
(Brown and others, 1986)

Net Pay Thickness

In T6-11S, R89-97W:

Corcoran: Gross completion interval is 63 ft for 119 wells. Net pay is typically 30 ft or less.

Cozzette: Gross completion interval is 61 ft for 89 wells. Net pay is typically 30 ft or less.

Undifferentiated lower Mesaverde: Average is 70 ft from four or more wells in T9S, R97W.

Production Rates

Pre-Stimulation

For most wells, TSTM.

Post-Stimulation

For wells completed since January 1983, range is from 3 to 6,475 MCFD, with an average of 764 MCFD (fig. 82).

Forty-nine of 71 wells (69 percent) produce 900 MCFD (Average=376 MCFD)

Thirty-two of 71 wells (45 percent) produce 500 MCFD (Average=219 MCFD)

Decline

Corcoran-Cozzette: Once placed on sustained production, selected decline curves show drop to one-half of IP in six to nine months. See figure 83.

Formation Fluids

No oil production from wells completed since January 1983.

Four of 71 wells produced an average of 3 BPD of condensate (ranging from 2 to 4 BPD).

Twenty-five of 71 wells produced an average of 116 BPD of water (ranging from 1 to 996 BPD).

Water Saturation

Corcoran: Average for eight core samples from five wells is 49 percent; range is 40 percent to 63 percent. Other operators report 50 percent as a typical value.

Mesaverde (undifferentiated): no data.

Well Stimulation Techniques

Fifty-four of 65 wells (83 percent) for which completion techniques were reported were hydraulically fractured by some technique. Thirty-four of these 65 wells (52 percent) were treated using either sand/water or sand/foam fracture techniques (fig. 80).

Typical hydraulic fracturing on the Mesaverde Group involves massive amounts of materials. An average treatment includes acidizing (variable amounts) and fracturing with 50,000 to 250,000 gal fluid and 100,000 to 400,000 lb sand. (fig. 81).

The largest treatment recorded among the 71 wells was a 2-stage sand/water treatment of the Mesaverde: 380,604 gal water, 1,328,000 lb sand, and 15,740 gal acid.

Success Ratio

No data.

Well Spacing

One hundred sixty to 320 acres.

Table A17. Economic Factors--Mesaverde Group (Piceance Basin).

FERC Status

FERC-designated area in the Piceance Basin is:
2,512 mi^2 (Corcoran-Cozzette).
2,689 mi^2 (Castlegate, Sego, Rollins, Coaly).
Estimated tight gas productive area: 4,500 mi^2.

Attempted Completions

Seventy-one successful completions and old well workovers from January 1983 to January 1988 (fig. 76). (See table A14 "Stratigraphic Unit/Play" section for a formation-by-formation breakdown.)

Ninety-one producing or shut-in wells in Mesa, Garfield, and Pitkin Counties as of December 1980 from Mesaverde (undifferentiated).

Success Ratio

For the period January 1983 to January 1988, 13 of 71 successful gas wells have been wildcat outposts; nine of 71 successful gas wells have been wildcat new field discoveries.

Drilling/Completion Costs

Drilling and completion costs: \$200,000 for a 4,500-ft well; \$520,000 for a 6,000-ft well.
Equipment costs: \$50,000.
Stimulation costs: \$170,000.
Operating costs: \$1,000/month.
(1988 dollars)

Market Outlets

Fourteen- and 10-inch pipelines (and several, 8 inches or less) serve the area of T6-11S (inclusive), R89-97W (inclusive). These pipelines are operated by Northern Natural, Northwest Pipeline Corporation, Panhandle Eastern Pipeline Company, Western Slope Gas Company, and Rocky Mountain Natural Gas, among others.

Industry Interest

High. Two FERC applications approved. Recent state applications approved for upper Mancos and Mesaverde probably include the Cozzette. (Data as of December 1983).

Operating Conditions

Physiography

In the middle Rocky Mountains physiographic subdivision. Area includes Battlement Mesa and a small part of Grand Mesa having elevations above 10,000 ft. Valleys of the Colorado River and Plateau Creek are below 7,500 ft. Local relief is generally 1,000 to 3,000 ft, and only 20 to 50 percent of the area is gently sloping.

Climatic Conditions

Semiarid, having 8 to 16 inches mean annual precipitation. Mild summers, cold winters. Winter conditions may cause suspension of exploration activities.

Accessibility

Very poor access to tops of mesas and bordering steep slopes. Drilling and development is concentrated in river valleys, primarily of the Colorado River and Plateau Creek; access is difficult away from the rivers.

Extrapolation Potential

Good. Expected to have similarities to barrier and bar facies of the Mesaverde Group in the San Juan, Uinta, and eastern Greater Green River Basins. Also similar to regressive strandplain/deltaic facies of the Berea, Olmos, Dakota, "J" Sandstone, Fox Hills, and Frontier Formations.

Comments

Overall geology and engineering parameters expected to be similar for Corcoran and Cozzette.

Table A18. Wells in Piceance Basin with cores from the Mesaverde and Corcoran-Cozzette Formations available for study at the U.S. Geological Survey. Thirty-three wells are listed in order, from northeast to southwest, by township and range numbers. Twenty townships are covered by this list.

County	Location*			Operator	Well	Name	Depth (ft)	Length (ft)
Rio Blanco	1N	99W	12	Pacific Trans Supply	22-12	Federal	6258 -6539	281
Rio Blanco	2N	97W	26	Citgo	4	Federal-A	5569 -5896	327
Rio Blanco	2N	101W	1	Western Fuels Assoc.	21011-5	Moon Lake	740 - 749	9
							755 - 819	64
Rio Blanco	3N	101W	29	Western Fuels Assoc.	310129-4	Moon Lake	870 - 900	30
Rio Blanco	3N	101W	35	Western Fuels Assoc.	310135-4	Moon Lake	1180 -1198	18
							1206 -1208	2
Rio Blanco	3N	101W	36	Western Fuels Assoc.	310136-2	Moon Lake	1311 -1355	44
Rio Blanco	3S	98W	14	CER Production	RB-U-2		7698 -7718	20
Rio Blanco	3W	98W	14	CER Production	RB-E-01		5710 -5761	51
							5855 -5899	44
							6018 -6048	30
							6451 -6473	22
							6900 -6946	46
							7696 -7754	58
Rio Blanco	3S	101W	14	Twin Arrow	4-14	C & K	671 - 824	153
							985 -1211	226
Garfield	6S	93W	36	Arco	1-36	Arco-Exxon	7698 -7718	20
							3605 -3638	33
							3680 -3737	57
							4110 -4117	7
							4154 -4167	13
							4705 -4724	19
							4893 -4953	60
							5634 -5695	61
							6200 -6260	60
							6530 -6591	61
							8203 -8263	60
Garfield	7S	104W	10	USGS	80-1-C	Carbonaro	12 - 844	832
Garfield	7S	104W	17	USGS	1	Brook Cliffs-Drill Hole	80 - 89	9
							147 - 156	9
							187 - 214	27
							232 - 264	32
Garfield	8S	97W	7	Coors Energy	1-7	Getty	2045 -2079	34
							2405 -2488	83
Mesa	9S	92W	35	Celeron O & G	1-35	Porter Mountain	8176 -8232	56
Mesa	9S	97W	21	Koch Expl	1-21	Horse Shoe Canyon	3030 -3176	146
Garfield	10S	90W	31	Ralston O & G	31	Federal	3603 -3735	132
Mesa	10S	95W	23	Teton Energy Co	23-2	Walck	4726 -4756	30
							4798 -4819	21
Mesa	10S	95W	36	Exxon Corp	2	Old Man Mountain	4494 -4507	13
							5831 -5873	42
Mesa	10S	96W	13	Flying Diamond Oil	13-1	B E Nichols	3730 -3789	59
Mesa	12S	97W	21	USGS	IP-771	Grand Mesa Project	361 - 562	201
Delta	13S	92W	14	USGS	GR-77-7	Grand Mesa Project	509 - 683	174
Delta	13S	92W	19	USGS	GR-77-3		703 - 933	230
Delta	13S	92W	20	USGS	GR-77-5		963 -1263	300
Delta	13S	93W	8	USGS	DC-77-3		83 - 308	225
Delta	13S	93W	10	USGS	DC-77-5		593 - 862	269
Delta	13S	93W	24	USGS	GR-77-1	Grand Mesa Project	533 -1038	505

Table A18 (cont.)

County	Location*			Operator	Well Name		Depth (ft)	Length (ft)
Delta	13S	94W	1	USGS	DC-77-2		803 - 913	110
							923 - 943	20
							953 - 963	10
Delta	13S	95W	2	USGS	CE-77-1	Grand Mesa Project	622 - 858	236
Delta	13S	95W	8	USGS	HK-77-4	Grand Mesa Project	680 - 803	123
Delta	13S	96W	25	USGS	HK-77-2	Grand Mesa Project	104 - 232	128
Delta	13S	96W	32	USGS	IP-77-2	Grand Mesa Project	810 - 1053	243
Delta	13S	96W	32	USGS	IP-77-2A	Grand Mesa Project	810 - 1053	243
Delta	13S	96W	34	USGS	HK-77-1	Grand Mesa Project	411 - 597	186

* Location given as Township-Range-Well Number.

Source: Thomas C. Michalski, U.S. Geological Survey, written communication, 1988.

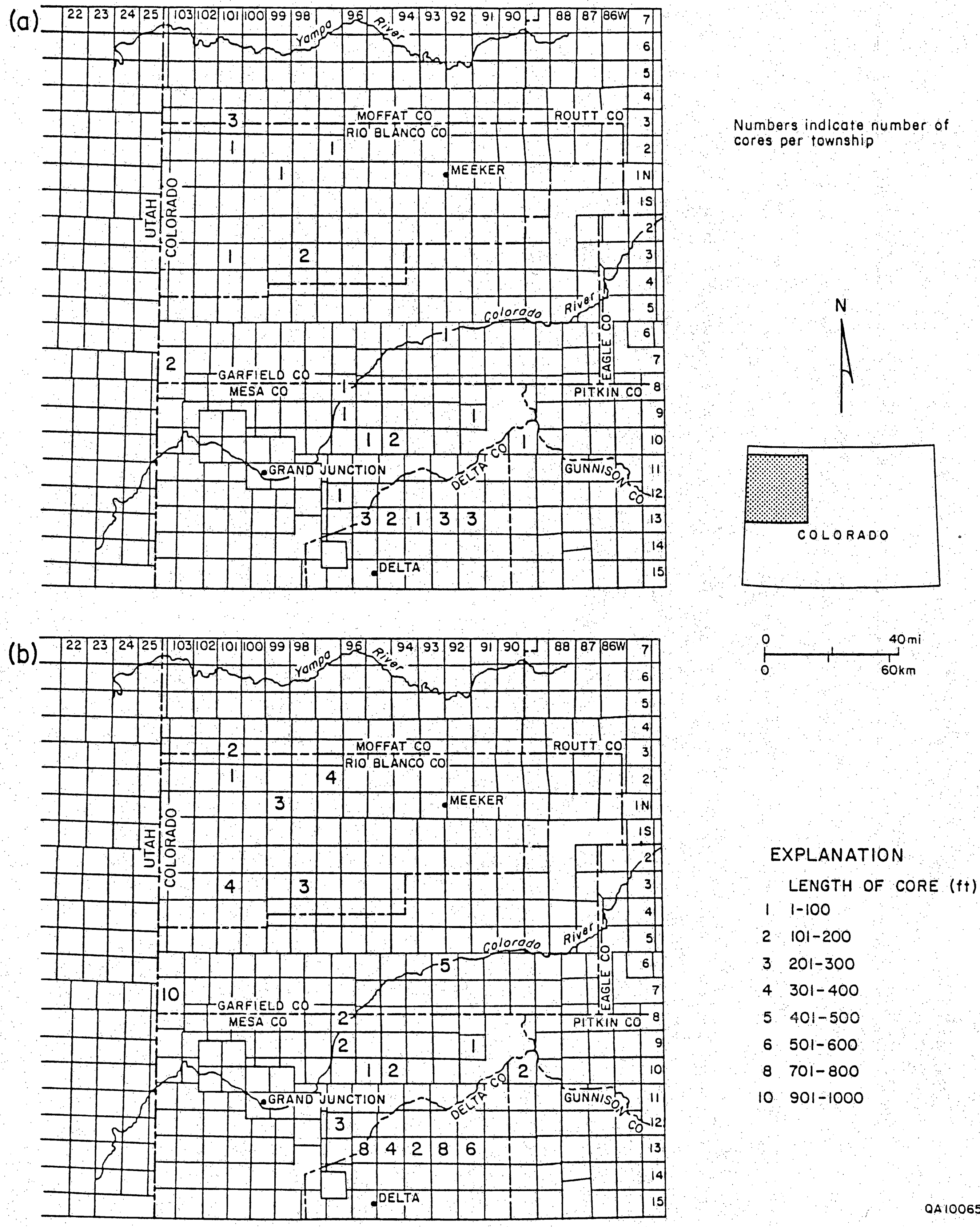

Figure A2. Cores from Mesaverde Group, Piceance Creek Basin, available for study at U.S. Geological Survey. (a) Number of cores per township. (b) Total length of cores per township.