GRI-93/0044

ATLAS OF MAJOR LOW-PERMEABILITY SANDSTONE GAS RESERVOIRS IN THE CONTINENTAL UNITED STATES

TOPICAL REPORT

(June 1992 – November 1992)

Prepared by

Shirley P. Dutton, Sigrid J. Clift, Douglas S. Hamilton, H. Scott Hamlin, Tucker F. Hentz, William E. Howard, M. Saleem Akhter, and Stephen E. Laubach

Bureau of Economic Geology
W. L. Fisher, Director
The University of Texas at Austin
Austin, Texas 78713-7508

for

Gas Research Institute
Contract No. 5082-211-0708
John Hansen, Project Manager

March 1993

QAe7697

DISCLAIMER

LEGAL NOTICE This report was prepared by the Bureau of Economic Geology as an account of work sponsored by the Gas Research Institute (GRI). Neither GRI, members of GRI, nor any person acting on behalf of either:

a. Makes any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any apparatus, method, or process disclosed in this report may not infringe privately owned rights; or .

b. Assumes any liability with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO. GRI-93/0044	2.	3. Recipient's Accession No.
4. Title and Subtitle Atlas of Major Low-Permeability Sandstone Gas Reservoirs in the Continental United States			5. Report Date March 1993
			6.
7. Author(s) S.P. Dutton, S.J. Clift, D.S. Hamilton, H.S. Hamlin, T.F. Hentz, W.E. Howard, M.S. Akhter, and S.E. Laubach			8. Performing Organization Rept. No.
9. Performing Organization Name and Address Bureau of Economic Geology The University of Texas at Austin University Station, Box X Austin, TX 78713			10. Project/Task/Work Unit No.
			11. Contract(C) or Grant(G) No. (C) 5082-211-0708 (G)
12. Sponsoring Organization Name and Address Gas Research Institute 8600 West Bryn Mawr Avenue Chicago, IL 60631	Project Manager: John Hansen		13. Type of Report & Period Covered Topical June 1992 - November 1992
			14.

15. Supplementary Notes

16. Abstract (Limit: 200 words) This report reviews 24 formations that, either because of the large volumes of natural gas reserves contained within them, or because of the data available for their characterization, are the most important tight gas sandstones in the United States. Assessment of these sandstone reservoirs indicates that geological controls play a critical role in gas producibility and that these reservoirs share a number of key geological attributes. Reservoir genesis, just as in conventional oil and gas fields, clearly influences gas accumulation and recovery. The major tight gas sandstone reservoirs surveyed herein were deposited in barrier/strandplain (10), deltaic (8), fluvial (2), shelf (2), slope and basin (2), and fan-delta (1) depositional systems. However, production characteristics of low-permeability gas reservoirs are in large part controlled by the diagenesis that the sediment has undergone after deposition, particularly precipitation of authigenic quartz and clays. Natural fractures are widespread features of tight gas sandstones, but because they are commonly vertical extension fractures that are easily missed by vertical core, detailed information on natural fracture attributes is rarely available. The low-permeability formations covered in this volume have produced 22.3 Tcf of gas through 1988, and this figure does not include production from the "Clinton"-Medina and Berea Sandstones in the Appalachian Basin or the Davis Sandstone in the Fort Worth Basin. Estimated ultimate recovery from existing wells in the 21 formations for which production data are available is 47.1 Tcf.

17. Document Analysis a. Descriptors

Tight gas sandstones, natural gas resources, stratigraphy, depositional systems, sandstone diagenesis, reservoir quality, natural fractures, maximum horizontal stress, hydraulic fracture treatment, reservoir engineering, production history

b. Identifiers/Open-Ended Terms

Geology and engineering characteristics of tight gas sandstones, reservoir genesis in tight gas sandstones, diagenetic history of tight gas sandstones, stress history and fracture of tight gas reservoirs, production history of tight gas reservoirs, geologic controls on tight gas sandstone productivity

c. COSATI Field/Group

18. Availability Statement	19. Security Class (This Report)	21. No. of Pages
Release unlimited	Unclassified	460
	20. Security Class (This Page) Unclassified	22. Price

(See ANSI-Z39.18) See Instructions on Reverse

OPTIONAL FORM 272 (4-77)
(Formerly NTIS-35)
Department of Commerce

RESEARCH SUMMARY

Title	Atlas of Major Low-Permeability Sandstone Reservoirs in the Continental United States
Contractor	Bureau of Economic Geology, The University of Texas at Austin, GRI Contract No. 5082-211-0708, entitled "Geologic Analysis of Primary and Secondary Tight Gas Sands Objectives."
Principal Investigator	S. E. Laubach
Report Period	June 1992 – November 1992
Objectives	To summarize geologic, engineering, and production information for 24 low-permeability, gas-bearing sandstone reservoirs in 13 basins in the United States. The formations in the atlas were selected because they contain abundant natural gas resources or because significant information is known about them that could be applicable to other, similar formations.
Technical Perspective	The atlas is intended to update an earlier summary of low-permeability sandstones by Finley (1984), entitled "Geology and Engineering Characteristics of Selected Low-Permeability Gas Sandstones: A National Survey." Considerably more geologic and engineering information now exists for the formations in the Finley report and for other low-permeability formations that have become important gas producers since 1984, and this atlas attempts to summarize the publicly available literature. Much of the new information was developed as part of the Gas Research Institute (GRI) Tight Gas Sands Project. The goals of this project were improving the recovery efficiency and reducing the cost of producing gas from low-permeability formations through integration of geology, formation evaluation, reservoir engineering, and fracture modeling.
Results	This report reviews 24 formations that, either because of the large volumes of natural gas reserves contained within them, or because of the data available for their characterization, are the most important tight gas sandstones in the United States. Assessment of these sandstone reservoirs indicates that geological controls play a critical role in gas producibility and that these reservoirs share a number of key geological attributes. Most of the tight gas reservoirs in this atlas are not immature, muddy sandstones with large volumes of diagenetically reactive detrital clay matrix, but rather are clean sandstones deposited in high energy depositional settings whose intergranular pores have been largely occluded by authigenic cements (mainly quartz and calcite).
	Reservoir genesis in tight gas reservoirs, just as in conventional oil and gas fields, clearly influences gas accumulation and recovery. The major

tight gas sandstone reservoirs surveyed herein were deposited most commonly in barrier/strandplain (10) and deltaic (8) depositional systems. Fluvial (2), shelf (2), slope and basin (2), and fan-delta (1) depositional systems make up the remainder. Depositional systems govern the physical processes under which sediment is deposited and thus influence sediment sorting, packing, and separation of fines, and these parameters determine the original porosity and permeability. However, production characteristics of low-permeability gas reservoirs are in large part controlled by the diagenesis that the sediment has undergone after deposition.

Sediment composition, depth of burial, and age of the reservoir are important parameters in diagenetic alteration. Quartz is the most abundant cement in low-permeability sandstones; it occludes intergranular pores and thus has a strong effect on reducing permeability. Quartz cement volume in most formations increases with increasing burial depth. Calcite cement can also fill intergranular pores, but its distribution is not as uniform as quartz. Therefore, although calcite cement may destroy porosity and permeability in some beds or layers, its effect on permeability of a formation is not as widespread as that of quartz cement. Clay minerals occur in most low-permeability sandstones, and they lower permeability the most where they occur in intergranular pores. Because of their high surface-to-volume ratio, clays increase water saturation, which decreases relative permeability to gas.

Our survey shows that natural fractures are widespread features of tight gas sandstones. Because they are commonly vertical extension fractures that are easily missed by vertical core, detailed information on natural fracture attributes is rarely available. Fractures can enhance production, and in some formations they need to be taken into account in drilling, completion, and stimulation design.

The low-permeability formations covered in this volume have produced 22.3 Tcf of gas through 1988, and this figure does not include production from the "Clinton"-Medina and Berea Sandstones in the Appalachian Basin or the Davis Sandstone in the Fort Worth Basin. Estimated ultimate recovery from existing wells in the 21 formations for which production data are available is 47.1 Tcf.

Technical Approach

The information compiled in this atlas comes from publicly available sources: GRI Tight Gas Sands project reports, applications by producers to state regulatory agencies for tight formation designation, and published literature. The atlas includes data on cumulative production, number of tight completions, average recovery per completion, and estimates of ultimate recovery for all except three formations. The production data come from the report "Tight gas field, reservoir, and completion analysis of the United States," which was prepared by Energy and Environmental Analysis, Inc. for the Gas Research Institute (Hugman and others, 1992).

This atlas is organized on the basis of the 13 basins in which the selected tight gas formations occur. Data are presented in geographic order from the Appalachian region through the southern and southwestern states to the Rocky Mountain region. An introduction to each basin summarizes the age and location of the basin, its structural history and major tectonic features, the age and stratigraphic relations of all formations in the basin that have been designated tight, including formations not covered in detail in the atlas, and information on stress orientation. The basin introduction is followed by chapters on the major tight gas sandstones within that basin. Each formation summary is divided into the following sections: (1) introductory information on thickness and depth of the formation, data availability, and previous studies, (2) depositional systems and reservoir facies, (3) composition and diagenesis of reservoir facies, (4) natural fractures, (5) engineering characteristics, and (6) production history.

Project Implications

The importance of detailed resource characterizations in tight gas sandstone formations has been realized for many years by GRI. Through GRI-funded research, the understanding of the geologic processes affecting the source, distribution, and recovery of gas from these reservoirs has been greatly enhanced. This report serves as a reference that will aid tight gas sand development in the United States.

John T. Hansen
Project Manager, Natural Gas Supply

CONTENTS

Figures

Tables

INTRODUCTION

This atlas summarizes geologic, engineering, and production information for 24 low-permeability, natural-gas-bearing sandstone reservoirs in 13 basins in the United States (fig. 1, table 1). The Federal Energy Regulatory Commission (FERC) has designated all but one of the units, the Davis sandstone in the Fort Worth Basin, to be tight formations in specified areas under the definition of section 107 of the Natural Gas Policy Act (NGPA) of 1978. The 24 low-permeability formations in the atlas were selected either because they contain abundant natural gas reserves and resources (table 2) or because the geologic and engineering data available for their characterization could be applicable to other, similar gas-bearing formations.

This atlas is intended to update an earlier summary of low-permeability sandstones by Finley (1984), entitled "Geology and Engineering Characteristics of Selected Low-Permeability Gas Sandstones: A National Survey." Considerably more geologic and engineering information now exists for the formations presented in the Finley (1984) report, and this atlas attempts to incorporate the latest publicly available literature on these and other gas-bearing formations in the United States.

Much of the new information was developed as part of the Gas Research Institute (GRI) Tight Gas Sands Project. The goals of this project were improving the recovery efficiency and reducing the cost of producing gas from low-perzmeability formations through integration of geologic analysis, formation evaluation, reservoir engineering, and fracture modeling (CER Corporation and S. A. Holditch & Associates, 1988). The main sources of data for the Tight Gas Sands project were cooperative wells in the Berea, Canyon, Cleveland, Cotton Valley, Davis, Frontier, and Travis Peak sandstones and Staged Field Experiment (SFE) wells in the Cotton Valley, Frontier, and Travis Peak Formations. Cooperative wells are gas wells in which operating companies allowed GRI contractors to collect data necessary for formation characterization and hydraulic-fracture evaluation. SFE wells are wells drilled and

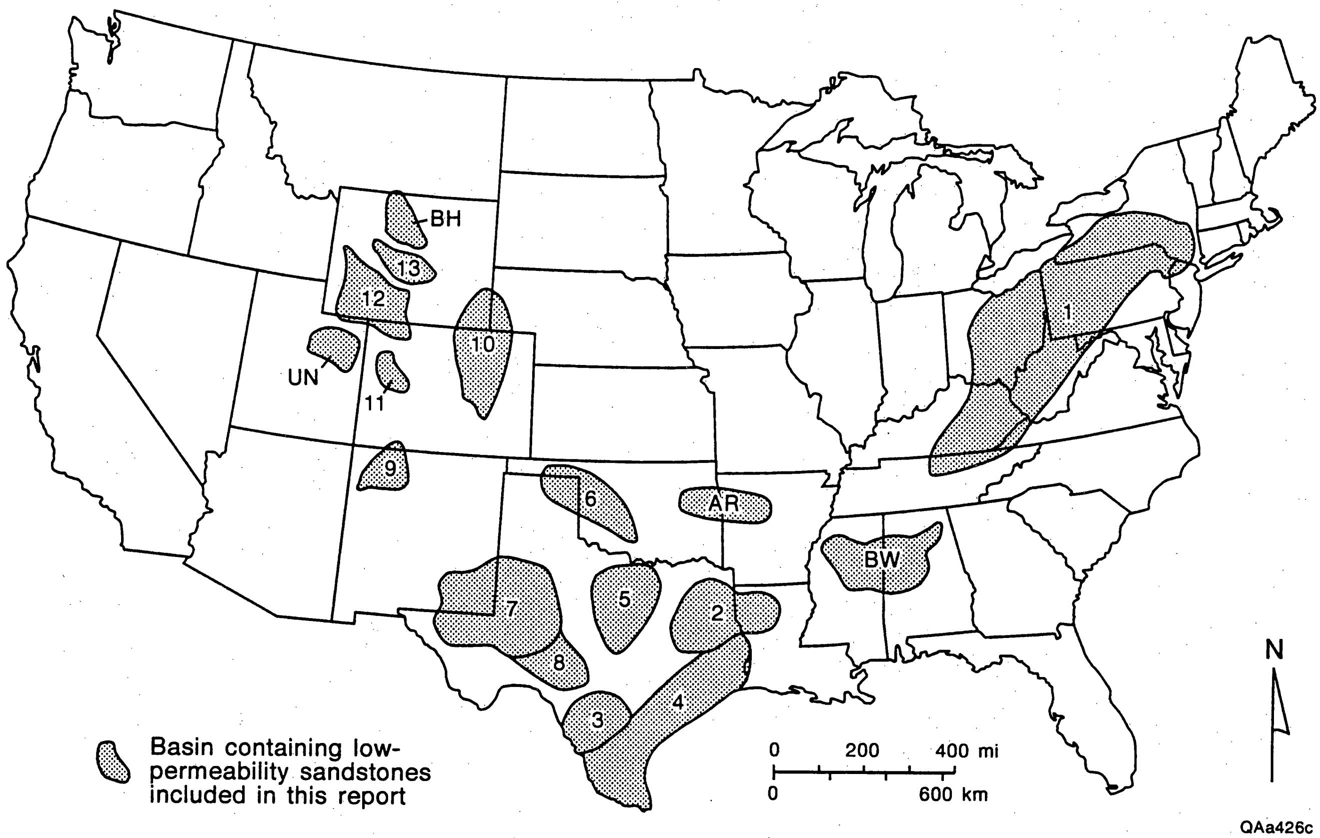


Figure 1. Location map of basins containing low-permeability sandstones. Basins containing sandstones summarized in this atlas are numbered, and the numbers are keyed to table 1. Other basins that contain low-permeability sandstones mentioned in this report are the Black Warrior (BW), Arkoma (AR), Uinta (UN), and Big Horn (BH) Basins. Modified from E. W. Collins, written communication (1990).

Table 1. Low-permeability sandstones and basins included in this atlas. Number following basin indicates location in figure 1.

APPALACHIAN BASIN (1)
- Berea Sandstone
- "Clinton"-Medina Sandstone

EAST TEXAS AND NORTH LOUISIANA BASINS (2)
- Travis Peak (Hosston) Formation
- Cotton Valley Sandstone

MAVERICK BASIN (3)
- Olmos Formation

GULF COAST BASIN (4)
- Vicksburg Formation
- Wilcox Formation

FORT WORTH BASIN (5)
- Davis Sandstone

ANADARKO BASIN (6)
- Cleveland Formation
- Cherokee Group
- Granite Wash Sandstone

PERMIAN BASIN (7)
- Abo Formation
- Morrow Formation

VAL VERDE BASIN (8)
- Canyon Sandstone

SAN JUAN BASIN (9)
- Pictured Cliffs Sandstone
- Mesaverde Group
- Dakota Sandstone

DENVER BASIN (10)
- "J" Sandstone

PICEANCE BASIN (11)
- Mesaverde Group
- Mancos "B" Shale
- Dakota Sandstone

GREEN RIVER BASIN (12)
- Mesaverde Group
- Frontier Formation

WIND RIVER BASIN (13)
- Frontier Formation

Table 2. Cumulative production and estimated ultimate recovery (from Hugman and others, 1992).

Basin	Formation	No. tight completions	Cum. prod. through 1988 (Bcf)	Est. ult. recov. (Bcf)
Anadarko	Cleveland	770	383.3	721
	Cherokee	507	566.3	1,041
	Granite Wash	506	468.0	698
Denver	J Sandstone	1,449	500.1	1,019
East Texas and North Louisiana	Cotton Valley	2,870	2,665.5	4,999
	Travis Peak	860	508.3	1,269
Green River	Mesaverde	517	528.3	1,350
	Frontier	855	809.7	1,844
Maverick	Olmos	973	298.6	408
Permian	Abo	864	222.7	344
	Morrow	280	500.2	748
Piceance	Mesaverde	253	57.0	141
	Mancos "B"	409	185.6	354
	Dakota	231	66.3	146
San Juan	Pictured Cliffs	3,431	1,086.9	2,757
	Chacra	598	123.8	272
	Mesaverde	4,779	4,473.9	12,315
	Dakota	4,728	2,921.1	7,322
Texas Gulf Coast	Vicksburg	479	881.5	1,479
	Wilcox Lobo	1,280	2,115.1	2,889
	Wilcox Deltaic	583	562.2	1,469
Val Verde	Canyon and Cisco	4,560	1,821.3	3,145
Wind River	Frontier	40	189.9	404

completed by GRI specifically for research on low-permeability reservoirs (CER Corporation and S. A. Holditch & Associates, 1988, 1989, 1990, 1991; CER Corporation, 1992b). Data collection in SFE wells is extensive and typically includes (1) cutting core from reservoir sandstones and adjacent shales, (2) an open-hole data acquisition program of Measurement While Drilling (MWD) logging, wireline logging (multiple passes), and open-hole stress testing, (3) fully instrumented hydraulic fracturing, and (4) extensive data collection during pre- and post-fracture well testing.

Data Sources

The information compiled in this atlas comes from publicly available sources: GRI Tight Gas Sands project reports, applications by gas producers to state regulatory agencies for tight formation designation, and published literature. GRI Tight Gas Sands projects were conducted in many of the major low-permeability sandstone reservoirs in the United States, and extensive data on the geologic and engineering characteristics of these formations are available in contract reports submitted to GRI and in published papers.

Applications by gas producers for tight formation designation under section 107 of the NGPA and associated rules of the Federal Energy Regulatory Commission (FERC) were also important sources of geologic and engineering data. These applications include data on porosity, permeability, water saturation, net pay thickness, production rates, and other key variables used to characterize the producing interval of a tight formation. Consequently, applications in the files of state regulatory agencies constitute the most complete data base on tight gas sandstones in the United States.

Other major sources of data were guidebooks and oil- and gas-field summary volumes published by local and regional geological societies, in which maps, cross sections, type logs, and completion, production, and historical data are commonly included. The U.S. Geological Survey has published extensively on western tight gas reservoirs (Krupa and Spencer, 1989).

Finally, the transactions volumes of the SPE/DOE/GRI Low Permeability Reservoirs Symposia were important sources of engineering data on tight gas sandstones.

Production Data

This atlas includes production data for all formations except the "Clinton"-Medina, Berea, and Davis Sandstones (table 2). These data come from the report "Tight gas field, reservoir, and completion analysis of the United States," which was prepared by Energy and Environmental Analysis, Inc. (EEA), for the Gas Research Institute (Hugman and others, 1992). Table 2 summarizes cumulative production through 1988 from the formations covered in this atlas and lists estimates of ultimate recovery (defined as cumulative production through 1988 + proven reserves) that will occur from existing wells (Hugman and others, 1992). Engineering data tables for each formation list other information from the EEA report, including the number of completions within the area of the formation that has been designated tight and average recovery per completion. Other information in the engineering data tables comes from recently published literature, application files to state regulatory agencies, GRI project data, or, where more recent information was not available, from the tables of Finley (1984, 1986).

The data from the report of Hugman and others (1992) may overestimate the current tight gas production and estimates of ultimate recovery in some formations because of the methods and data bases they used. For example, if a field contained one or more reservoirs within a tight formation area, all reservoirs producing from that formation in that field were included as tight production. In addition, if the designated tight area of a formation overlaps onto the edge of a large field that is mostly outside of the designated area, the entire production from the formation in that field was considered tight. Hugman and others (1992) recognized that the effect of this method may be to locally overestimate the tight production, but they point out that this may be offset by the fact that there are tight gas reservoirs in areas that have never been officially designated tight by FERC.

Selection of Formations

Formations discussed in this atlas were selected because they are major producers of gas from low-permeability ("tight") sandstone reservoirs or because significant information is available about them, or both. All formations listed by Hugman and others (1992) as having estimated ultimate recovery of >500 Bcf (table 2) are included. The EEA report (Hugman and others, 1992) did not cover the Appalachian Basin, but the two most prolific low-permeability Appalachian reservoirs, the "Clinton"-Medina and the Berea, are included herein. Several formations in this atlas were not in the Finley (1984) report: the Wilcox and Vicksburg Formations of the Texas Gulf Coast, the Granite Wash in the Anadarko Basin, the Abo and Morrow Formations in the Permian Basin, the Canyon Sandstone of the Val Verde Basin, and the Dakota Sandstone in the Piceance Basin. These formations have been added either because (1) drilling in them has been active since 1984, (2) more information about them is now publicly available, or (3) their resource potential as reported by Hugman and others (1992) is significant. Conversely, some formations that were in the Finley (1984) report are not included in this volume. Some formations that Finley anticipated would be designated tight by FERC have not been (Oriskany and Tuscarora Sandstones, Appalachian Basin; Carter Sandstone, Black Warrior Basin; Cromwell Sandstone, Arkoma Basin; and Frontier Formation, Big Horn Basin). Other formations were designated tight but have a low estimated ultimate recovery (Hugman and others, 1992) and so were not included: Hartselle Sandstone, Black Warrior Basin; Spiro Sandstone, Arkoma Basin; Sanostee Member of the Mancos Shale, San Juan Basin; Sego and Castlegate Sandstones in the Mesaverde Group and Mancos Shale, Uinta Basin; and Fox Hills Sandstone, Green River Basin.

Report Structure

This atlas is organized on the basis of the 13 basins in which the selected tight gas formations occur. An introduction to each basin summarizes the age and location of the basin, its structural history and major tectonic features, the age and stratigraphic relations of all formations in the basin that have been designated tight, including formations not covered in detail in the atlas, and information on stress orientation. The basin introduction is followed by chapters on the major tight gas sandstones within that basin. Each formation summary is divided into the following sections: (1) introductory information on thickness and depth of the formation, data availability, and previous studies, (2) depositional systems and reservoir facies, (3) composition and diagenesis of reservoir facies, (4) natural fractures, (5) engineering characteristics, and (6) production history.

Geologic Controls on Tight Gas Sandstone Productivity

This report reviews 24 formations that, either because of the large volumes of natural gas reserves contained within them, or because of the data available for their characterization, are the most important tight gas sandstones in the United States. Assessment of these sandstone reservoirs indicates that geological controls play a critical role in gas producibility and that these reservoirs share a number of key geological attributes. Perhaps a surprising result is that many of the tight gas reservoirs in this atlas are not immature, muddy sandstones with large volumes of diagenetically reactive detrital clay matrix, but rather are clean sandstones deposited in high-energy depositional settings whose intergranular pores have been largely occluded by authigenic cements (mainly quartz and calcite).

Just as in conventional oil and gas fields, reservoir genesis in tight gas sandstone reservoirs clearly influences gas accumulation and recovery. The major tight gas sandstone reservoirs surveyed herein were deposited most commonly in barrier/strandplain (10) and deltaic (8) depositional systems. Fluvial (2), shelf (2), slope and basin (2), and fan-delta (1) depositional systems make up the remainder. A survey of the largest conventional clastic oil reservoirs in Texas (Tyler and others, 1984) shows a comparable bias in hydrocarbon recovery toward wave-modified deltaic and barrier/strandplain reservoirs that together account for more than 60 percent of the estimated recoverable oil resource.

Depositional systems govern the physical processes under which sediment is deposited and thus influence sediment sorting, packing, and separation of fines, and these parameters determine the original porosity and permeability. However, production characteristics of low-permeability gas reservoirs are in large part controlled by the diagenesis, or chemical and physical changes, that the sediment has undergone after deposition. Sediment composition, depth of burial, and age of the reservoir are important parameters in diagenetic alteration.

Further geological attributes critical to gas producibility of tight sandstones are natural fractures and stress directions. In order to achieve FERC tight gas designation, formations must produce gas at less than a specified rate prior to well stimulation; the exact production limits vary with formation depth. Economic viability of such formations will depend on the success of hydraulic-fracture treatments to stimulate greater flow rates. An understanding of the natural fracture systems will benefit design of completion practices and guide drilling strategies.

The contributions of geology to evaluation and completion of tight gas sandstones are emphasized in this report. Thus, three major geologic topics (1) stratigraphy and depositional systems, (2) reservoir composition and diagenesis, and (3) natural fractures and stress directions, are summarized for each formation. Information on each of these topics is necessary for complete geologic characterization of any tight formation. Stratigraphic information provides an understanding of the physical framework in which the gas resource exists. Depositional history determines the regional distribution, geometry, and texture of the reservoir sandstones, as well as the characteristics of the nonreservoir facies that may act as barriers to vertical growth of hydraulic fractures as a result of high in situ stress. Production characteristics of tight gas reservoirs are in part controlled by diagenetic modifications to the reservoirs; extensive cementation is commonly the reason for low permeability. Finally, studies of natural fractures and stress directions are important to the understanding of tight gas resources because hydraulic fracture treatments are commonly carried out to achieve economic flow rates and horizontal drilling is a promising method for developing low-permeability gas reservoirs. Determination of present stress state in reservoir rocks and adjacent strata improves prediction of hydraulic fracture propagation direction and effectiveness of fracture containment. In addition to potentially providing conduits for fluid flow to the wellbore, the abundance and orientation of natural fractures may affect the orientation and shape of hydraulic fractures and influence fluid leakoff characteristics.

Stratigraphy and Depositional Systems

A *depositional system* is a group of lithogenetic facies linked by depositional environment and associated processes (Fisher and McGowen, 1967). In other words, it is a group of rock strata that were deposited in closely associated sedimentary environments. Depositional systems are the stratigraphic equivalent of major physical geomorphic units such as modern rivers or deltas (Galloway and Hobday, 1983). The depositional system can be divided into its component genetic *facies*, which are three-dimensional rock bodies characterized by specific sand-body geometries, lithologies, sedimentary structures, and initial porosity and permeability. Detailed understanding at the facies level is a goal of stratigraphic analysis because it is commonly at the facies scale that the basin's fluid migration pathways, including those of gases and connate waters, are established (Galloway and Hobday, 1983). A particular facies will have similar characteristics no matter where it has been deposited as long as energy conditions, processes, available sediment supply, and accommodation space were relatively uniform. Thus, classifying tight gas sandstones by their depositional systems and component facies establishes a framework for comparison among stratigraphic units of different ages in different sedimentary basins. Unlike details of a stratigraphic sequence, which may vary between and within basins, characteristics of genetic facies tend to remain constant within a range determined by conditions of deposition. This classification helps provide a basis for determining the extent to which geologic and engineering knowledge gained in the study of one formation can be applied to the study of another.

The nine principal clastic depositional systems reviewed by Fisher and Brown (1972) can be classified into three major groups established by Selley (1978): continental, shoreline (marginal marine), and marine environments (table 3, fig. 2). Each of the nine systems can be divided into additional categories. For example, the fluvial system can be divided into several subclasses: braided streams, fine-grained meanderbelts, coarse-grained meanderbelts, and stabilized distributary channels. Each of these subclasses has distinctive sand-body geometry, texture, and distribution of internal sedimentary structures. Similarly, deltas can be divided into river-dominated types that have digitate to lobate geometries and into wave-dominated types that have cuspate geometries. Table 4 classifies the formations in this atlas into major clastic depositional systems. Many of the formations discussed in this atlas were deposited in more than one depositional system, so the system of the most common low-permeability reservoir facies is listed.

The thickness of a sandstone depends on sediment supply, water depth, and rate of basin subsidence. Thick sandstones generally form by vertical stacking of the products of repetitive depositional events, which introduces layering that can be detrimental to hydraulic-fracture stimulation. The amount of sediment input, basin subsidence, and sea-level changes are the three main factors that control the vertical sequence of deposits. Clean (low clay content) sandstones, which generally make the best reservoirs, are deposited in environments where physical processes cause segregation of the bed-load (sand and gravel) and suspended-load (silt and clay) components of the sediment dispersal system. The high energy of the river channel or marine shoreface (the narrow zone affected by wave action) efficiently segregates the coarse

Table 3. Classification of clastic depositional systems by environment (after Fisher and Brown, 1972; Selley, 1978).

CONTINENTAL ENVIRONMENTS

- **Eolian** systems (deposits transported by wind)
- **Lacustrine** systems (deposited in lakes)
- **Fluvial** systems (deposited by a stream or river)
- **Terrigenous fan** systems (deposited by alluvial fans)

SHORELINE (MARGINAL MARINE) ENVIRONMENTS

- **Delta** systems
- **Barrier-strandplain** systems
- **Lagoon, bay, estuarine, and tidal-flat** systems

MARINE ENVIRONMENTS

- **Shelf** systems
- **Slope and basinal** systems

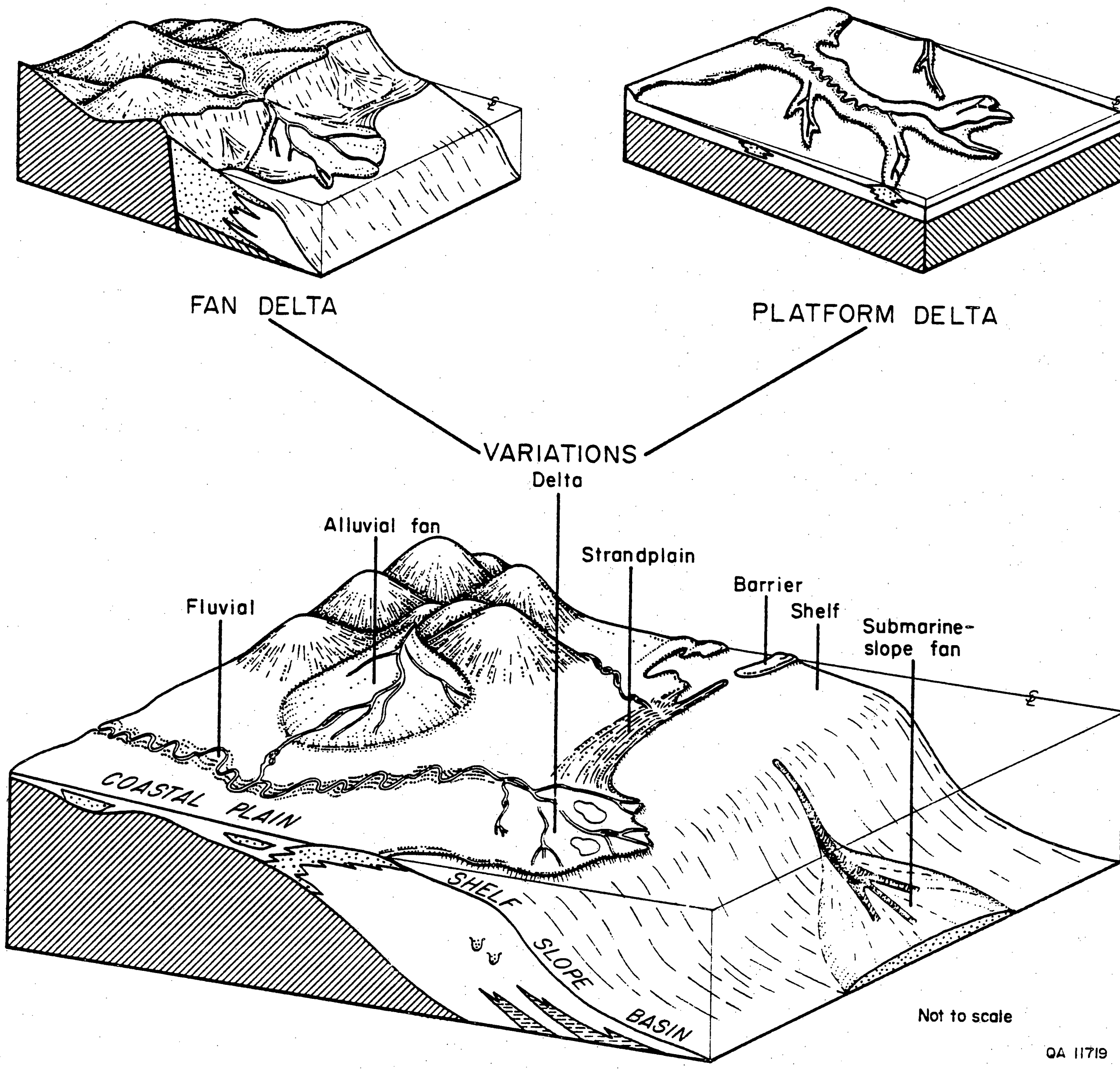


Figure 2. The range of typical sandstone depositional systems that typically host hydrocarbon resources (from Galloway and others, 1983).

Table 4. Tight gas sandstones classified by major depositional system.

Fluvial Systems
- Travis Peak Formation—East Texas and North Louisiana Basins
- Cherokee Group (Red Fork Formation)—Anadarko Basin
- Abo Formation—Permian Basin
- Morrow Formation—Permian Basin

Fan Delta Systems
- Granite Wash—Anadarko Basin

Deltaic Systems
- "Clinton"-Medina Sandstone—Appalachian Basin
- Vicksburg Formation—Texas Gulf Coast Basin
- Wilcox Formation—Texas Gulf Coast Basin
- Davis Sandstone—Val Verde Basin
- Cleveland Formation—Anadarko Basin
- Cherokee Group (Red Fork Formation)—Anadarko Basin
- "J" Sandstone—Denver Basin

Barrier-Strandplain (Shoreface) Systems
- Cotton Valley Sandstone—East Texas and North Louisiana Basins
- Morrow Formation—Permian Basin
- Pictured Cliffs Sandstone—San Juan Basin
- Mesaverde Group—San Juan Basin
- Dakota Sandstone—San Juan Basin
- Mesaverde Group—Piceance Basin
- Dakota Sandstone—Piceance Basin
- Mesaverde Group—Green River Basin
- Frontier Formation—Green River Basin
- Frontier Formation—Wind River Basin

Shelf Systems
- Berea Sandstone—Appalachian Basin
- Olmos Formation—Maverick Basin
- Mancos "B" Shale—Piceance Basin

Slope and Basin Systems
- Canyon Sandstone—Val Verde Basin

and fine fractions. Processes at the distributary mouth bar of delta systems are also efficient sediment sorters. The cleanest shales (with lowest sand and silt content), which are the best barriers to hydraulic-fracture growth, form in quiet, low-energy environments, such as a lagoon or deep marine basin. Transitional environments are common between the zones of highest and lowest energy, in which muddy sandstones and sandy mudstones are deposited. Only in special cases (during marine transgression, for example) are the clean sandstones that make the best reservoirs bounded by thick shale deposits that make the best barriers to fracture growth. The stress contrast between reservoir sandstones and the overlying and underlying beds is of critical importance to hydraulic-fracture design, and rock mechanical properties of these beds can vary as a result of subtle contrasts in rock composition and texture.

Reservoir Composition and Diagenesis

Original porosity and permeability of sandstones are determined by their depositional environment, but diagenesis can significantly alter reservoir characteristics after deposition. Most tight gas reservoir sandstones had moderate to high porosity and permeability at the time of deposition, but compaction and precipitation of authigenic mineral cements from aqueous pore fluids during burial has destroyed much of the original intergranular (primary) porosity. Older and deeper sandstones typically have lower porosity than do younger or shallower sandstones because they have undergone more extensive compaction and cementation (Schmoker and Gautier, 1989). The importance of time for these porosity-reducing reactions to occur is evident from the age of most of the tight gas sandstones in the United States, which are Paleozoic (570 to 245 Ma) or Mesozoic (245 to 66 Ma). The only Tertiary (66 to 1.6 Ma) sandstones in this atlas are the Wilcox and Vicksburg of the Texas Gulf Coast, which have been deeply buried.

In addition to providing information on porosity and permeability distribution, study of the mineral composition of tight gas reservoirs is necessary for calibrating the log response of the reservoir and adjacent nonreservoir rocks in the formation. Composition and volume of detrital grains, clay matrix, and authigenic cements, as well as the type of pores, size of pore throats, and distribution of clays are correlated to log response and petrophysical properties such as permeability, porosity, pore-throat diameter, water saturation, and rock strength.

Petrographic Analysis

Information on the composition and distribution of minerals and pores in tight gas sandstones is derived primarily from thin-section point counts, X-ray diffraction analysis, and scanning electron microscopy (SEM). Framework-grain composition of a sandstone is typically expressed as the ratio of quartz:feldspar:rock fragments (QFR), which are the "essential grains" that are used to classify a sandstone (Folk, 1974) (fig. 3). Quartz is the most abundant detrital mineral in most sandstones. If other minerals, such as feldspars or metamorphic rock fragments composed dominantly of mica are unusually abundant, log analysts will need to take this into account by using a different grain density. An abundance of feldspar grains, many of which are unstable and dissolve in the burial environment, may indicate that secondary porosity is an important component of the porosity network. In some sandstones, such as the Travis Peak, feldspar dissolution has been so extensive that the sandstone now has little remaining feldspar and has changed during diagenesis from a subarkose to a quartzarenite (fig. 3). Abundant rock fragments, particularly metamorphic and sedimentary rock fragments, may indicate that the sandstone has undergone loss of porosity by ductile grain deformation.

Measurements of porosity made by thin-section points counts are generally less than porosity determined by porosimeter. One reason for the difference is that the 30-μm thickness of a thin section causes the petrographer to overemphasize grain volume at the expense of pore space (Jonas and McBride, 1977). Secondly, it is difficult to observe and quantify microporosity in thin section, such as micropores between authigenic clay crystals and within clay matrix.

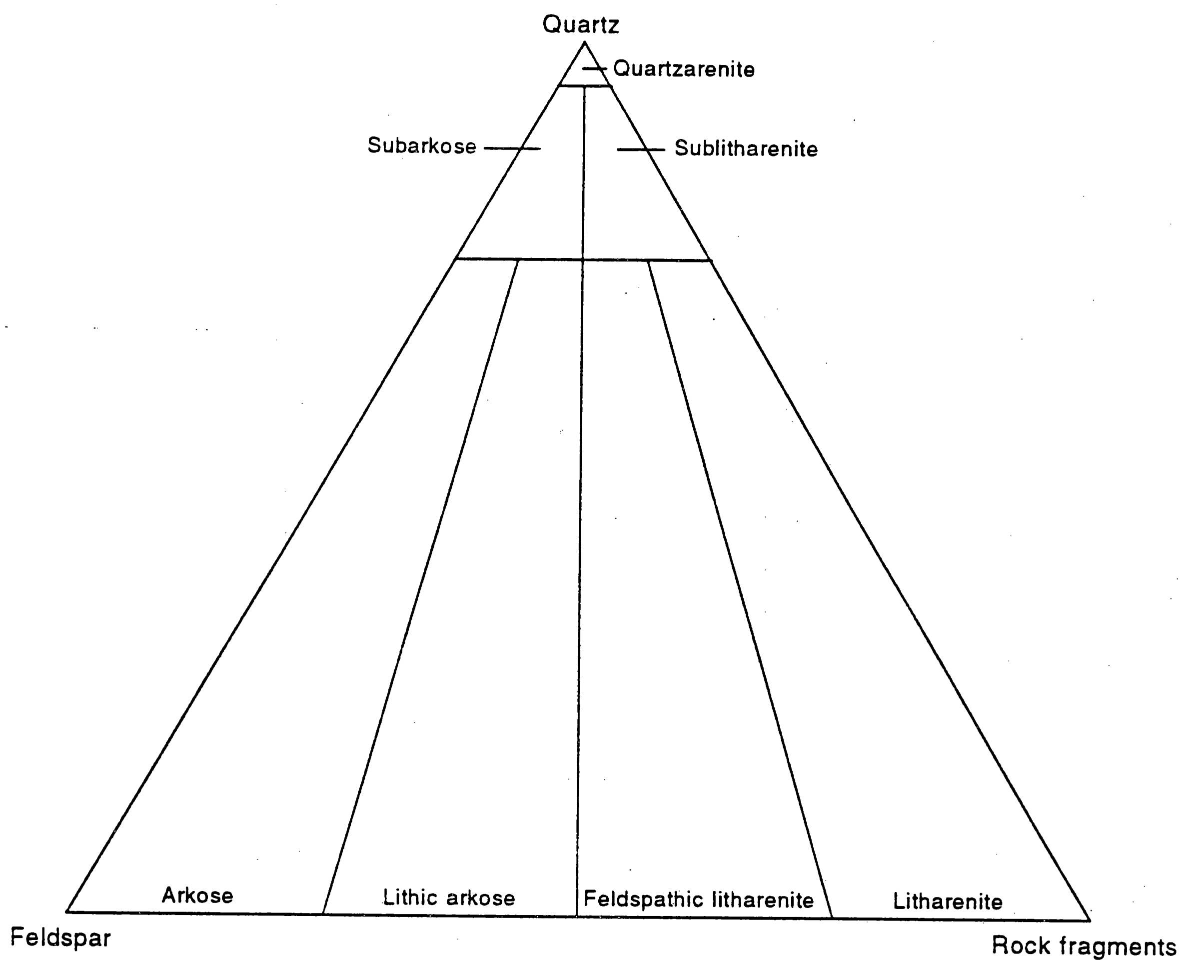


Figure 3. Classification system for sandstones by Folk (1974).

Petrographic analysis of framework mineralogy, porosity, clay content, and clay distribution can be used to reveal compositional controls on rock strength. This information can then be combined with well-log analysis to yield more accurate predictions of rock strength and mechanical properties in treatment intervals and potential fracture barriers (Plumb and others, 1992).

Types of Low-Permeability Sandstones

Fluid flow, including gas flow, in a sandstone is most effective through well-connected, intergranular pores. In most tight gas sandstones, the intergranular pore network has been almost completely occluded by precipitation of authigenic cements. The result is that narrow, slot-like apertures between pores provide the major connectivity for fluid flow, and these narrow slots are closed easily by increasing pressure (effective stress) (Walls, 1982). Thus, to accurately measure permeability in tight gas sandstones, it is necessary to perform core analyses under net overburden pressure conditions (stressed permeability), not at ambient surface pressure (unstressed permeability).

In many tight gas sandstones, the most abundant macropores (pores having pore-aperture radii >0.5 μm) are secondary pores formed by dissolution of detrital grains, particularly feldspars. Secondary pores provide pore volume for gas storage (Spencer, 1989), but they generally are connected only by the remaining narrow, intergranular pores. Therefore, permeability in tight gas sandstones containing mostly secondary pores is still controlled by the highly occluded intergranular pore network. Micropores (pore-aperture radii <0.5 μm) are common in some tight gas sandstones, such as the Frontier Formation in the Green River Basin, but microporosity contributes little to permeability. Formations with abundant microporosity may be interpreted from logs as having high porosity, but they have low permeability.

Soeder and Chowdiah (1990) divided tight sandstones into the following three types on the basis of pore geometry: (1) sandstones with open intergranular pores whose pore throats are plugged by authigenic clay minerals, (2) sandstones whose intergranular pores have been largely occluded by authigenic cements (mainly quartz and calcite) and reduced to narrow slots that connect large secondary pores formed by grain dissolution, and (3) muddy sandstones, in which the intergranular volume is filled by detrital clay matrix and porosity is mainly microporosity. Type 2 sandstones are the most common tight gas reservoirs according to Spencer (1989) and Soeder and Chowdiah (1990), and most of the 24 sandstones in this atlas are Type 2. Sandstones that are exclusively Type 1 are rare, but many of the formations discussed in this atlas are Type 2 sandstones that also contain authigenic clays plugging pore throats. The poorest reservoirs in many low-permeability formations are Type 3 sandstones, and they probably do not contribute significantly to total gas production. The low-permeability, downdip part of the Olmos Formation is an example of a Type 3 sandstone. Type 3 sandstones are poor reservoirs because they have low porosity and permeability from the time of deposition as a result of an abundance of detrital clay that was either deposited with the sand or mixed in shortly after deposition by burrowing. Compaction further reduces porosity, so that Type 3 sandstones typically have no visible macroporosity. Although log-measured porosity may be as high as 10 percent, the porosity is all microporosity, and the sandstone has very low permeability.

Diagenetic complexity in Type 2 low-permeability sandstones varies considerably; the Travis Peak provides an example of a relatively simple system. Travis Peak sandstones contain many different authigenic minerals, but quartz is the most abundant porosity-occluding cement. As the volume of quartz cement increases with increasing burial depth, the volume of intergranular primary porosity decreases and permeability also decreases (Dutton and Diggs, 1992). Average porosity and permeability can be predicted by depth in this formation. The Frontier Formation in the Green River Basin is a more complicated system. Quartz cement is the main control on porosity in some areas along the Moxa Arch, but in other areas calcite cement is dominant. As a result, no trend is observed in either porosity or permeability with burial depth (Dutton and others, 1992).

Clay Minerals

Authigenic clay minerals have an effect on the producibility of tight gas sandstones beyond simply reducing porosity. Because of their high surface-to-volume ratio, clays increase water saturation, which decreases relatively permeability to gas. Wilson (1982) determined the relative influence on permeability of the main types of clay minerals in tight gas sandstones. Kaolinite generally occurs in compact clusters or "books" inside secondary pores, so it has the least effect on permeability. Chlorite flakes commonly line primary pores and thus have a greater influence than kaolinite to decrease permeability. Illite and mixed-layer illite-smectite occur as fibers that have high surface areas and thus have the greatest effect in reducing permeability (Wilson, 1982). The presence of fibrous illite in a sample can cause problems in obtaining accurate permeability measurements from core plugs. Conventional core analysis of illite-bearing sandstones can indicate unrealistically high permeabilities caused by the collapse of illite fibers during drying (Luffel and others, 1990).

Clay minerals in sandstones can also cause production problems because of sensitivity to completion fluids. Iron-rich chlorite will react with acid and form iron hydroxides that reduce permeability if the treatment liquids are not properly chelated (Almon and Davies, 1978). Swelling clays such as smectite or mixed-layer illite-smectite with a high percentage of smectite layers are sensitive to fresh water. However, few tight gas sandstones contain smectite, and most authigenic mixed-layer illite-smectite in the formations covered in this volume has a high percentage of illite layers and thus is not very sensitive to fresh water. Probably a more significant problem is the reduction of permeability that results from increased water saturation caused by drilling or stimulating a low-permeability formation (see section on capillary pressure).

Natural Fractures in Low-Permeability Sandstones

Most rocks near the Earth's surface (depths less than 3 to 6 mi) act like brittle-elastic materials in response to natural stresses. Consequently, under the influence of extension, compression, flexure, uplift, cooling, and fluid migration, many rocks acquire networks of fractures of various types and sizes. Fractures can be classified according to the relative movement of the fracture walls. Fractures having movement perpendicular to the fracture plane are extension or opening-mode fractures, whereas fractures having lateral displacement parallel to the fracture plane are faults. The shape of fractures, their associated infilling minerals, and characteristic fracture patterns and associations can be used to further classify fractures, and define fracture style and architecture (Hancock, 1985). Another aspect of fracture style is the range of fracture dimensions present in an array. Reservoir rocks may contain both extension fractures and faults that range from microfractures normally only visible under the microscope to large fractures and faults thousands of feet in size.

Incidence of Natural Fractures in Tight Gas Sandstones

As described below, natural fractures are commonly observed in core from low-permeability-sandstone reservoir rocks (table 5), despite the fact that many of these fractures are near vertical and therefore have low probability of being intersected by vertical boreholes. This implies that fractures are locally abundant in the subsurface, even in areas distant from structural perturbations such as folds and faults. In many cases, these fractures are observed to have been open or partly open in the subsurface, and locally they are associated with abrupt inflows of gas into the wellbore. Most documented fracture porosity values are low (a few percent and generally less than 1 percent), and may be overestimated by commonly used logging methods (Hensel, 1987). Recently fractures in several of low-permeability reservoirs have

Table 5. Natural fractures in low-permeability sandstone reservoirs.

	Fractures observed in core	Published core fracture description	Published account of anomalous production	Outcrop fracture description	Published account of horizontal well	RE	LO	CO
"Clinton"-Medina	Y	a	1	N	N	5	5	2
Berea	Y	a	1	N	N	5	5	2
Cotton Valley	Y	a,c,g	1	N	N	5	5	2
Travis Peak	Y	b,c,d,e,f,g	1,h	N	N	5	Y	2
Olmos	—	N	—	—	N	Y,5	6	6
Wilcox deltaic	Y	N	—	—	N	2	6	6
Wilcox Lobo	Y	N	—	—	N	2	6	Y
Vicksburg	—	—	—	—	N	2	6	5
Cherokee/Red Fork	—	—	—	—	N	2	2	2
Cleveland	Y	a	—	—	N	2	2	2
Granite Wash	—	—	—	—	N	—	2	2
Davis	Y	b,c,d	Y	N	Y	5	4	2
Abo	Y	N,3	—	1	N	2	5	6
Morrow	—	N	—	—	N	2	2	—
Canyon	Y	8,a,c,d,g	1	N	N	5	5	2
Dakota	Y	3	—	N	N	6	6	2
Cliff House/Point Lookout	—	3	—	N	N	6	6	2
Pictured Cliffs	Y	a,c	Y,i	Y,j	N	6	6	2
Muddy (J)	Y	2,3	—	—	N	5	3	2
Mancos "B"	Y	a,c	—	—	Y	5	3	2
Mesaverde	Y	a,c	Y,i	Y,j,7	Y	5	6	2
Upper Almond/Blair	—	—	—	—	N	6	4,5	2
Frontier	Y	b,c,d,f,g	1,h	Y,j	N	5	5	2

Key

— = Unknown
Y = Yes
N = No
1 = Limited study
2 = Limited information is available on topic
3 = Anecdotal evidence
4 = Not definitive
5 = Probable
6 = Unknown, suggested by structural setting
7 = Local
8 = In press
a = Core study in one or a few wells
b = Core study of subregional scale, numerous wells
c = FMS or BHTV data are available
d = Published microstructural study
e = Established "mechanical stratigraphy"
f = Basin-scale fracture study
g = Specific published data on *in situ* stress directions
h = Published account of anomalous treatment response
i = Production study of natural fractures
j = Published account of outcrop analog of reservoir fractures
RE = Regional
LO = Local fracture permeability in folds and fault zones
CO = Reservoirs compartmentalized by small faults

become targets for horizontal drilling, and in some cases increased gas production has been linked to fractures observed in core or on logs from horizontal wells.

Implications of Natural Fractures for Efficient Gas Production

Knowledge of fracture occurrence, orientation, and pattern is important for engineering evaluation and development of reservoirs having low matrix permeability (Aguilera, 1980; Reiss, 1980; Van Golf-Racht, 1982) and for correct placement of deviated and horizontal wells designed to cross fractures (for example, Nolen-Hoeksema and Howard, 1987; Finley and others, 1990). Fracture patterns in reservoir rocks and their origins have been extensively researched and reviewed (for example, Price, 1974; Friedman, 1975; Kranz, 1983; Hancock, 1985; Nelson, 1985; Bles and Feuga, 1986; Engelder, 1985, 1987; Pollard and Segall, 1987; Hancock and others, 1987; Pollard and Aydin, 1988; Laubach, 1988; Lorenz and others, 1991), but the full extent of the impact of fractures on fluid flow or engineering operations in most low-permeability-sandstone reservoirs has not been quantitatively assessed. In a review of low-permeability-sandstone reservoirs, Spencer (1989) concluded that natural fractures likely play a key role in production from parts of most, if not all, low-permeability-sandstone reservoirs. This inference was based on the disparity observed in some reservoirs between permeability measured on core samples and that implied by production histories.

In addition to locally providing pathways for fluid movement, recent engineering analyses have also confirmed geological predictions that natural fractures can profoundly affect the way induced hydraulic fractures grow. The growth of multiple fracture strands in naturally fractured intervals has been postulated to account for pressure anomalies detected during hydraulic fracture treatments. Opening of natural fractures could account for (1) wide scatter in the location of microseismic signals detected following hydraulic-fracture treatments monitored using in-well geophones and (2) evidence from some basins that hydraulic fractures have grown parallel to natural-fracture rather than maximum-horizontal-stress direction

(Laubach and others, 1992a). In several reservoirs described here, hydraulic fracturing experience suggests that natural fractures need to be taken into account in hydraulic-fracture-treatment design.

Anticipating Natural Fracture Attributes

Fractures can be classified by the processes that produced the fractures, and knowledge of the processes that have affected a formation can aid prediction of overall fracture patterns and abundance in a formation or area. The main processes that contribute to fracturing in reservoir sandstones are folding, faulting, progressive subtle changes in basin shape resulting from regional shortening or extension and stretching due to tectonic or burial loading, unloading, cooling, and migration of fluids. All of these processes can act together or separately to produce fractures, and as a result fractures having different origins can coexist in the same reservoir interval. Nevertheless, relatively simple structural and tectonic models can be used to predict important attributes of fracture systems (fig. 4).

Regional fractures commonly occur in subparallel sets, but sets generally show variable spacing and patterns may change gradually or abruptly on both regional and local (field, interwell) scales. Such patterns can be documented and predicted in a general way, but accurate predictions of fracture patterns on the reservoir scale is difficult. Reservoir fractures are arranged in networks that reflect the history of burial and tectonic loads that caused fracture propagation, and the evolving physical properties of the rock. Fracture-network interconnectivity and patterns of mineral fill within fracture networks control the size and shape of the rock volume contacted by a given borehole intersecting the network (Long and Witherspoon, 1985; LaPointe, 1988). As described below, fractures having marked effects on reservoir performance have been described from the Cotton Valley sandstone in the East Texas and North Louisiana basins, the Mesaverde in the Piceance Basin, the Frontier Formation in the Green River Basin, and the Davis Sandstone in the Fort Worth Basin.

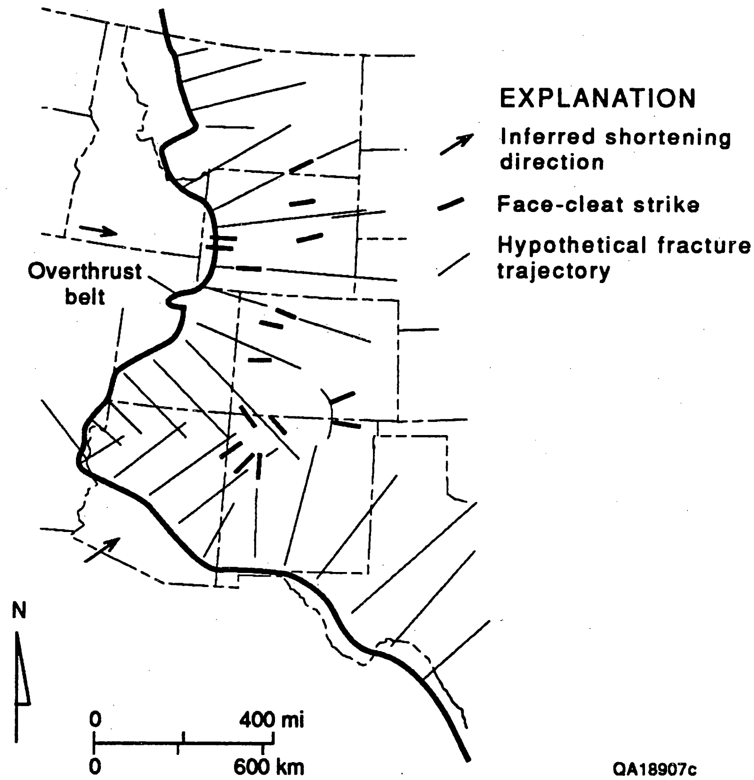


Figure 4. Predicted fracture strikes from tectonic model compared to measured fracture strikes. Representative coal-fracture (face-cleat) strikes in Cretaceous and Tertiary coal beds and lines drawn normal to generalized trace of the late Mesozoic-Cenozoic thrust belt. Arrows and normals show shortening direction across thrust belt based on assumption that shortening is normal to trace of thrust front. Lines are not meant to signify contemporaneous stress or failure trajectories (Laubach and others, 1992b).

Faults are common geologic features that are a type of reservoir heterogeneity occurring in tight gas sandstones in a wide spectrum of sizes. Large faults can compartmentalize reservoirs by juxtaposing reservoir and nonreservoir rocks, but small faults may also be barriers to fluid flow as a result of grain breakage and porosity reduction (Knipe, 1992), even where faults produce sandstone-on-sandstone contacts. Normal faults are common features of many Gulf Basin reservoirs such as the Lobo Wilcox and Vicksburg. Reverse faults occur locally in some sandstones adjacent to the Cordilleran thrust belt, such as the Frontier and Mesaverde, and strike-slip faults are possibly features of some Abo reservoirs. Data on faults in a given reservoir are commonly incomplete and affected by sampling bias. Short faults with small throw are generally invisible on seismic lines, and data from infill wells, where available, is seldom adequate to illuminate fault patterns in areas distant from these wells.

Natural fracture analysis is hindered by obstacles to fracture sampling. Fractures commonly escape detection with logs or core. Even simple fracture network patterns are difficult or impossible to document with conventional methods in vertical boreholes. Detailed information on fracture density, connectivity, and orientation patterns currently can only be obtained from outcrop studies of reservoir analogs (exposed reservoir-facies rocks having similar structural histories to target horizons). Well test and other engineering tests have provided little insight into natural fracture systems; commonly oversimplified representations of fracture networks are used to interpret such tests, which may obscure the effects of natural fractures on well tests and long-term reservoir behavior.

Prediction, detection, and characterization of natural fractures are key aspects of reservoir assessment, but successful evaluations are challenging. The effect of fractures on production depends on, among other factors, the relative permeability, porosity, and interconnectivity of the fracture network compared with the matrix rock. Fracture connectivity or the distribution of fracture-occluding minerals in fracture systems has not yet been successfully predicted on the prospect scale. The cumulative effect of long exposure to fracturing processes associated with tectonism, burial, uplift, and migrating fluids should work to produce an interconnected, conductive fracture network in older rocks. However, diagenetic processes of mineral precipitation tend to fill and close fractures. In the descriptions that follow, complex patterns would be expected in Paleozoic sandstones near orogenic belts such as the Appalachian orogen that have had protracted deformation histories, whereas Mesozoic and Tertiary units distant from orogenic disturbances might be expected to have simpler patterns. The intense faulting that characterizes the Tertiary Wilcox Lobo trend shows that such generalized models are no substitute for direct measurement of fractures and formation-specific predictive models.

Stress Directions and Stress Contrasts

Information on stress directions and stress contrasts in low-permeability sandstone reservoirs is important for designing engineering operations in these rocks. Hydraulic fracturing is an important stimulation method for low-permeability reservoirs, and hydraulic fracture growth directions and heights are key variables in hydraulic fracture treatment design in all of the sandstones described in this report. Under typical reservoir conditions, the growth direction of hydraulic fractures tends to parallel maximum horizontal stress (SHmax), so knowledge of principal stress directions is necessary for effective placement and stimulation of wells. This information is also important where open natural fractures contribute to production, because open fractures may be preferentially aligned parallel to SHmax.

The contrast in the magnitude of the minimum principal stress between different beds is one of the most important factors that governs the vertical growth of a hydraulic fracture. If hydraulically created fractures grow significantly taller in the vertical direction than specified in treatment design, then fracture width and length will be less than anticipated, and strata above and below the treatment interval may be inadvertently intersected by treatment fractures with potentially deleterious results for the success of the well.

It is beyond the scope of this report to review the state-of-the-art of methods for measuring in situ stress, but each section of the report briefly summarizes information on stress directions and stress-magnitude contrasts for the various formations. In most cases, high-quality data on stress directions and stress contrasts are not available in the literature at the field scale, and the results we cite should only be regarded as context for evaluating data obtained at specific wellsites. When judging the reliability of stress-direction information, regional patterns are useful guides owing to increasingly well documented stress-direction maps of the United States (Zoback and Zoback, 1989). Users of stress data need to carefully scrutinize the results and methods used to obtain stress-direction and stress-contrast information, because all methods are not equally reliable and all may give spurious results under certain circumstances. Below we briefly summarize background material on stress directions and stress contrasts to provide a context for formation-specific observations.

Stress Directions

Intraplate tectonic stresses such as those that affect virtually all low-permeability gas reservoir rocks are the result of plate tectonic forces acting on the lithosphere. As a result, regional maps of current stress directions are useful tools for predicting approximate maximum horizontal stress directions on the local (field or interwell) scale. Analysis of tectonic history is helpful for predicting paleostress directions and the orientation of natural fractures. For most of eastern North America, mid-ocean-ridge push forces are responsible for a large province of generally north-northeast-trending maximum horizontal stress (Richardson, 1992), the mid-plate compression province (Zoback and Zoback, 1989; fig. 5). This province extends east from the Rockies to the vicinity of the Mid-Atlantic Ridge.

Worldwide, most intraplate stresses are compressional (Zoback, 1992), but a complex extensional stress province exists in the western United States: the Cordilleran extensional province (Zoback and Zoback, 1989; fig. 5). Such provinces commonly have elevated topography and heat flow. The Cordilleran province also comprises several domains having contrasting directions of maximum horizontal stress. This variability in stress orientation, and

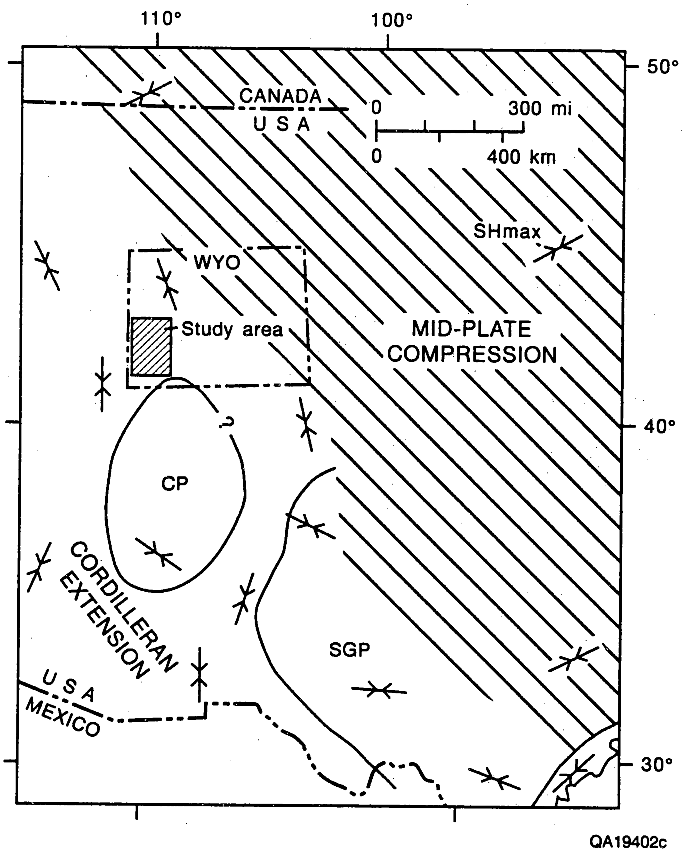


Figure 5. Stress province map showing major stress-province boundaries in the western United States (modified from Zoback and Zoback, 1989). Inward-pointing arrows indicate SHmax direction. CP = Colorado Plateau stress province; SGP = Southern Great Plains province. Inset labeled "Study area" shows location of detailed map in figure 6. From Laubach and others (1992a).

the limited resolution of regional stress-direction maps that arises from sparse well data, makes stress directions in some western basins challenging to predict. An example is the conflicting evidence of stress directions that has been reported from the Frontier Formation in the Green River Basin (Laubach and others, 1992a; fig. 6).

Stress directions in the formations described in this report have been determined by several methods. These methods include (1) measurement of core-scale phenomena such as core strain recovery (anelastic strain recovery, ASR), differential core contraction (differential strain curve analysis, DSCA), acoustic P-wave velocity analysis (circumferential velocity analysis, CVA), and rock strength anisotropy (measured with axial point-load tests, APT), (2) determination of the orientations of wellbore breakouts, coring- and drilling-induced fractures, and hydraulic fractures created in stress tests, and (3) remote monitoring of hydraulic fracture growth directions by circumferential detection of microseismicity (CMS).

Stress Contrasts

Knowledge of contrasts in minimum principal stress (commonly referred to as in situ stress) between rock layers is vital to hydraulic-fracture-treatment design, because fracture growth is governed by contrasts in fracture-closure stress, a measure of the tendency for beds to resist fracture propagation. Knowledge of fracture-closure stress is useful for specifying the locations of perforations and the type of treatment material to be pumped. Because vertical fracture growth is strongly dependent on in situ stress contrast among layers, optimizing a hydraulic-fracture treatment requires an accurate profile of stress above, within, and below the zone of interest (Gas Research Institute, 1992). Figure 7 is an example stress profile from the lower Travis Peak Formation of East Texas.

In the absence of a geophysical logging tool that can measure in situ stress, it is necessary to find some log-measured property that correlates with stress and then calibrate logs using stress tests. Using poroelastic principles and assumptions about boundary conditions (for

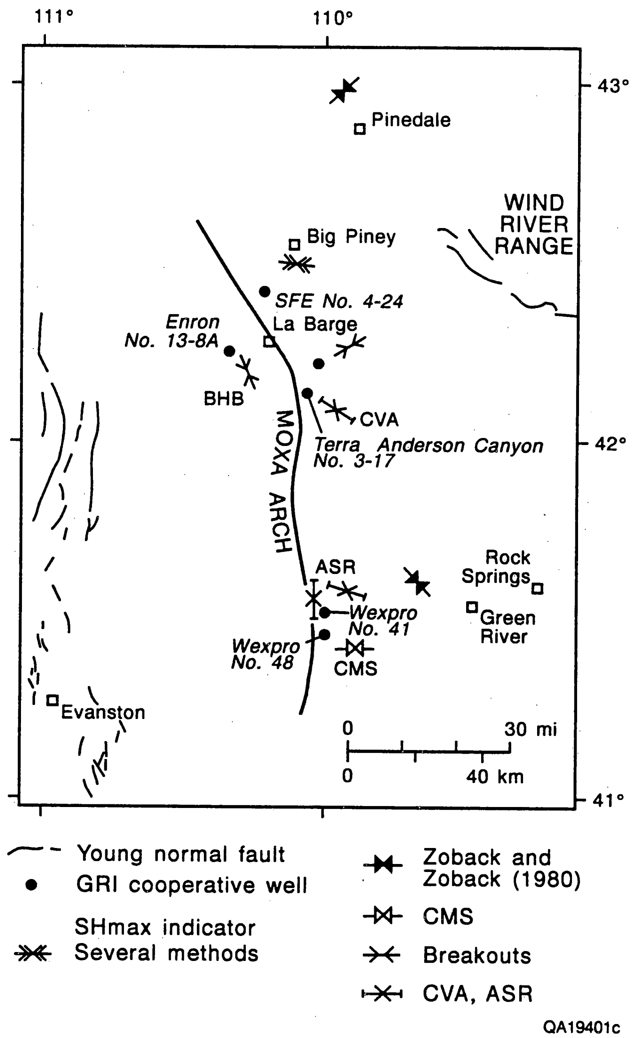


Figure 6. Map showing stress directions in GRI research and cooperative wells in the Green River Basin, published stress direction determinations, and young normal fault scarps (reflecting recent tectonic deformation). Inward-pointing arrows indicate the direction of SHmax. Locations of normal faults from Case (1986). CMS = circumferential detection of microseismicity; BHB = borehole breakouts; CVA = circumferential velocity analysis; ASR = anelastic strain recovery. From Laubach and others (1992a).

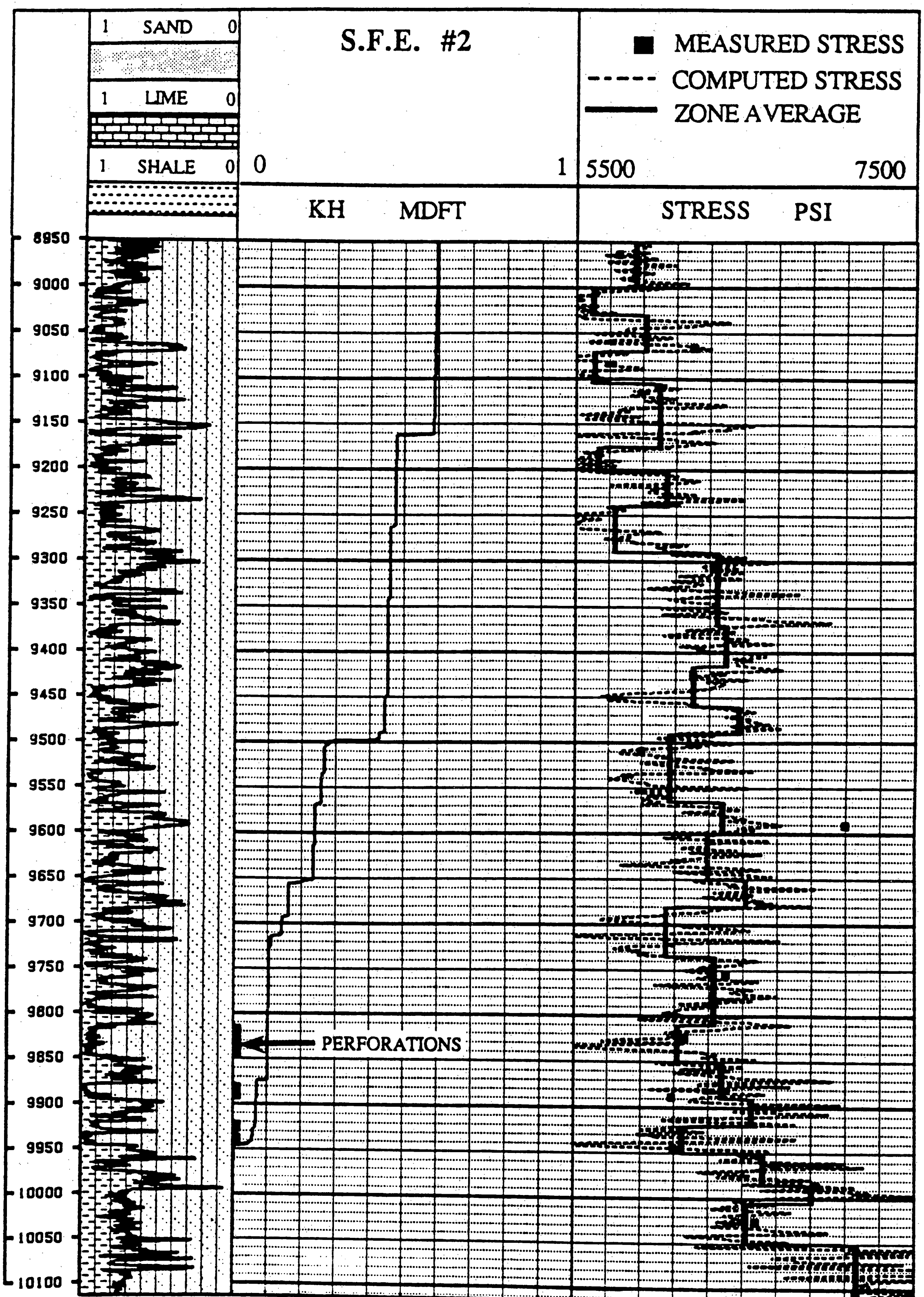


Figure 7. Stress profile of the lower Travis Peak completion interval, SFE No. 2 well, northern Nacogdoches County, Texas (from CER Corporation and S. A. Holditch & Associates, 1990).

example, horizontal strains are commonly and erroneously assumed to be zero), the value of in situ stress can be estimated from density and acoustic logs and core data, but these calculations do not account for tectonic stress components. To be accurate guides to hydrofracturing, these estimates require calibration with stress measurements (for example, Whitehead and others, 1989). Some of the reasons for mismatches between uncalibrated calculated stresses and measured stresses are discussed by McGarr (1988).

Because it relies on calibration by stress tests, the method used to derive the stress profiles presented here is essentially empirical and can be used independently of assumptions about elastic and permanent strains associated with various loads in a formation's history. This approach is consistent with experience in calculating stress profiles, which shows that core- and log-derived stress profiles locally require recalibration over relatively short distances (field and basin scale).

The most accurate measure of minimum principal stress for a particular layer is obtained from injecting fluid into a rock layer in stress tests that yield fracture-closure pressure. Several methods have been used to measure fracture-closure pressure (for example, Veach and Moschovidis, 1986; Whitehead and others, 1989). These include injection/flowback and injection/falloff tests (monitored small-volume hydraulic fractures, called minifracs, microfracs, and stress tests). For example, during stress tests carried out in the Travis Peak Formation, total fluid volume injected into a zone was less than 500 gal in several different pumping stages. Injection volume in most stages was less than 50 gal (Whitehead and others, 1989). Because of the small volumes that are typically pumped, injection/falloff tests are generally the most accurate. Stress tests have been carried out in both open and cased holes.

GRI research projects have shown that cores and stress tests can be used to calibrate log data so that an in situ profile can be obtained using acoustic data, density data, and estimates of formation rock type if profiles are properly calibrated with stress tests. When developing a log-based stress profile, it is necessary to run gamma-ray, SP, resistivity, density, neutron, and acoustic logs. The acoustic logs should be processed to obtain values of compressional velocity and shear velocity. The remainder of the logs should be processed to determine values of porosity, water saturation, and rock type. In addition, wireline formation pressure tests can be run to determine values of reservoir pressure in each layer of rock, if the pressure distribution is not known beforehand.

In this report, we provide representative stress profiles where they are available. Whitehead and others (1989; S. A. Holditch & Associates, 1991; Gas Research Institute, 1992) review the methods and assumptions involved in producing these profiles. An assessment by Holditch and Voneif (1992) shows the economic value of such profiles.

Engineering Characteristics of Tight Gas Sandstones

Tight gas sandstones are characterized by high capillary pressures, high irreducible wetting-phase saturation, low porosity, and low permeability. Economic production of gas from the rock matrix commonly requires that flow to the wellbore be aided by natural or induced fracture systems, but the production rate is determined by the gas flow rate from the matrix into the fracture system. Therefore, knowledge of fluid flow in the matrix is important for predicting overall production behavior. Experimental studies of flow properties of low-permeability sandstones include Jones and Owens (1980), Walls and others (1982), Soeder (1986), and Arastoopour and others (1987).

Capillary Pressure

The flow of gas from the rock matrix into the wellbore or fracture system depends on the detailed pore structure of the matrix and the distribution of water contained within the pore spaces. Information about pore size can be obtained by measurements of capillary pressure. Capillary-pressure data are used to evaluate the reservoir rock quality, fluid saturations in the reservoir, thickness of reservoir and nonreservoir quality rocks, and recovery efficiency. In addition, capillary pressures can be related to absolute and relative permeability values.

Capillary pressure results from interactions of forces acting within and between liquids and their bounding solids. These include both cohesive (liquid-liquid) forces and adhesive (liquid-solid) forces. Where adhesive forces are greater than cohesive forces, the liquid is "wetting"; if cohesive forces exceed adhesive forces, the liquid is "nonwetting." If the end of a narrow capillary tube is placed in a wetting fluid (such as water), net adhesive forces draw the fluid into the tube. The wetting phase rises in the capillary tube above the original interface or free water level until adhesive and gravitational forces are balanced. Capillary pressure P_c is defined as the difference in pressure across the meniscus in the capillary tube. In other words, capillary pressure is the amount of extra pressure required to force the nonwetting phase (air in this example) to displace the wetting phase (water) in the capillary.

Internal pore geometry of many reservoir rocks can be approximated by a system of capillaries, formation water being the wetting phase and hydrocarbons the nonwetting phase. The displacement of formation water by hydrocarbons first occurs in the largest pore throats (capillaries), leaving the smaller capillaries water filled. As the hydrocarbon column increases, capillary pressure increases, forcing hydrocarbons into smaller pore throats. Therefore, hydrocarbon saturation of formation pores is directly related to the capillary pressure.

Reservoir capillary-pressure relationships can be evaluated by using either (1) porous plate or centrifuge methods or (2) mercury injection methods. Reservoirs dominated by shaly or tightly cemented sandstone require higher capillary pressures to attain the same saturations reached at lower pressures in well-sorted, porous sandstone. Therefore, tight gas sandstones typically have high capillary pressures at moderately low wetting phase saturations (Spencer, 1989). At 50-percent water saturation, capillary pressures may be >1,000 psi, indicating that the rocks have very small pore throats and capillaries.

Capillary pressure data can be used to help distinguish reservoir rock from nonreservoir rock and pay from nonpay. Although "reservoir rock" has the potential to contain hydrocarbons, it may not necessarily contain any, or they may not be producible quantities. In contrast, "pay" is defined as "the hydrocarbon-bearing volume of the reservoir that would produce at economic rates using a given production method" (Vavra and others, 1992, p. 848). Sneider (1987) and Vavra and others (1992) present tables of mercury-injection capillary-pressure (MICP) data that can be used to distinguish reservoir versus nonreservoir rocks and pay versus nonpay.

Capillary pressure data are important in tight gas sandstones because they have high surface area per unit pore volume. Surface adsorption and capillary condensation contribute to retention of large amounts of water at extremely high capillary pressures. At higher water saturations, the relative permeability to gas is greatly reduced, thereby reducing the producibility of the sandstones. Thus, water forced into a low-permeability sandstone reservoir during drilling, acidizing, or fracture stimulation takes a long time to flow back to the well (clean up) during testing and production, and a much higher in situ gas pressure is required for establishment of a consistent gas flow into the wellbore. Very tight reservoirs may never produce back the water that was forced into the formation, preventing the reservoirs from regaining their original permeability (Walls, 1982; Spencer, 1989), and in some cases, the wells may produce no gas at all.

Formation Evaluation in Tight Gas Sandstones

The three basic purposes of formation evaluation are (1) to evaluate formations for volumetric properties, which include porosity, lithology, and water and gas saturation, (2) to determine the deliverability of the zones of interest by estimating the in situ permeability, and (3) to identify the principal stress values and other rock mechanical properties to assist the design of fracture stimulation treatments, so critical in the completion of tight gas sandstones. Formation evaluation in tight sandstones is challenging and requires planning. Although it stretches the use of geophysical well logs, core analysis, and well-test analysis to the limit, when used with care these techniques have proven to be accurate for determining reservoir properties. Useful procedures are summarized in GRI reports on SFE wells (CER Corporation and S. A. Holditch & Associates, 1988, 1989, 1990, 1991; CER Corporation, 1992b).

Methods of log analysis commonly fall short when evaluating low-porosity, low-permeability sandstones, and for this reason formation evaluation has been the subject of intense research in the GRI Tight Gas Sands project (ResTech, Inc., 1989). Geophysical well logs provide the most continuous source of data for evaluation of any tight gas well. However, interpretation models need to be based on core-based measurements of physical characteristics such as porosities and permeabilities, fluid saturations, lithology, well-test measurements of permeability, and mini-fracture stimulations or in situ stress tests to determine formation strength. By performing log interpretation modeling based on physical measurements, properties can be determined that represent the reservoir properties existing downhole.

Once models are developed for a specific area or field, it is no longer necessary to collect the same extensive data required for the first one or two wells. Logging programs can be designed that are cost effective but that provide sufficient data for volumetric analysis, rate prediction, and estimation of rock mechanical properties.

Irregular or rugose boreholes can severely impair the accuracy of geophysical well logs for analysis. These borehole irregularities are caused either by fluid interaction with the rock or by borehole spalling, and they are widespread features in research wells in tight gas sandstones (CER Corporation, 1992b). Borehole breakouts and other borehole rugosity cause pad-type logging devices to lose contact with the face of the borehole, resulting in invalid readings that must be corrected either by regression analysis or by replacement with other nonpad-type porosity devices (Howard and Hunt, 1986). The bulk-density log is most severely affected, followed by the compensated neutron log. The acoustic log, which has centralized recording, is the least affected. This problem occurs in low-permeability sandstones in every basin that has been studied as part of this report. Higher permeability formations normally will build a filter cake, which acts to prevent formation spalling.

The second most serious problem in log evaluation of tight gas sandstones is the calibration accuracy required in recording porosity logs, particularly the bulk density log. In typical wells, it is not unusual for 50 percent of wireline logs to require recalibration (CER Corporation and S. A. Holditch & Associates, 1989). These errors must be corrected for (Connolly, 1974). In formations where average porosities are 4 to 11 percent, a miscalibrated density log can cause errors of up to 50 percent in porosity calculations.

Once these two corrections are made, shaly sandstone water-saturation and porosity models can be used to estimate reservoir properties for reserve analysis. Dual water (Clavier and others, 1984) or Waxman-Smits (Waxman and Smits, 1968) equations are both reliable techniques for determining water saturation. A laminated shale model (Howard and Hunt, 1986) works well for porosity determinations. All of these techniques work well, provided the models have been validated by either core or well-test analysis.

Permeabilities are routinely estimated using porosity and lithology analysis. Equations are based on in situ core permeability and relative permeability measurements, then confirmed by well-test-derived permeabilities (ResTech, Inc., 1989). Another method to determine permeability is by analysis of geochemical logs (CER Corporation, 1992b), which have become more prevalent in determining the mineralogy of tight sandstones.

Finally, the design of fracture-stimulation treatments can be improved dramatically if rock-mechanical-property moduli are known. Acoustic logs are used for determination of these moduli by general equations, then the logs are recalibrated using the results of mini-fracture-stimulation treatments or formation stress tests (Whitehead and others, 1986).

The use of the techniques described above is recommended in all formations and basins that will be discussed in the following text. A multidisciplinary approach to formation evaluation provides the most accurate assessment of reservoir properties.

APPALACHIAN BASIN

The Appalachian Basin (fig. 8) is an elongate basin that extends southwestward from New York to Tennessee. It is separated from the Black Warrior Basin of Alabama and Mississippi by the Sequatchie Anticline along the southern Tennessee border (Milici and De Witt, 1988). The eastern edge of the basin is buried beneath the Piedmont thrust sheets (Cook and Oliver, 1981), and the Nashville-Cincinnati-Findlay-Algonquin Arch forms the western boundary (fig. 8). The oldest Appalachian Basin sediments are late Precambrian to Cambrian in age, and the youngest are Permian (Milici and De Witt, 1988). The Silurian "Clinton"-Medina and the Mississippian Berea sandstones are the two major tight gas sandstones in the Appalachian Basin (fig. 9). Production of gas from low-permeability reservoirs in both of these sandstones occurs in the Western Basin structural province (corresponds to Appalachian Plateau region), which is characterized by very gentle folding with little structural relief (Diecchio, 1985). Of the tight gas wells drilled nationwide between 1981 and 1988, 80 percent were drilled in the Appalachian Basin, and the majority of the activity was in the "Clinton"-Medina and Berea (Haas and others, 1988).

Lower Silurian sandstones of the Medina Group of western Pennsylvania and New York and the equivalent "Clinton" Sandstones (Albion Group) of Ohio and Kentucky (fig. 10) were derived from erosion of the Taconic highlands, which were uplifted to the east of the Appalachian foreland basin during the Taconic Orogeny beginning in the Middle Ordovician (Milici and De Witt, 1988). The Taconic highlands were eroded and ceased to be a sediment source by the end of the Silurian. The Lower Mississippian Berea sandstones of Virginia, West Virginia, Kentucky, and Ohio (fig. 9) were derived from erosion of highlands in eastern Virginia and West Virginia that developed during the Devonian Acadian orogeny and from highland source areas in eastern Canada (Pepper and others, 1954; De Witt and McGrew, 1979).

Lower Silurian stratigraphic nomenclature varies from state to state (figs. 9 and 10). The use of the term "Clinton" for the sequence of Lower Silurian sandstones in Ohio and Kentucky

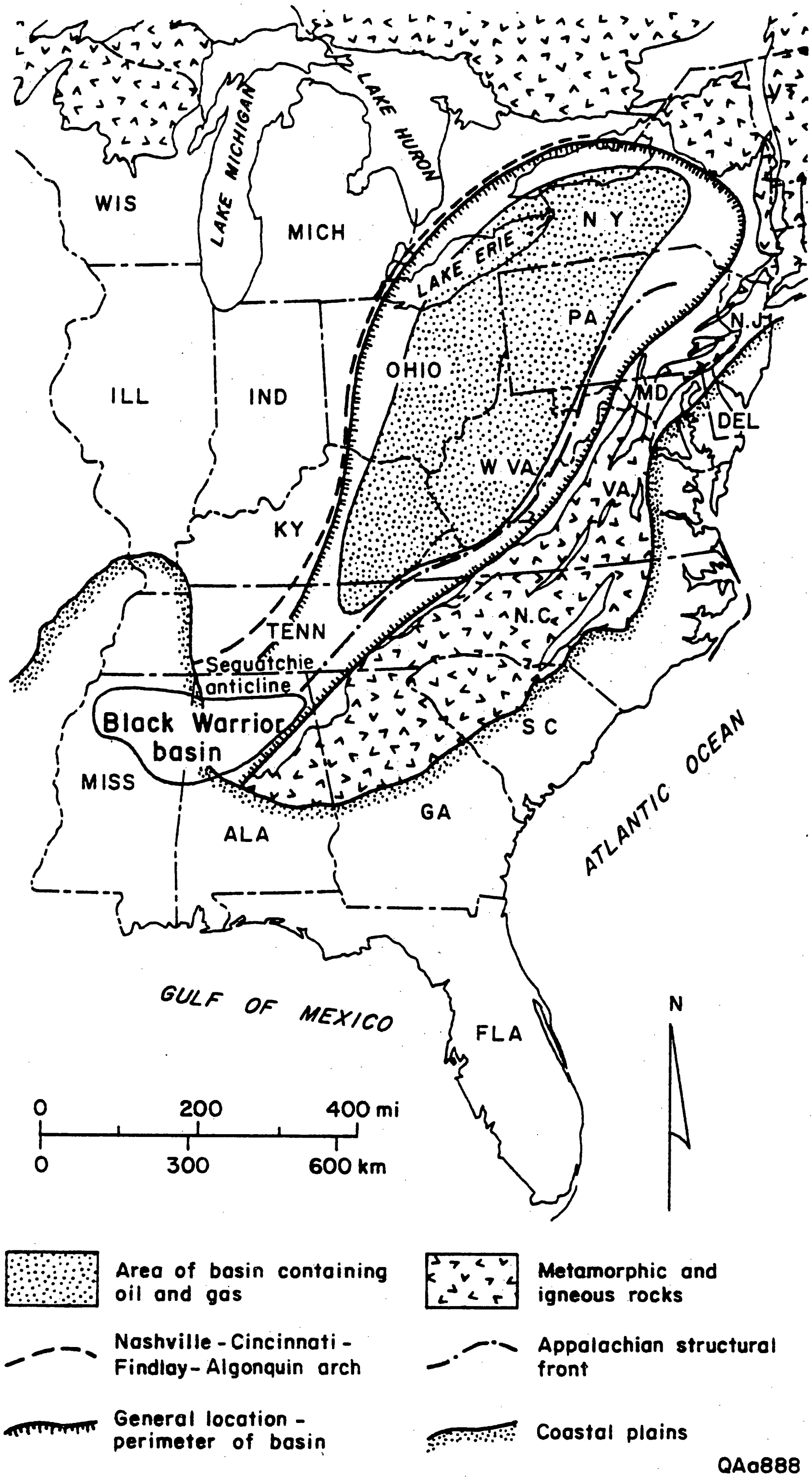


Figure 8. Location of the Appalachian Basin and related tectonic features (modified from Roth, 1968; revisions based on Thomas and Mack, 1982; Milici and De Witt, 1988).

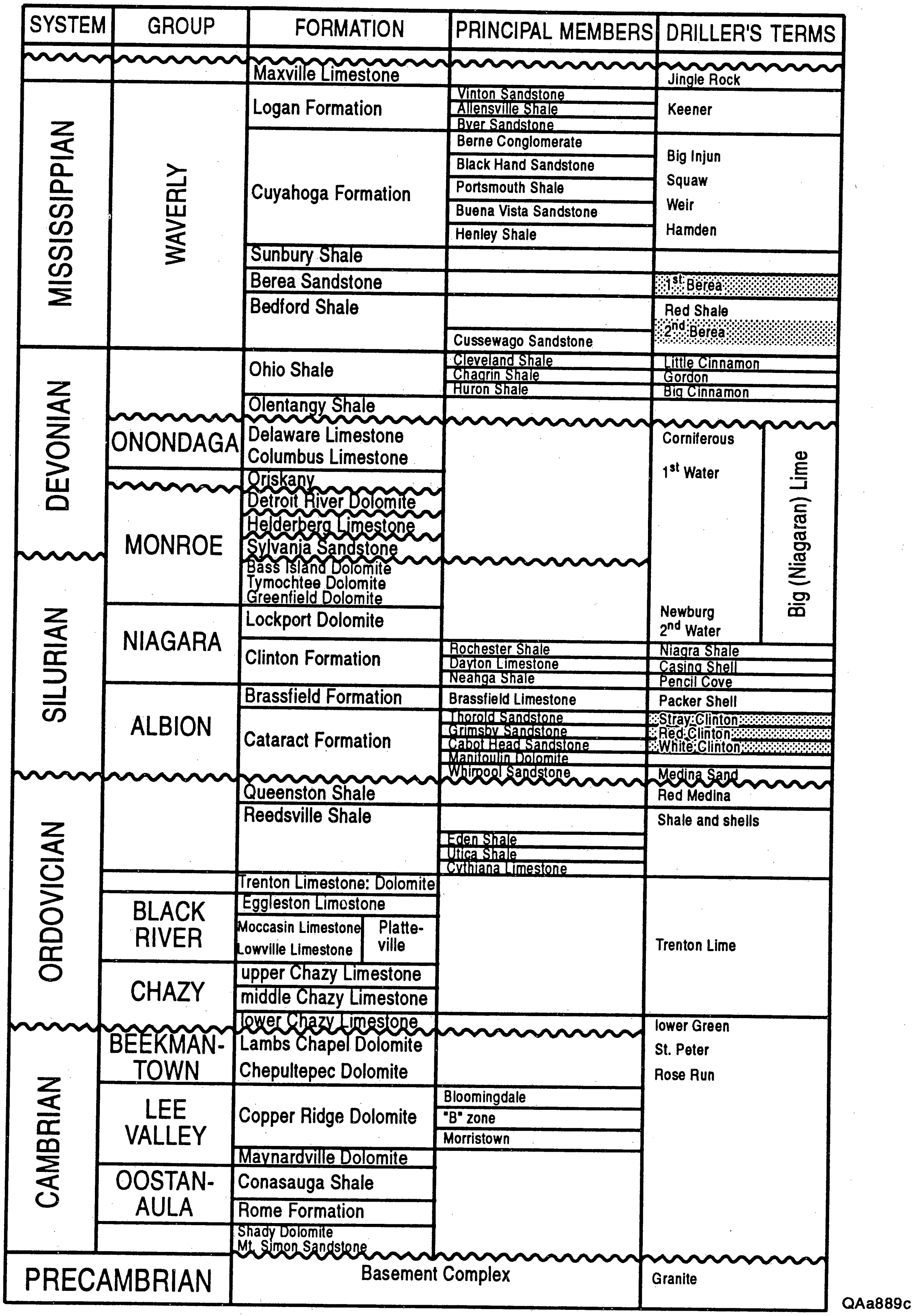


Figure 9. Generalized stratigraphic column of Cambrian through Mississippian units for Ohio east of the Cincinnati Arch (from Channas, 1971). Highlighted intervals have been designated tight by FERC.

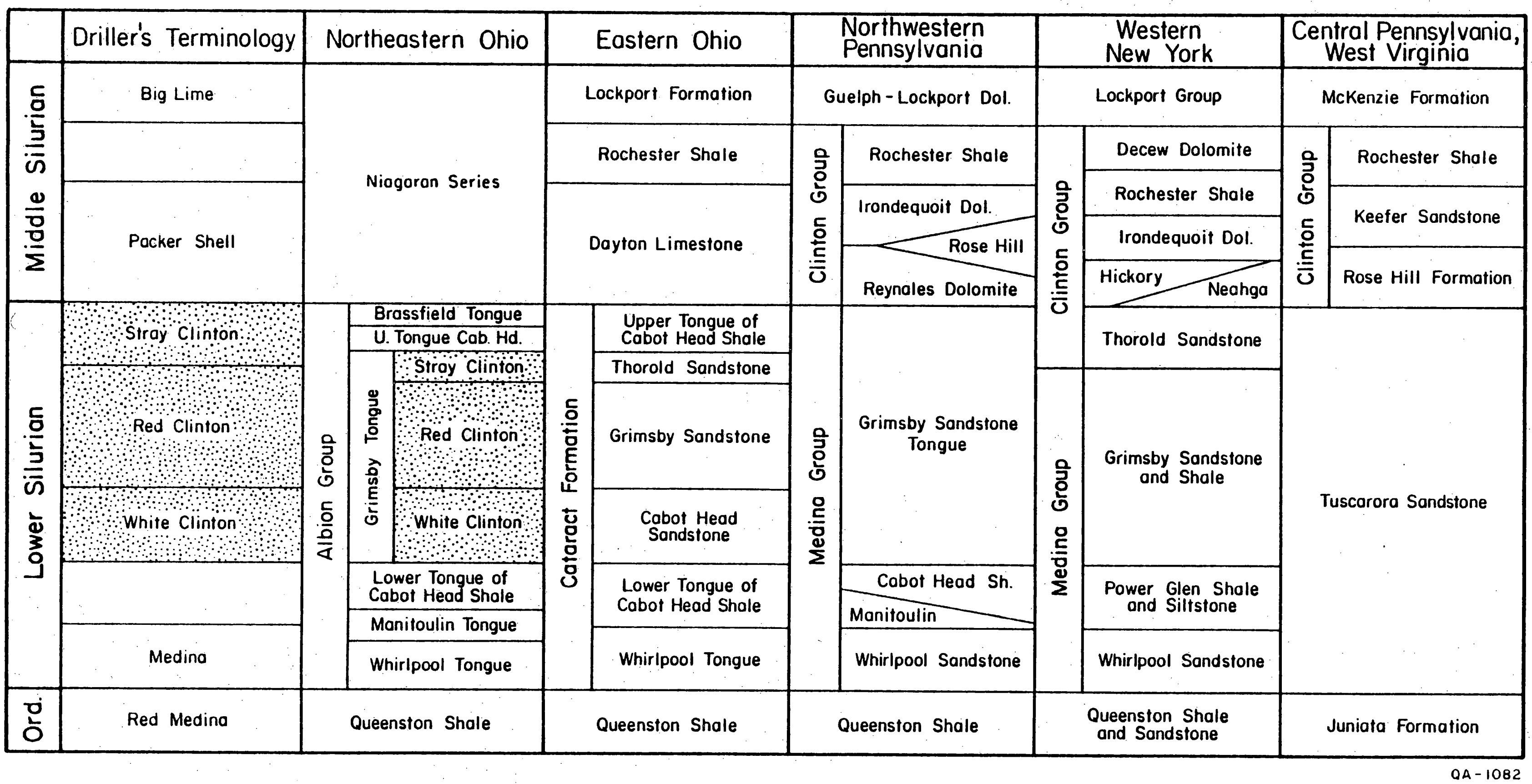


Figure 10. Stratigraphic terminology used to describe the Lower Silurian (from Finley, 1984). Not to scale; correlations are tentative. Tight gas sandstones are stippled.

began many years ago and was based on an incorrect correlation (Keltch and others, 1987). The "Clinton" of this report is not equivalent to the Middle Silurian Clinton Group in the eastern part of the Appalachian Basin (fig. 10). Another source of confusion is the term "Medina." In New York the Medina Group is everything above the Ordovician (Queenston) and below the Thorold (fig. 10). In West Virginia and Ohio, drillers use the term "Red Medina" to refer to the Upper Ordovician Queenston Shale or Juniata Formation and "Medina" or "White Medina" to refer to the Lower Silurian Tuscarora or Whirlpool Sandstones (fig. 10).

The Berea is the oldest Mississippian sandstone formation in the Appalachian Basin. The Second Berea, which is also designated a tight gas sandstone in Ohio, refers to a sandstone and siltstone member within the Bedford Shale (Pepper and others, 1954) (fig. 9).

Other formations in the Appalachian Basin that have been designated tight by FERC (table 6) are (1) Upper Devonian sandstones in the Venango and Bradford Groups and the Catskill and Lock Haven Formations in Pennsylvania (Laughrey and Harper, 1986), (2) the Maxon, Injun, Weir, and Berea sandstones and the Big Lime and Little Valley limestones in Virginia, (3) the Big Lime, Little Lime, and numerous Upper Devonian and Mississippian sandstones in West Virginia (see table 6 for names), and (4) the Big Six Sandstone ("Corniferous") in Kentucky. In the Black Warrior Basin of Alabama and Mississippi, the Upper Mississippian Hartselle Sandstone and sandstones in the Lower Pennsylvanian Pottsville Formation have been designated tight.

The term "Corniferous" in eastern Kentucky refers to Middle Silurian to Middle Devonian rocks. Oil and gas is produced from both dolomite and sandstone facies in the "Corniferous" interval, but only the Big Six Sandstone has been designated a tight reservoir by FERC. The names Maxon and Maxton are informal drillers' terms that are both used to refer to an Upper Mississippian sandstone in West Virginia.

Table 6. Appalachian Basin formations designated tight by FERC.

State[1]	Formation	Geologic Series
Kentucky	Berea Sandstone	Lower Mississippian
	Corniferous Big Six Sandstone	Middle Silurian
	"Clinton" Sandstone	Lower Silurian
New York	Medina Group	Lower Silurian
	Queenston Shale	Upper Ordovian
Ohio	Berea and Second Berea Sandstone	Lower Mississippian
	"Clinton" Sandstone	Lower Silurian
Pennsylvania	Venango Group	Upper Devonian
	Catskill Formation	Upper Devonian
	Lock Haven Formation	Upper Devonian
	Bradford Group	Upper Devonian
Virginia	Maxon sandstone (Mauch Chunk Gp.)	Upper Mississippian
	Little Valley Limestone	Middle Mississippian
	Big Lime	Middle Mississippian
	Injun sandstone (Pocono Gp.)	Lower Mississississippian
	Weir sandstone (Pocono Gp.)	Lower Mississississippian
	Berea Sandstone	Lower Mississippian
West Virginia	Ravencliff sandstone (Mauch Chunk Gp.)	Upper Mississippian
	Maxton or Maxon sandstone (Mauch Chunk Gp.)	Upper Mississippian
	Little Lime (Mauch Chunk Gp.)	Upper Mississippian
	Blue Monday sandstone (Greenbriar Gp.)	Middle Mississippian
	Keener sandstone(Greenbriar Gp.)	Middle Mississippian
	Big Lime (Greenbriar Gp.)	Middle Mississippian
	Injun sandstone (Pocono Gp.)	Lower Mississippian
	Squaw sandstone (Pocono Gp.)	Lower Mississippian
	Weir sandstone (Pocono Gp.)	Lower Mississippian
	Berea sandstone (Pocono Gp.)	Lower Mississippian
	Gantz sandstone (Hampshire Fm.)	Upper Devonian
	Fifty Foot sandstone (Hampshire Fm.)	Upper Devonian
	Gordon sandstone (Hampshire Fm.)	Upper Devonian
	Fourth sandstone (Hampshire Fm.)	Upper Devonian
	Fifth sandstone (Hampshire Fm.)	Upper Devonian
	Riley sandstone (Chemung Gp.)	Upper Devonian
	Benson sandstone (Chemung Gp.)	Upper Devonian

[1]These formations are designated tight by FERC only in specified counties or parts of counties within these states.

"Clinton"-Medina Sandstone

The Lower Silurian "Clinton"-Medina Sandstone (fig. 10) has been designated tight in a large area of New York, Pennsylvania, Ohio, and Kentucky (fig. 11, table 7). The "Clinton"-Medina was not included in the EEA study of reserves in tight gas sandstones, but Haas and others (1988) estimated that 94 Tcf of gas in place exist in the FERC-designated area. Average depth to the top of the Brassfield Limestone (Packer Shell, fig. 9) above the "Clinton" Sandstone in Ohio varies from more than 7,000 ft in eastern Ohio to slightly more than 1,000 ft at the western limit of production (Finley, 1984). In Pennsylvania, depth to the top of the Medina Group ranges from 2,500 ft along Lake Erie to more than 7,000 ft in the southeast corner of Venango County (Finley, 1984). In New York, depth to the top of the Medina Group varies from 7,000 ft in southeastern Allegany County to outcrop just south of Lake Ontario. Production occurs at depths as shallow as 1,000 ft (Finley, 1984). Thickness of the "Clinton" interval (between the Queenston Shale and the Packer Shell, fig. 10) in Ohio is >220 ft in southeast Ohio, thinning to the west and north to about 130 ft thick at the western limit of production (Coogan, 1991). In Pennsylvania, maximum thickness of the Medina Group is about 200 ft in the area around Clarion County, and it thins to the northwest to about 150 ft along the shoreline of Lake Erie (Laughrey and Harper, 1986). The Grimsby Sandstone within the Medina Group varies from 80 to 180 ft in Pennsylvania. The Medina Group in New York varies from 180 ft in southern Chautauqua County to nearly complete pinch-out in northern Cayuga County (Finley, 1984). The Grimsby Sandstone in New York is thickest (150 ft) in southeastern Allegany County and thins to the west, north, and east.

Several detailed studies of the "Clinton" in Ohio have been conducted as Master's theses, and these and other studies are listed and summarized by Coogan (1991). The Ohio Geological Society has published two volumes of papers on "Clinton" reservoirs in Ohio, which are good sources of both engineering and geologic data (Ohio Geological Society, 1985a, b). A cooperative well was drilled by GRI in the "Clinton" Sandstone in Mahoning County, Ohio, to determine

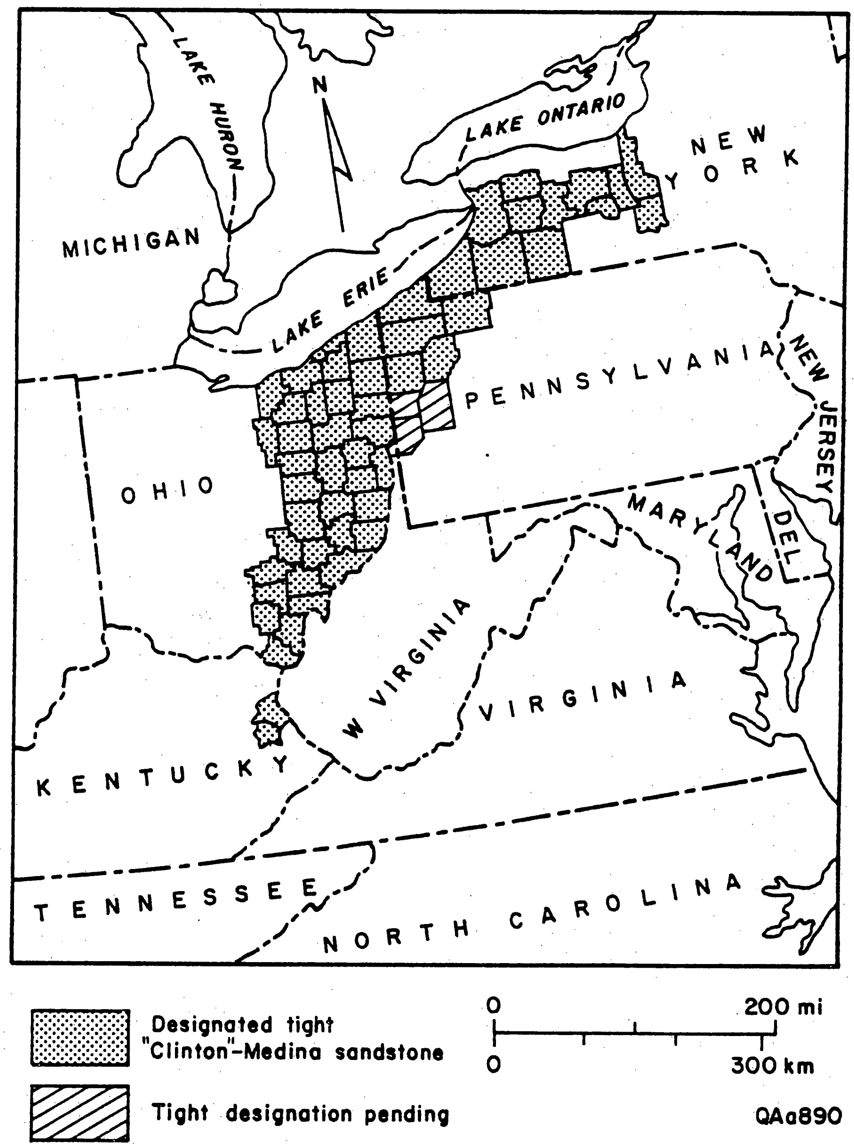


Figure 11. Counties in Kentucky, New York, Pennsylvania, and Ohio in which the "Clinton"-Medina sandstone is designated tight by FERC. See table 7 for county names.

Table 7. Counties in which the "Clinton"-Medina Sandstone has been designated tight. The qualified area may not cover the entire county.

Kentucky	Johnson, Lawrence
New York	Allegany, Cattarugus, Cayuga, Chautaugua, Erie, Genesee, Livingston, Ontario, Seneca, Tompkins, Wyoming, Yates
Ohio	Ashland, Ashtabula, Athens, Belmont, Carroll, Columbiana, Coshocton, Cuyahoga, Gallia, Geauga, Guernsey, Harrison, Hocking, Holmes, Jackson, Jefferson, Lake, Lawrence, Lorain, Mahoning, Medina, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Portage, Stark, Summit, Trumbull, Tuscarawas, Vinton, Washington, Wayne
Pennsylvania	Crawford, Erie, Mercer, Venango, Warren; pending in Beaver, Butler, and Lawrence

azimuth of natural fractures and maximum horizontal stress. The "Clinton" Sandstone in Muskingum and Noble Counties, Ohio, was also evaluated by the GRI Tight Gas Sands project as a location for conducting experiments on hydraulic fracturing.

Depositional Systems and Reservoir Facies

Lower Silurian clastic sediments that were shed off the Taconic foreland fold-belt highlands are primarily deltaic and shoreface deposits in the western Appalachian Basin, where they form hydrocarbon reservoirs. The "Clinton"-Medina producing trend (fig. 11) corresponds to the trend of deltaic-shoreface sandstones that occurs between continental fluvial deposits to the southeast and offshore marine shelf deposits to the northwest (Martini, 1971). In Medina outcrops in New York, Martini (1971) recognized areas of delta progradation along the axes of major distributary channels, separated by interdeltaic areas where sediment was reworked and dispersed by waves and longshore currents. Interdeltaic environments are characterized by shoreface, beach, longshore-bar, tidal-flat, and tidal-channel deposits. Similar deltaic and shoreface facies occur in the subsurface in northwestern Pennsylvania (Laughrey and Harper, 1986). The Whirlpool Sandstone (fig. 10) is interpreted to be a basal transgressive sandstone that was deposited on the older deltaic coastal-plain sediments of the Queenston Formation (Laughrey and Harper, 1986). Offshore and longshore bars of the Whirlpool Sandstone are overlain by shelf mud deposits of the lower Cabot Head Shale. Progradation of the shoreline is represented by lower shoreface sandstones in the upper Cabot Head Shale and upper shoreface and nearshore sandstones of the lower Grimsby Formation. The sequence is capped by red and green muddy sandstones of the upper Grimsby Formation that were deposited in a prograding coastal sand-mud complex (Laughrey and Harper, 1986). In places, northwest-oriented fluvial channels cut out part of the shoreface sequence, and small deltas formed at river mouths.

Deltaic deposits are the main reservoir sandstones in the "Clinton" of Ohio (Knight, 1969; Keltch, 1985; Keltch and others, 1987; Coogan, 1991), and the vertical sequence of deposits is typical of cratonic delta systems. The depositional sequence of the "Clinton" in Ohio can be divided into four major depositional phases (Keltch, 1985), illustrated in figure 12. (1) Initial marine transgression deposited the thin Whirlpool strandplain sandstone on the Upper Ordovician erosional surface. (2) A prograding delta deposited prodelta shales (Lower Cabot Head Shale) overlain by delta front and delta plain sandstones (Grimsby and Cabot Head Sandstones). (3) A destructional phase following delta abandonment, in which delta-plain sandstones were reworked to produce the thin, littoral Thorold Sandstone. (4) Continued marine transgression deposited marine shelf shales (Upper Cabot Head Shale) and carbonates (Brassfield Formation).

"Clinton" production in Guernsey County, Ohio, occurs from distributary mouth bars, distributary channels, and delta-plain point bars (fig. 13), and gas production in this part of the "Clinton" trend is controlled by reservoir facies and sandstone thickness (Keltch and others, 1987). Distributary mouth bar sandstones are widespread, occurring in 70 percent of the wells. Individual sandstones have a maximum thickness of about 22 ft, but it is common for several upward-coarsening mouth-bar sandstones to be stacked vertically (fig. 13). They are relatively poor producers; in Guernsey County, median gas production from distributary mouth bar sandstone reservoirs is only 13 MMcf in the first year (Keltch and others, 1987). Distributary channel-fill sandstones are better reservoirs, having median first-year gas production of 30 MMcf, but they occur in only 18 percent of the wells (Keltch and others, 1987). The distributary channel-fill sandstones are narrow, elongate, and laterally discontinuous and have blocky log signatures (figs. 13 and 14). Point-bar sandstones are the best "Clinton" reservoirs in this area, but they occur in only 8 percent of the wells. Point-bar reservoir sandstones are as much as 25 ft thick and have upward-fining log signatures (fig. 13). Median first-year gas production from point-bar reservoirs is about 60 MMcf (Keltch and others, 1987). In general, better gas production in this area occurs in wells with greater thicknesses of clean

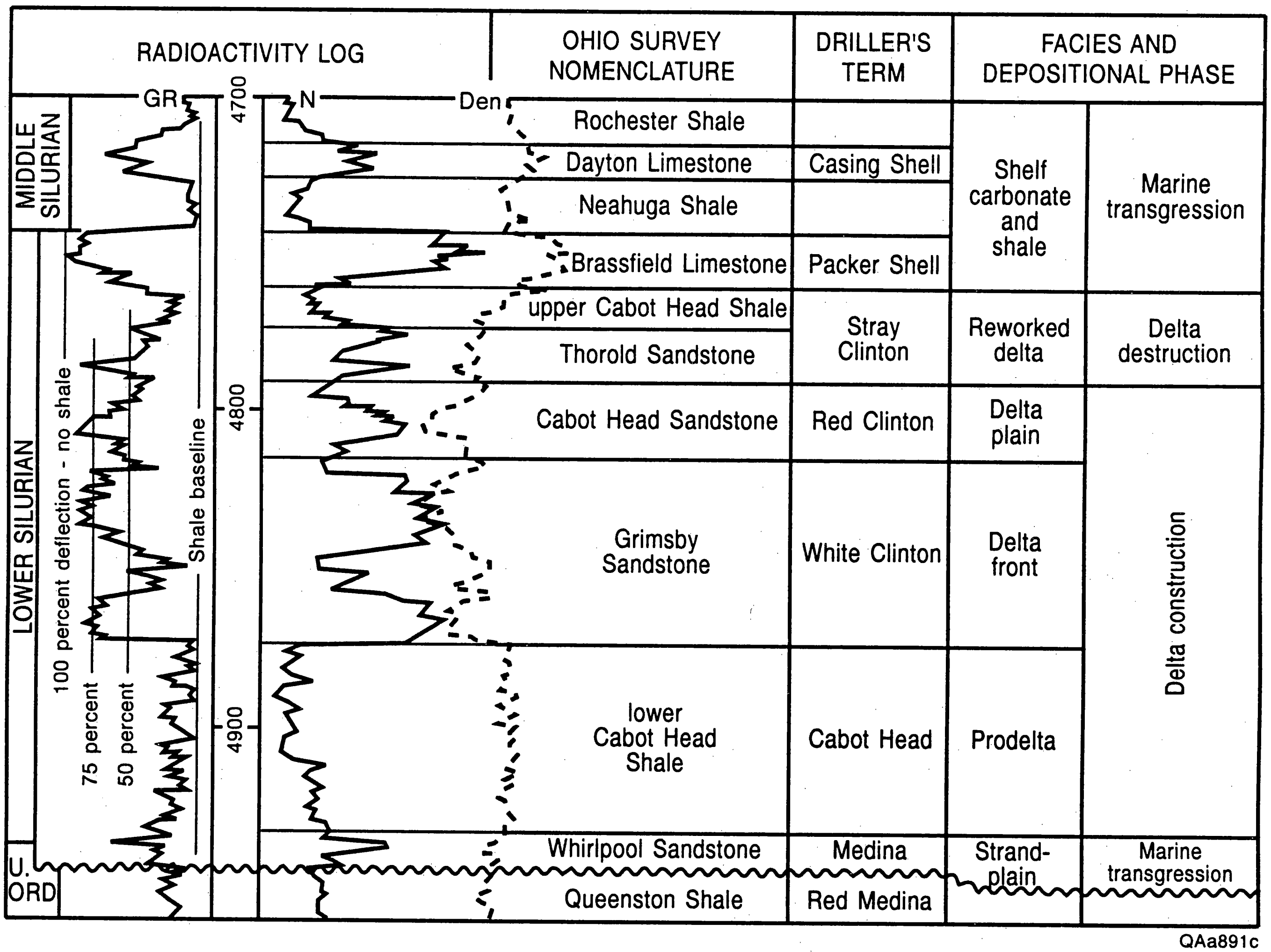


Figure 12. Typical log signature of the "Clinton" sandstone in Ohio showing stratigraphic nomenclature and equivalent drillers' terms and facies interpretations (from Keltch and others, 1987). Stratigraphic nomenclature applied to the Lower Silurian in Ohio is not standardized. Note that this interpretation places the Cabot Head Sandstone above the Grimsby Sandstone, whereas the correlation charts in figures 9 and 10 show the Cabot Head Sandstone below the Grimsby.

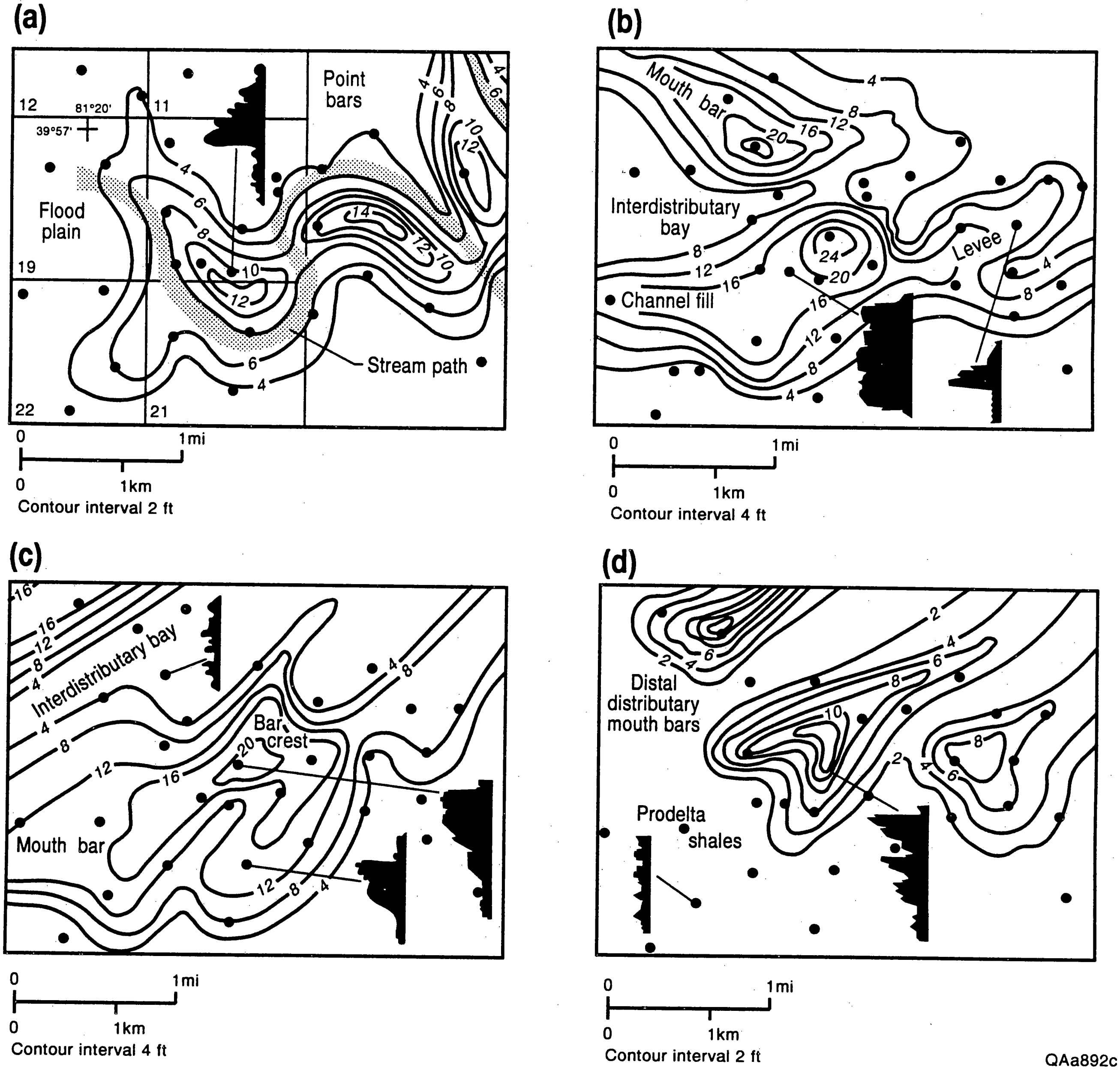


Figure 13. Isopach maps of four slices of the "Clinton" interval, illustrating "Clinton" depositional facies and log signatures in Richland Township, Guernsey County, Ohio (from Keltch and others, 1987).

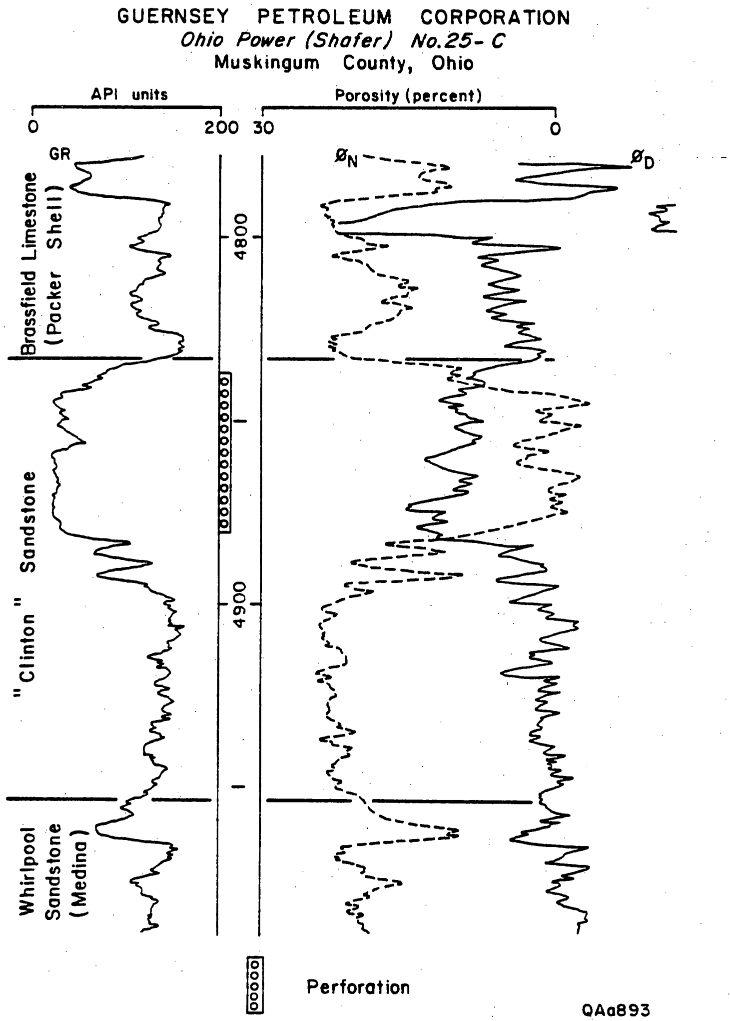


Figure 14. Neutron-density log of a "Clinton" pay zone in Muskingum County, Ohio.

sandstone (clean sandstone being defined as 75-percent deflection from the shale line, fig. 12) (Keltch, 1985). In other areas of the "Clinton," however, gas production may be controlled by the abundance of natural fractures and not by sandstone thickness (Ohio Geological Society, 1985b).

Composition of Reservoir Facies

Medina sandstones in Pennsylvania are very fine to medium-grained subarkoses, sublitharenites, and quartzarenites; most reservoir sandstones are moderately well sorted to very well sorted (Laughrey and Harper, 1986). Mudstone rip-up clasts are common as basal lag deposits in upward-fining sequences. Feldspars compose 2 to 21 percent of the detrital grains, and microcline and orthoclase are more abundant than perthite and albite. Most potassium feldspars are altered, but plagioclase grains appear fresh and may have been albitized during diagenesis. Detrital clay matrix is composed mainly of illite and chlorite. Authigenic cements in the Medina include chlorite, illite, quartz, calcite, dolomite, siderite, hematite, anhydrite, and gypsum (Laughrey and Harper, 1986). Most macroporosity in Medina sandstones is secondary porosity that formed by dissolution of feldspar grains and calcite cement.

In eastern Ohio, the "Clinton" consists of very fine to fine-grained sandstone and siltstone, interbedded with shale (Smiraldo, 1985). Composition and diagenesis of "Clinton" sandstones in Ohio are similar to those of the Medina sandstones described by Laughrey and Harper (1986). The "Clinton" sandstones are primarily quartzarenites, subarkoses, and sublitharenites, and extensive quartz cement is the main reason for the low porosity and permeability (Frech, 1983). The highest volume of intergranular porosity remains in the thickest sandstone beds (Smiraldo, 1985). Variability in gas production from local areas or individual wells may be caused by differences in relative proportion of porosity types, particularly intergranular and fracture porosity (Burford and Frech, 1988).

Natural Fractures

Operator opinion varies on the role of fractures in "Clinton"-Medina producing areas, but a 1985 panel discussion of experts on "Clinton" production in eastern Ohio shows that natural fractures are widely considered to be critical to production success. Among other comments, participants stated that ". . . reservoirs are dominated by fractures . . . [they] should be more intensely studied" (W. Shafer, *in* Ohio Geological Society, 1985b); and ". . . natural fractures are probably the most important [reservoir] characteristics" (R. Alexander, *in* Ohio Geological Society, 1985b). Schrider and others (1970) state that numerous small natural fractures give "Clinton" reservoirs an overall permeability greater than the average matrix permeability, but that the fractures are limited in extent and are "not in massive communication." Watts and others (1972) concede that fractures play an important role in "Clinton" production (presumably fracture permeability), but assert that fracture *porosity* may not be as important to success as good intergranular porosity and thick sandstone sections. According to Finley (1984) some FERC applicants considered fractures to play a minor role in "Clinton"-Medina production. Based on sporadic reports of fractures in core and the lack of published fracture analyses, it is likely that the influence of natural fractures in "Clinton"-Medina sandstones has not been adequately assessed.

In "Clinton" sandstone core, macrofractures and microfractures are locally present as inclined to vertical extension fractures and bedding-parallel fractures (Multer, 1963; Schrider and others, 1970; Overbey and Henninger, 1985). In Hocking County, Overbey and Henninger (1985) report core data that show a "well-developed natural fracture system . . . oriented N55° to 75°E. This system correlates with a surface-joint set and the orientation of the principal horizontal stress measured in outcropping rocks" in Hocking County. Finley (1984) reported that fractures are present in "Clinton"-Medina sandstone in eastern Ohio, but most fractures that were observed were healed (closed). In northwestern Pennsylvania and western New York, fractures are reported to be present in core, but the extent of their contribution to production is unknown (Sitler, 1985).

According to R. Alexander (*in* Ohio Geological Society, 1985b) "Clinton" production and reserve trends in Mahoning County, Ohio, suggest that productive natural fractures there trend northwest-southeast; no northeast-southwest interwell interference has been observed in this area. The lack of interference during well tests in the East Canton field indicates that wells in this area were not connected by open fracture systems (Watts and others, 1972). For "Clinton" reservoirs in the East Canton-Magnolia field, Sitler (1985) asserted that the best production is from the "Red Clinton" sandstone interval (figs. 10 and 12), which is characterized by locally high permeability due to natural fractures and superior matrix porosity. Sitler's opinion is that, in general, natural fractures are the controlling factor in determining relative productivity of "Clinton" sandstone reservoirs, and that they can account for increases in hydrocarbon yield of as much as 15 percent in otherwise geologically similar reservoirs. It has also been reported that drastic drops in pressure occur after the breakdown of some "Clinton" wells, and this has been ascribed to leak-off into natural fracture systems (Biddison, *in* Ohio Geological Society, 1985b).

Fractures have been observed in some core from areas of "Clinton"-Medina production in western Pennsylvania (Laughrey and Harper, 1986), and fractures may be responsible for some areas of higher-than-normal permeability within Medina gas fields (matrix permeabilities are generally less than 0.1 md). In part of western Pennsylvania, the timing of formation of some fractures is indicated to be late in the diagenetic history of Medina sandstones (Laughrey, 1984), so these fractures may be less likely to be occluded by diagenetic cements. High fracture permeabilities are reported from laboratory tests on these cores (Laughrey and Harper, 1986), but the significance of these measurements for production is uncertain because the subsurface extent of the type of fracture tested is unknown. In addition to subvertical fractures, Multer (1963) and Laughrey and Harper (1986) have reported *horizontal* or bedding-plane-parallel open fractures in the "Clinton," and it was this type of fracture that was tested. These horizontal fractures may not be natural because similar fractures are commonly created by unloading during core recovery. Open horizontal natural fractures would have important implications for evaluation of hydraulic fracture treatments.

In Ohio, hydraulic fracture growth directions in "Clinton" reservoirs are reported to be either northwest or northeast and to switch rapidly from one area to the next (*in* Ohio Geological Society, 1985b). If natural fractures have low resistance to reopening by fracturing fluids, shifts in dominant natural fracture direction could be responsible for these changes in hydraulic-fracture direction. The effect is important enough that some operators in Ohio report spotting wells along northeast or southwest offsets to avoid well-to-well communication (*in* Ohio Geological Society, 1985b). Both northwest and northeast fracture orientations have been recognized in the area of "Clinton"-Medina production. Prominent fractures in the subsurface strike at approximately right angles to the Appalachian orogen (fig. 15). Descriptions of regional fracture patterns in this area include Ver Steeg (1944), Nickelsen and Hough (1967), and Engelder (1985).

Overbey and Rough (1971; see also Ver Steeg, 1944) carried out a study of surface fractures in eastern Ohio for the purpose of predicting reservoir attributes. The study also reports subsurface data from core, bottom-hole impression packer surveys, and borehole photography. In this study, subsurface fractures in Hocking County, Ohio, were found to strike east-northeast with a wide scatter. Similar patterns are evident in outcrop. Outcrop fractures and some fractures in the shallow subsurface were also found to parallel the current northeast maximum horizontal stress direction. Use of the results of this study should be tempered with the provisos that surface fractures may differ significantly from subsurface characteristics, as demonstrated by Verbeek and Grout (1983) and Baumgardner (1991). Engelder (1985, and references therein) has shown that in the area of figure 15, cores from deep wells mainly contain cross-fold joints (generally striking west-northwest), whereas shallow cores contain joints parallel to the contemporary tectonic stress field (striking northeastward).

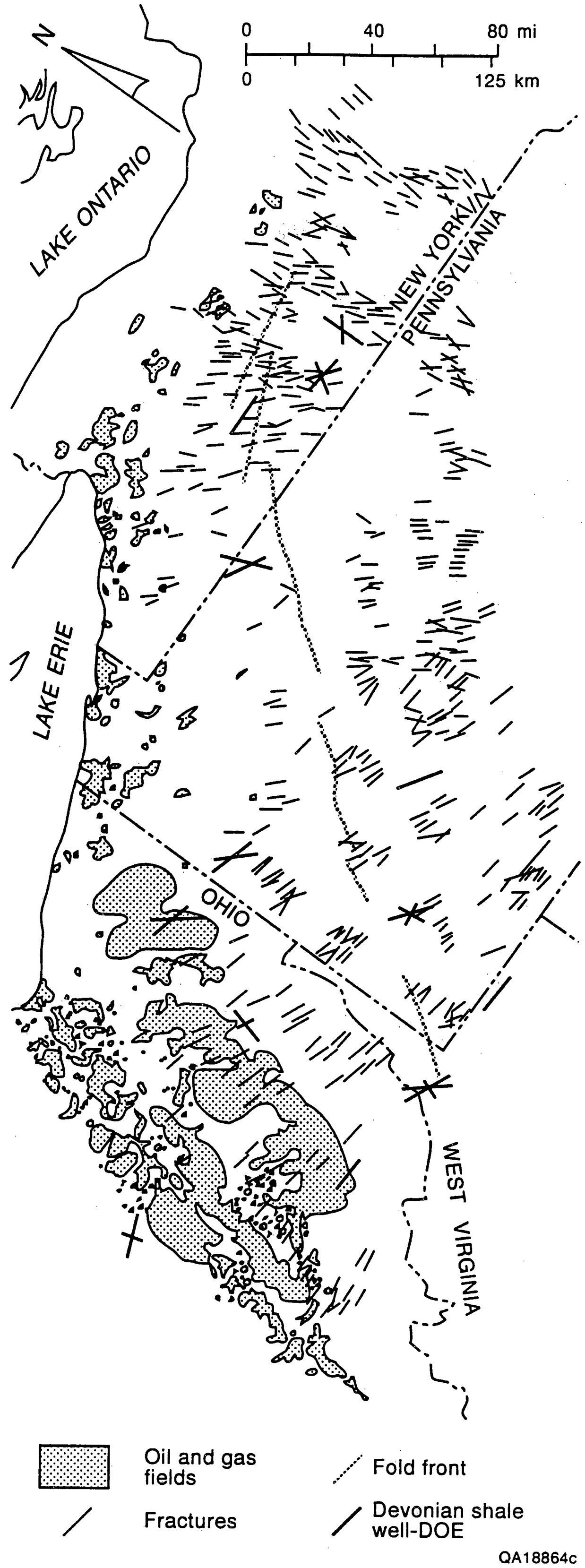


Figure 15. Regional fractures in area of "Clinton"-Medina production that strike normal to fold front (based on Engelder and others, 1985, and references therein).

Fracture patterns important for production appear to be regional in character, although local fracturing associated with folds and faults may also be significant. Allegehenian thrust faulting in the eastern Appalachian Plateau and the Valley and Ridge province produced local fracture porosity associated with splay faults and folds (De Witt, 1986). In the Medina gas-producing area of northwestern Pennsylvania, structures are generally subtle, having dips of less than 1 degree, and they may result from stratigraphic variations (Laughrey and Harper, 1986).

In addition to subtle folds, large structural features that strike parallel and perpendicular to the axis of the basin have been recognized in the Appalachian Basin. These features are manifested as patterns in lithofacies, surface drainage patterns, offset surface and subsurface structural axes, and in gravity and magnetic patterns. Gravity and magnetic data have been used commercially to identify basement structures that may influence or localize fracture occurrence in "Clinton" sandstones. Several authors cited in Laughrey and Harper (1986) have speculated on the origin of these features, which may be recurrently active basement faults. These features have been equated with an orthogonal arrangement of fractures that is assumed to exist in the subsurface. The relationship of these features to trends of gas and oil fields is speculative (Laughrey and Harper, 1986). Laughrey and Harper (1986) postulate that long-lived zones of strike-parallel and strike-normal crustal movement created fractures in sedimentary rocks that affect hydrocarbon migration and flow.

Engineering Assessment

The majority of wells in the "Clinton"-Medina trend have been drilled in Ohio, where "Clinton" porosities range from 5 to 16 percent (S. A. Holditch & Associates, 1991) (table 8). Permeabilities generally are less than 0.1 md. As part of a GRI review, three typical "Clinton" wells were evaluated for permeability using well test analysis. Permeabilities in these wells ranged from 0.034 to 0.29 md.

Table 8. "Clinton"-Medina Sandstone, Appalachian Basin: production data and engineering parameters.

Estimated resource base (Tcf): 94

No. tight completions: No data

Cumulative production from tight completions 1970–1988 (Bcf): No data

Estimated ultimate recovery from tight areas (Bcf): No data

Net pay thickness (ft): 9–63

Porosity (%): 5–16, OH; 2–12, PA and NY

Permeability (md): 0.03–0.6

Water saturation (%): 20–35

Reservoir temperature (°F): 95–120

Reservoir pressure (psi): 340–1,400

Typical stimulation/hydro-frac: 1,500–2,000 bbl fluid and 30,000 lb sand

Production rate:

prestimulation (Mcf/d): Usually negligible

poststimulation (Mcf/d): 20–120, OH; 500–2,000, PA; 80–2,700, NY

Average recovery per completion (MMcf): 80–275

Decline rate: Half of total production in first 3–5 yr

Porosities in the Medina of Pennsylvania are described as ranging from 2 to 12 percent (Laughrey and Harper, 1986) (table 8). Cores in six Medina gas wells in Pennsylvania generally have permeabilities less than 0.1 md, although there are some recorded permeabilities as high as 0.6 md. Some reported pressure transient tests indicate permeability values similar to those determined by core analysis (Laughrey and Harper, 1986). Laughrey and Harper (1986) mention that wells in the Medina having 3 to 4 percent porosity are generally as permeable as those having porosity of 6 to 8 percent.

Evaluation of a well log in the Medina of New York indicates porosities in the 5 to 8 percent range (Copley, 1980). Porosities in New York Medina sandstones are described by Finley (1984) as 3 to 10 percent. Sandstones in all three areas are primarily composed of quartz with some feldspar grains, so a grain density of 2.65 g/cc is appropriate for log-analysis calculations.

Net-pay thicknesses in all three areas range from 9 to 63 ft (Finley, 1984) (table 8). Initial reservoir pressure in Ohio "Clinton" wells generally is 800 to 1,000 psi but in some wells may be as high as 1900 psi. Finley (1984) lists pressures in the Pennsylvania Medina of 700 to 1,400 psi and in the New York Medina of 340 to 1,020 psi.

Formation water salinity averages 250,000 ppm total dissolved solids (Sanders, 1991). Laughrey and Harper (1986) indicate there is some difficulty in making log calculations for water saturations in the Medina. Cementation and saturation exponent measurements are different than commonly used sandstone values (Dresser Atlas log interpretation seminar, Pittsburgh, 1982). Even when the recommended parameters are used in the Medina, log-calculated water saturations do not always agree with core measured water saturations, which average 20 to 35 percent in pay sandstones (Finley, 1984; Laughrey and Harper, 1986) (table 8). Operators are prone to set casing and complete the well regardless of calculated water saturations. Copley (1980) advocates making an open hole test in the "Clinton" before setting casing because most wells are drilled with air.

Many types of fracture treatments have been tried in the "Clinton" (S. A. Holditch & Associates, 1991), including water, nitrogen, foam, and carbon dioxide. A typical well is stimulated with 1,500 to 2,000 bbl of fluid. Total quantities of 20/40 mesh sand range from 20,000 to 102,000 lb and average 30,000 lb. Fracture gradient in the "Clinton" of Ohio is 0.55 psi/ft. Fracture height growth is not excessive in Pennsylvania or Ohio (S. A. Holditch & Associates, 1991) and is not expected to be in New York.

Production History

"Clinton" wells in Ohio produce initially at rates of 17 to 123 Mcf/d (S. A. Holditch & Associates, 1991), and total reserves for these wells average 275 MMcf. Medina wells in New York have average reserves of 154 MMcf (Copley, 1980). Ketch and others (1987) estimate that "Clinton" wells of Ohio will average half of their production in the first 5 years. Decline curves for wells in the three areas are about the same. Laughrey and Harper (1986) state that an average well in Pennsylvania with initial production of 150 Mcf/d will produce 80 MMcf in the first 5 years. Applying Ketch's rule to those figures, reserves for the Pennsylvania Medina are about 160 MMcf per well.

The success ratio of completed to total wells is high for the "Clinton" and Medina. Copley (1980) indicates that certain areas in New York to have a 95 percent success ratio. S. A. Holditch & Associates (1991) describe a 98.7 percent success ratio in the "Clinton" of Ohio. The question posed by most operators is not if a well will produce gas but whether the evaluation process can discriminate economic completions.

Berea Sandstone

The Berea is the oldest Mississippian sandstone in the Appalachian Basin; it is part of the Waverly Group in Ohio (fig. 9) and the Pocono Group in West Virginia. The Berea Sandstone has been designated tight by FERC in 31 counties in Ohio, West Virginia, Virginia, and Kentucky (fig. 16, table 9). Haas and others (1988) report that the Berea contains an estimated 69 Tcf of gas in place in the FERC-designated tight gas area.

The Berea Sandstone is shallowest in Ohio, where it occurs at 1,200 to 2,000 ft, and deepest in Virginia, where it ranges in depth from 3,300 to 6,000 ft (Finley, 1984). In West Virginia and Kentucky the Berea Sandstone occurs at depths of about 2,500 to 3,500 ft. The Berea is generally 20 to 60 ft thick throughout the area in which it is designated tight (Pepper and others, 1954). It is thinnest over a post-Devonian structural high near the juncture of Kentucky, Virginia, and West Virginia and thickens to the east and west away from this high (Thomas and Lauffer, 1964).

Regional studies of the Berea include the work of Pepper and others (1954), Larese (1974), De Witt and McGrew (1979), Potter and others (1983), and Pashin and Ettensohn (1987), but little published information exists on Berea tight gas reservoirs. A GRI cooperative well with Ashland Exploration was drilled in the Berea in Pike County, Kentucky, in which the Berea was cored and open- and cased-hole stress tests were performed to develop a stress profile (Lowry and others, 1991).

Depositional Systems and Reservoir Facies

Berea sand was derived from the highland area to the east, carried west by several major river systems, and deposited in deltas that prograded into the epicontinental sea in western West Virginia and eastern Kentucky (fig. 17) (De Witt and McGrew, 1979). Another delta, called the Berea delta, prograded into northern Ohio at this time, carrying sediment from eastern Canada. Sandstone from the Berea delta is quarried in northern Ohio and is commonly used for rock-mechanics and reservoir-flow studies because of its relatively uniform porosity and permeability (Potter and others, 1983). Sands from these two sources prograded across the shallow sea and coalesced in eastern Kentucky (Milici and De Witt, 1988). Berea sandstone is coarsest in northern Ohio near the distributaries of the Berea delta and in central West

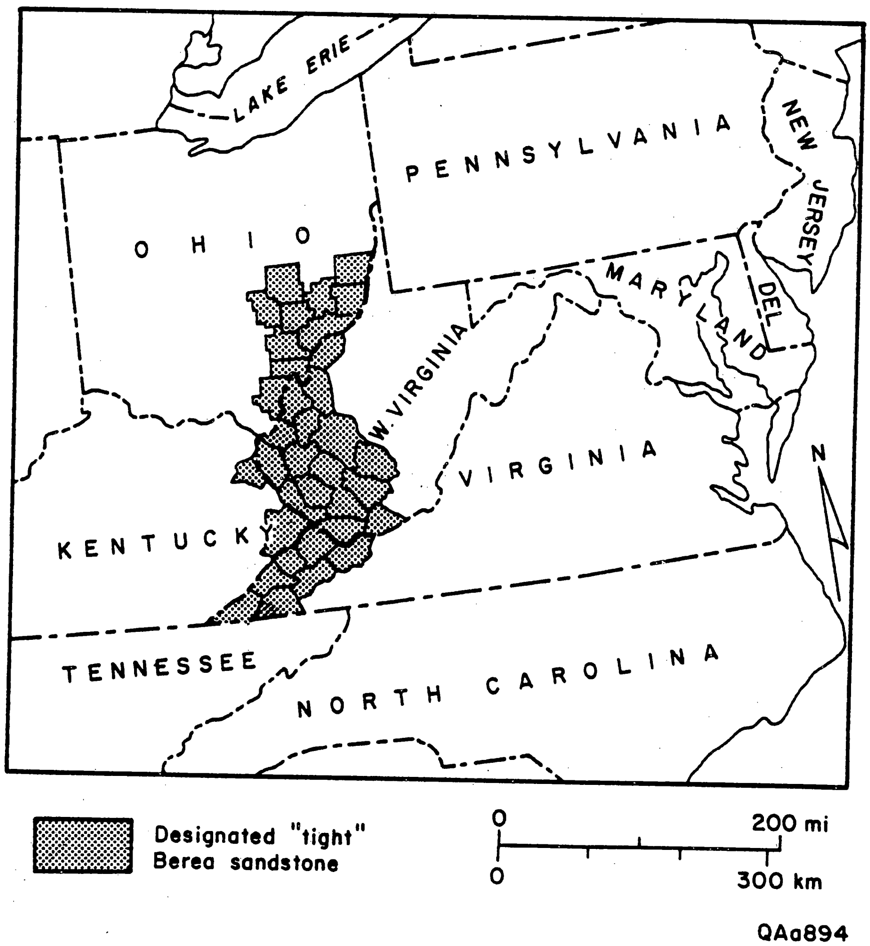


Figure 16. Counties in Kentucky, Ohio, Virginia, and West Virginia in which the Berea sandstone is designated tight by FERC. See table 9 for county names.

Table 9. Counties in which the Berea Sandstone has been designated tight. The qualified area may not cover the entire county.

Kentucky	Lawrence, Pike
Ohio	Athens, Belmont, Gallia, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Washington
Virginia	Buchanan, Dickenson, Lee, Russell, Scott, Tazewell, Wise
West Virginia	Boone, Cabell, Fayette, Jackson, Kanawha, Logan, Lincoln, Mason, Mercer, McDowell, Mingo, Putnam, Raleigh, Wayne, Wood, Wyoming

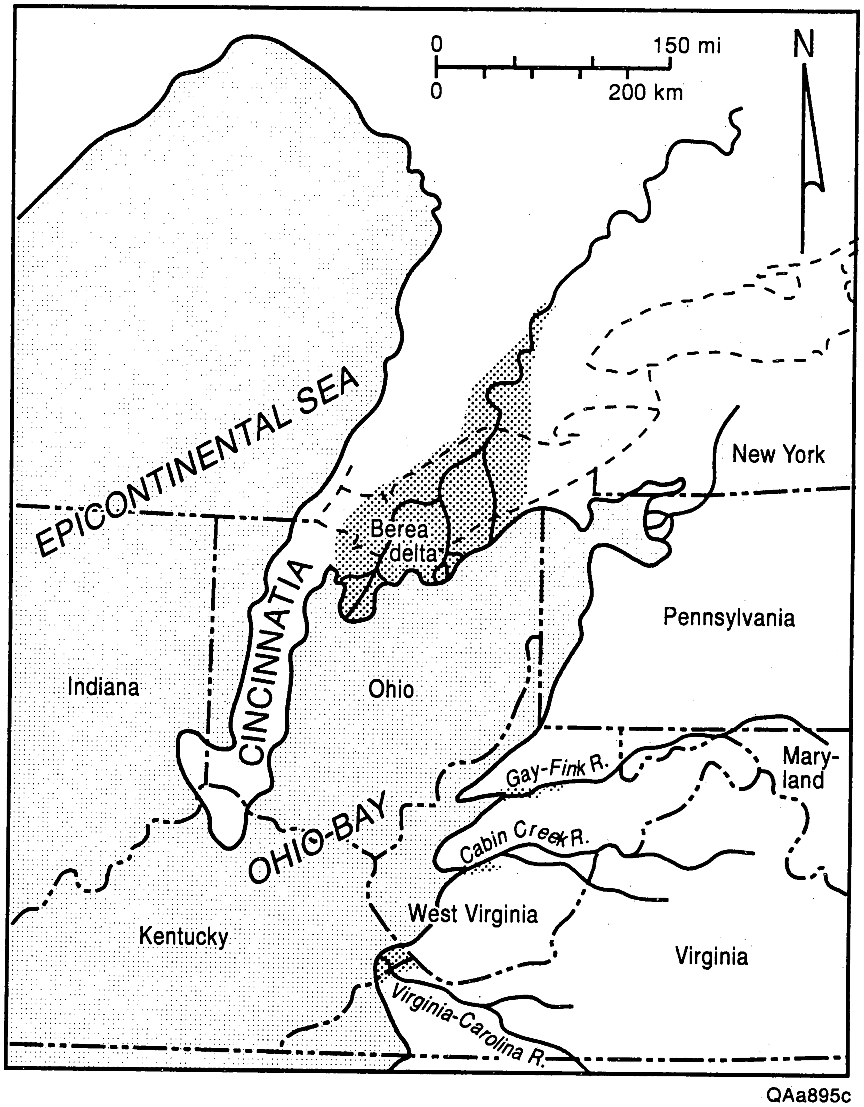


Figure 17. Paleogeographic map of middle Berea time showing the location of rivers that carried sediment to Ohio Bay (from De Witt and McGrew, 1979, after Pepper and others, 1954). Berea sandstone in the designated tight area was deposited as fine-grained sand and silt offshore from the rivers in delta-front, prodelta, and storm-dominated shallow-shelf environments.

Virginia near the mouths of the distributaries of the Gay-Fink and Cabin Creek deltas (De Witt and others, 1979).

Finer grained sandstone and siltstone were deposited down dip in delta-front, prodelta, and shallow-shelf environments, and it is these finer grained Berea deposits that are designated tight (fig. 16). Donaldson and Shumaker (1981) interpreted the West Virginia and Virginia Berea deltas to be wave-dominated. Larese (1974) recognized a barrier-island deposit north of the Gay-Fink distributary mouth bar (fig. 17), another indication of marine influence on the Berea deltas. Much of the Berea Sandstone in the tight area occurs as a widespread sheet of rippled sandstones and siltstones, which are interpreted as having been deposited in open-marine shelf environments (De Witt and others, 1979; Potter and others, 1983; Pashin and Ettensohn, 1987). These shelf sandstones may represent reworked abandoned deltaic sandstones (Larese, 1974). Pashin and Ettensohn (1987) concluded that silt and very fine sand derived from the deltas was transported by storms onto a relatively wide, storm-dominated shelf, resulting in deposition of widespread Berea sheet sandstones and siltstones.

Most Berea fields are associated with stratigraphic traps caused by porosity pinchout due to variations in depositional energy, degree of marine reworking, and selective cementation of sand bodies (De Witt and others, 1979). Structure plays little or no role in the traps in Berea fields in the western part of the basin, where strata dip gently to the west (Lowry and others, 1991). In Pike County, Kentucky, the Berea is divided into upper, middle and lower members, and zone isolation work suggests that better production commonly occurs in a specific member. However, production does not always correspond to net-pay thickness, suggesting that natural fractures may strongly influence productive capacity (Lowry and others, 1991).

The Second Berea Sandstone of Ohio is a sandstone member in the Bedford Shale, which underlies the Berea Sandstone (fig. 9). It formed as an offshore barrier-bar facies of the Red Bedford delta, which prograded southward across the Ohio area from a source area in Canada (Milici and De Witt, 1979). The Second Berea bar complex, which is composed of coarse silt and very fine sandstone, produces gas from tight reservoirs along a linear trend that extends 85 mi from Morgan to Gallia Counties, Ohio.

Composition of Reservoir Facies

In a representative well in the area in which it is designated tight (Ashland Ford Motor Company No. 80, Pike County, Kentucky [fig. 18]), the Berea is composed of very fine grained sandstone and siltstone and is classified as a subarkose (S. P. Dutton, unpublished data, 1992). Quartz and plagioclase are the most abundant detrital grains, and illite the most abundant detrital clay. Quartz is the main pore-filling cement, having volumes of 8 to 14 percent, but carbonate cements are locally abundant (Larese, 1974). Authigenic chlorite and illite are common, and kaolinite occurs in some secondary pores formed by feldspar dissolution. Both primary intergranular and secondary grain-dissolution pores are present, but secondary pores are more abundant.

Natural Fractures

Natural fractures are thought to enhance production from some Berea sandstone wells (Overbey and Henninger, 1985). The Berea sandstone in the Appalachian Basin in Kentucky has been the subject of GRI engineering research that shows that natural fractures contribute to production in these reservoirs (Frantz and others, in press).

Core from the GRI cooperative well drilled in Pike County in eastern Kentucky contains subvertical, partly open fractures (fig. 19). Fracture traces are visible on FMS logs in both the upper and lower Berea. Average matrix permeability is in the micro- to nanodarcy range, based on routine and special core analyses. These matrix permeabilities measured in the laboratory are too low to account for the average Berea production and for the results of pre-fracture production tests in the cooperative well. Enhanced flow through natural fractures, on the other

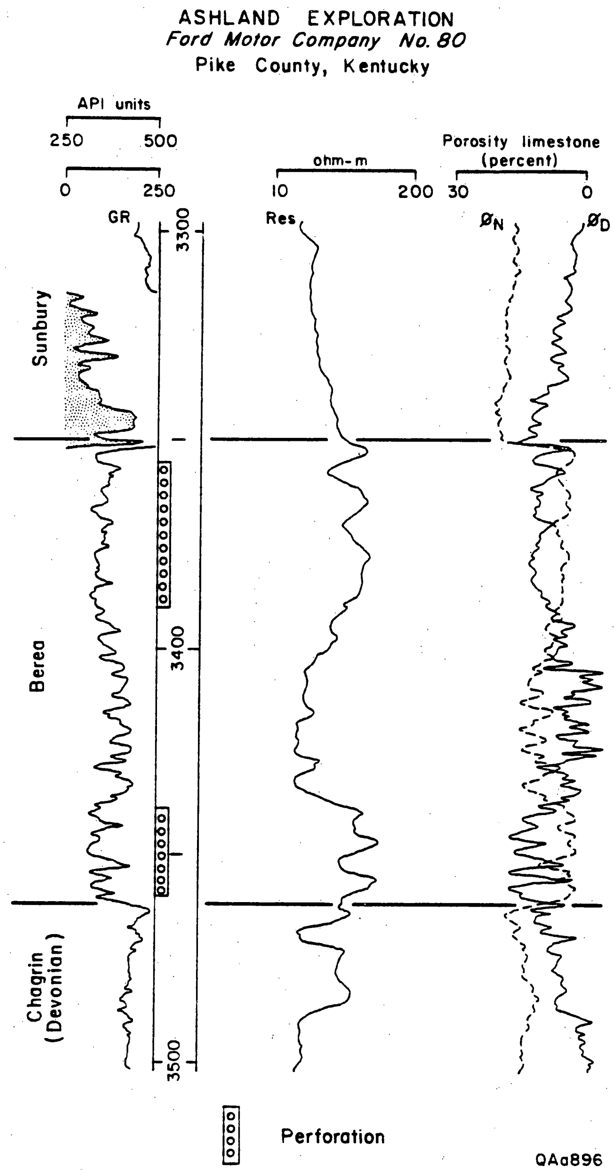


Figure 18. Representative log of Berea sandstone in Pike County, Kentucky.

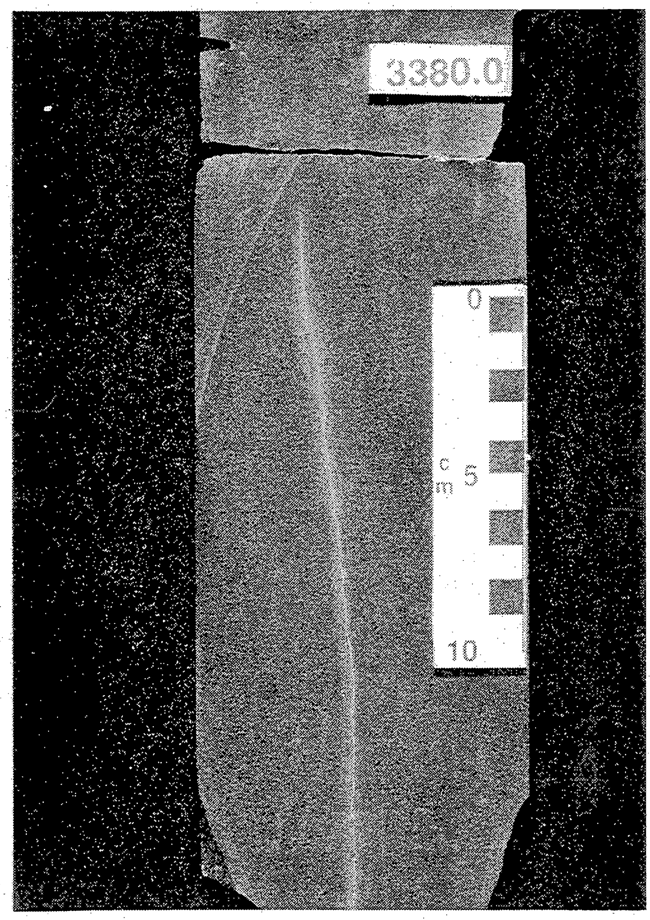


Figure 19. Fracture in Berea Sandstone core.

hand, can account for higher-than-expected average production and highly variable cumulative gas production from individual wells, ranging from 50 MMcf to 2.5 Bcf for wells producing exclusively from the Berea for 30 years.

Sparse mineralization visible in some natural fractures in core and the locally underpressured (pressure gradient of 0.22 psi/ft in the GRI study wells) character of the Berea in this area suggest that Berea natural fractures may be sensitive to changes in effective reservoir stress. This effective stress sensitivity may need to be taken into account in Berea production strategy. Fractures have limited vertical extent, being generally only a few feet tall, and they do not extend across the entire thickness of the unit. Fracture systems are therefore likely to be vertically partitioned.

According to J. Frantz (written communication, 1992), the Berea in Kentucky can best be described as a multilayered reservoir with two noncommunicating sandstone intervals. The sandstones are separated by about 40 ft of shale and have different reservoir pressures. The vertical extent of natural fractures is limited, and production tests indicate that natural fractures enhance fluid flow within each sandstone interval but they are not pathways for fluid migration between the two sandstone intervals.

The arrangement of fractures in interconnected networks can produce heterogeneity and anisotropy in flow characteristics; preferred orientation of fractures is the principal cause of anisotropy. Published core information on fracture orientation is too limited to be conclusive, but in oriented GRI core Berea fractures strike northeastward and northwestward, in agreement with fracture orientations inferred from fracture-imaging geophysical logs from GRI study wells. On the basis of this core and production characteristics, Frantz and others (in press) conclude that fracture-related permeability anisotropy exists in Berea reservoirs and that it is important to diagnose this permeability anisotropy in order to correctly predict pre- and post-stimulation performance.

Fractures in GRI's Berea cores have many attributes of regional fractures. Some of the regional structural elements that may control fracture strike in the Berea are discussed in the section on the "Clinton"-Medina sandstones, because the two sandstones occur in approximately the same area. Information on regional and local controls of fracture occurrence in Devonian shale (Cliffs Minerals, 1982) is probably also relevant to Berea sandstone fracture patterns. If dominant fractures in the Berea strike normal to the Appalachian orogenic front as predicted by regional fracture models (Hancock and Bevan, 1987), fractures with northwest and north-northwest strikes should be expected in this area. On the other hand, early fractures in the Appalachian Basin (Laubach, 1988) may tend to parallel the depositional basin axis and have northeasterly strikes at this latitude, as will bending-related fractures localized in folds.

Berea sandstone reservoirs are in the mid-plate stress province, according to stress-direction maps covering the area of Berea production (Zoback and Zoback, 1989). In this stress field, east-northeast-striking fractures will tend to be open.

Engineering Assessment

Porosities are low in the Berea, averaging 4 percent in Virginia (Virginia Tight Sand Committee, 1981) (table 10), but may be as high as 17 percent locally. In the GRI cooperative well (fig. 18), the FMC No. 80, core porosities ranged from 6 to 10 percent and averaged 8 percent (fig. 20). Core permeabilities in the FMC No. 80 well are mostly less than 0.1 md, except for 5 ft in the highest porosity interval (10 percent), where permeabilities are slightly more than 0.1 md (fig. 20) (ResTech, Inc., written communication, 1992). Typical permeabilities for the part of the Berea that has been designated tight are less than 0.1 md (Virginia Tight Sand Committee, 1981) (table 10). In West Virginia, porosities of less than 7.7 percent have permeabilities of less than 0.1 md (West Virginia Tight Formation Committee, 1981, 1982). No stabilized flow test data were available in any of the areas for well test analysis to confirm core permeability. Matrix permeability apparently is "too low to account for the typical Berea production" (J. Frantz, written communication, 1992), suggesting that natural fractures are responsible for the disparity.

Table 10. Berea Sandstone, Appalachian Basin: production data and engineering parameters.

Estimated resource base (Tcf): 69

No. tight completions: No data

Cumulative production from tight completions 1970–1988 (Bcf): No data

Estimated ultimate recovery from tight areas (Bcf): No data

Net pay thickness (ft): 17–30

Porosity (%): 4–8

Permeability (md): <0.1

Water saturation (%): 25–35

Reservoir temperature (°F): 95–110 in KY

Reservoir pressure (psi): 780 in KY

Typical stimulation/hydro-frac: 75–90 quality nitrogen foam carrying 100,000 lb sand

Production rate:

prestimulation (Mcf/d): 5–80

poststimulation (Mcf/d): 500–915

Average recovery per completion (MMcf): 350–460

Decline rate: 25% in first yr, then 10–12%

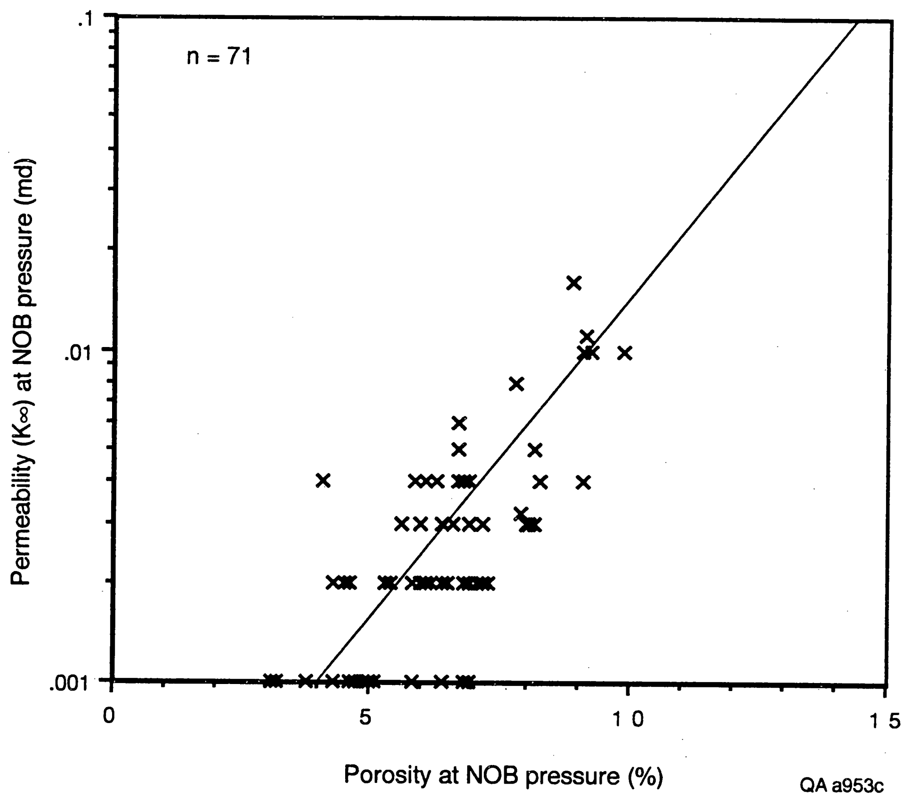


Figure 20. Semi-log plot of porosity measured at net overburden (NOB) pressure vs. Klinkenberg-corrected gas permeability measured at NOB pressure for 71 Berea sandstone samples.

Net pay is described by Lowry and others (1992) as being consistently in the range of 17 to 30 ft (table 10), based on a 6 percent porosity cutoff. Water saturations in Virginia range from 8 to 50 percent and average 35 percent. In the FMC No. 80 well, water saturations range from 17 to 55 and average 27 percent. Formation water salinity is 300,000 ppm total dissolved solids (ResTech, Inc., personal communication, 1992).

Thomas and Lauffer (1964) describe typical fracture treatments as consisting of 26,000 gal water and 46,000 lb of 20/40 mesh sand. The fracture stimulation treatment on the FMC No. 80 well was 75 to 90 quality nitrogen foam carrying 103,000 lb of 20/40 mesh sand (J. Frantz, written communication, 1992). Reservoir pressure in this well after fracturing was 780 psi.

Production History

Post-fracturing production rates in two Berea wells in Kentucky are 915 Mcf/d and 497 Mcf/d (Lowry and others, 1992). It is common for Berea wells to have high flow rates immediately after fracturing. Reserve estimates range from a prediction of 350 MMcf for the FMC No. 80 well to 460 MMcf averages (described by Thomas and Lauffer, 1964). Decline rate is 25 percent for the first year and 10 to 12 percent per year for the life of the well (M. C. Behling, written communication, 1991). Gas wells in the Second Berea have initial yields ranging from 5 to 80 Mcf/d, which increases to as much as 500 Mcf/d after hydraulic fracture treatment (De Witt and others, 1979).

EAST TEXAS AND NORTH LOUISIANA BASINS

The East Texas and North Louisiana Basins (fig. 1) formed during Late Triassic rifting (Buffler and others, 1980). Crustal extension produced thinning and heating of the lithosphere, and subsequent cooling and subsidence formed basins in which thick sequences of Mesozoic and Cenozoic sediments accumulated. The major low-permeability sandstones in the East Texas and

North Louisiana Basins comprise the Upper Jurassic to Lower Cretaceous Cotton Valley Sandstone and the Lower Cretaceous Travis Peak Formation (Finley, 1986) (fig. 21).

Sandstones of the Cotton Valley and Travis Peak represent the first major clastic progradation into the East Texas—North Louisiana area after the opening of the Gulf of Mexico in the Jurassic (Seni and Jackson, 1983). Clastic deposition was interrupted by marine transgression that resulted in deposition of the Knowles Limestone in downdip parts of the East Texas Basin and in Louisiana. In updip areas of the East Texas Basin the Travis Peak Formation unconformably overlies the Cotton Valley Group. Where it occurs, the Knowles Limestone is used as the Cotton Valley—Travis Peak boundary. The end of Travis Peak deposition was also marked by marine transgression, and the top of the Travis Peak is picked at the base of the limestones of the overlying Sligo Formation (fig. 21). Stratigraphic terminology varies across the area, but the Cotton Valley Sandstone is commonly known as the Schuler Formation and represents the upper part of the Cotton Valley Group (fig. 21). The Travis Peak Formation in East Texas is equivalent to the Hosston Formation in Louisiana, Arkansas, and Mississippi.

The Sabine Arch, also called the Sabine Uplift, is a broad, low-relief arch between the East Texas and North Louisiana Basins (fig. 22) with an area of closure greater than 2,500 mi^2. The arch is the result of Late Cretaceous and Tertiary movement (Jackson and Laubach, 1991). Secondary structures on the Sabine Arch cover 75 to 150 mi^2 and form 100 to 300 ft of closure at northern Waskom and Bethany fields, respectively (Kosters and others, 1989). The Sabine Arch focused gas migration toward it from the East Texas and North Louisiana Basins. Many of the traps associated with the Sabine Arch are combination traps. Specific trap mechanisms may be controlled by small folds or paleo-topographic highs, as at Bethany field, or by porosity pinchouts, as at Carthage and southern Waskom fields (Rogers, 1968; Forgotson and Forgotson, 1975).

The origin of smaller structural highs on the arch is uncertain. However, elongate anticlines and associated fields rimming the western margin of the uplift in Harrison (Whelan and Lansing fields), Gregg (Willow Springs field), Rusk (Danville and Henderson fields), and

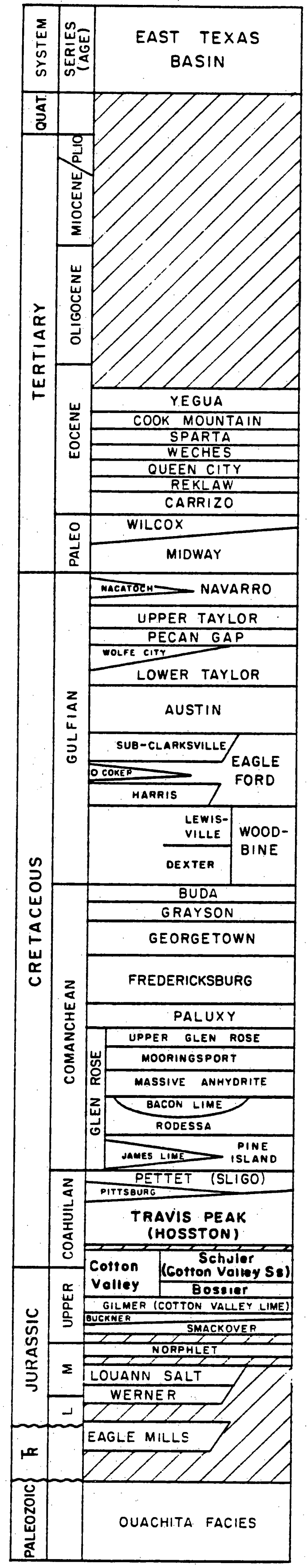


Figure 21. Stratigraphic nomenclature, East Texas Basin (modified from Galloway and others, 1984).

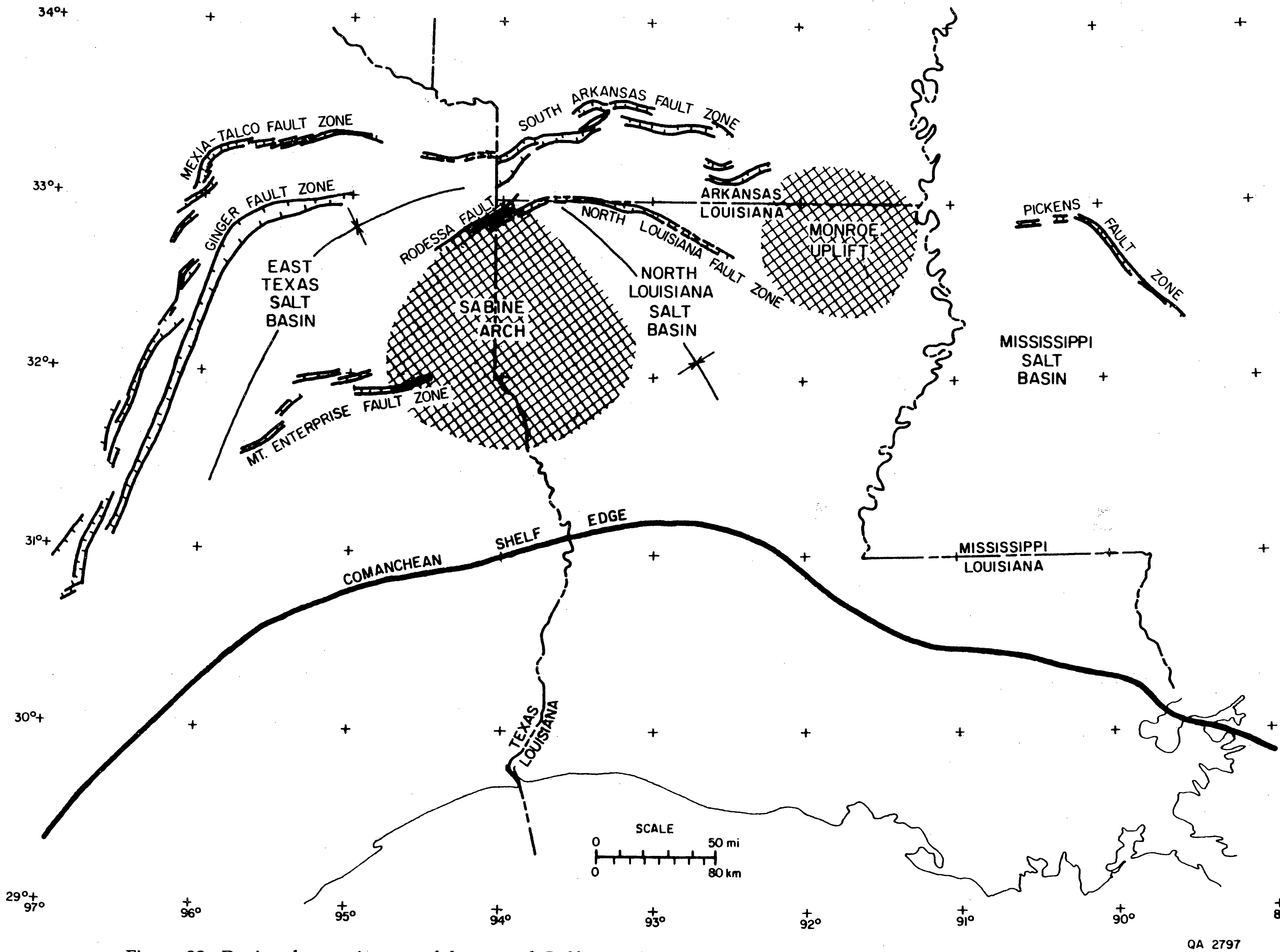


Figure 22. Regional tectonic map of the central Gulf coastal province modified from the tectonic map of the Gulf Coast region (Gulf Coast Association of Geological Societies, 1972).

Nacogdoches (Trawick field) Counties are underlain by an average of 1,200 ft of penetrated Louann Salt (Jackson and Laubach, 1991). These structures are nonpiercement salt pillows (Kosters and others, 1989).

Other formations in the North Louisiana basin that have been designated tight by FERC in limited areas include (1) sandstones within the predominantly carbonate Upper Jurassic Smackover Formation (called Gray and C Sands), (2) sandstones of the Upper Jurassic Haynesville Formation (equivalent to the carbonates of the Gilmer Limestone in East Texas), (3) the Lower Cretaceous James Limestone Member of the Lower Glen Rose Formation, and (4) the Mid-Cockfield Sandstone, equivalent to the Eocene Yegua Formation in East Texas (fig. 21). Chalks and calcareous claystones of the Upper Cretaceous Arkadelphia Formation (Sohl and others, 1991) have been designated tight on the Monroe Uplift in northeast Louisiana. In the East Texas Basin, the James Limestone and the Pittsburg Sandstone (fig. 21) have been designated tight in limited areas.

Cotton Valley Sandstone

The Upper Jurassic to Lower Cretaceous Cotton Valley Sandstone, or Schuler Formation (fig. 21), has been designated tight in a large area of East Texas and North Louisiana (fig. 23). However, 15 fields within this area that produce from porous and permeable Cotton Valley facies have been excluded from the FERC designation: Beekman, Calhoun, North Carlton, Cheniere, Cotton Valley, South Downsville, Greenwood-Waskom, Hico Knowles, Lisbon, Northeast Lisbon, West Lisbon, Ruston, Sentell, Sligo, and Terryville. Average depths to the top of the Cotton Valley Sandstone vary from –4,000 ft subsea in the western parts of the East Texas Basin and in northeast Louisiana to >–13,000 ft subsea on the southern margins of the East Texas and North Louisiana basins (fig. 23). Most production occurs from depths of about 7,800 to 11,000 ft below ground surface (Kosters and others, 1989; Bebout and others, in press). The Cotton

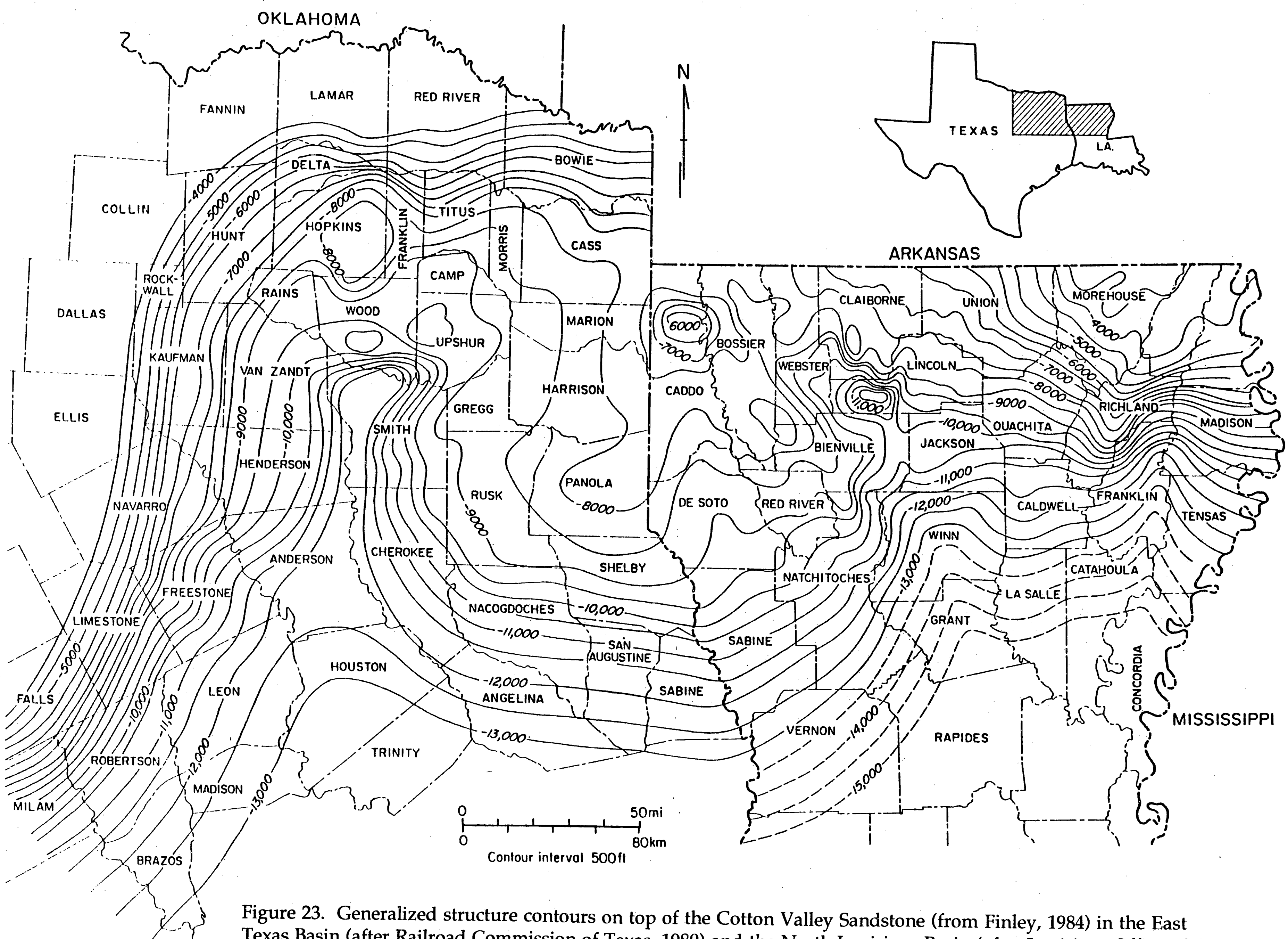


Figure 23. Generalized structure contours on top of the Cotton Valley Sandstone (from Finley, 1984) in the East Texas Basin (after Railroad Commission of Texas, 1980) and the North Louisiana Basin (after Louisiana Office of Conservation, 1981). The Cotton Valley Sandstone has been designated tight in all counties named in this figure.

QAo429

Valley Sandstone interval is 1,000 to 1,400 ft thick in the low-permeability trend (Finley, 1984; Presley and Reed, 1984).

Regional studies of the Cotton Valley include the work of Mann and Thomas (1964), Collins (1980), Coleman and Coleman (1981), Wescott (1983), and McGowen and Harris (1984), as well as several papers in the volume *The Jurassic of East Texas* (Presley, 1984). The Taylor sandstone at the base of the Cotton Valley Sandstone in Waskom field, Harrison County, Texas, was the focus of the GRI SFE No. 3 well. (The formal name for the SFE No. 3 well is the Mobil Cargill No. 15.) Core from the Taylor sandstone and adjacent shales was recovered in the well, and an extensive open-hole data acquisition program of Measurement While Drilling (MWD) logging, wireline logging (multiple passes), and open-hole stress testing was conducted. An extensive data set was also collected during well testing and fracture treatments performed in the Taylor sandstone (CER Corporation and S. A. Holditch & Associates, 1991).

Depositional Systems and Reservoir Facies

Depositional systems of the Cotton Valley Sandstone in Louisiana include a fluvial-dominated delta system associated with the ancestral Mississippi River in northeast Louisiana and a wave-dominated delta complex near the Texas–Louisiana border (Forgotson, 1954; Coleman and Coleman, 1981; McGowen and Harris, 1984; Coleman, 1985; Wescott, 1985). In between, and fed by these fluvial-deltaic complexes, are facies interpreted as shallow-marine sandstones, including barrier-island, shoreface, and offshore-bar deposits (Thomas and Mann, 1966; Coleman and Coleman, 1981), called the Terryville Sandstone (Mann and Thomas, 1964). Thin wedges of transgressive blanket sands were deposited landward of the barrier facies as washover-fan and flood-tidal-delta deposits that pinch out updip into the lagoonal deposits of the Hico Shale. Some of the blanket sandstones are porous and permeable and form conventional gas reservoirs that yield gas in drill-stem tests (fig. 24). Downdip, the blanket sandstones lose permeability and grade into a thick, massive sequence of undifferentiated, low-

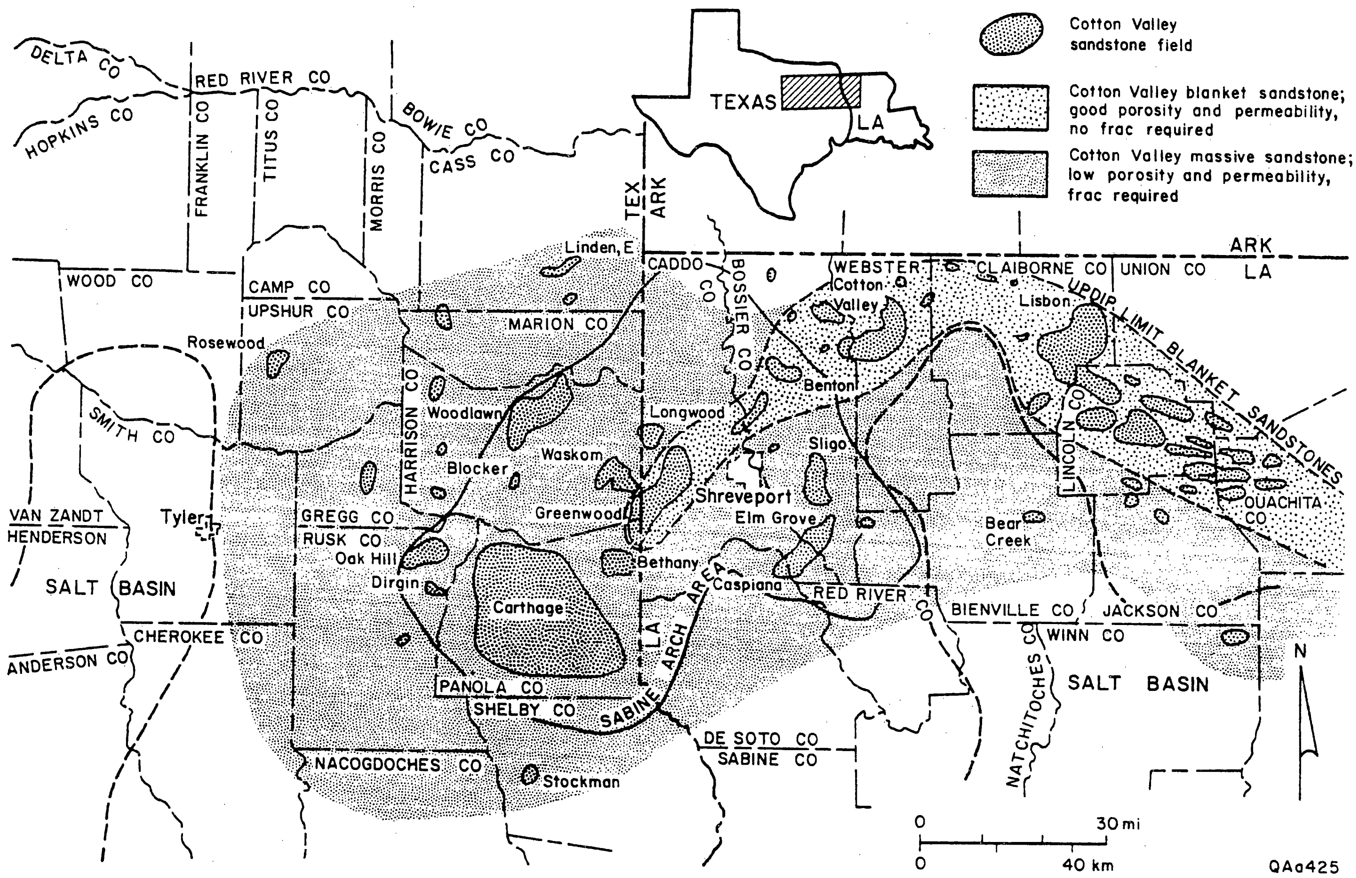


Figure 24. Distribution of Cotton Valley reservoir trends (modified from Collins, 1980).

permeability sandstones (Collins, 1980) that do not flow gas in drill-stem tests and that require fracture stimulation (fig. 24).

The depositional systems of the Cotton Valley in East Texas are somewhat different than those in Louisiana (Coleman, 1985; Wescott, 1985). Fan-delta deposits comprising prodelta, delta-front, and braided-stream facies have been identified in the Cotton Valley Sandstone along the western margin of the East Texas Basin (McGowen and Harris, 1984). Along the northern edge of the basin in the area of the present-day Sabine Arch, fan deltas prograded at the earliest stage of Cotton Valley deposition, then evolved into wave-dominated deltas (Bailey, 1983; Wescott, 1985). Strandplain and barrier-island environments probably existed contemporaneously along strike from the wave-dominated deltas, away from major fluvial axes (fig. 2).

Thick upward-coarsening sequences in the lower Cotton Valley Sandstone in East Texas are composed of shale at the base, bioturbated, fine-grained sandstones interbedded with siltstones and mudstones in the middle, and clean, well-sorted sandstones at the top (fig. 25). These upward-coarsening sequences (labeled Taylor and Lone Oak Sandstone in fig. 26) were deposited in either prograding shoreface, barrier-island, or wave-dominated-delta environments (Wescott, 1983; Hall and others, 1984; Presley and Reed, 1984; Coleman, 1985; Wescott, 1985). Upward-fining chert-pebble conglomerates and sandstones, which commonly overlie the upward-coarsening sandstones, probably were deposited in tidal channels (Dutton and others, 1991b), but an alternate interpretation is that they were deposited in fluvial channels that fed wave-dominated deltas (Presley and Reed, 1984). The Taylor sandstone (fig. 25) is an important Cotton Valley reservoir. In the SFE No. 3 well (fig. 27), sandstones and mudstones in the Taylor interval are interpreted as being deposited in a marine-shoreline setting (Dutton and others, 1991c). In an upward direction, the environments represented included the following: (1) shoreface, (2) microtidal barrier island, (3) lagoon and washover, (4) a second microtidal barrier island, (5) tidal-inlet channels, and (6) marsh-lagoon (fig. 27).

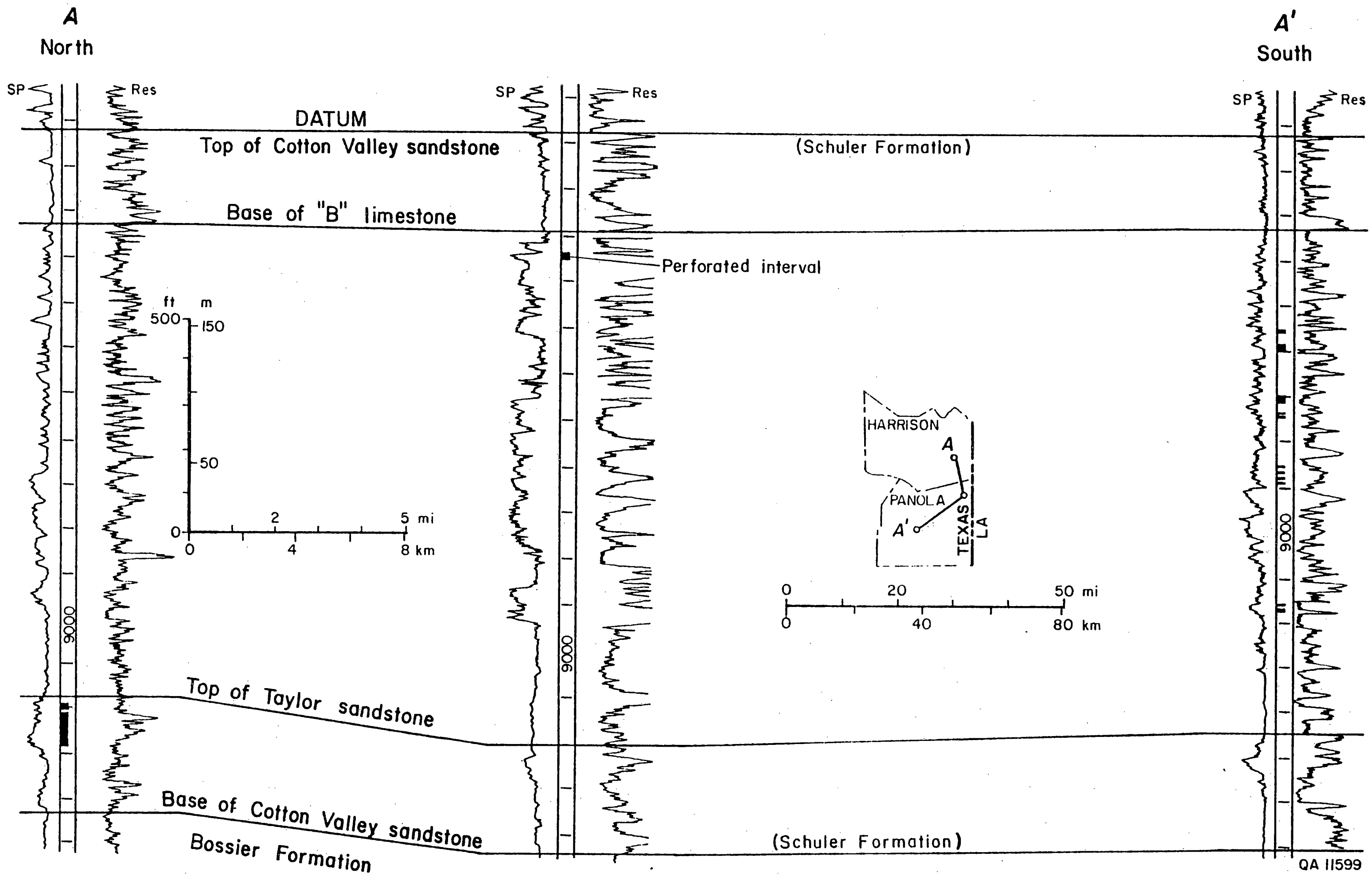


Figure 25. North–south stratigraphic cross section A–A' showing typical wells in Cotton Valley Sandstone in Carthage and Bethany East fields, Panola County, and Waskom field, Harrison County, Texas. Although packages of sandstone can be readily correlated, individual sandstones are less persistent. The widespread distribution of producing reservoirs within the Cotton Valley is indicated by location of perforated intervals. (Modified from Kosters and others, 1989, after Railroad Commission of Texas, 1986).

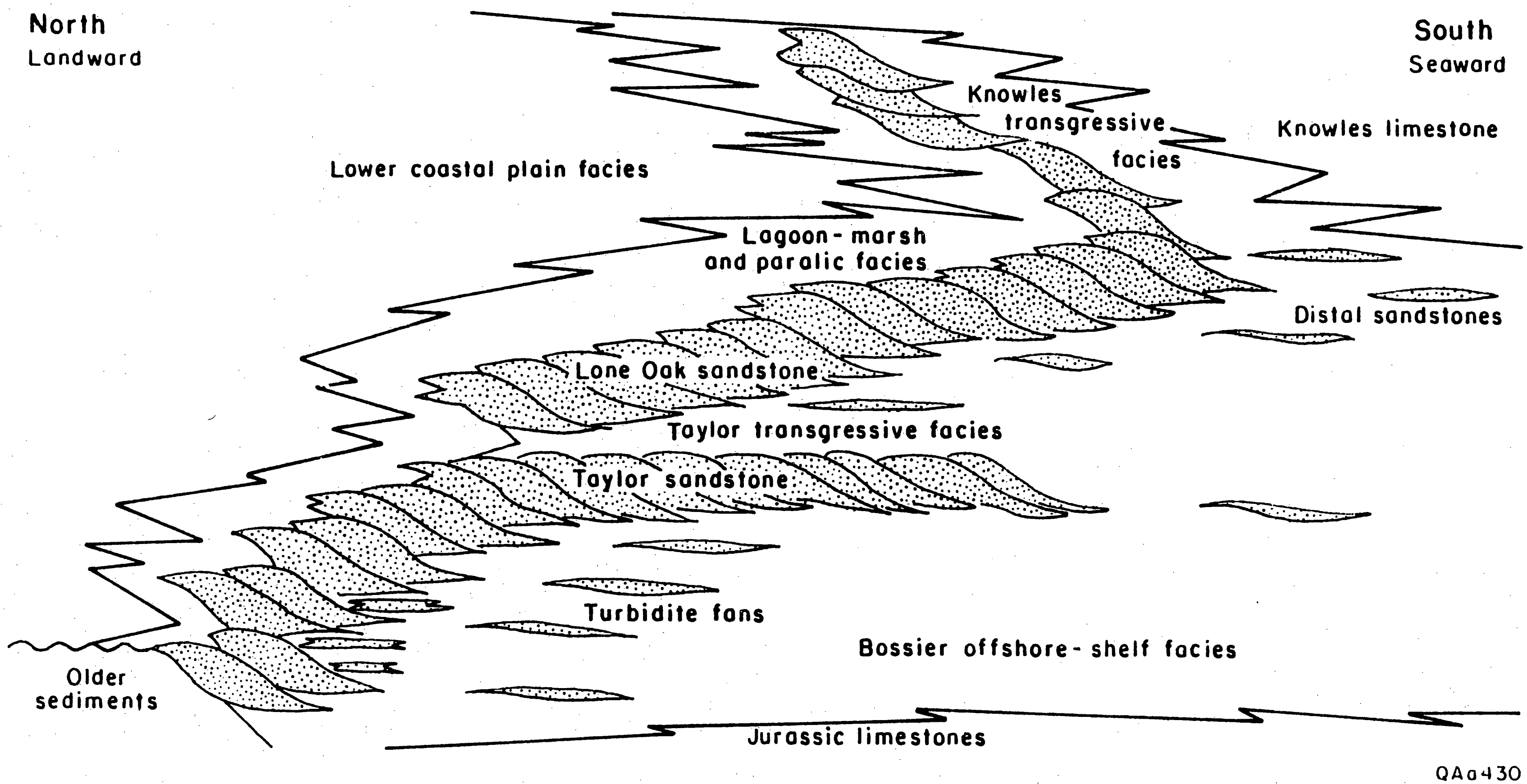


Figure 26. Schematic north–south cross section through the Cotton Valley Group in East Texas (from Wescott, 1985). The wave-dominated deltaic sandstones of the Taylor interval are overlain by the Taylor transgressive facies and sandstones deposited by the fluvial-dominated Lone Oak delta.

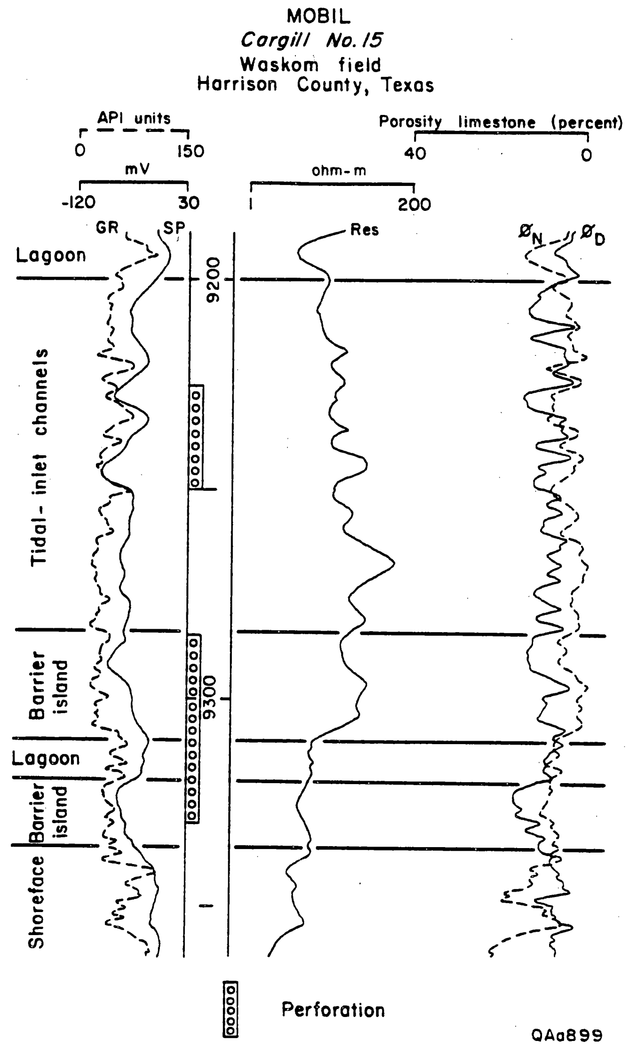


Figure 27. Representative log of a pay zone in the lower Cotton Valley Taylor sandstone from the GRI SFE No. 3 (Mobil Cargill No. 15) well. Interpretation of depositional environments from Dutton and others (1991c). It is estimated that SFE No. 3 will produce 1.14 Bcf over a 20-year interval from this zone.

The best porosity and permeability occur at the tops of barrier-island sequences and the base of tidal-channel deposits.

Above the Taylor sandstone is a thick, sandstone-rich interval (fig. 25) that composes the bulk of the Cotton Valley. Thick, upward-coarsening sandstones, which are generally the best exploration targets (Presley and Reed, 1984), are present in the lower part of this interval and extend into the upper Cotton Valley to varying extents (figs. 25 and 26). The dip-elongate nature of the sandstone bodies suggests they were deposited in a fluvial-dominated delta (Wescott, 1985). Sandstones in the uppermost Cotton Valley are relatively thin (2 to 10 ft [Presley and Reed, 1984]) and are interbedded with siltstones and shales. These thin sandstones probably were deposited in a variety of estuarine, paralic, or coastal-plain environments (Bailey, 1983; Presley and Reed, 1984; Wescott, 1985) (fig. 26). Some of the thin upper Cotton Valley sandstones contain gas, but zones of high water saturation also are present. The water-rich zones typically are connected to the wellbore after fracture stimulation because interbedded shales are thin and do not act as barriers to vertical growth of hydraulic fractures (Presley and Reed, 1984).

Composition of Reservoir Facies

Cotton Valley sandstones in East Texas generally are very fine-grained, well-sorted quartzarentites and subarkoses, and the average composition is $Q_{92}F_7R_1$ (Wescott, 1983; Dutton and others, 1991c). Plagioclase and orthoclase feldspars occur in most samples. Lithic components are primarily chert and low-rank metamorphic rock fragments. Mud rip-up clasts and chert pebbles are common at the base of tidal-channel sandstones. Fossil fragments, particularly oyster shells, are locally abundant.

Quartz and calcite are the most abundant authigenic minerals. The average volume of quartz cement is 8 percent; the average volume of calcite is 9 percent, but total carbonate (calcite, Fe-calcite, and ankerite) pore-filling and grain-replacing cement may compose

>60 percent of some sandstones (Wescott, 1983). In a regional diagenetic study, Wescott (1983) classified East Texas Cotton Valley sandstones into three groups: (1) Type I rocks are clean sandstones that are tightly cemented by quartz and calcite and are poor reservoirs, (2) Type II rocks are poorly sorted sandstones with a high clay content that have abundant microporosity, and (3) Type III sandstones contain abundant unstable grains and well developed secondary porosity due to dissolution of feldspars, rock fragments, and cements. Wescott (1983) states that Type II sandstones have the highest porosities in the Cotton Valley, but he does not report their permeability.

In the Taylor sandstone in the GRI SFE No. 3 well, Waskom field, the highest permeability occurs in sandstones that were deposited in high-energy environments such as barrier-island foreshore or at the base of tidal channels and that are cemented primarily by quartz (Dutton and others, 1991c). The geometric mean permeability (measured under net overburden pressure and Klinkenberg-corrected) is 0.014 md in barrier-island sandstones and 0.009 md in tidal-channel sandstones. High-energy sandstones that were cemented early in their burial history by extensive calcite have lower porosity (average = 1.6 percent) and permeability (<0.001 md). Permeability also is poor in muddy sandstones deposited in low-energy environments, such as lower shoreface. Even though little cement precipitated in these rocks, they have low permeability because of extensive compaction.

Natural Fractures

Documents submitted by operators to FERC show that natural fractures are thought to enhance production in Cotton Valley sandstone of the East Texas and North Louisiana basins (Finley, 1984). Naturally occurring fractures are suggested by locally high, anomalous production (Finley, 1984) and the need for fluid-loss treatments in some Cotton Valley wells. Accounts of the regional distribution and density of natural fractures in the Cotton Valley have not been published, but fractures have been documented on core and logs (Finley, 1984). The overall contribution to production of naturally occurring fractures has not been quantified.

Cotton Valley fractures are probably regional fractures oriented approximately parallel to the Gulf Basin margin, as documented in the SFE No. 3 well, and similar to those in the Travis Peak Formation (Laubach and others, 1989; Dutton and others, 1991c). Finley and others (1990) speculated that Cotton Valley fractures may tend to be larger and more continuous or interconnected adjacent to faults, within folds, and near salt domes than in areas having subdued structure.

Core from SFE No. 3 well in the Cotton Valley Taylor sandstone shows that many natural fractures are subvertical, east-northeast-striking extension fractures that are partly filled with calcite (Dutton and others, 1991c). In this well, fractures are confined to individual sandstone beds and do not extend across the entire interval. Instead, they terminate at minor lithologic breaks within sandstone beds. This lack of vertical continuity at the core scale suggests that locally Cotton Valley natural fracture systems are discontinuous and poorly interconnected vertically, but the characteristic size of fractures in this formation is unknown. Fractures are visible on FMS and borehole televiewer logs, and they are oriented nearly parallel to maximum horizontal stress (Laubach and others, 1990) (fig. 28).

Stress

The Cotton Valley is in the Gulf Coast extensional stress province (Zoback and Zoback, 1989). In the Cotton Valley in East Texas, SHmax trends predominantly east-northeast and eastward (Dutton and others, 1991c; compare with Brown and others, 1980). A stress profile from the Cotton Valley is shown in figure 29.

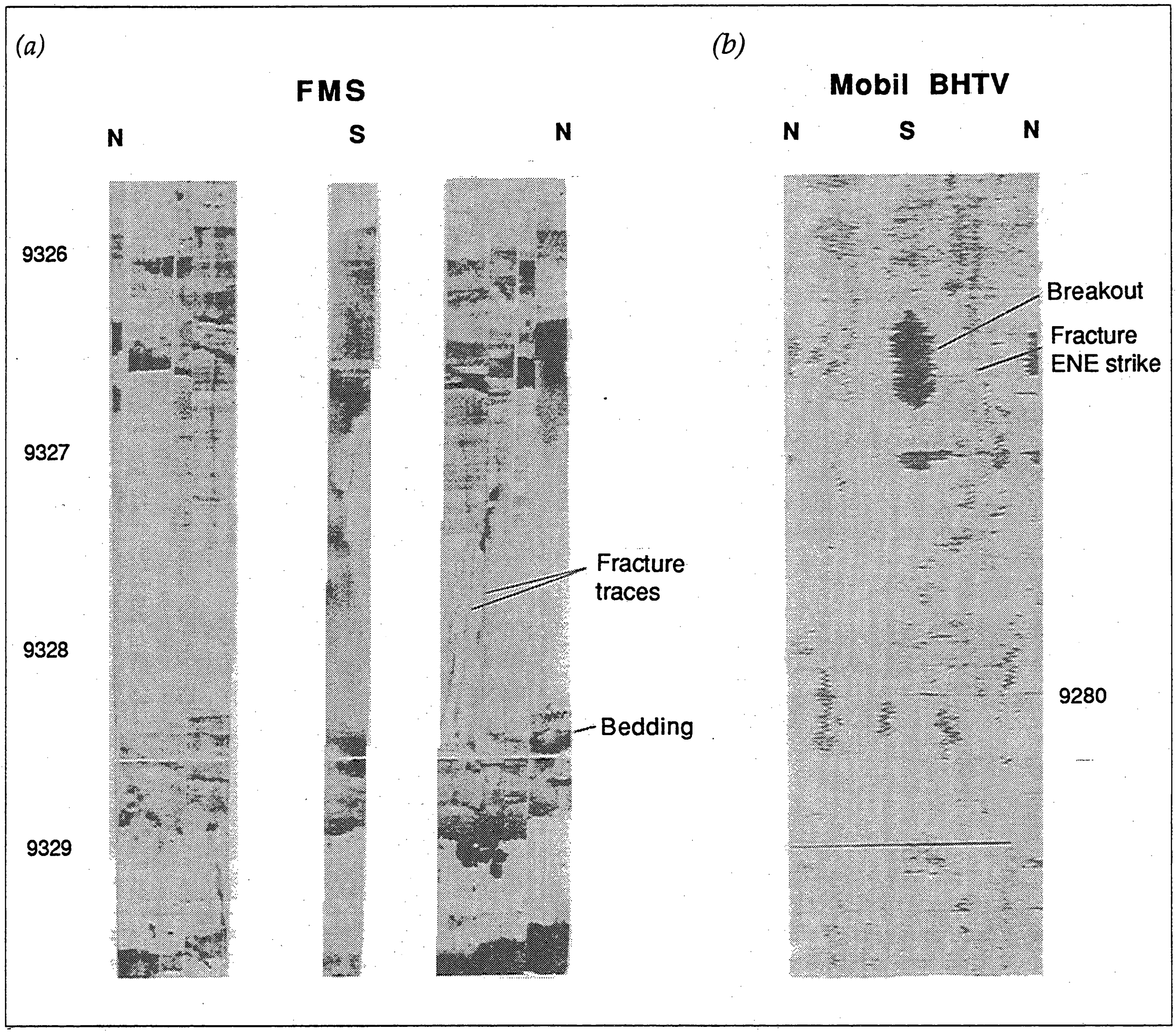


Figure 28. Fractures in Cotton Valley Formation, Holditch SFE No. 3 well, Waskom field, Harrison County, Texas, imaged with (a) Formation Microscanner (FMS) and (b) borehole televiewer (BHTV). From Dutton and others (1991b).

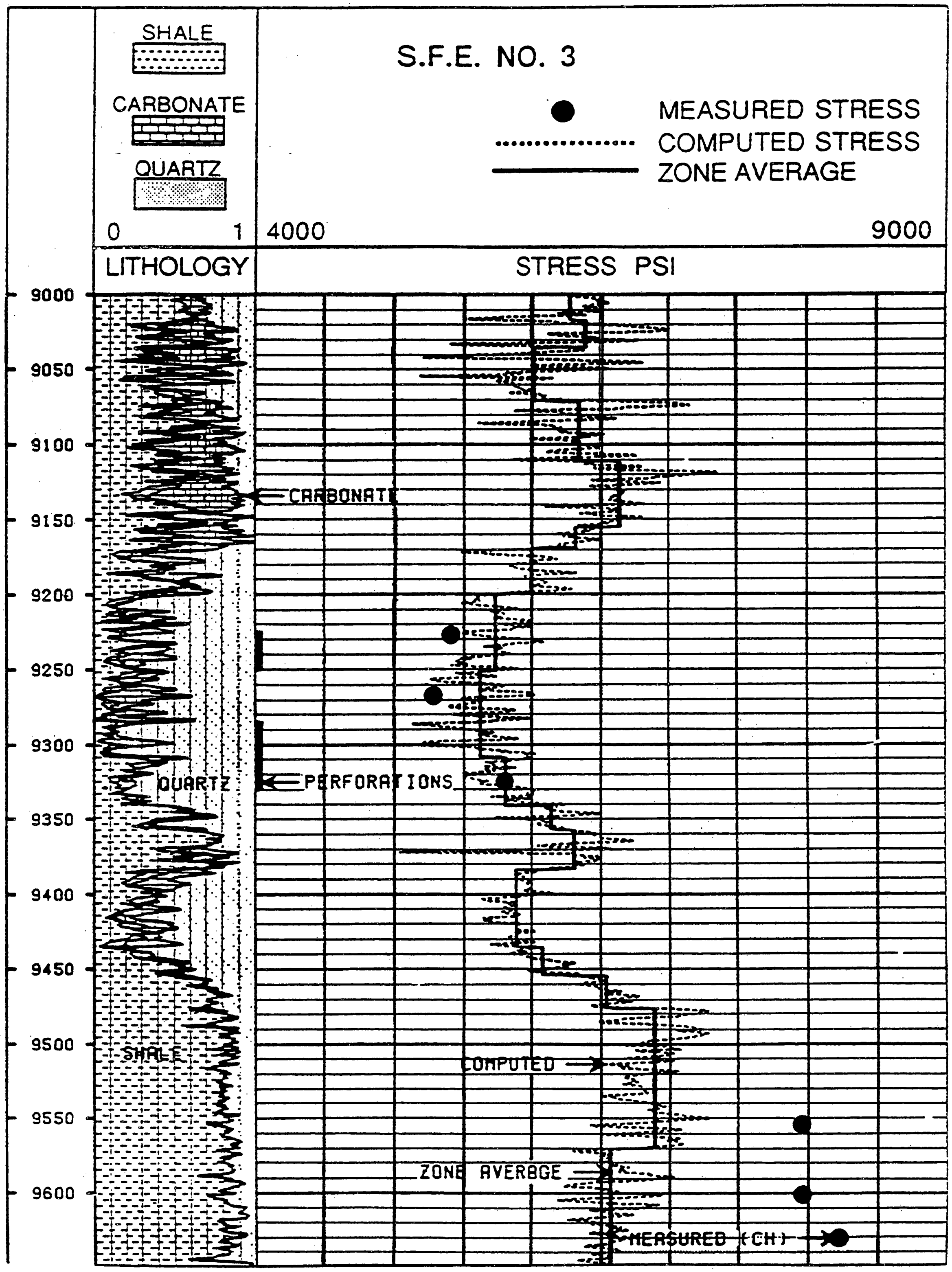


Figure 29. Comparison of measured stress with stress profile generated using elastic model (from CER Corporation and S. A. Holditch & Associates, 1991) for SFE No. 3 well, Harrison County, Texas.

Engineering Characteristics

Cotton Valley sandstones have variable porosities ranging from 1 to 18 percent (table 11). The higher porosity sandstones are generally found in North Louisiana, where some fields have been excluded from FERC tight gas sand designation. Most of the pay sandstones in northeast Texas average less than 10 percent porosity and fall in the 6 to 11 percent range (fig. 30) (Collins, 1980). Reservoir heterogeneity is a problem in the Cotton Valley. A 9 percent porosity sandstone may have permeabilities of 1 to 3 md, and several feet away another 9-percent-porosity sandstone may have permeabilities as low as 0.05 md (Wilson and Hensel, 1982).

Generally core porosities agree with log-calculated porosities if a grain density of 2.68 g/cc is used. Caution must be used, however, when utilizing logs to calculate porosity. The degree of hole rugosity has a severe effect on pad-contact logging tools, and as much as 40 to 50 percent of Cotton Valley and Travis Peak porosity log data may be unusable due to poor pad contact (CER Corporation and S. A. Holditch & Associates, 1989). Porosity cut-off for production is generally in the 7 to 8 percent range (fig. 30). Locally, however, some sandstones produce gas with porosities as low as 4 percent.

The arithmetic mean of ambient air permeability measurements for 11 cored wells at Carthage field (Panola County), one of the best studied Cotton Valley fields, was 0.067 md (Wilson and Hensel, 1982). Porosity in the 11 wells averaged 6.6 percent. One of the wells in this group had average permeability of 0.33 md. If data from this well are removed, average permeability for the group is 0.041 md, which is typical of Cotton Valley sandstones. A mean permeability of 0.043 md for 126 wells in Harrison, Rusk, and Panola Counties was reported by Finley (1984). Average permeability in 302 Cotton Valley wells in Louisiana is 0.015 md (table 11). As a general rule, 75 ft of net pay is necessary for an economic completion in the Cotton Valley (Collins, 1980). Net pay thicknesses range from 50 to 200 ft.

Table 11. Cotton Valley Sandstone, East Texas and North Louisiana Basins: production data and engineering parameters.

Estimated resource base (Tcf): 24.2

No. tight completions: 2,870

Cumulative production from tight completions 1970–1988 (Bcf): 2,665.5

Estimated ultimate recovery from tight areas (Bcf): 4,999

Net pay thickness (ft): 50–200

Porosity average (%): 6–11

Permeability average (md): 0.015–0.043

Water saturation average (%): 25–30

Reservoir temperature (°F): 250–270

Reservoir pressure (psi): 5,500–6,000

Typical stimulation/hydro-frac: 9000 bbl crosslink gel and 1,200,000 lb sand (in Taylor sandstone)

Production rate:

prestimulation (Mcfd): 50

poststimulation (Mcfd): 500–1,500

Average recovery per completion (Bcf): 1.8–2.4

Decline rate: 46% in first 1–2 yr

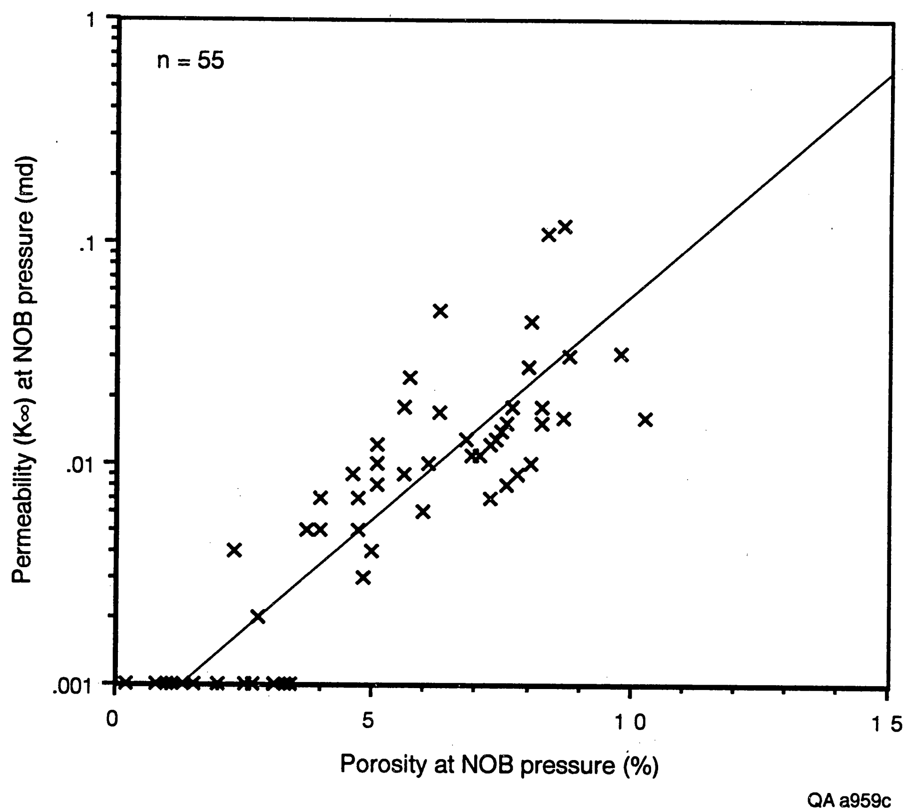


Figure 30. Semi-log plot of porosity measured at NOB pressure vs. Klinkenberg-corrected gas permeability measured at NOB pressure for 55 Cotton Valley Taylor sandstone samples.

Water saturations are generally 25 to 30 percent in the productive zones (table 11). However, water-free completions have been made in zones with water saturations as high as 60 percent. Cementation and saturation exponents are 1.83 and 2.09, respectively (Wilson and Hensel, 1982) in Carthage field. Many people use an exponent of 2 for both, but Wilson and Hensel (1982) describe the pitfalls of doing this; in sandstones with low porosities, the error induced by using the wrong saturation exponent may be severe. However, few special core analyses exist to determine the proper cementation and saturation exponents on a local basis. Formation water salinity in the Cotton Valley is 170,000 ppm total dissolved solids. This corresponds to a water resistivity of 0.048 $\Omega \cdot m$ at 75°F. Reservoir temperature is 250° to 270°F.

A typical capillary pressure curve for a Cotton Valley sandstone is shown in figure 31. Irreducible water saturation approaches 30 percent, which is consistent with log calculations. There are water zones in the Cotton Valley, so height above the water table is important when interpreting capillary pressure curves. For zones 200 ft above the free water level, water saturation should be less than 40 percent for a successful gas completion.

Two producing intervals exist in low permeability Cotton Valley sandstones. The deeper one is the Taylor sandstone (fig. 25). The Taylor has high stress contrast with the shales immediately above and below it, and it is routinely fracture stimulated using massive hydraulic fracture treatments. In the SFE No. 3 well, the fracture job consisted of 9,000 bbl of crosslink gel carrying 1,168,900 lb of 20/40 mesh Ottowa sand proppant (CER Corporation and S. A. Holditch & Associates, 1991). This type of massive hydraulic fracture treatment has become typical in Cotton Valley Taylor sandstones. In contrast, the upper Cotton Valley above the Taylor (fig. 25) has insufficient fracture barriers to sustain this size fracture stimulation treatment without extensive fracture growth out of zone. Because there are water-bearing sandstones in the upper Cotton Valley that do not exist in the Taylor, treatments in the upper Cotton Valley are in general significantly smaller than those in the Taylor sandstone.

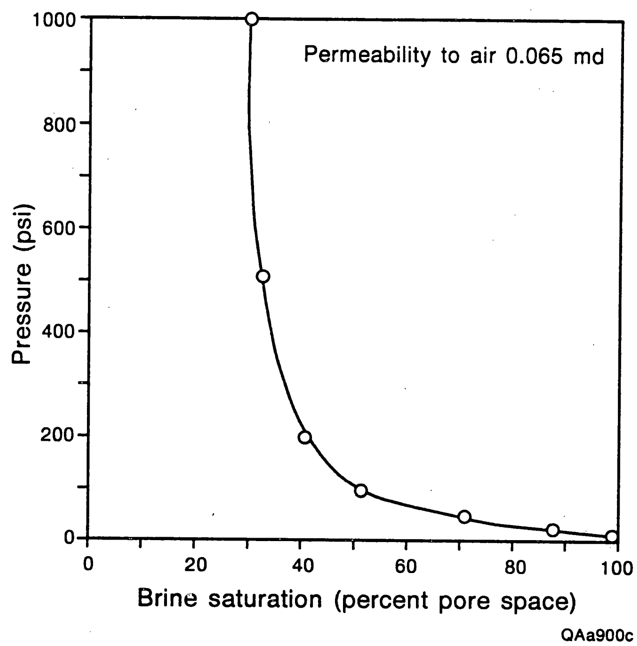


Figure 31. Typical air-brine capillary pressure behavior for Cotton Valley Taylor sandstone (from CER Corporation and S. A. Holditch & Associates, 1991). Sample is from a depth of 9,295 ft in the SFE No. 3 well.

Production History

Because of low permeability and high reservoir heterogeneity in the Cotton Valley, well spacing has been reduced from 640 acres per well to 320 acres for many fields. In Carthage field, an even higher well density is allowed.

The resource base in the Cotton Valley has been estimated at 24.2 Tcf (Haas, 1990). Ultimate recovery from wells already drilled is slightly less than 6 Tcf (table 11). Average recovery per completion is 1.8 to 2.4 Bcf (Hugman and others, 1992) (table 11).

Pre-stimulation completions in the Cotton Valley usually produce at low rates (50 Mcf/d). Post-stimulation rates are commonly on the order of 0.5 to 1.5 MMcf/d. The SFE No. 3 well, which was fractured using massive hydraulic fracture technology, produced at a rate shortly after fracture stimulation of 0.6 MMcf/d. Decline for Cotton Valley reservoirs is significant; rate decline has been estimated at 46 percent in the first 1 to 2 years. Initial water production of more than 200 bbl of salt water per day is common in Cotton Valley wells. The rate of water production typically decreases to 50 bbl/day over a 1 to 2 year period and continues for the life of the well (Collins, 1980).

Travis Peak Formation

Introduction

The Lower Cretaceous (Hauterivian-Barremian) Travis Peak Formation produces gas primarily from low-permeability sandstone reservoirs in East Texas and North Louisiana (fig. 32), although limited production also occurs in the Mississippi Salt Basin (fig. 22) of Mississippi and northeastern Louisiana (Weaver and Smitherman, 1978). Only one Hosston well in Mississippi, in Jefferson Davis County, has been designated tight by FERC (Hagar and Petzet, 1982). Application was made for the Travis Peak to be designated a tight gas sandstone by FERC in all of Railroad Commission of Texas Districts 5 and 6, with the exception of all oil

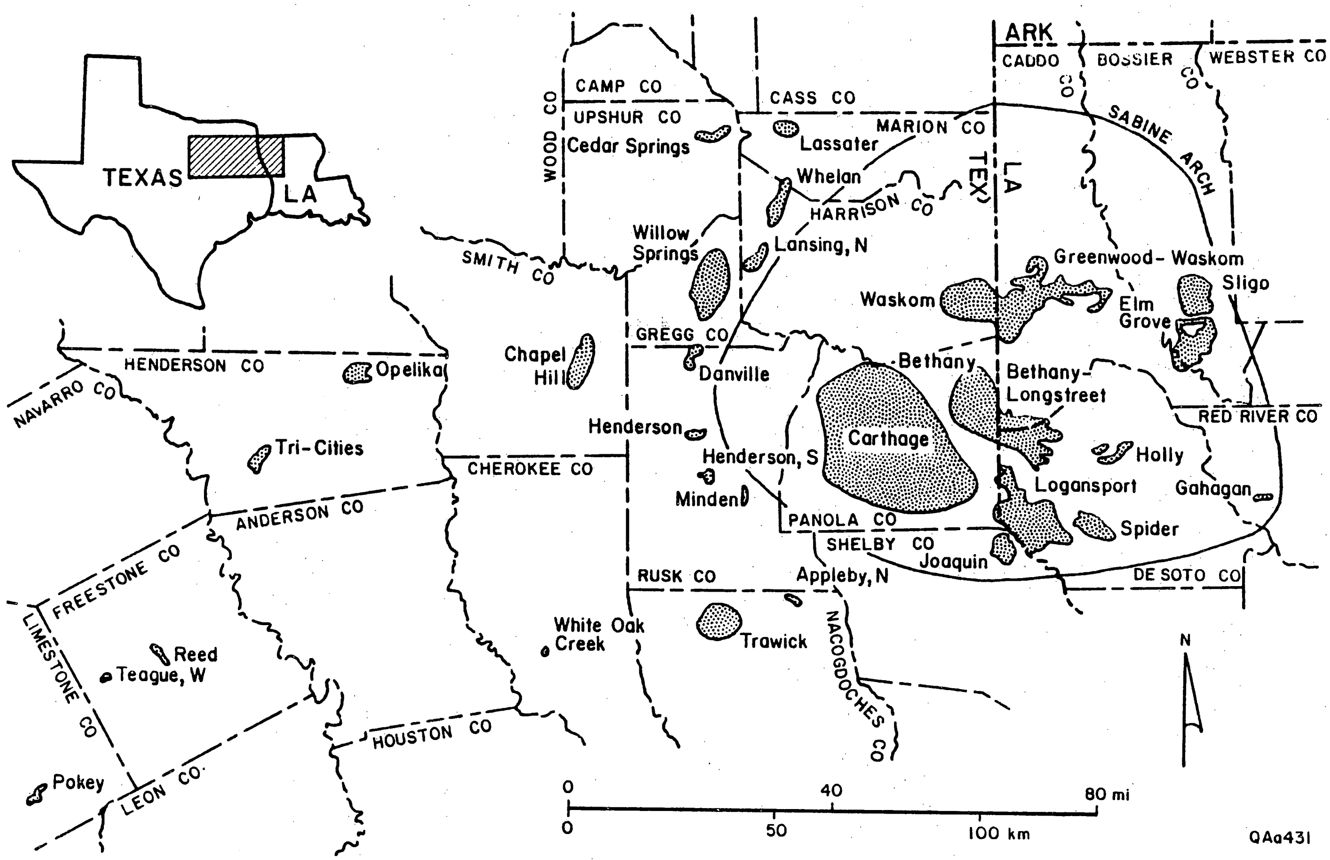


Figure 32. Location of major Travis Peak (Hosston) gas fields in the East Texas and North Louisiana Basins that have produced more than 10 Bcf of gas (from Kosters and others, 1989; Bebout and others, in press). North Appleby field, which has produced about 7 Bcf of gas (Tye, 1991), is included to locate the cross section in figure 35.

wells and 31 gas wells in this area. The application was remanded by FERC to the Railroad Commission of Texas, and in 1992 the tight gas designation was denied. However, the Travis Peak is designated tight in selected areas within Cherokee, Freestone, Leon, Limestone, Nacogdoches, Robertson, Rusk, and Smith Counties, Texas. In Louisiana, the Hosston Formation has been designated tight in parts of Bienville, Claiborne, Natchitoches, and Red River Parishes.

The Travis Peak Formation ranges from 1,400 to 3,200 ft thick and generally increases in thickness from northwest to southeast (Dutton and others, 1991b). Subsea depths of the Travis Peak range from <–4,000 ft to >–10,000 ft and increase radially away from the crest of the Sabine Arch. Most Travis Peak production occurs at depths from 6,000 and 10,000 ft below land surface.

The Travis Peak Formation in East Texas was the subject of a multidisciplinary study funded by the Gas Research Institute that integrated geology, formation evaluation, reservoir engineering, and fracture modeling. As a result of this study, abundant geologic and engineering data are available for the Travis Peak Formation, including 2,238 ft of core from 10 wells in East Texas (CER Corporation and S. A. Holditch & Associates, 1988, 1989, 1990, 1991; Dutton and others, 1991a, b).

Depositional Systems and Reservoir Facies

Many researchers have studied the depositional environments represented by Travis Peak deposits (Bushaw, 1968; McGowen and Harris, 1984; Saucier and others, 1985; Tye and others, 1989; Davies and others, 1991; Dutton and others, 1991a, b). A generalized Travis Peak depositional systems tract in East Texas and western Louisiana (fig. 33) consists of: (1) a braided- to meandering-fluvial system that forms the middle of the Travis Peak section, (2) deltaic deposits that are interbedded with and encase the distal portion of the fluvial section, (3) paralic deposits that overlie and interfinger with the deltaic and fluvial deposits

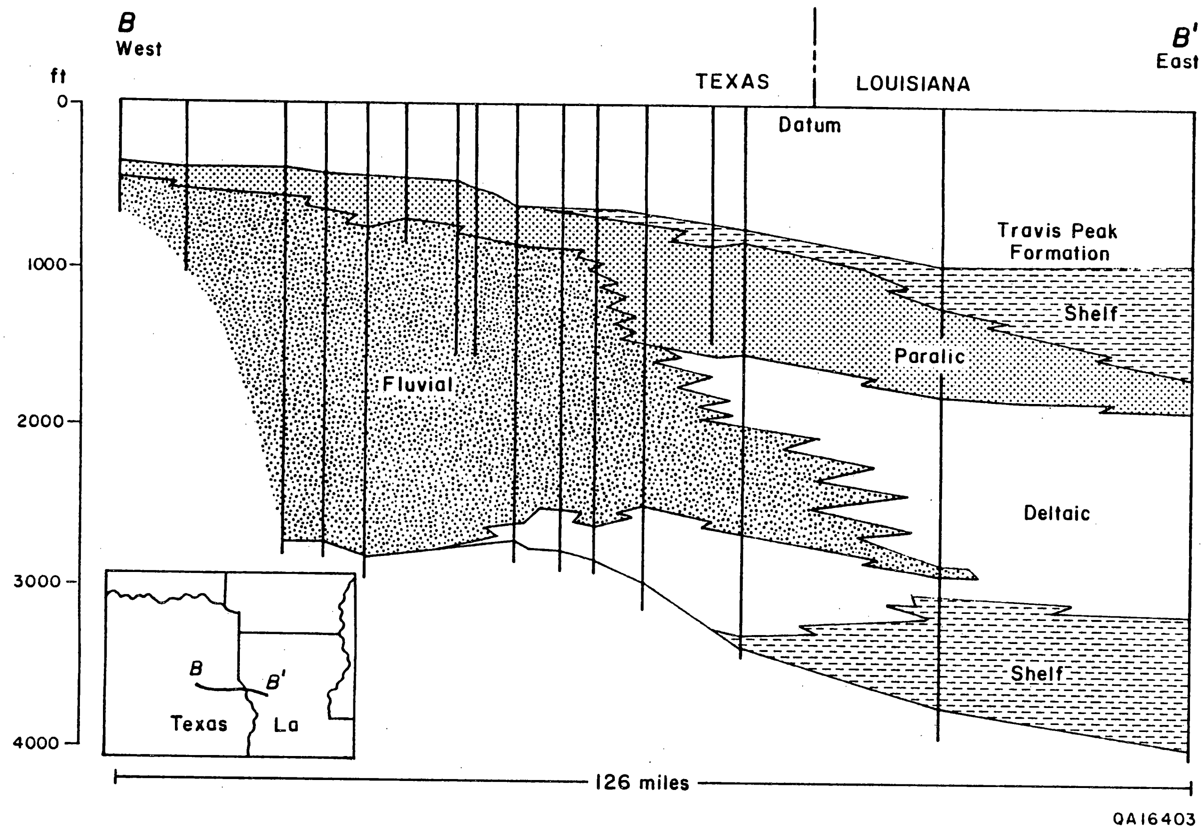


Figure 33. Paleo-dip-oriented stratigraphic cross section B–B′ of the Travis Peak Formation (from Dutton and others, 1991, modified from Tye, 1989). Datum is the top of the Pine Island Shale.

near the top of the Travis Peak, and (4) shelf deposits that are present at the downdip extent of the Travis Peak and interfinger with and onlap deltaic and paralic deposits.

Two main depositional systems, a lower aggradational fluvial system and an upper retrogradational paralic system (fig. 34) occur in East Texas, where most Travis Peak gas is produced. The 1,600-ft-thick sandstone-rich fluvial interval is interpreted to have been deposited in fluvial systems that evolved from braided to more meandering streams during Travis Peak deposition (Tye, 1989, 1991). Initially, fluvial systems consisted of broad, low-sinuosity, sand-rich channels. The thickest and most continuous sandstones were deposited in 3- to 5-mi-wide fluvial channel belts that form a network of overlapping, broad, tabular sandstones with thickness-to-width ratios of 1:800 (fig. 35). Reservoir sand bodies in this part of the Travis Peak are large (at least 5,000 acres) and thick (12 to 45 ft) (Davies and others, 1991). As a result of relative sea-level rise, the systems tract was compressed and the fluvial style in East Texas evolved from braided to braided-meandering deposition (bed-load to mixed-load sedimentation) during later Travis Peak time (Tye, 1989). Fluvial-channel deposits in the upper Travis Peak are arranged multilaterally, as are channel belts in the lower Travis Peak, but the upper Travis Peak channel-belt sandstones are thinner (8 to 29 ft) and vertically separated by thicker floodplain and overbank deposits (fig. 36). Thickness-to-width ratios of approximately 1:100 are typical of the braided-to-meandering-channel sandstones in the upper Travis Peak (Dutton and others, 1991a, b). Reservoir sandstones in the upper fluvial interval cover approximately 300 acres (Davies and others, 1991).

The upper, 160 to 600 ft of the Travis Peak (fig. 34) contains interbedded sandstones and mudstones that were deposited in a paralic depositional setting that consisted of coastal-plain (fluvial meanderbelt, floodplain) and marginal-marine (marsh, estuary, bay, tidal-flat, shoal) environments (Finley and others, 1985; Dutton and others, 1991a, b). Sandstones in the paralic interval are an average of 10 ft thick. Mudstones in the paralic section are thicker and more laterally continuous than are mudstones in the fluvial section. However, mudstones in both the fluvial and paralic intervals have low stress contrast with the interbedded

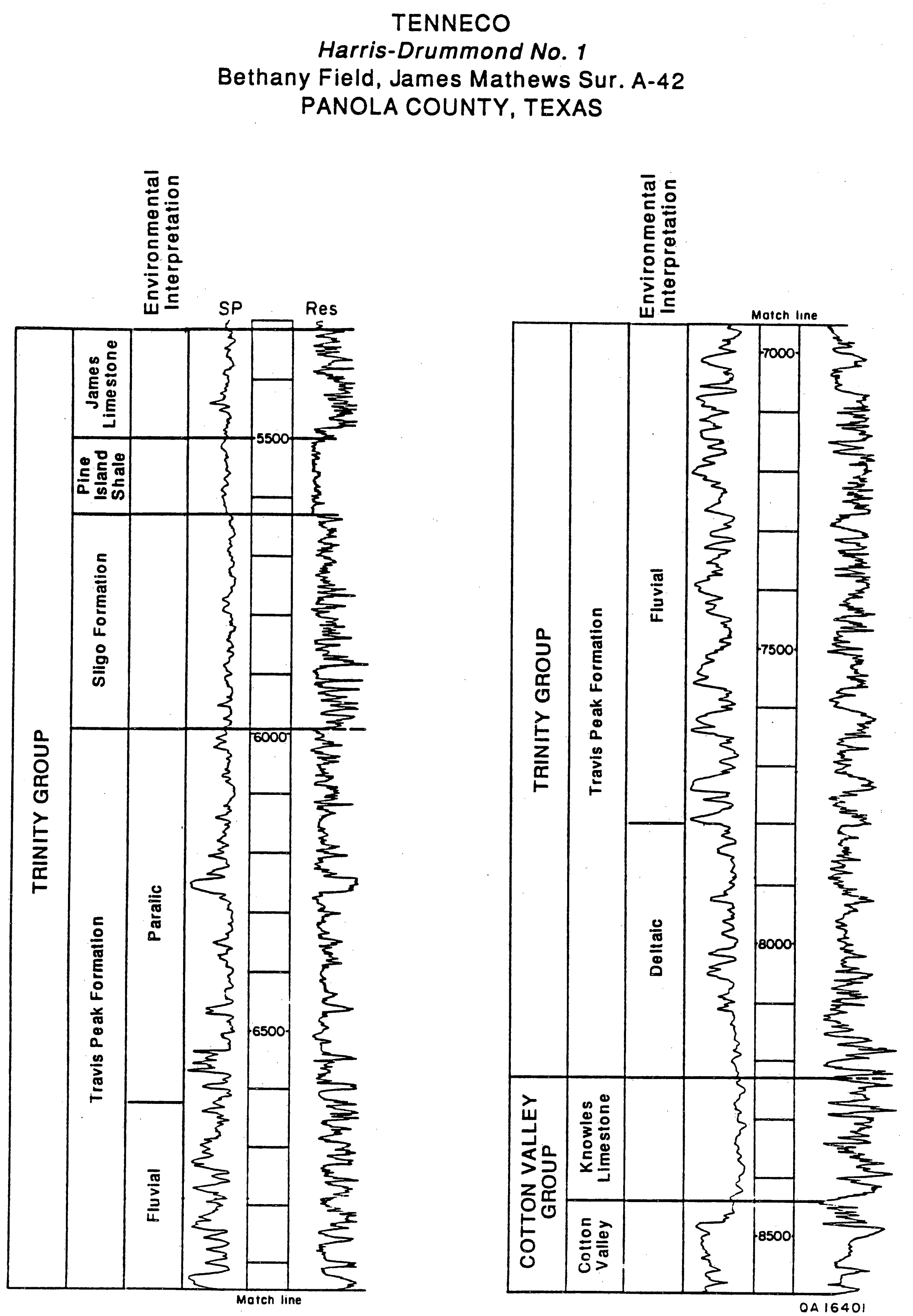


Figure 34. Representative log of Travis Peak Formation from eastern Panola County, Texas (from Dutton and others, 1991a, modified from Tye, 1989). Formal stratigraphic divisions and environmental interpretations are indicated.

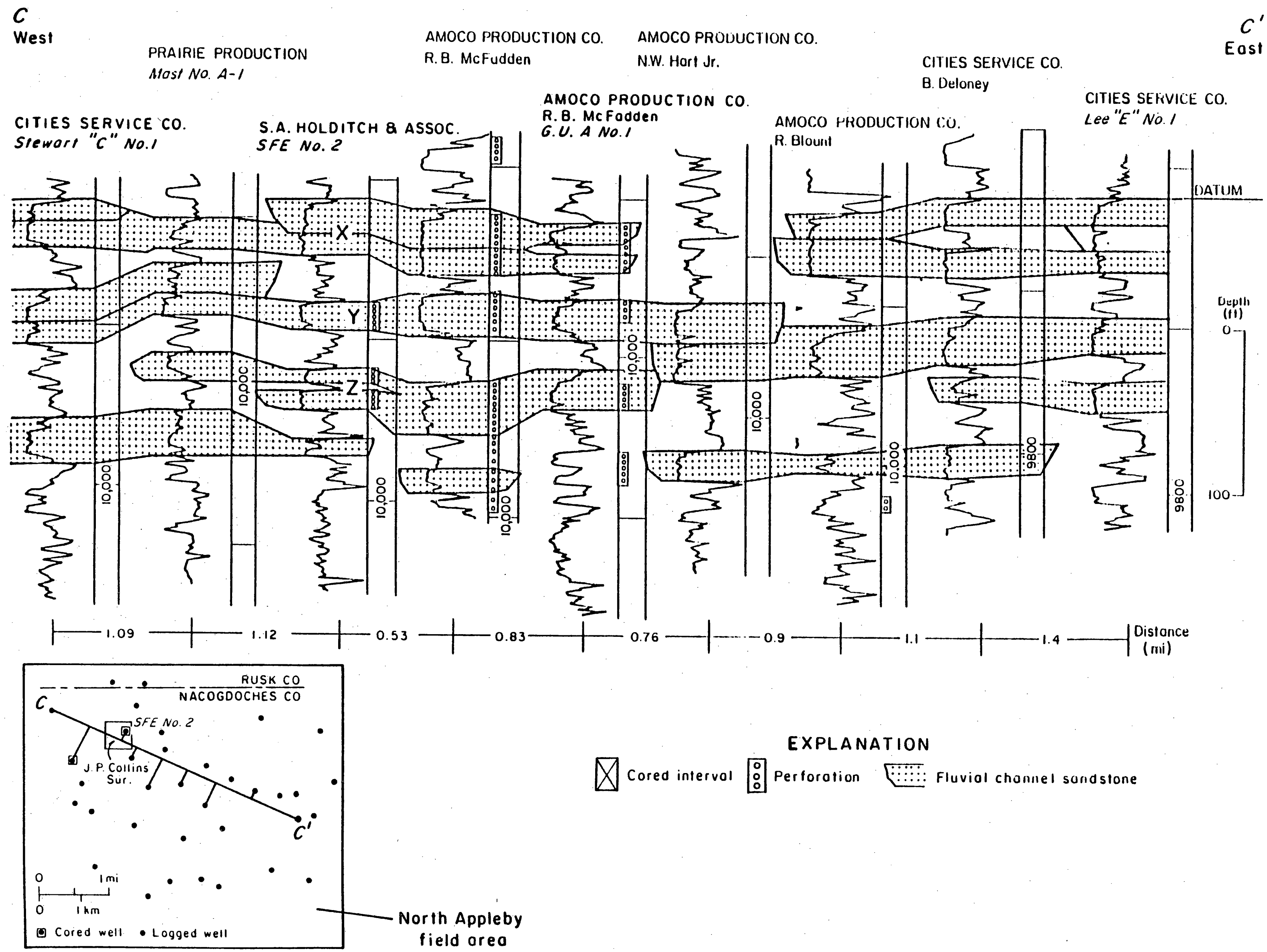


Figure 35. Stratigraphic cross section C–C′ illustrating the occurrence and geometry of channel-belt sandstones in lower Travis Peak, North Appleby field (shown in fig. 32) (modified from Tye, 1989). Multilateral fluvial-channel sandstones occur in broad lenses. Discrete sandstone lenses may be in horizontal contact because of lateral channel migration. Gamma-ray log curves are shown.

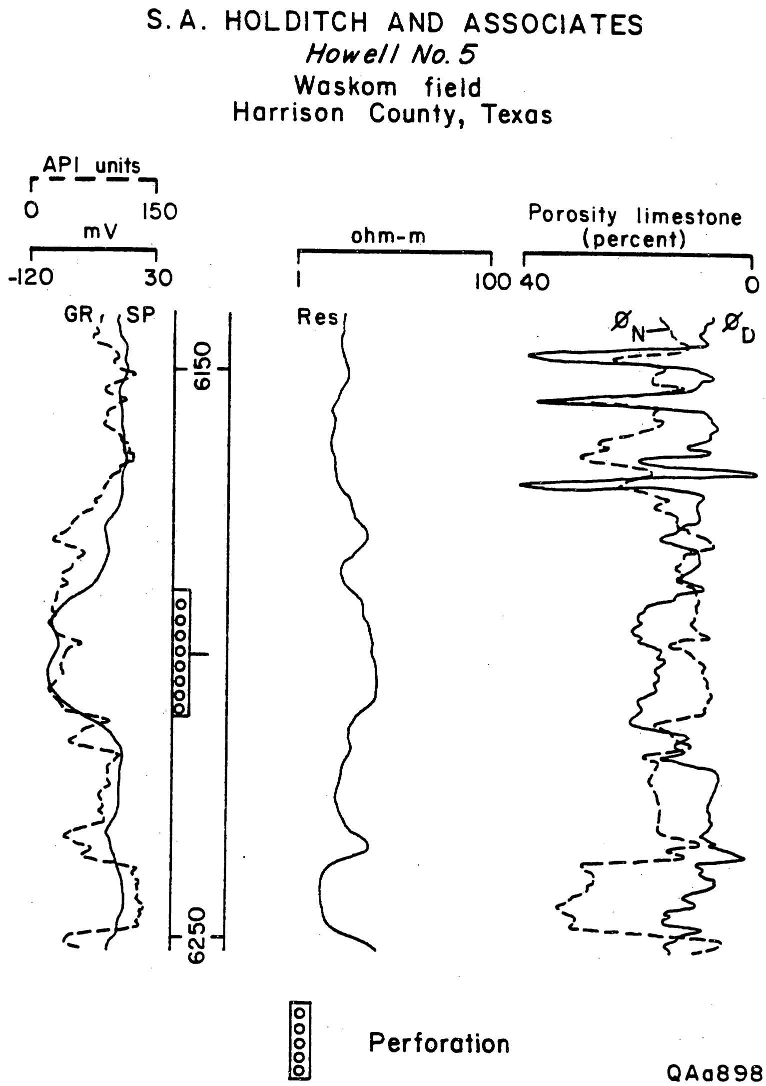


Figure 36. Representative log of a pay zone in the upper Travis Peak from the GRI SFE No. 1 well (S. A. Holditch & Associates Howell No. 5). It is projected that 1.14 Bcf of gas will be recovered from this zone over 6.5 years (from CER Corporation and S. A. Holditch & Associates, 1989).

sandstones and thus do not act as barriers to vertical hydraulic fracture growth (Dutton and others, 1991a, b).

Progradational deltaic sandstones occur at the base of the formation above the Knowles Limestone (fig. 34). Travis Peak deltas and the shelf over which they prograded were located mainly in western Louisiana and south of the Mount Enterprise Fault Zone (fig. 22).

Most hydrocarbon production from Travis Peak reservoirs in East Texas is from structural and stratigraphic traps over the crest of the Sabine Arch and from combination traps associated with salt-cored anticlines and pillows off the flanks of the uplift (Dutton and others, 1991a). The reservoirs occur in both fluvial and paralic sandstones, but most of the production has been from paralic sandstones in the upper 300 ft of the formation. Sandstones in the lower Travis Peak are gas saturated (Davies and others, 1991) but have low porosity and permeability because of extensive quartz cementation.

Composition of Reservoir Facies

The Travis Peak Formation in East Texas is composed mainly of fine-grained to very fine-grained sandstone, silty sandstone, and sandy mudstone. Matrix-free sandstones are moderately to well sorted and texturally mature. Travis Peak sandstones are quartzarenites and subarkoses, and the average composition is $Q_{95}F_4R_1$ (Dutton, 1987). Plagioclase is more abundant than orthoclase feldspar in most samples. Lithic components are primarily chert and low-rank metamorphic rock fragments. Ripped up and redeposited mud clasts are common at the base of fluvial-channel sandstones.

Extensive cementation during burial diagenesis has resulted in the present low porosity and permeability in Travis Peak sandstones. Cements and replacive minerals constitute an average of 23 percent of the rock volume. Quartz, illite, chlorite, ankerite, and dolomite are the most abundant authigenic minerals in Travis Peak sandstones (Dutton, 1987). Reservoir bitumen, a solid hydrocarbon residue that occurs in some sandstones (Dutton and others, 1987;

Lomando, 1992), is also considered a cement. Authigenic quartz, which averages 17 percent by volume in clean sandstones, is the main reason for low porosity and permeability in the Travis Peak. The volume of quartz cement increases with present burial depth, from an average volume of 15 percent at 6,000 ft to 20 percent at 10,000 ft (Dutton and Diggs, 1990).

Illite and chlorite are the most abundant authigenic clays. Authigenic illite occurs as delicate fibers inside both primary and secondary pores. Routine preparation of core plugs by Soxhlet extraction and air drying damages the morphology of fibrous illite in pore systems and consequently alters measured permeability (Luffel and others, 1990). Brine permeabilities of air-dried and extracted core plugs are an average of 1.5 times higher than brine permeabilities measured on preserved plugs (Luffel and others, 1990).

Reservoir bitumen that lines and fills pores is present in about 1/3 of Travis Peak sandstones. Reservoir bitumen occurs primarily within the paralic facies and is most abundant in the upper 300 ft of the formation. Among samples that contain bitumen, the average volume is 4 percent, but bitumen volume ranges as high as 19 percent. The presence of bitumen makes accurate reservoir evaluation more difficult because it affects both neutron and density log response (Dutton and others, 1987).

Natural Fractures

Open and filled subvertical extension fractures have been documented in the Travis Peak Formation in East Texas (Laubach, 1989a, b). Fractures range from microfractures to open macrofractures as much as several feet tall. Many fractures, however, are short (<1 ft tall) and probably have poor lateral and vertical interconnection. Fractures in core are confined to individual sandstone beds, suggesting that fracture systems in the Travis Peak are vertically isolated.

Fractures in the Travis Peak Formation in East Texas strike east-northeast (Laubach, 1989a), parallel to the margin of the Gulf of Mexico Basin and the local direction of maximum horizontal stress (Laubach and Monson, 1988). Open fracture apertures in core are as much as 0.5 cm. Minerals lining and filling Travis Peak fractures include quartz, ankerite, and calcite. Wireline formation tests of individual fractures (identified in core and on borehole televiewer logs) show that at least some Travis Peak fractures can conduct fluid (Laubach, 1989a).

In addition to fractures visible in oriented core, information on Travis Peak fractures was obtained from logs, petrographic studies, and rock-properties tests. Fracture shapes and orientations were assessed using dipmeter logs equipped to produce high-resolution resistivity images of the borehole wall (FMS logs) and borehole televiewer logs (Laubach and others, 1989). The orientation of microfractures visible under the petrographic microscope was used to infer macrofracture orientation (Laubach, 1989b). Microfracture strikes were detected using tests designed to reveal tensile strength anisotropy (Clift and others, 1992). Dutton and others (1991b) and GRI publications on East Texas SFE wells (CER Corporation and S. A. Holditch & Associates, 1989, 1991) provide further information relevant to natural fractures.

Fractures occur in both the lower Travis Peak (fig. 37) and in the generally more gas-productive upper Travis Peak. Fractures were recovered from areas lacking folds and faults. These fractures apparently result from regional tectonic stretching combined with evolving rock properties and episodically high pore-fluid pressures accompanying diagenesis (Laubach, 1988; Laubach and others, 1989). Although evidence is sparse for fractures being more common adjacent to faults, within fold hinges, and near salt structures, where local bending and stretching are expected, diagenetic and structural studies show that quartz cementation occurred earlier in the burial history of the Travis Peak. The formation therefore likely had appropriate physical properties for fractures to form during these later structural processes.

A potentially important role for natural fractures in the outcome of stimulation procedures is suggested by experiments in GRI's SFE No. 2 well in North Appleby field (fig. 32), northern Nacogdoches County. In this well, overcored hydraulic-stress-test fractures in naturally fractured intervals developed multiple, bifurcating strands rather than single fractures (Laubach, 1989a), resulting in narrower apertures of individual fracture strands than

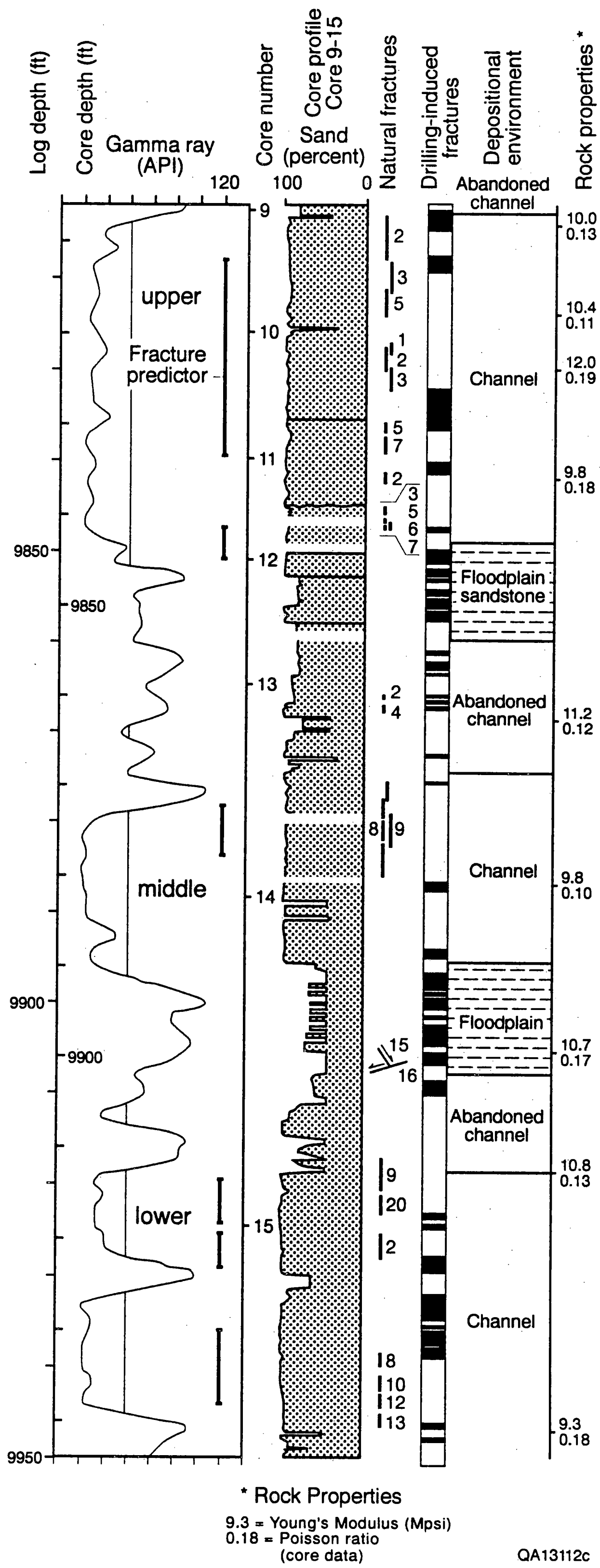


Figure 37. Distribution of fractures with depth and rock type, Travis Peak Formation, Holditch SFE No. 2 well, North Appleby field, northern Nacogdoches County, Texas. From Dutton and others (1991b).

would otherwise be the case. One manifestation of fracture branching during hydraulic fracture treatment is high net fracturing pressures such as those encountered in the lower Travis Peak treatment intervals in the SFE No. 2 well (Laubach and others, 1989).

Stress

The Travis Peak Formation is in the Gulf Coast extensional stress province (Zoback and Zoback, 1989). In East Texas, SHmax trends predominantly east-northeast and eastward (Laubach and others, 1989; see also Brown and others, 1980). A stress profile from the Travis Peak is shown in figure 38.

Engineering Characteristics

Porosity and permeability are not uniform throughout the Travis Peak Formation (Dutton and Diggs, 1992). Porosity ranges from 1 to 21 percent and generally decreases with increasing depth, from a (geometric) mean of 10.6 percent at 6,000 ft to 4.4 percent at 10,000 ft (fig. 39, table 12). In clean sandstones, porosity decreases from a (geometric) mean of 16.6 percent at 6,000 ft to 5.0 percent at 10,000 ft. Mean stressed permeability (geometric mean) in Travis Peak samples decreases significantly between 6,000 and 10,000 ft, from 0.8 to 0.0004 md (fig. 40, table 12). Mean stressed permeability (geometric mean) in clean sandstones is 10 md at 6,000 ft and 0.001 md at 10,000 ft. Permeability at any given depth varies by more than four orders of magnitude (fig. 40). The observed decline in porosity and permeability with depth between 6,000 and 10,000 ft results from: (1) increasing quartz cement, (2) decreasing secondary porosity, and (3) increasing overburden pressure that closes narrow pore throats (Dutton and Diggs, 1992).

The correlation between porosity and permeability in Travis Peak sandstones is reasonably good ($r = 0.79$) (fig. 41), but for a given porosity value, the 95-percent prediction interval for permeability is ±2 orders of magnitude (Dutton and Diggs, 1992). For example, for

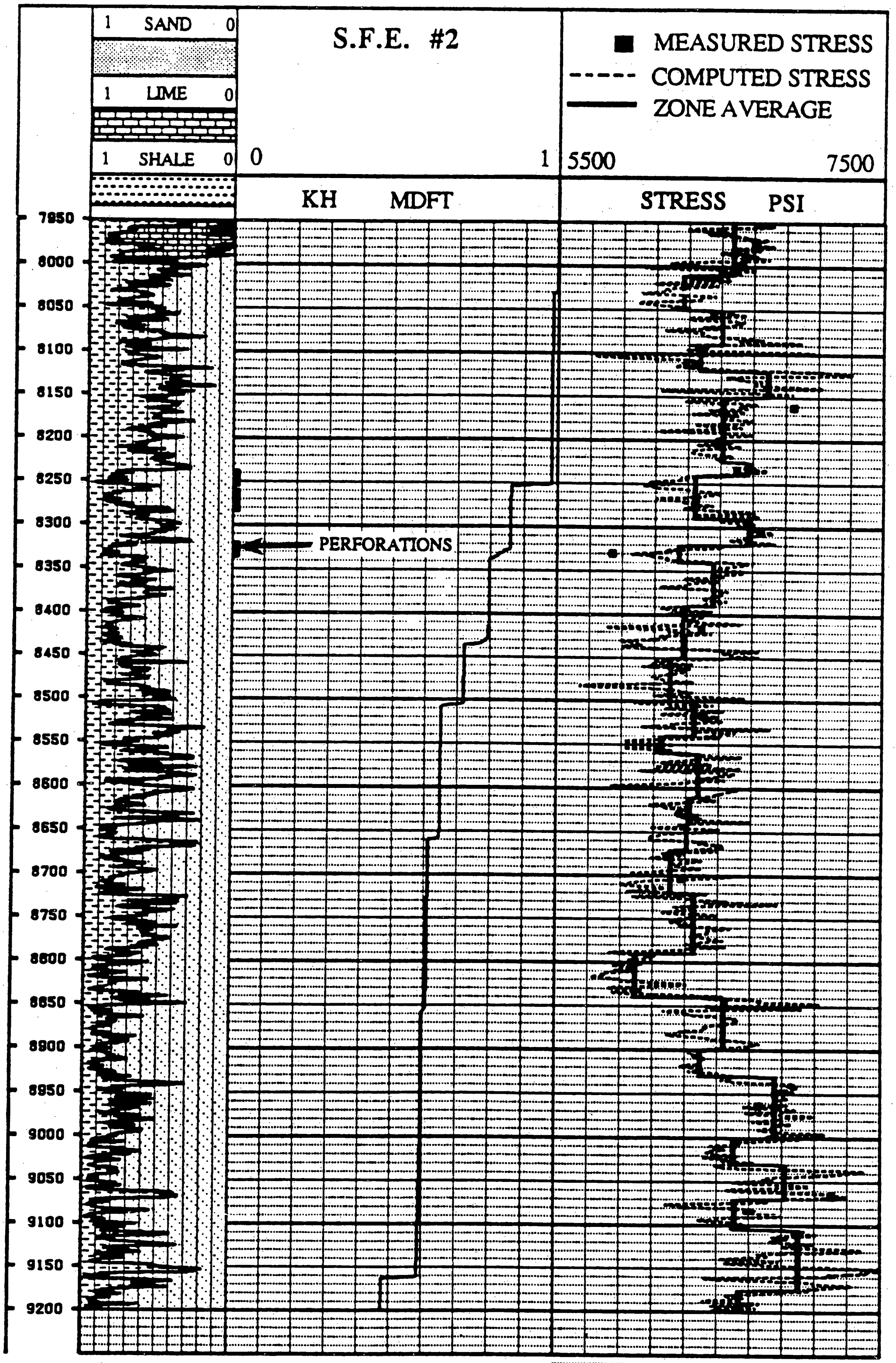


Figure 38. Permeability and stress profile, upper Travis Peak completion interval, SFE No. 2 well, northern Nacogdoches County, Texas (from CER Corporation and S. A. Holditch & Associates, 1990).

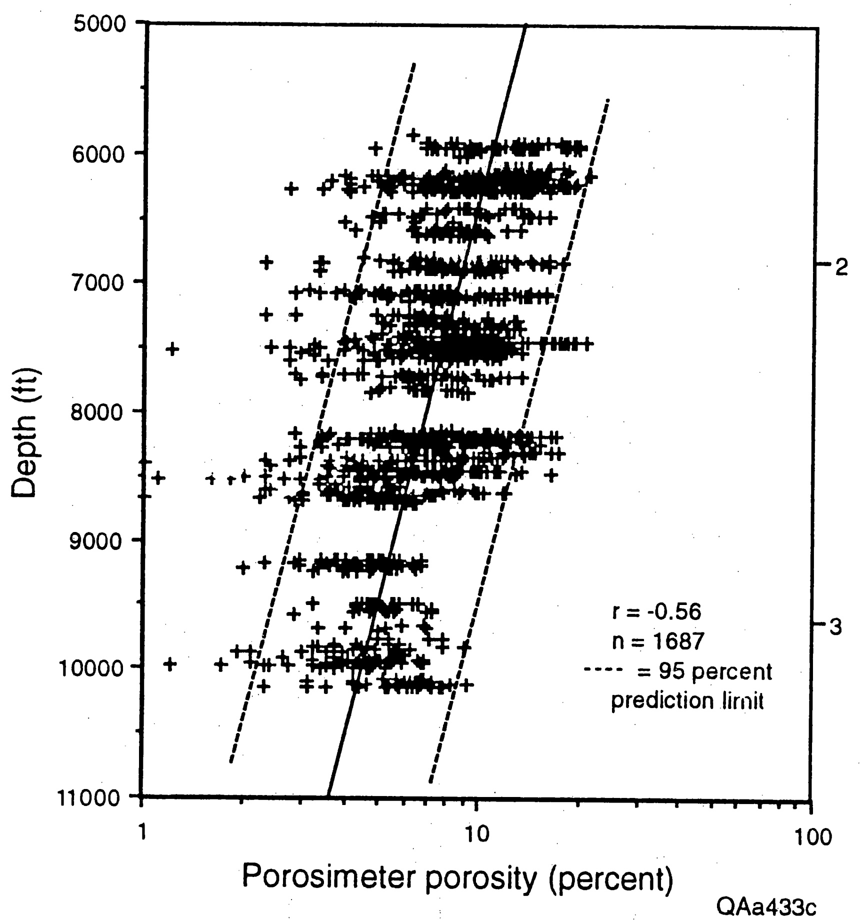


Figure 39. Semi-log plot of porosity vs. depth for 1,687 Travis Peak sandstone samples (from Dutton and Diggs, 1992). Porosity values have a log normal distribution. Linear regression equation relating depth and log porosity: log porosity (percent) = 1.6 – 9.6 × depth (ft) × 10^{-5}.

Table 12. Travis Peak Formation, East Texas and North Louisiana Basins: production data and engineering parameters.

Estimated resource base (Tcf): 6.4

No. tight completions: 860

Cumulative production from tight completions 1970–1988 (Bcf):508.3

Estimated ultimate recovery from tight areas (Bcf): 1,269

Net pay thickness range and average (ft): 30–86; 48

Porosity (%): 5–17

Permeability (md): 0.0004–0.8

Water saturation (%): 30–60

Reservoir temperature (°F): 190–272

Reservoir pressure (psi): 3,920–6,000

Typical stimulation/hydro-frac: 78,000 gal crosslink gel and 87,500 lb sand in upper Travis Peak; 235,000 gal fluid and 520,000 lb interprop in lower Travis Peak

Production rate:

- prestimulation (Mcfd): 0–765
- poststimulation (Mcfd): 500–1,500

Average recovery per completion (Bcf): 1.8–2.4

Decline rate: Up to 65% in first 1–2 yr

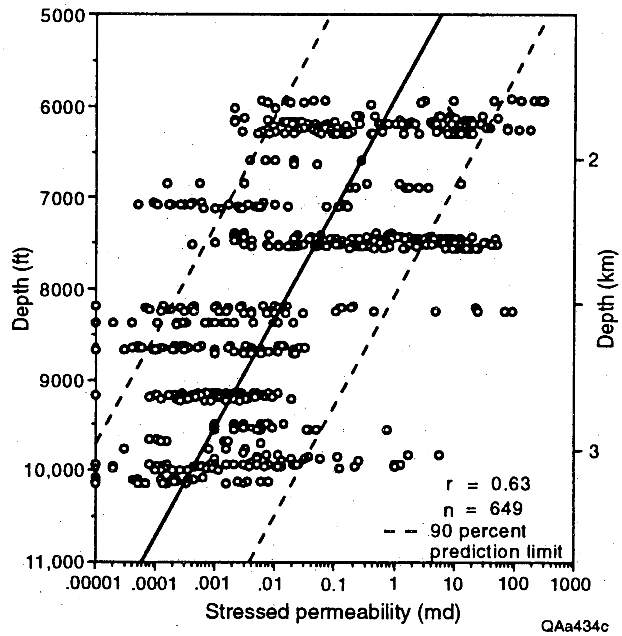


Figure 40. Semi-log plot of stressed permeability vs. depth for 649 Travis Peak sandstone samples (from Dutton and Diggs, 1992). Linear regression equation relating depth and permeability in Travis Peak sandstones: log stressed permeability (md) = $4.9 - 8.3 \times$ depth (ft) $\times 10^{-4}$.

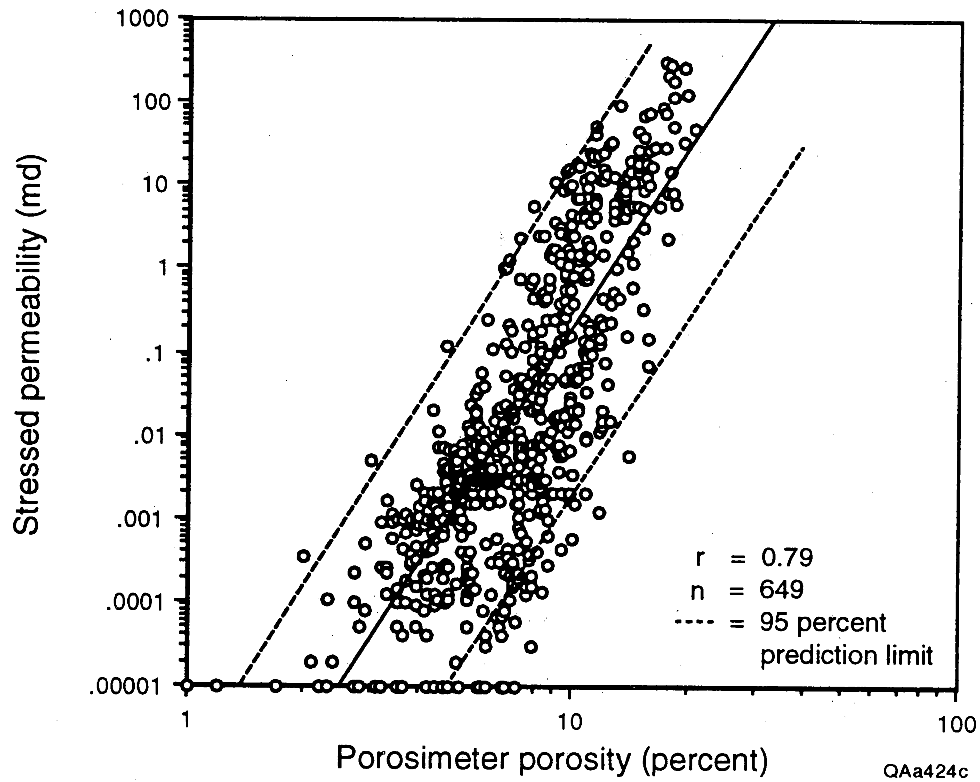


Figure 41. Log-log plot of porosity vs. stressed permeability for 649 Travis Peak sandstone samples (from Dutton and Diggs, 1992). Linear regression equation relating log porosity and log stressed permeability: log stressed permeability (md) = –7.9 + 7.1 × (log porosity).

an individual sample with 10 percent porosity, the 95-percent prediction interval for permeability ranges from 0.001 to 21 md. Travis Peak sandstones have a good relationship between porosity and permeability because the main control on porosity is the volume of quartz cement. As more quartz fills intergranular pore space, permeability is reduced.

As is the case in the Cotton Valley, there is reasonable agreement between core porosity and porosity derived from log analysis. Because the sandstones are dominated by quartz, a grain density of 2.65 g/cc should be used in log calculations. Hole rugosity causes a severe problem in log response. Logs should be carefully scrutinized for this problem when making porosity calculations.

Average net pay thickness in the Travis Peak is 48 ft (Finley, 1984). The normal range is from 30 to 86 ft. Most of the successful completions occur in the upper 300 ft of the Travis Peak Formation, where permeability is higher than in the lower Travis Peak.

Water saturations in productive Travis Peak sandstones vary from 30 to 60 percent (Finley, 1984) (table 12). Cementation (m) and saturation (n) exponents vary according to area. In the area studied during GRI Travis Peak research (ResTech, Inc., 1989), cementation exponents were fairly constant, ranging from 1.87 to 2.07. Saturation exponents varied from 1.32 to 2.21, depending not only on the county, but on the field as well. As in the Cotton Valley, many people use 2 for both m and n. Without the benefit of core analysis in an offset well, this is the procedure we recommend.

Formation water salinity is 170,000 ppm total dissolved solids, which corresponds to formation water resistivity of 0.048 at 75°F. In the southern part of the basin (Nacogdoches County), formation water resistivities have been measured at 0.065 at 75°F. Reservoir temperature in the Travis Peak ranges from 190° to 272°F.

A typical Travis Peak capillary pressure curve is shown in figure 42 for a clean, fine-grained sandstone. The curve is much like that of the Cotton Valley, with irreducible water saturation of 27 percent in reservoirs significantly above the water table.

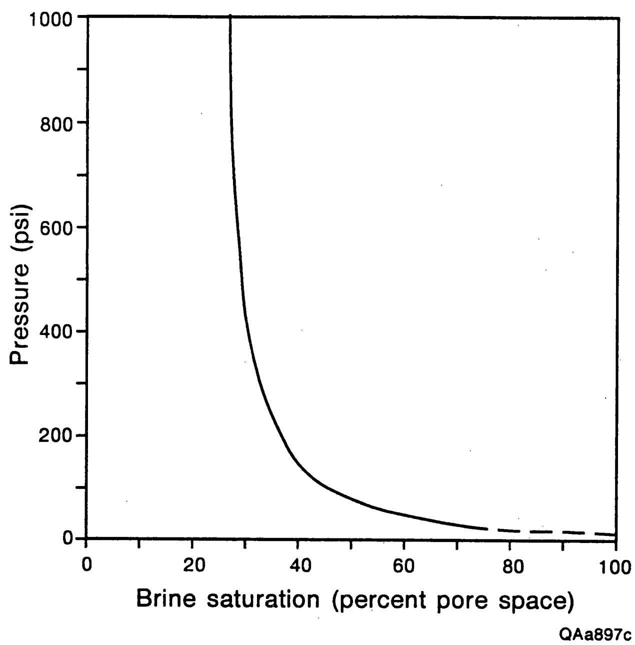


Figure 42. Typical air-brine capillary pressure behavior for Travis Peak sandstone (from CER Corporation and S. A. Holditch & Associates, 1989). Sample is from a depth of 8,251.9 ft in the SFE No. 2 (S. A. Holditch & Associates SFE No. 2) well.

Hydraulic fracture treatments vary in size depending on the reservoir. Some Travis Peak sandstones produce naturally. In the upper 300 ft of the Travis Peak, fracture stimulation treatments may be small. Two fracture treatments were made in GRI research wells, SFE No. 1 and SFE No. 2. In SFE No. 1 a completion was made in the upper Travis Peak (fig. 36) (CER Corporation and S. A. Holditch & Associates, 1988). The fracture stimulation consisted of 78,000 gal of 30-lb cross-linked gel and 87,500 lb of 18/20 mesh intermediate strength proppant.

In SFE No. 2, the completion was made in the lower Travis Peak. This fracture stimulation treatment was larger and was designed to pump 520,000 lb of interprop in 235,000 gal of fluid. However, the fracture stimulation was terminated after pumping 115,000 lb of interprop due to increasing pump pressure indicating formation "screen out," not uncommon in the lower Travis Peak. Normally the lower Travis Peak requires much larger jobs to improve its flow characteristics.

Production History

Well spacing in the Travis Peak is 640 acres. Estimated resource base is 6.4 Tcf (Haas, 1990), and ultimate recovery from current Travis Peak wells is estimated to be 1.3 Tcf (Hugman and others, 1992). Unstimulated wells range from negligible flow rates to a natural flow of 765 Mcf/d. Post-fracture flow rates can be as high as 1.5 MMcf/d. Recovery per completion ranges from 1.8 to 2.4 Bcf. Decline rate is rapid, up to 65 percent in the first 1 to 2 years.

MAVERICK BASIN

The Maverick Basin is a restricted depression in the Rio Grande Embayment (fig. 43) that probably formed as an aulacogen following the Triassic breakup of Pangea (Walper, 1977). The basin is bounded on the west by the Salado Arch, and on the east by the San Marcos Arch, which acted as a mildly positive structure that subsided at a slower rate than did adjacent

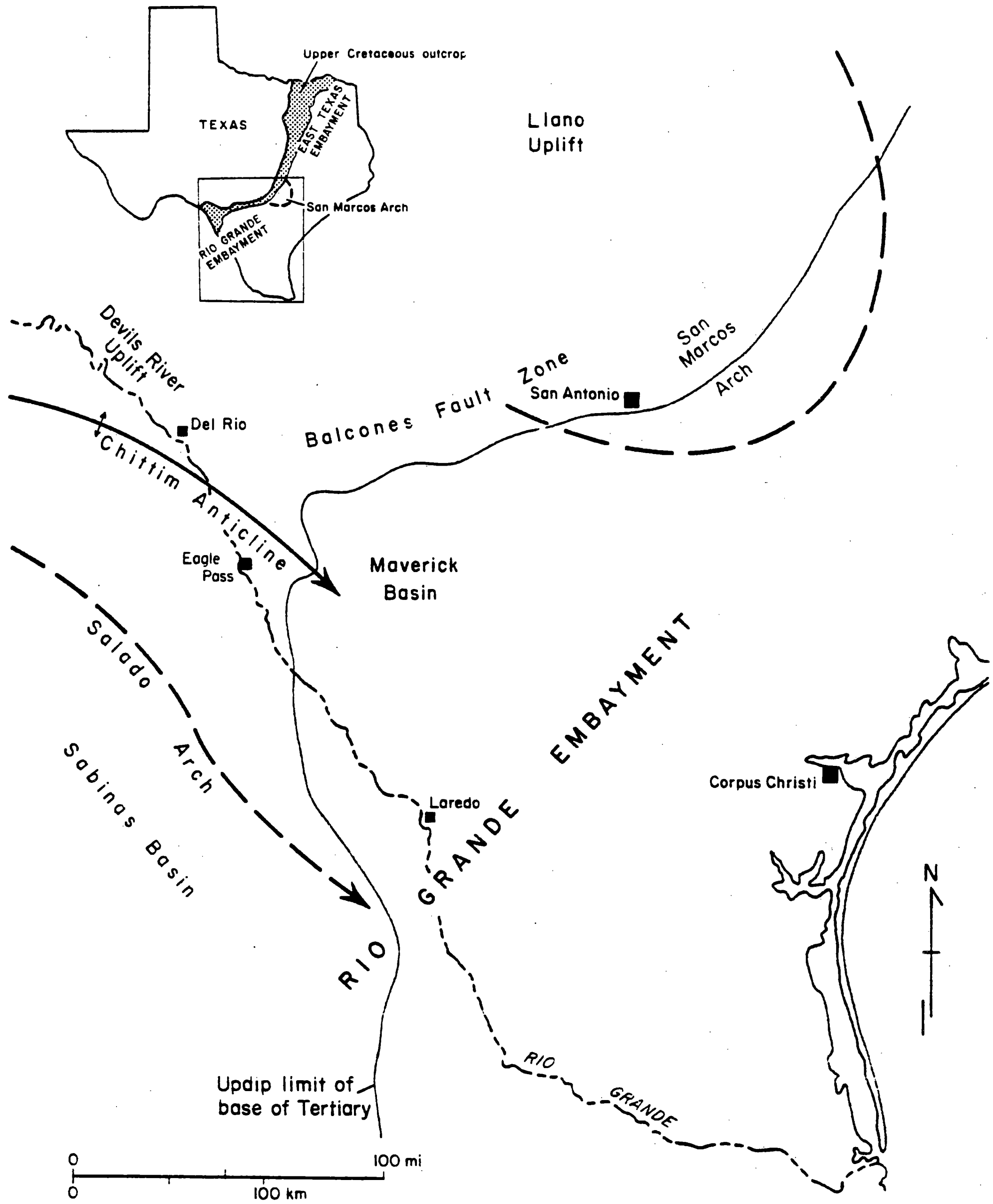


Figure 43. Structural framework of the Maverick Basin (from Weise, 1980).

basins during Cretaceous sedimentation (Loucks, 1976). The northwestern and northern limits of the basin are defined by the Devils River Uplift and the Balcones Fault Zone (fig. 43). Structural influences in this basin therefore include those of a passive margin basin and distal effects of the northwest-trending Cordilleran thrust belt of Mexico.

Carbonates dominated the Lower Cretaceous sedimentation, whereas the Upper Cretaceous sequence is characterized by terrigenous clastics derived from adjacent highlands following renewed tectonism in the latest Cretaceous (Murray, 1957; Weise, 1980). By the Late Eocene, the embayment was filled, and centers of deposition had begun to shift gradually southeastward into the Gulf Coast Basin (Spencer, 1965).

The tight gas sandstone reservoirs occur within the Upper Cretaceous Olmos Formation. There are as many as 973 tight completions in the Olmos, and cumulative production is 298.6 Bcf with an estimated ultimate recovery of 408 Bcf (Hugman and others, 1992).

Olmos Formation

Introduction

The Olmos Formation is one of three Upper Cretaceous terrigenous clastic wedges deposited in the Maverick Basin of the Rio Grande Embayment in South Texas (Tyler and Ambrose, 1986; fig. 43). The Olmos Formation conformably overlies the lowermost clastic wedge, the San Miguel Formation, and is in turn unconformably to disconformably overlain by the uppermost clastic wedge, the Escondido Formation (fig. 44). Snedden and Jumper (1990) dated the Olmos as Maestrichtian. The formation is exposed around the Chittim Anticline in Maverick County and is erosionally truncated by the pre-Escondido unconformity along a line that trends approximately easterly from the Uvalde–Zavala County border (fig. 45). The formation extends in the subsurface to the southeast beyond the Lower Cretaceous shelf edge in Webb and La Salle Counties (fig. 45).

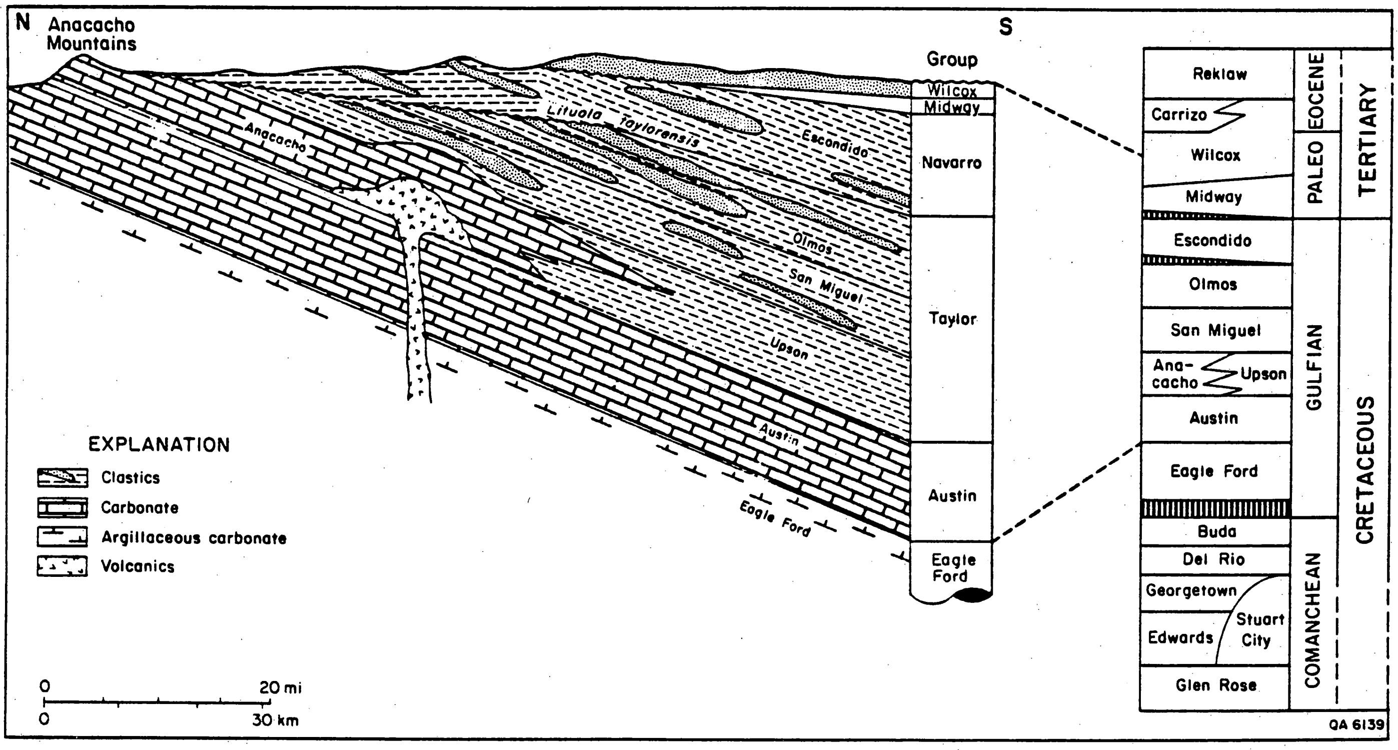


Figure 44. Schematic dip section through the Maverick Basin. Modified from Weise (1980) after Spencer (1965).

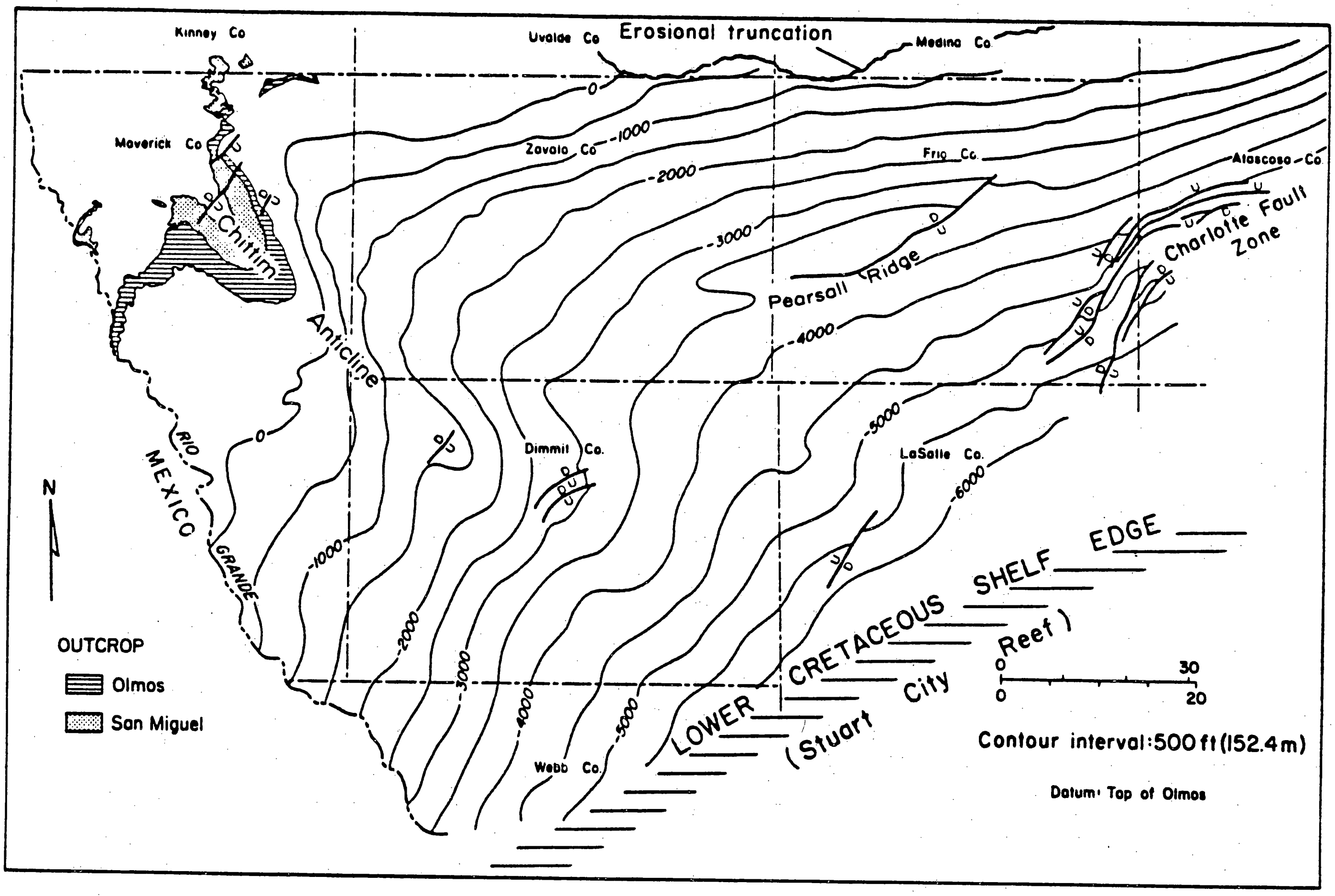


Figure 45. Regional structure map of the Maverick Basin contoured on the top of the Olmos Formation. Modified from Weise (1980).

Tyler and Ambrose (1986) recognized seven Olmos exploration and production plays on the basis of trapping mechanism and depositional setting of the reservoirs. The tight-gas-producing reservoirs reviewed here are included in their downdip deltaic and shelf tight-gas sandstone play (fig. 46). The area formally designated by FERC as tight-gas-producing covers northwestern Webb County and southern Dimmitt County (Railroad Commission of Texas, 1981). The A.W.P. Olmos field, which covers an area of approximately 5,000 acres in McMullen County, was also designated as tight-gas-producing (Railroad Commission of Texas, 1985, 1986), and is within the shelf edge trap play of Tyler and Ambrose (1986; fig. 46).

The Olmos Formation is 400 to 500 ft thick at outcrop and thickens to the southeast, where it is as much as 1,200 ft in Webb County. Net sandstone of the formation is typically from 50 to 150 ft but exceeds 200 ft in three distinct areas centered in Frio, Maverick, and Dimmitt Counties. Structural dip in the Maverick Basin is to the southeast and east-southeast at 50 to 150 ft/mi such that the depth to the top of the Olmos Formation varies from outcrop to slightly more than 6,000 ft at the Lower Cretaceous shelf edge (fig. 45).

The Olmos Formation has been the subject of many recent studies. Tyler and Ambrose (1986) carried out a regional study of the formation from the shallow subsurface down to the Lower Cretaceous shelf edge, and Snedden and Jumper (1990) investigated Olmos deposition beyond the Lower Cretaceous shelf edge. Barrow and Asquith (1992) resolved correlation problems across the shelf edge. The Las Tiendas trend, an Olmos tight-gas-producing zone down-dip of the shelf edge, was a target of the State Lands Energy Resource Optimization (SLERO) project headed by the Bureau of Economic Geology, The University of Texas at Austin. Barrow and others (1992) reported on the utility of shaly sand log analysis as an indicator of hydrocarbon potential in these tight Las Tiendas reservoirs.

The key studies listed above represent a broad data set that provides a good overview of reservoir characteristics, production trends, and completion practices for the Olmos Formation.

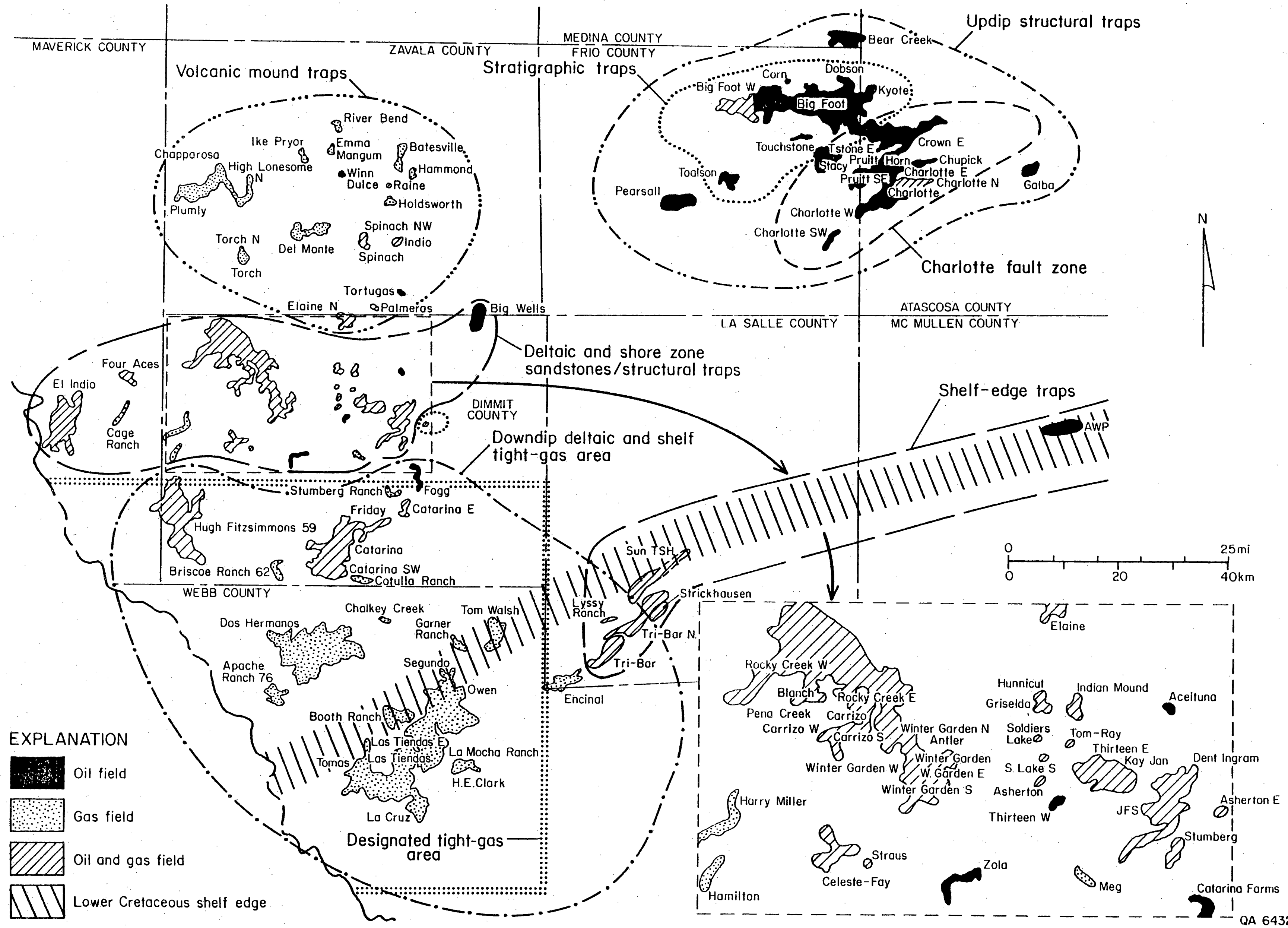


Figure 46. Oil and gas fields and major exploration and production plays of the Olmos Formation (from Tyler and Ambrose, 1986). The designated tight-gas-producing area coincides with the downdip deltaic and shelf tight-gas sandstone play. The A.W.P. Olmos field is a shelf-edge trap.

Depositional Systems and Reservoir Facies

Olmos deposition updip of the Lower Cretaceous shelf edge occurred in two principal depocenters (Tyler and Ambrose, 1986; fig. 47). Sedimentation was initially focused in the western depocenter where the Catarina delta system first deposited a highly wave-reworked, strike-elongate delta complex (Unit A), followed by more fluvially-influenced, wave-modified delta complexes (Units B and C; fig. 48). Sedimentation shifted to the eastern depocenter where again a wave-dominated delta complex (Unit F) was followed by two episodes of high constructive but wave-modified deltaic sedimentation (Units G and H; fig. 48). Units F, G, and H compose the Big Foot delta system. Sands not retained in the Big Foot delta system migrated alongshore to the west, where they formed thick retrogradational coastal/interdeltaic complexes (Units D and E) of the Rocky Creek barrier/strandplain system (Tyler and Ambrose, 1986; fig. 48).

Downdip of the Lower Cretaceous shelf edge, the Olmos sandstones are informally designated the Olmos "A" and underlying Olmos "B," although Barrow and Asquith (1992) have shown the Olmos to consist of at least nine individual sandstone bodies (A1 through A3, B1 through B6 [fig. 49]). A regional shale marker enabled Barrow and Asquith (1992) to establish correlation across the Lower Cretaceous shelf edge. They demonstrated that the Olmos "A" is equivalent to the lower portion of the Rocky Creek barrier/strandplain system (Unit D of Tyler and Ambrose, 1986) and the Olmos "B" correlates with the upper portion of the Catarina delta system (Units B and C of Tyler and Ambrose, 1986). The Olmos "A" sandstones are interpreted as storm-dominated lower shoreface to marine shelf deposits (Snedden and Jumper, 1990; Barrow and others, 1992), which is consistent with their stratigraphic position, seaward of the Rocky Creek barrier/strandplain system. The Olmos "'B" sandstones were deposited basinward of the Catarina delta system and were interpreted by Snedden and Jumper (1990) as shelf sand ridge/shoal facies. Barrow and others (1992) argued that there was no

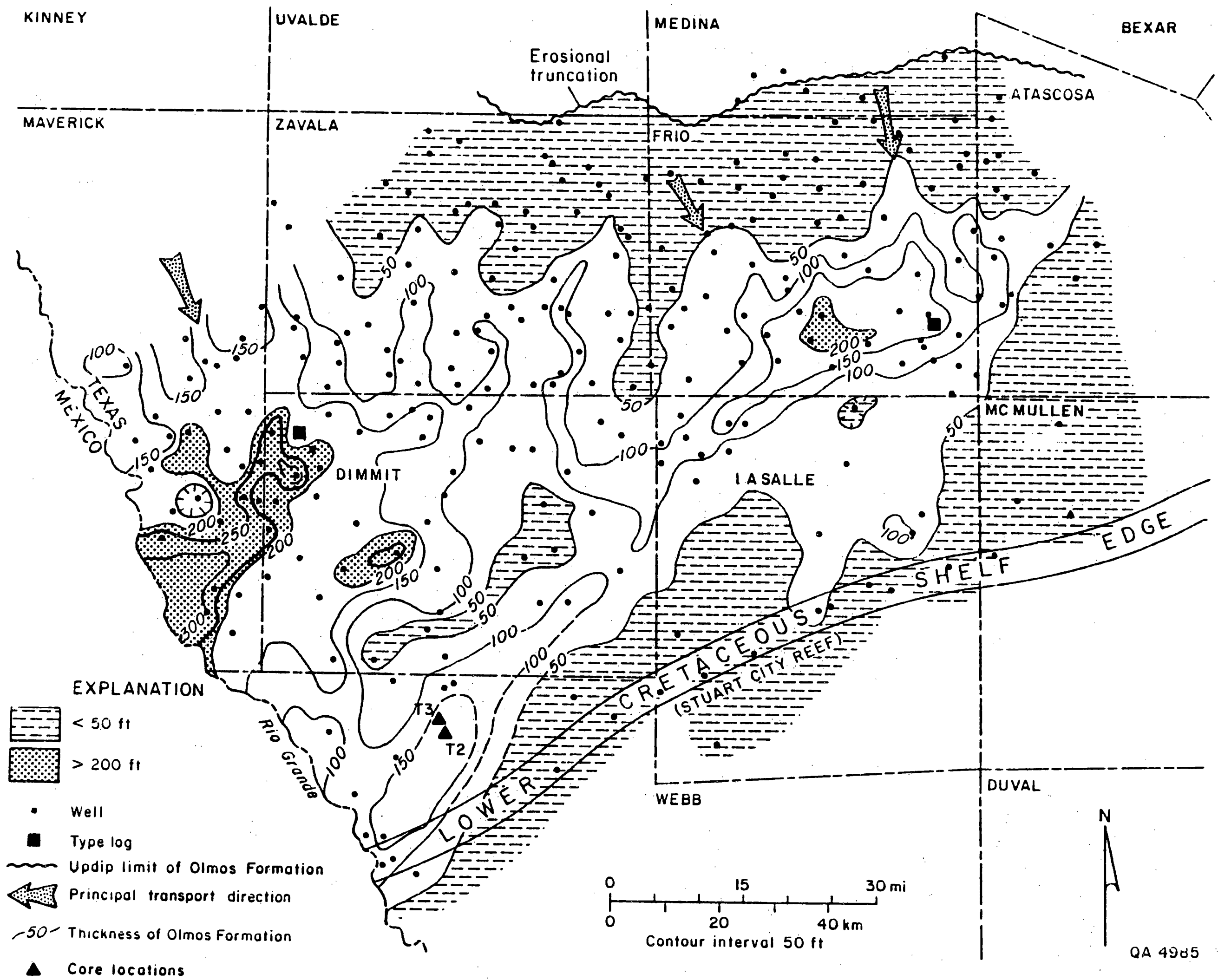


Figure 47. Net sandstone map of the Olmos Formation. Sediments were transported from the north and northwest into an eastern depocenter in Frio County and a western depocenter in Maverick and western Dimmit Counties (from Tyler and Ambrose, 1986).

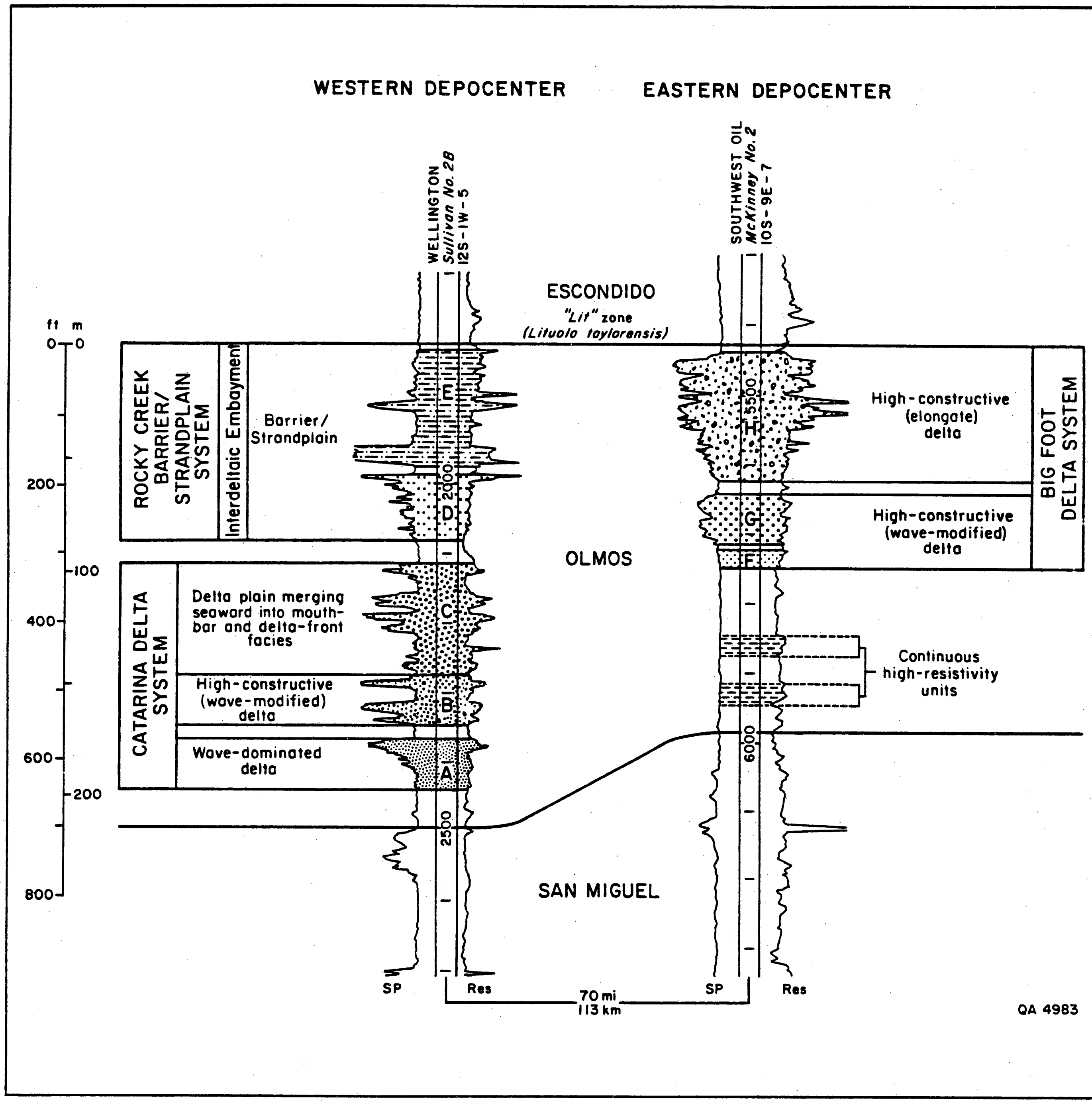


Figure 48. Type logs of the Olmos Formation from the eastern and western depocenters (from Tyler and Ambrose, 1986). Well locations shown in figure 47.

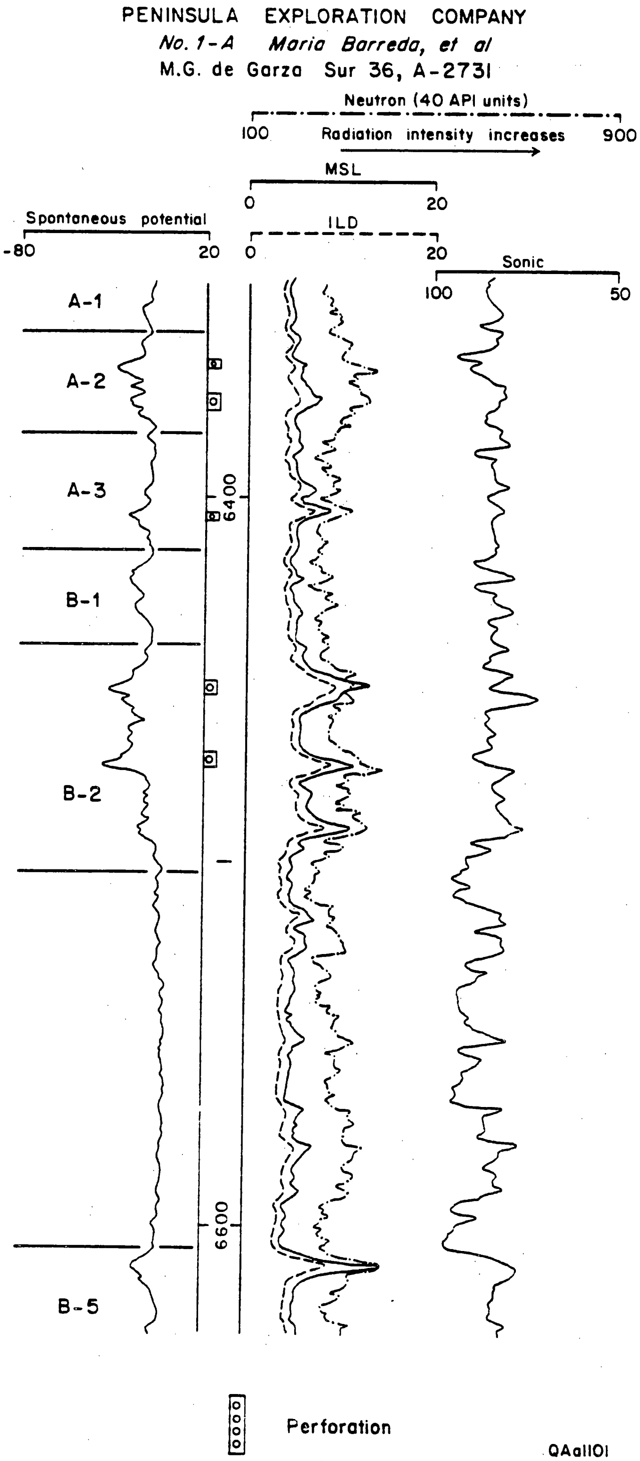


Figure 49. Type log of the Olmos Formation showing A1 through A3 sandstones and B1, B2, and B5 sandstones. The well is Peninsula Exploration Company No. 1-A, Maria Barreda, et al. (API 42-479-30434). The well was drilled in 1972 and has produced 262 MMcf of gas.

evidence of wave-generated traction current structures in these sandstones and interpreted them as storm reworked distal delta-front deposits.

Description of reservoir facies for the Catarina delta system and the Rocky Creek barrier/strandplain system is synthesized from Tyler and Ambrose (1986). Deposits of the Big Foot delta system do not occur in the designated tight-gas-area and are not discussed. Facies description of the distal deposits, the Olmos "A" and "B," are taken from the work of Snedden and Jumper (1990) and Barrow and others (1992).

Catarina Delta System

Unit A sandstones are up to 60 ft thick, display simple upward-coarsening SP log patterns, and are arranged in a 75-mi-long, strike-elongate sandstone-rich trend. Potential reservoir sandstones are thus extensive in the strike direction. Unit A sandstones however, are present only in the northwesternmost corner of the designated tight-gas-producing area.

Unit B sandstones display both lobate and digitate sand axes that are up to 120 ft thick. Four SP log motifs are recognized within Unit B: upward-coarsening, upward-fining, thick complex upward-coarsening, and mixed (upward-fining and upward-coarsening). The arrangement of SP responses is complex, reflecting the diverse depositional environments on a wave-modified, fluvially dominated delta platform. Potential reservoirs are dip-elongate upward-fining channel sandstones (70 to 100 ft thick), upward-coarsening channel-mouth bar sandstones (20 to 50 ft thick) and thin, muddy delta-front sandstones. Unit B sandstones are developed in the northern half of the tight-gas area.

Unit C is extensive in the tight-gas area and contains two distinct lithofacies with reservoir potential. The upward-fining, crossbedded sandstone lithofacies consists of 15 to 20 ft of fine-grained sandstone with clay rip-up clasts at the base and a progression in bedforms from crossbeds to low-angle inclined laminations. This facies is interpreted as distributary-channel deposits. The upward-coarsening, ripple-laminated, fine-grained sandstone lithofacies ranges in thickness from 7 to 12 ft and shows a succession in bed forms of horizontal laminations at the base to climbing ripples at the top. This facies has abundant roots and plant fragments and is interpreted as crevasse splay and levee deposits. The facies are distributed as a dip-elongate system containing a maximum of 80 ft of sandstone in southern Dimmitt County and as a strike-oriented system with up to 100 ft of sandstone in northwestern Webb County.

Rocky Creek Barrier/Strandplain System

The shore-zone of Unit D was centered over the tight gas area in northwestern Webb County and consists of a major strike-elongate belt with up to 90 ft of sandstone. Two lithofacies of this system are potential reservoirs. The upward-coarsening, internally eroded sandstone lithofacies represents storm-washover sheets or fans and consists of sandstone units up to 5 ft thick. The erosionally based crossbedded sandstone lithofacies are interpreted as transgressive barrier deposits and are up to 30 ft thick.

Unit E was deposited during continuing marine onlap and most sandstone deposition occurred updip of the tight-gas area. Small-scale (10-ft-thick), erosionally based, trough crossbedded tidal channel units, however, may have limited reservoir potential in southwestern Dimmitt County and southeastern Maverick County.

Olmos "A" and "B" Sandstones

The Olmos "A" and "B" sequence consists of thin sandstone beds that are interbedded with bioturbated shaly to sandy siltstones. In cores, the sandstones display sharp to clearly erosional bases. The upper contacts are sharp to gradational and commonly burrowed. The sandstone is uniformly very fine grained, but the amount of admixed clay and silt increases upward, in part from bioturbation. The dominant bedform in the sandstones is horizontal lamination, with subordinate low-angle cross lamination, hummocky cross stratification, and combined current and wave ripples. The Olmos "A" and "B" sandstones differ slightly in areal and vertical distribution. Olmos "A" sandstones display a sheet-like geometry, are generally thinner, and more widely separated by interbedded shales, whereas the "B" sandstones show more discrete sand bodies and are thicker because of amalgamation. Contrast in the sandstone distribution suggests that the "A" sandstones were deposited in a more distal setting than the "B" sandstones. Sandstone beds of both however, display considerable lateral extent and may be continuous from 1 to 2 mi.

Composition of Reservoir Facies

Sandstones of the Olmos Formation are classified as subarkose and sublitharenite (classification of Folk, 1974) and are dominated by quartz and detrital clay matrix (Snedden and Jumper, 1990). Feldspar and rock fragments comprise less than 25 percent of the whole rock composition. The clay minerals are largely detrital and include subequal amounts of mixed-layer illite/smectite and chlorite (Snedden and Jumper, 1990). The accessory mineral glauconite averages 2 to 3 percent. Core, SEM, and petrographic analyses indicate that porosity, which ranges from 6 to 16 percent and averages slightly under 10 percent, is 80 percent primary macroporosity, 10 percent secondary macroporosity, and 10 percent primary microporosity. Dissolution of feldspar, calcite cement, and shale clasts contributes to secondary porosity. The very fine grain size and high clay content results in low permeability, which ranges from 0.01 to 8.0 md (unstressed) and is undoubtedly much lower in situ (Snedden and Jumper, 1990).

Natural Fractures

The role of fractures and faults in Olmos reservoirs has not been described in the literature. Three structural zones having Olmos production, the Charlotte fault zone, Stuart City reef trend and associated minor faults (Snedden and Kersey, 1982), and Chittim Anticline, are areas where the potential for natural fracture-enhanced production has been identified (W. A. Ambrose, personal communication, 1992). The types of faults and fractures likely to be important in this unit are similar to those described below for the Wilcox Lobo trend: small normal faults that tend to block or enhance fluid movement and extension fractures that, if not filled with authigenic minerals, may promote fluid flow and permeability anisotropy parallel to regional strike. Olmos reservoirs are locally overpressured (Tyler and Ambrose, 1986), and fractures and faults may play a role in defining pressure compartments in this unit. Large faults and associated fracture zones may locally be conduits for fluid movement. Minor faults that are indistinguishable on regional maps (for example, Weise, 1980) are present in parts of the Olmos trend (Tyler and Ambrose, 1986).

Engineering Assessment

Consistent with the geological subdivision, engineering analysis of the Olmos indicates two distinct trends, one updip and one downdip of the Lower Cretaceous shelf edge. In the updip trend, such as at Dos Hermanos, net pay thickness ranges from 50 to 250 ft. In the downdip trend, net pay thickness averages 50 ft (Snedden and Jumper, 1990) (table 13). Completion and production data are most comprehensive in the downdip portion of the trend, particularly in Tom Walsh and Owen fields, which have together produced 44 percent of downdip trend gas (Snedden and Jumper, 1990).

The Olmos sandstones at Tom Walsh-Owen are divided into two producing zones, "A" and "B." Downdip Olmos sandstones are shaly, and the two zones at Tom Walsh-Owen average 24 percent detrital clay matrix (Snedden and Jumper, 1990). Measured permeabilities in these two sandstones are 0.09 md for the "A" zone and 0.56 md for the "B" zone (geometric mean for unstressed core data). Core porosities are 6 to 16 percent, averaging 10 percent. Log porosities generally indicate porosities of 15 percent in the better wells. At Apache Ranch, porosities are 8 to 15 percent, and in situ gas permeabilities are 0.001 to 0.01 md (S. A. Holditch, personal

Table 13. Olmos Formation, Maverick Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 722

Cumulative production from tight completions 1970–1988 (Bcf): 298.6

Estimated ultimate recovery from tight areas (Bcf): 408

Net pay thickness (ft): 50

Porosity range and average (%): 6–16/10

Permeability (md): 0.034–0.072

Water saturation (%): up to 65

Reservoir temperature (°F): No data

Reservoir pressure (psi): No data

Typical stimulation/hydro-frac: hydraulic fracturing and acidizing

Production rate:

prestimulation (Mcfd): 25

poststimulation (Mcfd): 86

Average recovery per completion (MMcf): 490–730

Decline rate: No data

communication, 1991). Finley (1984) documented median permeabilities ranging from 0.034 to 0.072 md from 149 wells (table 13) and permeabilities are generally lower in the downdip trend than in the updip trend.

Bed thickness is the best indicator of producibility at Tom Walsh-Owen field (Snedden and Jumper, 1990). Reservoir simulation of five wells indicated that net pay at Apache Ranch averages 50 ft. Finley (1984, 1986) reports net pay ranging from 12 to 81 ft for the Olmos overall.

Because Olmos sandstones are shaly, some sort of shaly sand log analysis technique (Barrow and others, 1992) should be used or log calculated water saturations will be too high and potential pay zones overlooked. Barrow and others (1992) recommend using a 10 percent porosity and 30 percent log-calculated shaliness for a net pay cutoff. Water saturations after correction range from 28 to 55 percent in the pay sandstones in the Olmos at Tom Walsh-Owen field (Barrow and others, 1992) (table 13). Formation temperature at Apache Ranch (typical) is 155°F.

Snedden and Jumper (1990) recommend high density (greater than 4 shots per foot) perforations because of the vertical heterogeneity of Olmos sandstones. They also state a typical fracture stimulation treatment is 65,000 lb of gel water and 350,000 lb 20/40 mesh sand. At Apache Ranch, fracture stimulation treatments of 150,000 gal of 75 percent quality nitrogen foam and 212,500 lb 20/40 mesh sand produce fractures with 750 ft half-length (S. A. Holditch, personal communication, 1991). The presence of smectite in the matrix can produce severe formation damage with significant fresh water contact.

Production History

As of 1987, 170 Bcfg and 0.7 MMBO had been produced in 465 wells from 8 of the largest fields in the downdip trend (Snedden and Jumper, 1990). A typical well with 690 MMcf of reserves will produce gas at an average sustained rate of 100 Mcf/d. The best wells will produce

2 Bcf. A typical well at Apache Ranch produces 385 MMcf (S. A. Holditch, personal communication, 1991).

Wells in the updip trend have an average production of 52 MMcf per year and are economically more attractive than downdip wells that average 33 MMcf per year. Drilling depths are also 2,000–3,000 ft less in the updip wells. However, downdip wells are economic, even after the expense of fracture stimulating, because they produce at low rates for a long time (Snedden and Jumper, 1990).

TEXAS GULF COAST BASIN

The Gulf of Mexico basin originated with rifting during the Triassic–Jurassic as North America began separating from Africa–South America (Buffler and Sawyer, 1985). Along the Texas Gulf Coast, slow rates of sediment influx persisted throughout the Mesozoic until regional uplift and tectonism in western North America provided a surge of terrigenous clastic sediment during the Cenozoic (Galloway, 1989). Texas Gulf Coast Tertiary formations include a series of sandstone-rich wedges composed of coastal-plain and marginal-marine deposits separated by transgressive marine shales (fig. 50). These formations, which thicken and dip basinward, are segmented by regional strike-parallel fault zones (fig. 51).

Low-permeability gas reservoirs occur along the deeply buried, downdip margins of Texas Gulf Coast Tertiary formations, where fine-grained sandstones are thinly interbedded with shales. Because of basinward dips, gas productive trends of successively younger formations are found progressively farther to the southeast (fig. 51). The lower Wilcox Lobo trend contains the most prolific tight-gas sandstones in the Texas Gulf Coast (Hugman and others, 1992; table 2). The Wilcox deltaic trends are dominantly conventional gas plays (Kosters and Hamlin, 1989) but also include tight zones locally. The Vicksburg (figs. 50 and 51) is the only other Tertiary formation of the Texas Gulf Coast to produce significant amounts of gas from low-permeability sandstones. The Frio Formation, a prolific conventional gas producer (Kosters and Hamlin,

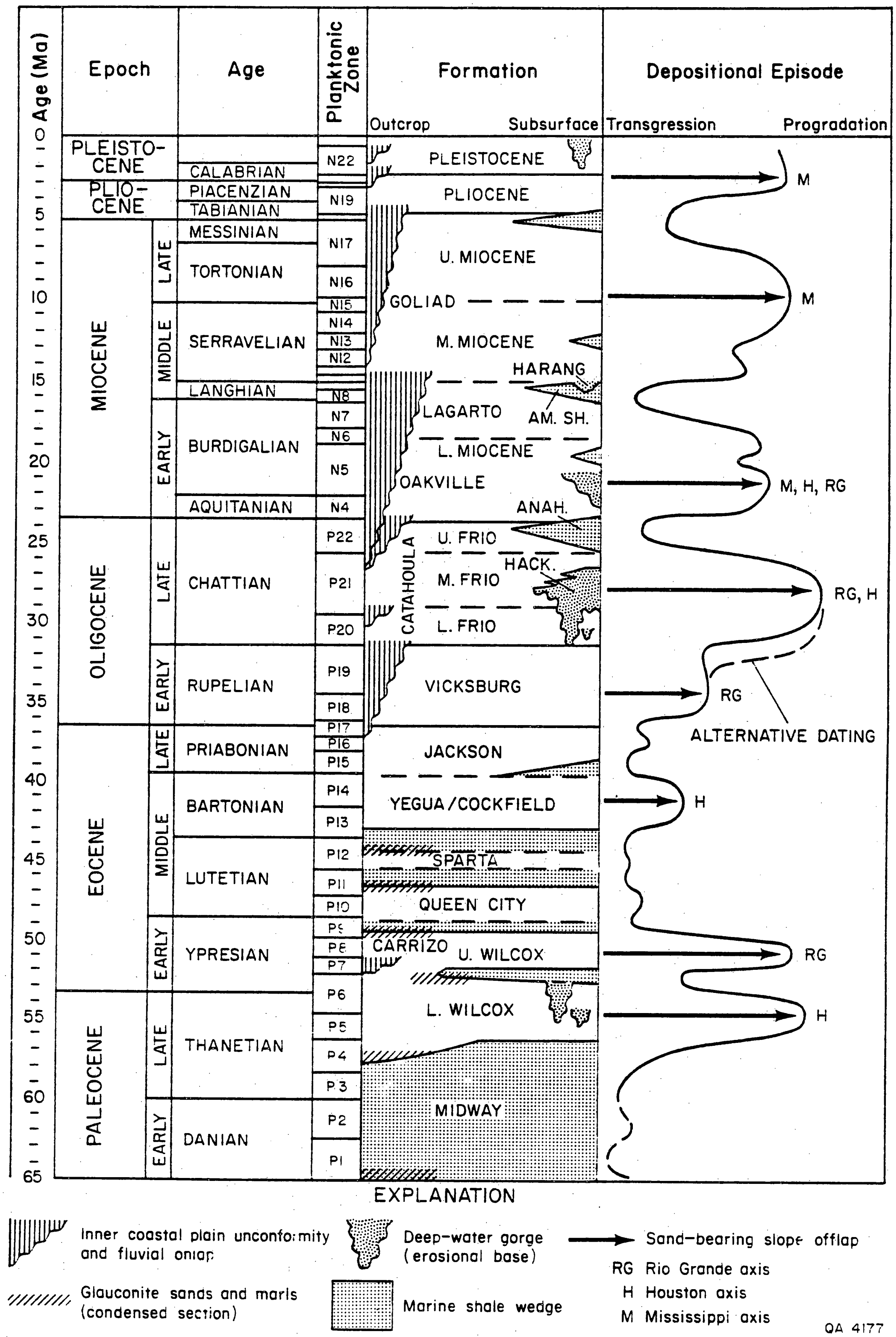


Figure 50. Texas Gulf Coast Cenozoic stratigraphy and depositional episodes. Modified from Galloway (1989).

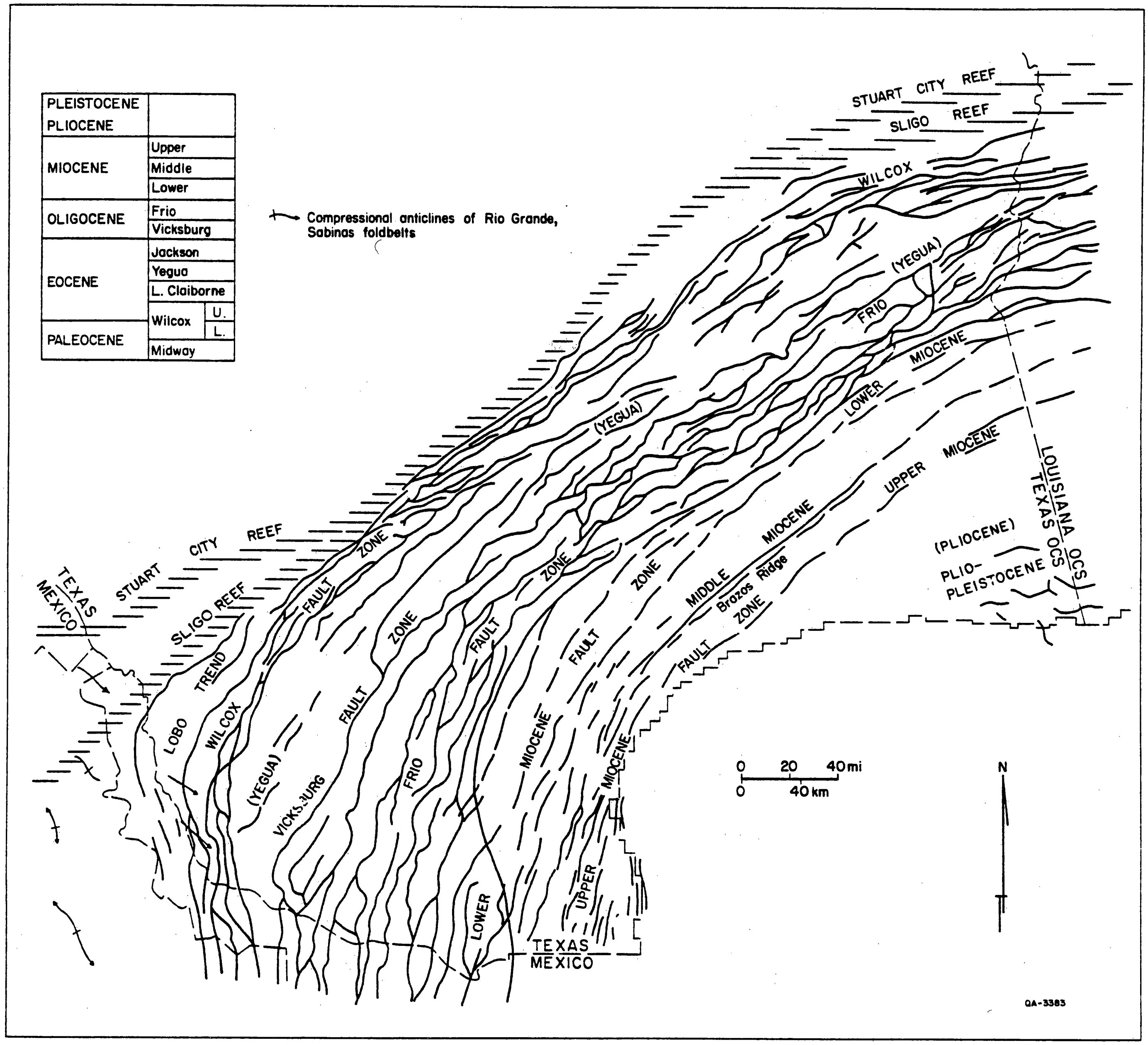


Figure 51. Regional fault zones and producing trends of the Texas Gulf Coast Tertiary Basin. From Ewing (1986).

1989), contains formally designated tight-gas reservoirs in only one small field. Because of the isolated distribution of tight-gas reservoirs within larger intervals of conventional reservoirs, tight-gas production statistics for the Wilcox, Vicksburg, and Frio formations compiled by Hugman and others (1992) are probably overestimations.

Wilcox Formation

Introduction

The Wilcox Group is Paleocene to Eocene in age and extends across the entire Texas Gulf Coast. Most Wilcox gas reservoirs, however, are conventional, some having permeabilities as high as several thousand millidarcys (Kosters and Hamlin, 1989). The Wilcox Group comprises several trends, each having distinctive geographic locations and geologic characteristics. The Wilcox Lobo trend is the major low-permeability gas producer of the Texas Gulf Coast and is formally designated tight in Webb and Zapata Counties of South Texas (fig. 52). Isolated reservoirs in local areas have been designated tight in three other Wilcox trends in the following counties: (1) lower Wilcox in Austin, Colorado, Fort Bend, and Wharton Counties; (2) middle Wilcox in Lavaca and Webb Counties; and (3) upper Wilcox in Duval, Jim Hogg, Live Oak, McMullen, and Starr Counties. In this report these minor tight-gas producers will be described together as the Wilcox deltaic trends. Total Wilcox gas production exceeds 11 Tcf (Kosters and Hamlin, 1989). The Wilcox Lobo has produced 2.1 Tcf of gas from areas designated tight (Hugman and others, 1992), and cumulative tight-gas production from the Wilcox deltaic trends, because of the isolated distribution of tight zones, has not been accurately tabulated but is probably less than 100 Bcf.

The Wilcox Group is composed of a wedge of sandstone and shale that thickens and dips toward the coast. Most of the tight-gas reservoirs lie in the deep downdip part of the Wilcox, a region characterized by thick shales and thin sandstones, high fluid pressures, and closely

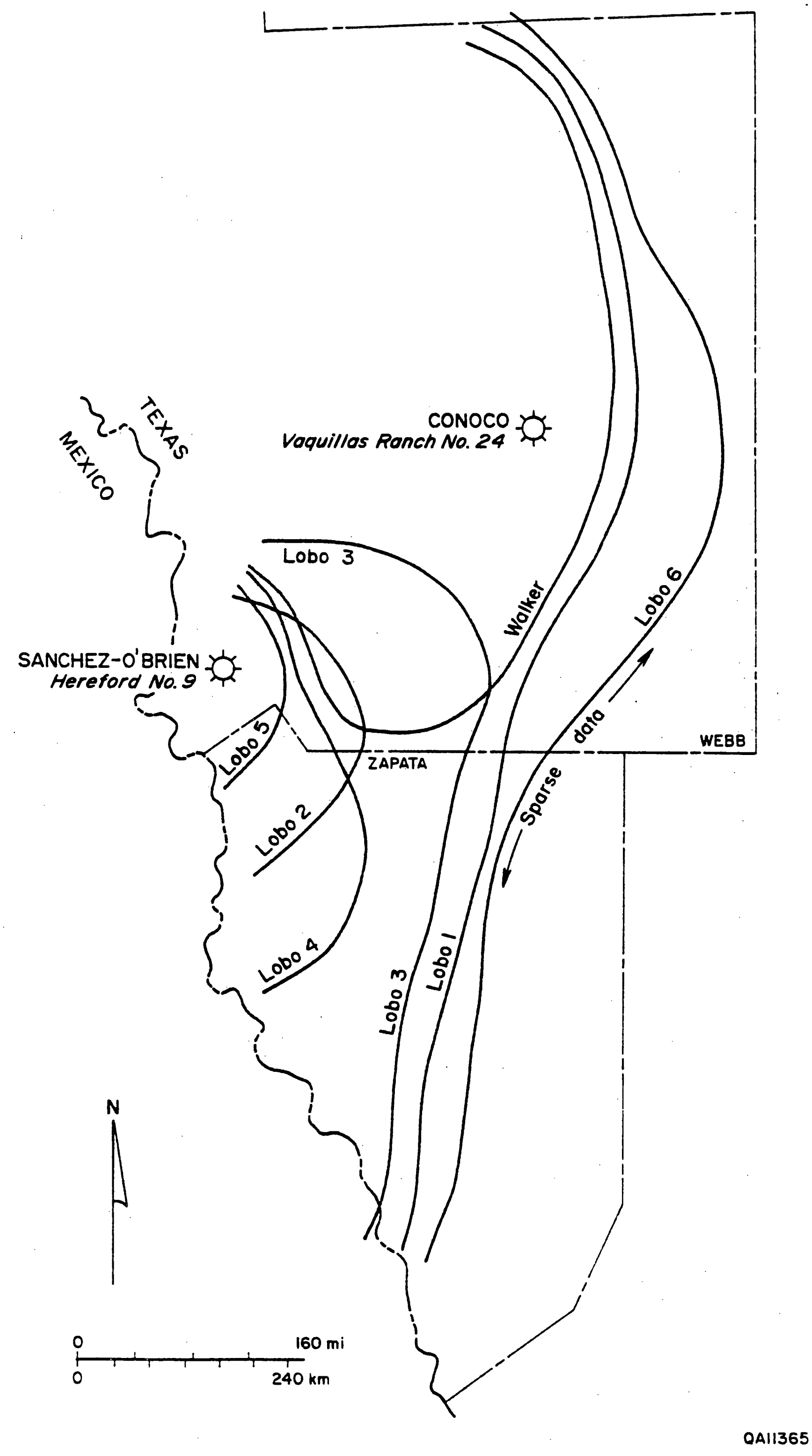


Figure 52. Lateral extents of Lobo productive sandstones, also showing locations of typical logs (fig. 53). Modified from Long (1986).

spaced faults (fig. 51). Total thickness of the downdip Wilcox ranges from 5,000 to 12,000 ft. The Lobo interval, which includes only the lowermost part of the Wilcox, is generally less than 1,200 ft thick, although thicker Lobo intervals are preserved locally near the Rio Grande. Lobo sandstone reservoirs individually are less than 100 ft thick and are interbedded with thicker shales (fig. 53). The Lobo is separated from overlying Wilcox sandstones by 500 to 1,200 ft of shale and is underlain by an equally thick shale in the Midway Group (fig. 50). Depths to Lobo reservoirs vary widely between 5,000 and 12,000 ft. The Wilcox deltaic tight-gas reservoirs range from 9,000 to 15,000 ft deep.

Numerous studies of the Wilcox Group have been published, but only a few of these deal specifically with tight-gas reservoirs (Garbis and others, 1985; Robinson and others, 1986). Regional descriptions (Fisher and McGowen, 1967; Edwards, 1981; Bebout and others, 1982; Loucks and others, 1986) provide the structural, stratigraphic, and diagenetic context necessary for field- and reservoir-scale interpretations. Published studies of the Lobo trend (O'Brien and Freeman, 1979; Henke, 1982; Alexander and others, 1985; Long, 1986) are applicable because most Lobo reservoirs are tight. In the Wilcox deltaic trends, however, tight-gas reservoirs are a minor component and are rarely described in published reports. Most specific information about the engineering and geologic properties of Wilcox deltaic tight-gas reservoirs is found in documents submitted to the Railroad Commission of Texas for designation as tight-gas sandstone.

Depositional Systems and Reservoir Facies

The Wilcox sandstone-shale sequence records the first major Tertiary progradational episode of the Texas Gulf Basin (fig. 50). In outcrop and the shallow subsurface, the Wilcox was deposited primarily in fluvial environments, whereas downdip the main gas-producing intervals were deposited by large deltas and associated barrier/strandplain systems (Kosters and others, 1989; fig. 2). An extensive growth-fault zone of synsedimentary normal faults

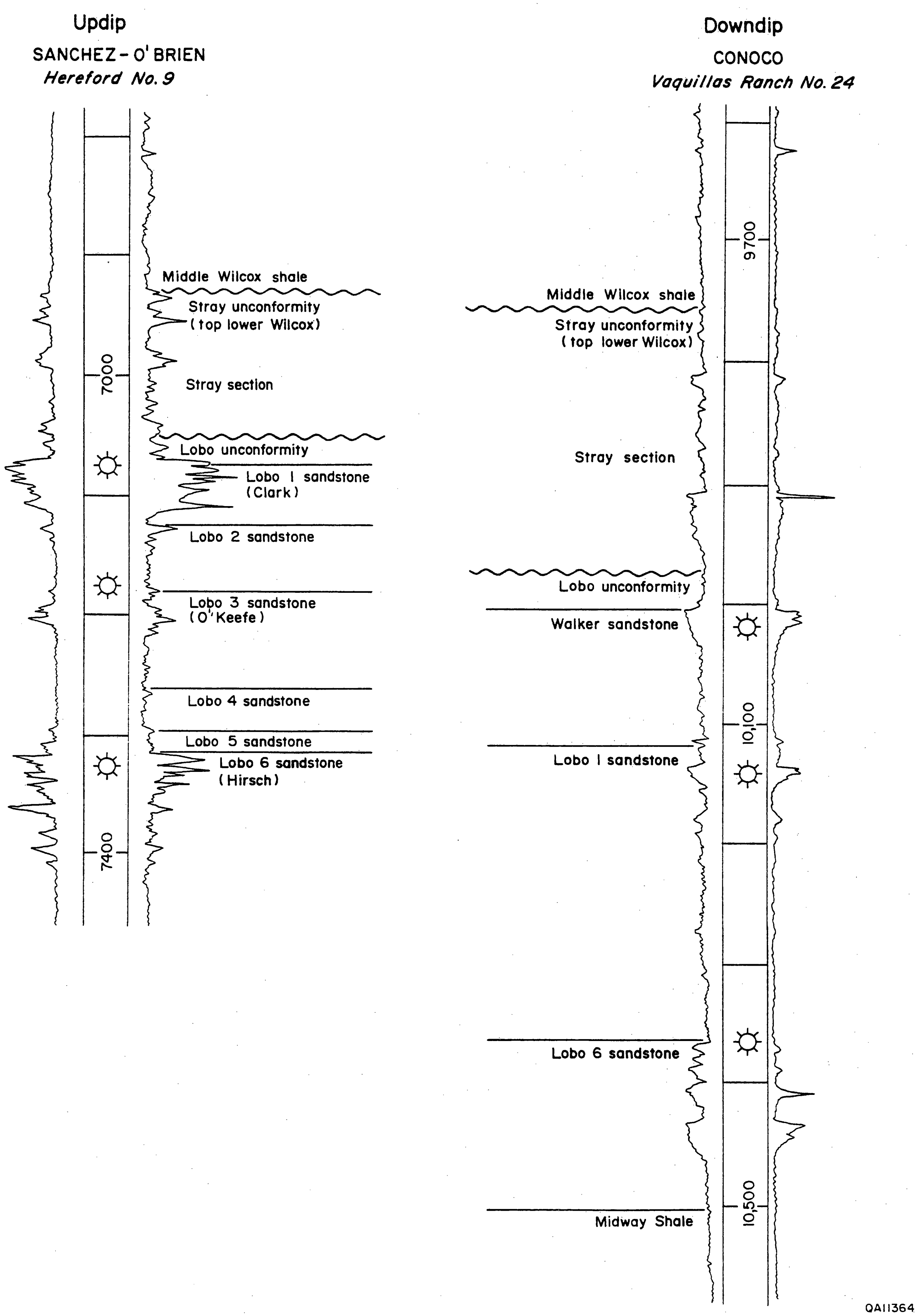


Figure 53. Typical logs from the lower Wilcox Lobo trend showing productive sandstones and unconformities. Modified from Long (1986). Well locations shown in figure 52.

(fig. 51), with associated dip reversals and rollover anticlines, developed along the unstable Wilcox shelf margin, forming the most important traps. Because Wilcox deltaic reservoirs lie in the distal parts of delta front and delta flank shoreface facies, they are commonly thinly bedded shaly sandstones.

The depositional setting and structural history of the Lobo trend are still poorly understood (Long, 1986). The Lobo productive interval includes seven sandstone reservoirs and several unconformities (fig. 53). The Lobo 6 and Lobo 1 sandstones are most widespread, extending throughout the trend, whereas the rest are more restricted in lateral extent (fig. 52). The entire trend is complexly faulted (fig. 54); some fault-blocks are less than 80 acres (Robinson and others, 1986). Evidence suggests that a series of lowermost Wilcox deltas (or possibly delta-fed submarine fans) prograded across an unstable shelf margin composed of thick, undercompacted mud in the Midway Group. Large-scale gravity sliding and extensional faulting resulted (Long, 1986). Subaerial or subaqueous erosion, or both, created pronounced unconformities, locally truncating productive sandstone. Another episode of faulting followed the period of erosion (Railroad Commission of Texas, 1980d).

Individual Lobo reservoirs are found in upward-coarsening parasequences having a gross thickness of 300 ft or less but consisting of thinly interbedded sandstone and shale (figs. 53 and 54). Net reservoir quality sandstone generally ranges from 10 to 60 ft. Lobo parasequences are interbedded with thicker, more homogeneous shales, which, based on paleontological evidence, were deposited in marine waters 300 to 600 ft deep (Railroad Commission of Texas, 1980d). The principal reservoirs, Lobo 1 and Lobo 6, are depositionally continuous throughout the tight-gas area, but are commonly missing locally owing to postdepositional erosional truncation or faulting. Approximately 11 percent of wells drilled in the Lobo trend have encountered none of the reservoir sandstones (O'Brien and Freeman, 1979).

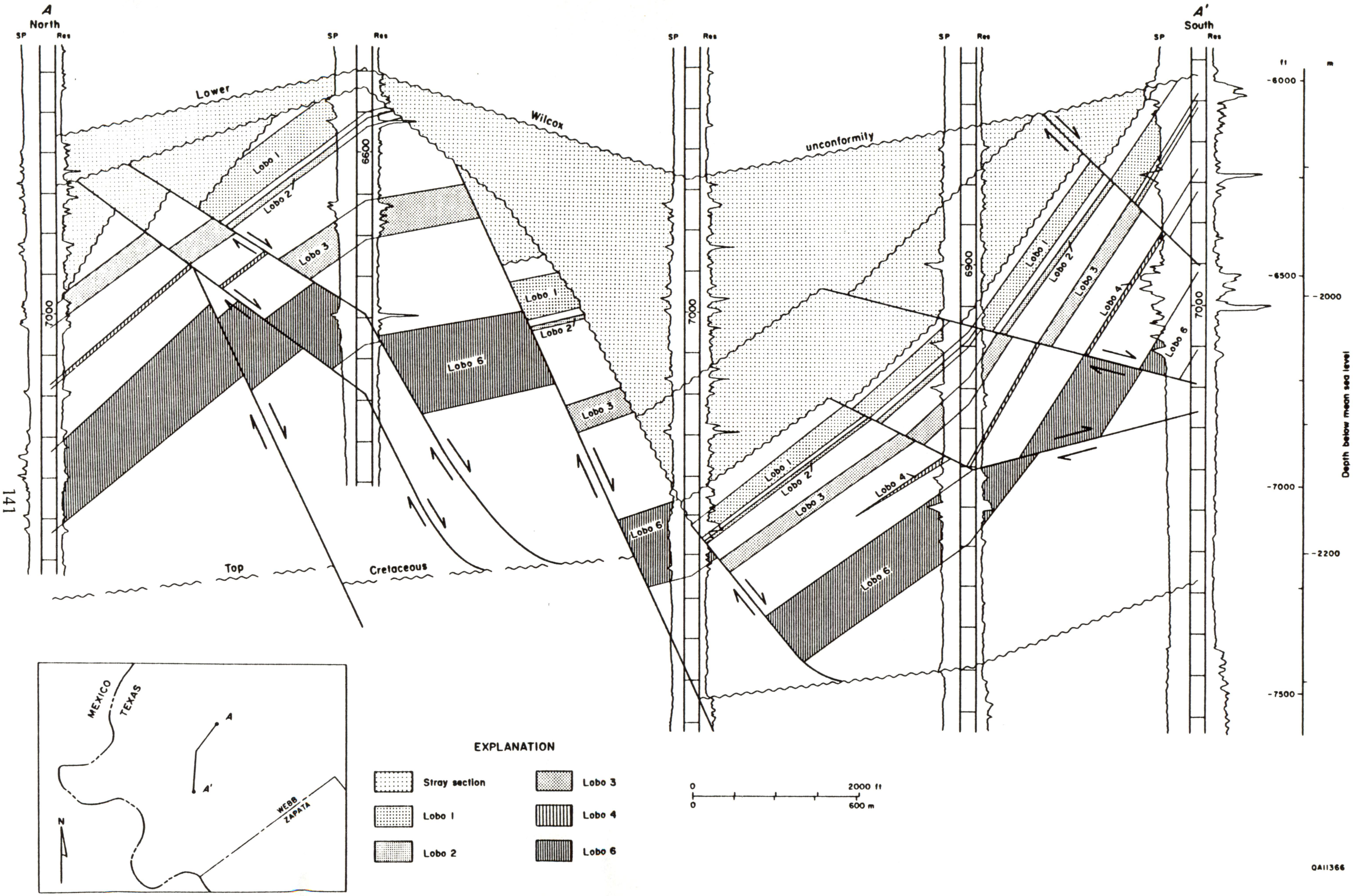


Figure 54. North–south cross section of Laredo (Lobo) field, Webb County, Texas, showing complex configuration of faults and unconformities that compartmentalize Lobo reservoirs. From Railroad Commission of Texas (1977).

Composition of Reservoir Facies

Lobo reservoirs are predominantly very fine grained, well sorted sandstones. Lobo sandstones are mineralogically immature; framework grain composition varies from feldspathic litharenite to litharenite (Railroad Commission of Texas, 1980d; Henke, 1982; Alexander and others, 1985). The most common feldspar grains are orthoclase and albite, and rock fragments are dominantly sedimentary. In selected Lobo 1 and Lobo 6 sandstones, authigenic cements constitute 7 to 15 percent of rock volume, and thin section porosity ranges from 0 to 28 percent (Alexander and others, 1985).

Major diagenetic events in Lobo sandstones were (1) mechanical compaction, (2) cementation by quartz and calcite, (3) dissolution of calcite cement and feldspar grains, and (4) precipitation of clay minerals. Alexander and others (1985) recognized two general sandstone classes: (1) massive to laminated, clean sandstones and (2) bioturbated sandstones having abundant detrital clay matrix. Dissolution of calcite cement, feldspars, and rock fragments led to the formation of secondary porosity in clean Lobo sandstones, where most remaining porosity is secondary (Alexander and others, 1985). Kaolinite, chlorite, illite, and mixed-layer illite-chlorite-smectite precipitated in intergranular and secondary pores. Compaction-induced deformation of ductile framework grains and detrital clay matrix occluded most porosity in the bioturbated shaly Lobo sandstones. Thus, clean sandstone, having measured porosities of 12 to 25 percent, forms the primary reservoir rock (fig. 55), but net pay varies widely from well to well. In-situ gas permeabilities range from 0.0003 to 0.5 md generally but locally exceed 1.0 md (Robinson and others, 1986).

The compositions of Wilcox deltaic tight-gas reservoirs vary with location along the Texas Gulf Coast, ranging from lithic arkoses to feldspathic litharenites. Most clean Wilcox sandstones are well sorted and fine grained. In deeply buried Wilcox reservoirs, primary porosity has been largely destroyed by quartz and carbonate cementation. The remaining porosity is mainly secondary, resulting from the dissolution of feldspar grains and carbonate

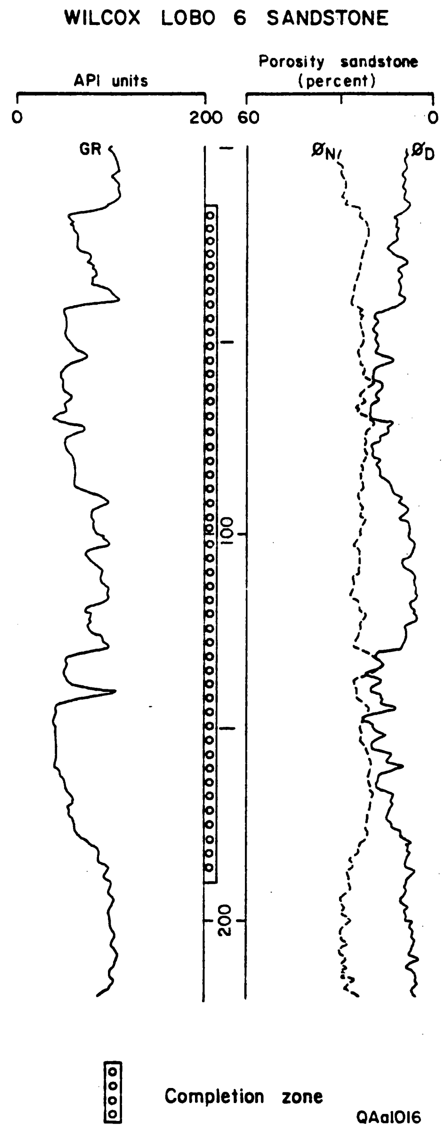


Figure 55. Porosity logs from a typical Wilcox Lobo well showing the Lobo 6 sandstone completion zone. From Berligen and others (1988). Well identification and actual zone depth are not reported.

cement (Loucks and others, 1986). Cores from several Wilcox wells in Live Oak and Wharton Counties yielded porosities ranging from 2 to 23 percent and permeabilities as high as 10 md (fig. 56), although these measurements were made at ambient conditions; in situ values probably are much lower.

Natural Fractures

No published information is available on core-scale natural fractures in Wilcox deltaic reservoirs. Rare open and filled extension fractures and small faults in Wilcox deltaic core have been observed from depths greater than 9,000 ft (S. E. Laubach, unpublished core description, 1992). Such observations, and the presence of mappable faults in several Wilcox deltaic reservoirs, imply that in Wilcox deltaic reservoirs having low matrix permeability, fractures could be more widespread than hitherto believed.

Gas accumulations in lower Wilcox sandstones of the Lobo trend are controlled by faults and erosional truncation. Syn-sedimentary and intense early post-depositional normal faulting was followed by severe erosion and truncation, followed by post-truncation faulting (Railroad Commission of Texas, 1980d; Robinson and others, 1986). Consequently the Wilcox is locally extensively fractured and faulted. However, all faults do not extend through the entire section; locally some early (syn-sedimentary) faults do not extend to the top of the lower Wilcox interval (Railroad Commission of Texas, 1991b). Quartz cementation is prevalent in Wilcox Lobo sandstones, and if fracturing accompanied quartz precipitation, as is the case in the Travis Peak Formation, some fractures may tend to be held open by quartz that partly fills fractures despite high closure pressures encountered in some deep wells.

The structural complexity that is the result of repeated faulting and erosional truncation has made accurate prediction of the size and distribution of reservoir sandstones difficult (Railroad Commission of Texas, 1980d; Henke, 1982, 1985). Missing section results from faulting, a major regional unconformity, and several local unconformities (Railroad Commission of Texas,

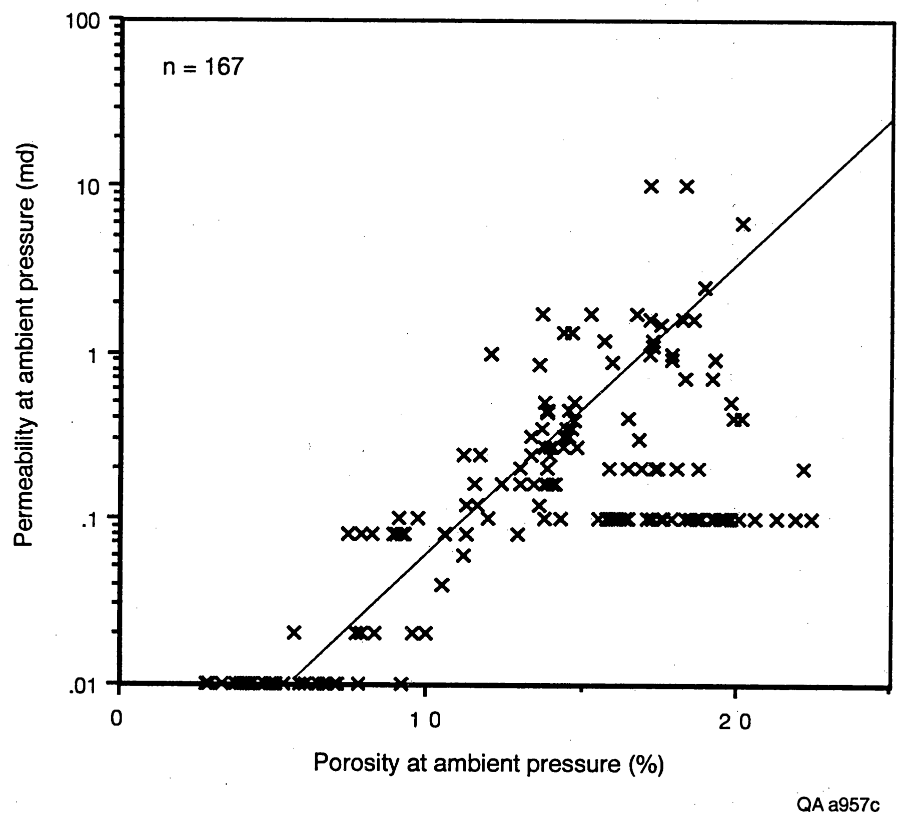


Figure 56. Semi-log plot of porosity vs. permeability from routine core analysis at ambient conditions of 167 Wilcox deltaic sandstone samples. Data from Railroad Commission of Texas (1981c, 1982b). Line is approximate trend line for porosity-permeability relationship, ignoring data interpreted to be of poor quality.

1991b). Some fault blocks are extremely small, creating pressure compartments of less than 80 acres (Robinson and others, 1986). Published geologic cross sections and maps are highly simplified and probably are not representative of structural and stratigraphic heterogeneity in this unit. Consequently, projection of production performance and reserves in a highly faulted area like the Wilcox Lobo trend is challenging.

Traps in the Lobo trend are provided by counter regional, westward-tilted fault blocks bounded by northwest-striking, down-to-coast normal faults (O'Brien and Freeman, 1979). Displacements across faults are commonly as much as 700 to 1,000 ft; because the major producing zones are in a stratigraphic section that is commonly no more than 1,000 ft thick, the location of faults can be critical. Although major fault trends in this area can be determined from seismic data, on the reservoir scale fault and fracture orientations and slip patterns are highly variable (fig. 57) (for example, Self and others, 1986a, b). Some aspects of small-scale fault complexity can be predicted through structural modeling (Laubach and others, 1992c).

Abrupt shifts in bedding dip is one manifestation of faulting and fault-block rotation that has been noted in Wilcox core (Railroad Commission of Texas, 1980d). Local areas where bedding dips range from nearly flat-lying to subvertical have been noted. In the absence of core, such shifts in bed dips can be mistaken on dipmeter logs for sedimentary structures such as crossbedding, resulting in misleading views of reservoir architecture. Soft-sediment deformation features are also evident, including tight recumbent folds, microfaults, and vertical beds. Some of these features may be entirely contained within large slump blocks (Railroad Commission of Texas, 1980d).

Experience in other normal-faulted areas shows that mappable faults are commonly associated with numerous smaller faults and fractures (Laubach and others, 1992c) that may subdivide and compartmentalize reservoir rocks at scales below typical map scales or seismic resolution. Normal faults have been mapped in most Lobo trend reservoir intervals, and the prevalence of mapped faults is an indication that small faults and fractures may be locally abundant in reservoir rocks. Some Wilcox Lobo reservoirs are reported to be extensively

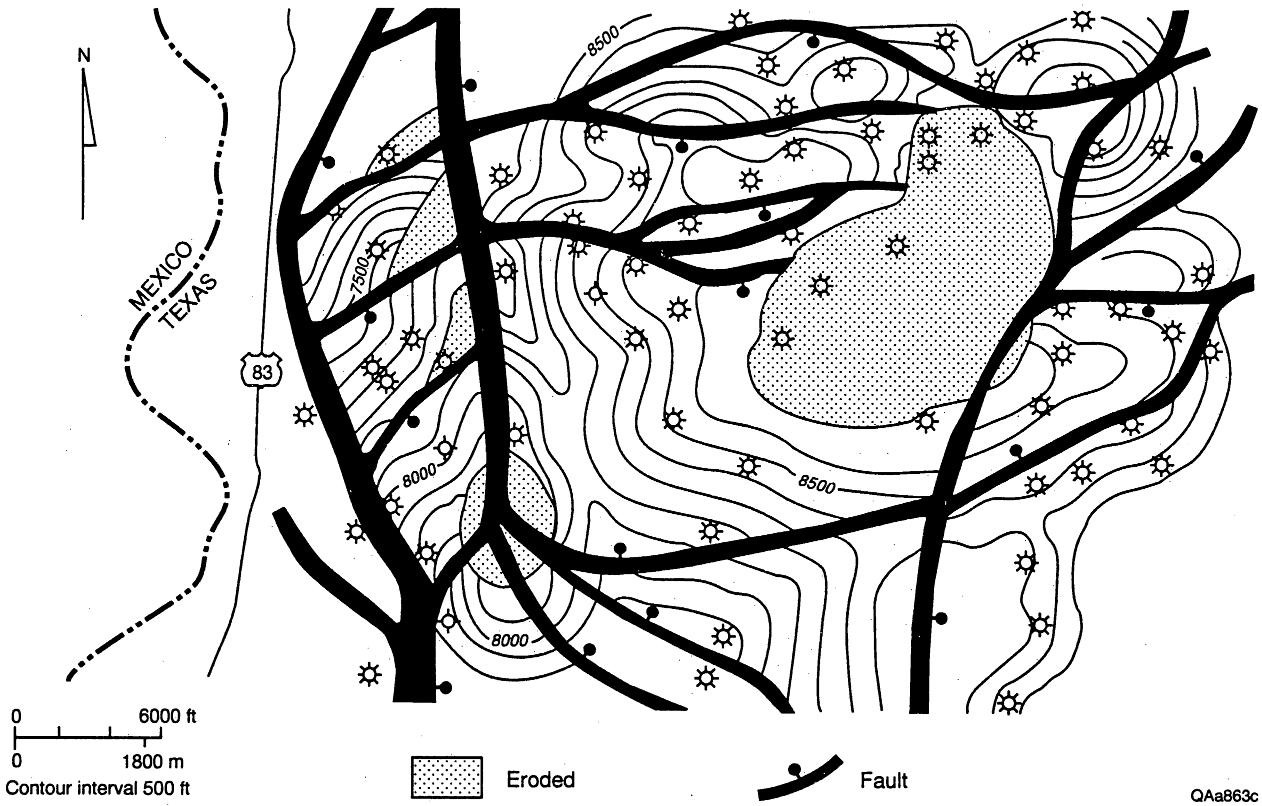


Figure 57. Structure map of faulted Wilcox Lobo reservoir (Lobo 1, J. C. Martin). From O'Brien and Freeman (1979).

microfaulted (Railroad Commission of Texas, 1980d). In these areas, small, steeply to shallowly dipping normal faults (millimeter-scale fault displacement) are arranged in horst-and-graben patterns. Where these faults are reported to postdate sedimentation, fault-related grain crushing and compaction can be expected to have altered (increased or decreased) porosity and permeability along fault surfaces (Knipe, 1992).

Engineering Assessment

Most of the tight-gas-related data that have been collected in the Wilcox in recent years are from the Wilcox Lobo trend. However, Wilcox deltaic tight-gas sandstones probably have similar properties. Porosities in the Lobo sandstones range from 12 percent in the downdip portion of the trend to the east to as high as 25 percent in the western, updip portion of the trend (Robinson and others, 1986) (table 14). Lobo Sandstone permeabilities can vary on a well-by-well basis with in situ gas permeabilities from 0.0003 to 0.5 md (Robinson and others, 1986). The median permeability to gas is 0.0327 md (Railroad Commission of Texas, 1980d) (table 14). A porosity-permeability plot of data from two Wilcox deltaic wells is shown in figure 56.

Reservoir quality rock is typically 10 to 60 ft thick. Locally, net-pay thicknesses as high as 100 ft have been recorded. Porosity cutoff is 10 to 12 percent for net pay determination (fig. 55) and is high because of the abundance of clay in the Lobo sandstones. Water saturation ranges from 25 to 70 percent (table 14). Because shaliness increases water saturation, higher water saturation values are not necessarily indicative of water production. Capillary pressure measurements should be run in poor quality rock if there is a question of potential water production.

Reservoir temperature can be over 300°F. Depth varies in the Lobo from west to east, and temperatures range from 175°F at 6,000 ft in the west to 310°F at 12,000 ft in the east. The Lobo sandstones are overpressured. Pressures range from 3,000 psi at 6,000 ft to 8,000 psi at 11,000 ft

Table 14. Wilcox Lobo Formation, Texas Gulf Coast Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 1,280

Cumulative production from tight completions 1970–1988 (Bcf): 2,116.5

Estimated ultimate recovery from tight areas (Bcf): 2,889

Net pay thickness (ft): 10–100

Porosity (%): 12–25

Permeability range and average (md): 0.0003–0.5/0.0327

Water saturation range (%): 25–70

Reservoir temperature (°F): 175–310

Reservoir pressure (psi): 3,000–8,000

Typical stimulation/hydro-frac: 101,800 gal gel and 207,000 lb proppant

Production rate:

prestimulation (Mcfd): No data

poststimulation (Mcfd): No data

Average recovery per completion (Bcf): 3.2

Decline rate: No data

(Robinson and others, 1986). The higher pressures and temperatures create severe problems for drilling, logging, and completion.

Perforations are usually made on a one shot per foot density across the zone of interest. Fracture stimulation treatments on 29 wells in 1981 averaged 101,800 gal gel and 207,000 lb of proppant. Prior to 1981 fracture treatments were larger, averaging 395,000 lb of proppant in 1980. Reducing the size of the jobs and applying higher technology fracture designs reflect an effort to optimize fracture length. As technology has progressed, higher strength proppants have been used. Sand crushing and embedment were a problem in the Lobo sandstone. Acid is not recommended because of potential formation damage caused by reaction with chlorite pore lining clay.

Production History

The median Wilcox Lobo well produces at a rate of 195 Mcf/d (Railroad Commission of Texas, 1980d). This agrees with other data in Webb County (Railroad Commission of Texas, 1991b) where the arithmetic mean for wells in southern portion of the county was 270 Mcf/d. However, a few wells are extremely prolific, with productions as high as 10,000 Mcf/d.

The average well in the Lobo sandstones produces 3.2 Bcf while draining 100 acres (Long, 1978). Reserves may be difficult to calculate because of the extreme faulting (Robinson and others, 1986). Tight-gas ultimate recovery from wells currently producing will be 3.7 Tcf. Average recovery per reservoir is 28.4 Bcf (Hugman and others, 1992).

Vicksburg Formation

Introduction

Low-permeability reservoirs in the Vicksburg Formation (lower Oligocene) are found in fields along the Vicksburg fault zone in South Texas (fig. 51). All but one of the formally designated tight-gas areas in the Vicksburg lie in west Hidalgo and east Starr Counties. The Vicksburg is also designated tight in Portilla (9,000 ft) field in north San Patricio County. Hidalgo and Starr Counties contain many prolific multiple-reservoir Vicksburg fields, such as McAllen Ranch, where low-permeability reservoirs are concentrated in deep high-pressure zones (Kosters and Hamlin, 1989). Formal tight-gas designations in the Vicksburg apply to specific reservoirs in limited areas.

The Vicksburg clastic wedge thickens and dips basinward (eastward) across the Vicksburg fault zone (fig. 58). Updip (west) of the fault zone, the Vicksburg is only a few hundred feet thick and less than 6,000 ft deep. The formation thickens greatly on the downthrown sides of syndepositional growth faults, reaching 6,000 to 10,000 ft in thickness in the tight-gas areas. The Vicksburg Formation is composed of interbedded sandstones and shales, overlying thick shales in the Jackson Group (upper Eocene) and underlying basal Frio Formation (upper Oligocene) sandstones (figs. 58 and 59). The upper part of the Vicksburg is shale dominated, the middle part contains several (largely conventional) reservoir sandstones, and the lower part comprises a thick sequence of sandstones that includes most of the low-permeability reservoirs (fig. 59). Lower Vicksburg sandstones are found 6,000 to 16,000 ft deep in the tight-gas areas, although most of the productive zones are 10,000 to 14,000 ft deep.

The Vicksburg Formation has been the subject of numerous studies, from which much published data are available. Coleman (1990) and Coleman and Galloway (1990a) describe regional Vicksburg stratigraphy, structure, and petroleum geology and summarize previous work. Kosters and Hamlin (1989) characterize Vicksburg gas plays. Studies that cover parts of

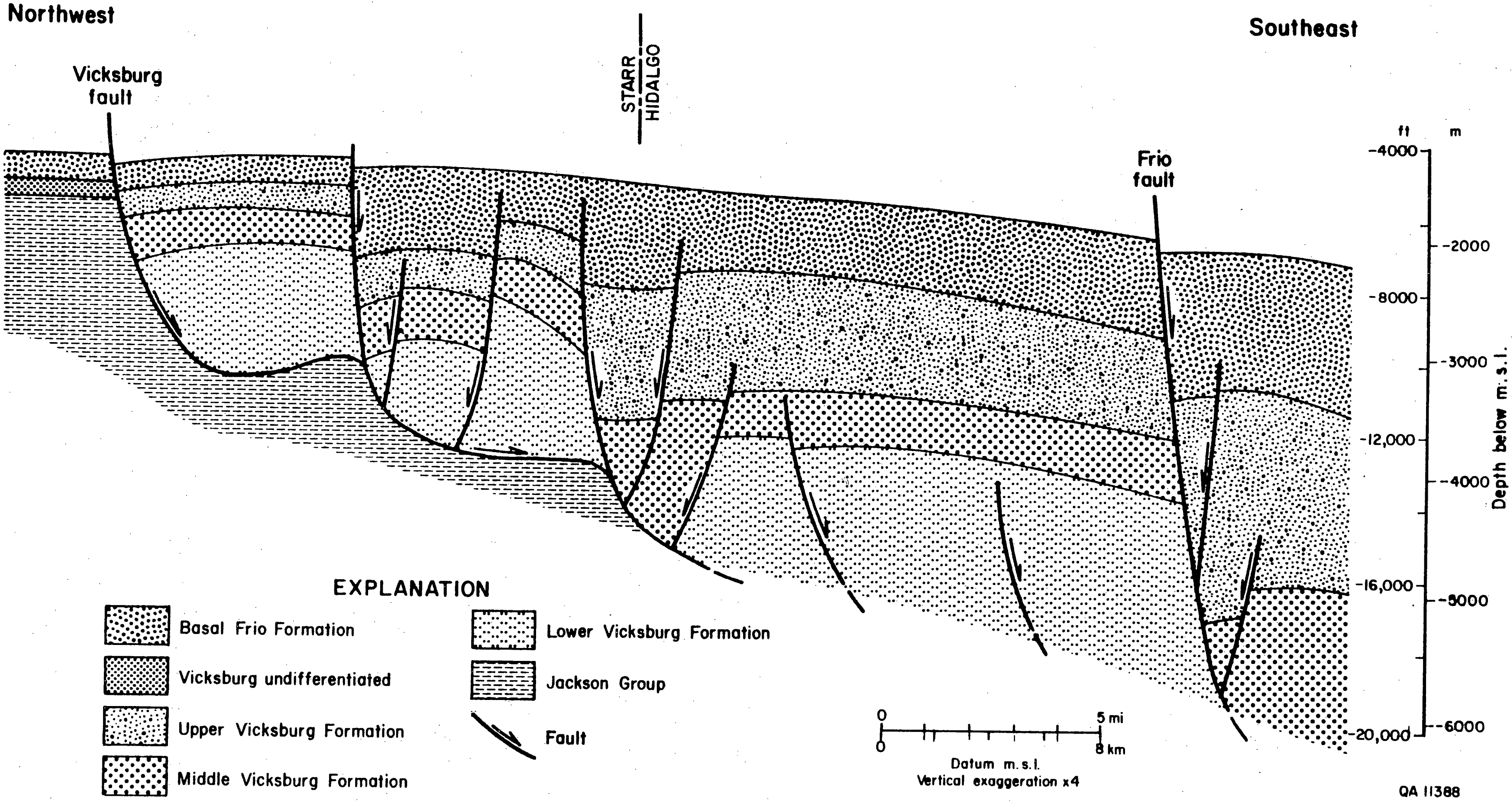


Figure 58. Dip-oriented cross section through the Vicksburg tight-gas areas in Starr and Hidalgo Counties, South Texas. Modified from Han (1981). Stratigraphic thickening across Vicksburg growth faults and increasing fault density with depth are well displayed.

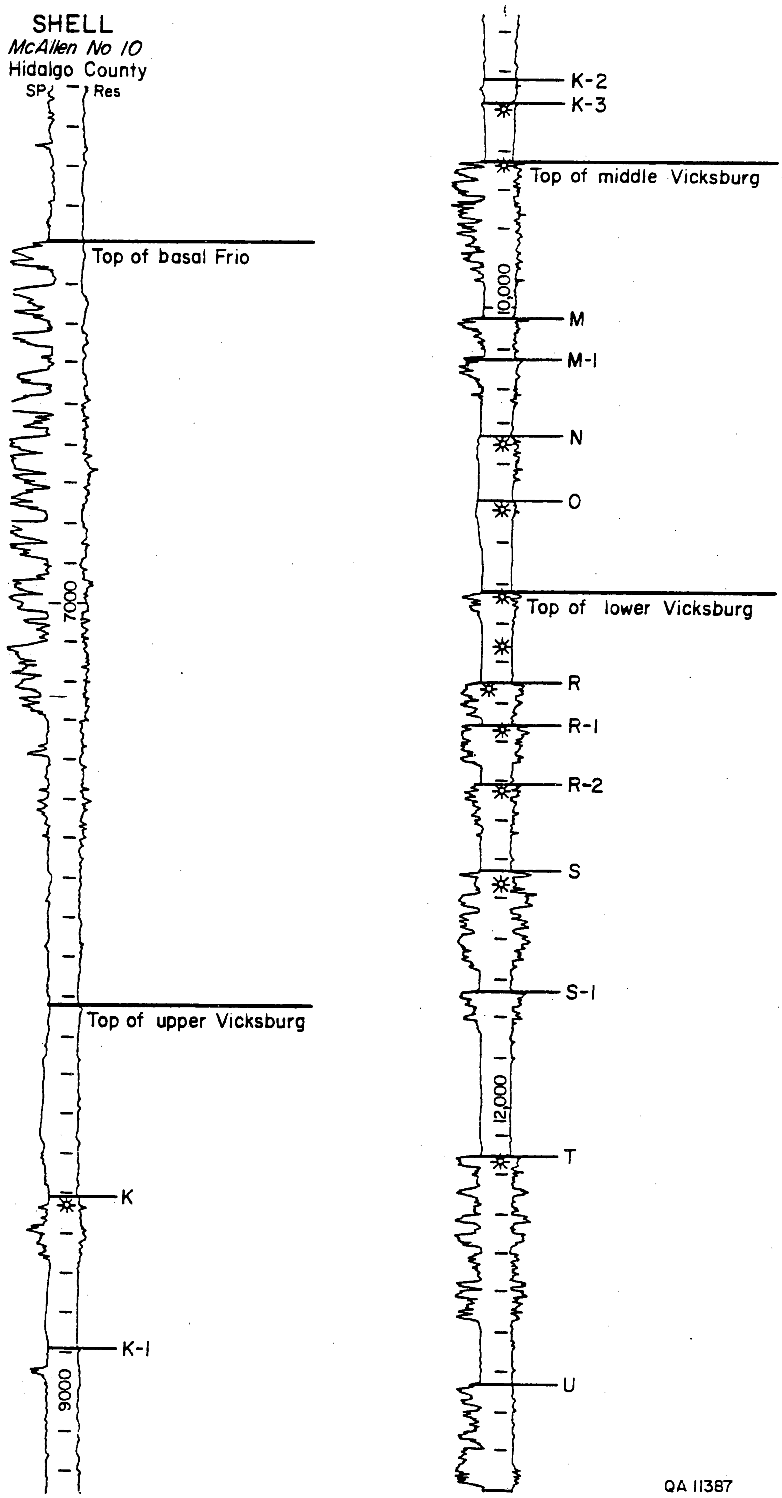


Figure 59. Typical electric log from McAllen Ranch field, Hidalgo County, Texas, showing Vicksburg reservoir sandstones. From Kosters and Hamlin (1989). Most tight-gas reservoirs are in the lower Vicksburg, which is not completely penetrated by this well.

the South Texas tight-gas areas (especially McAllen Ranch field) include Loucks (1978), Berg and others (1979), Richman and others (1980), Dramis (1981), Han (1981), Han and Scott (1981), Klass and others (1981), Marshall (1981), Picou (1981), and Hill and others (1991). Recently, GRI and the U.S. Department of Energy have supported integrated geological, petrophysical, and engineering efforts to determine gas reservoir heterogeneity and potential infield reserve additions, using Vicksburg reservoirs in the McAllen Ranch field as a natural laboratory (Finley and others, 1990; Langford and others, 1990, 1992). This project involved cooperation among several government and industry partners and collection of data during the drilling of two wells.

Depositional Systems and Reservoir Facies

Near the end of the Eocene, when relative sea level fell, Vicksburg deltas prograded across an unstable shelf margin composed of undercompacted Jackson Group mud, causing large-scale slope failure along listric glide planes, deformation of underlying mud into ridges and diapirs, and regional extension that provided space for large volumes of Vicksburg sediment (Picou, 1981; Winker and Edwards, 1983; Coleman and Galloway, 1990b). Synchroneity of deposition and faulting resulted in greatly expanded sedimentary sections in downthrown fault blocks. Structural traps formed in rollover anticlines segmented by synthetic and antithetic faults (fig. 58). Stratigraphic traps are also important locally, where sandstones pinch out toward structural highs (Hill and others, 1991). The tight-gas areas in Hidalgo and Starr Counties lie in a major deltaic lobe of the lower Vicksburg, which deposited a thick interval of upward-coarsening sandstones (fig. 59). Middle and upper Vicksburg deltaic depocenters are mainly northeast of the tight-gas areas.

Lower Vicksburg reservoir sandstones occur in progradational deltaic parasequences (30 to 500 ft thick) capped by marine flooding surfaces (Coleman and Galloway, 1990a). Because sandstone development typically increases upward in each parasequence, production is primarily from the uppermost zones just below marine shales that form the seals (fig. 59). Although distributary channel and channel-mouth bar, massive sandstone facies have historically been the most productive lower Vicksburg reservoirs (Kosters and Hamlin, 1989), most of the low-permeability reservoirs are probably delta front and delta-flank shoreface, thinly bedded sandstone facies (figs. 60 and 61). Some basal Vicksburg sandstones may be upper slope mass-flow and turbiditic facies (Coleman and Galloway, 1990a). Vicksburg reservoirs are compartmentalized by closely spaced faults, facies heterogeneities, and diagenetic barriers (Langford and others, 1992).

Composition of Reservoir Facies

Vicksburg sandstones in South Texas are poorly to moderately sorted, fine grained, feldspathic litharenites and lithic arkoses (Richman and others, 1980; Klass and others, 1981; Loucks and others, 1981, 1986; Langford and others, 1992). The percentage of detrital quartz in the Vicksburg is low. Volcanic rock fragments and plagioclase feldspars constitute the majority of the framework grains, reflecting extensive volcanism in West Texas and Mexico during the Oligocene. Carbonate rock fragments are also abundant (up to 14 percent) and may have been derived from soil caliche (Lindquist, 1977). Major authigenic components in Vicksburg sandstones are calcite, chlorite, and quartz cements.

Diagenetic modification of Vicksburg sandstones involved multiple phases of alteration, cementation, and dissolution. Early physical compaction of argillaceous rock fragments created pore-filling pseudomatrix. Calcite is the most abundant authigenic constituent; both ferroan and non-ferroan calcite are present as poikilotopic and sparry cements and grain replacements (Richman and others, 1980; Loucks and others, 1981). Quartz overgrowths are ubiquitous but volumetrically minor. Chlorite cement is abundant in the lower Vicksburg "S" sandstone in McAllen Ranch field (Langford and others, 1990, 1992), where foot-by-foot reservoir quality is closely related to cementation patterns (figs. 60 and 61). Most remaining porosity in Vicksburg

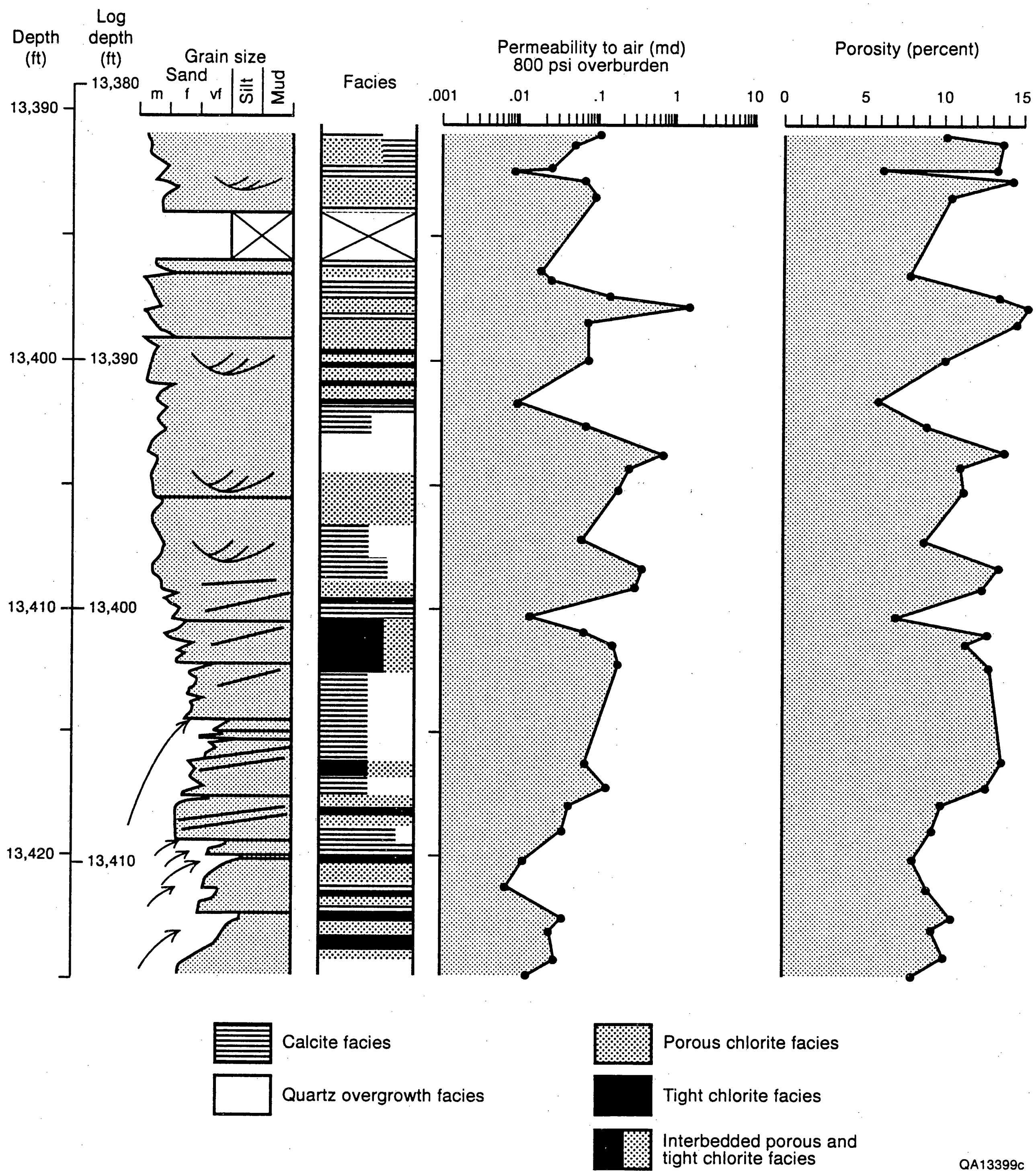


Figure 60. Core description from the lower Vicksburg "S" reservoir, McAllen Ranch field, also showing diagenetic facies, porosity, and permeability. From Langford and others (1990). Diagenetic facies are determined by dominant authigenic cement type. Interpreted depositional facies is delta front sandstone.

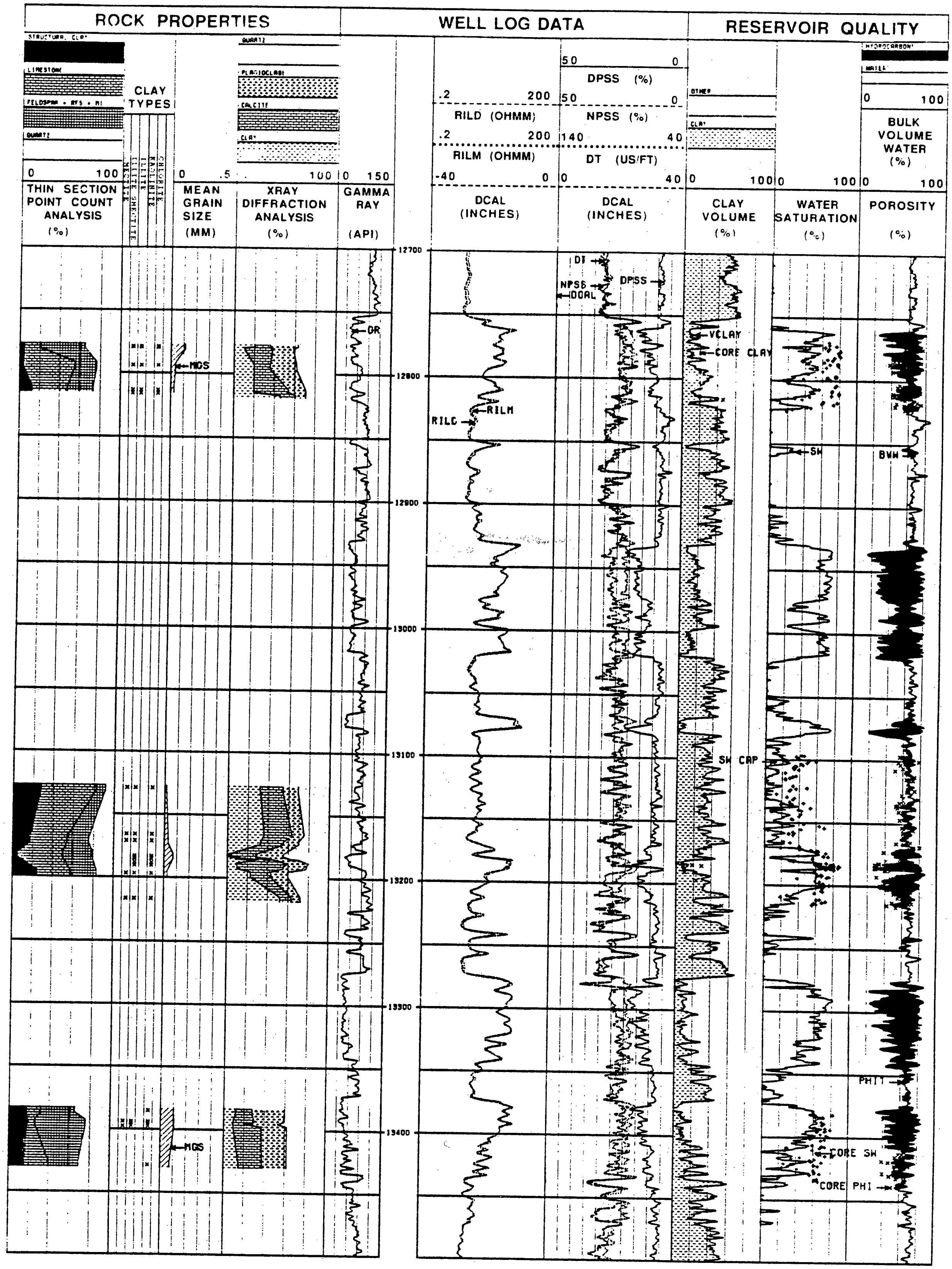


Figure 61. Composite log- and core-analysis plot of the lower Vicksburg "S" reservoir, McAllen Ranch field (same well as fig. 60). From Langford and others (1990).

sandstones below 8,000 ft is secondary, resulting from dissolution of feldspars, volcanic rock fragments, and calcite (Loucks and others, 1986). Unfortunately, much of that secondary porosity has been filled by late-formed iron-rich carbonate cement. Although secondary porosity (as determined from thin sections) may reach as high as 20 percent (Klass and others, 1981), it averages less than 10 percent in tight-gas reservoirs in McAllen Ranch field. In general, chemically and mechanically unstable mineralogy, along with high geothermal gradients, causes poor reservoir quality in deep Vicksburg sandstones in South Texas (Loucks and others, 1986).

Natural Fractures

Traps in Vicksburg reservoirs include rollover structures with strong dip reversal on the downthrown side of listric normal faults. For example, in the Guerra sandstone reservoir in McAllen Ranch field, mapped faults vary in throw from approximately 100 to more than 1,000 ft, and complex faulting is thought to be present throughout the area where tight gas designation was sought in McAllen Ranch field (Railroad Commission of Texas, 1990). Faults are both synsedimentary and postdepositional. In this type of structural setting, numerous small faults and fractures can be expected that can either enhance or detract from reservoir permeability and continuity (Laubach and others, 1992c). Processes that reduce grain size and porosity along faults can result in permeability barriers, even where small-displacement faults result in sandstone-on-sandstone contacts across faults (Knipe, 1992).

Published information is sparse on core-scale faults and natural fractures in Vicksburg reservoirs. In over 2,000 ft of McAllen Ranch core, R. P. Langford (personal communication, 1992) reported that few natural fractures were observed and that all fractures were closed as a result of infilling minerals. Southeast of McAllen Ranch, extensively fractured cores have been described that have open or partly open fractures (R. Lennon, verbal communication to R. P. Langford, 1990). Because filled or healed fractures can have higher permeability than surrounding matrix despite infilling minerals, these observations of healed and partly open fractures are significant.

Stress

In a study conducted in McAllen Ranch field, the azimuths of wellbore breakouts measured with caliper logs ranges from northward to northwestward (Langford and others, 1992), indicating east to northeast-trending maximum horizontal stresses. These results are consistent with the overall stress-direction patterns in this part of the Gulf Coast Basin. No published Vicksburg stress profiles are available. Deep reservoirs in the McAllen Ranch field have high geopressures in addition to low permeability; many wells show rapid declines in gas production rates and flowing pressures after fracture stimulation (Railroad Commission of Texas, 1980c).

Engineering Assessment

The Vicksburg was a subject of GRI research from 1989 to 1992 (Langford and others, 1992), and reservoir properties in the GRI study area (McAllen Ranch field, B lease) are typical of tight Vicksburg sandstones in Hidalgo and Starr Counties. Average porosity in the McAllen Ranch Vicksburg reservoirs is 14.3 percent (Langford and others, 1992) (table 15). Porosities range from 3 to 22 percent. Net pay thicknesses average 80 ft on the McAllen Ranch B lease. A porosity cut-off value of 12 percent is common for most deep Vicksburg sandstone reservoirs. A grain density of 2.66 to 2.68 g/cc is appropriate for log analysis calculations. This is due to the presence of calcite cement, which has a higher grain density than quartz (fig. 61). Data presented to the Railroad Commission of Texas indicate stabilized flow permeabilities of 0.035 md (Railroad Commission of Texas, 1980c) to 0.092 md (Railroad Commission of Texas,

Table 15. Vicksburg Formation, Texas Gulf Coast Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 479

Cumulative production from tight completions 1970–1988 (Bcf): 881.5

Estimated ultimate recovery from tight areas (Bcf): 1,479

Net pay thickness (ft): 80

Porosity range and average (%): 3–22/14.3

Permeability (md): 0.035–0.092

Water saturation range and average (%): 35–55/43

Reservoir temperature (°F): 250–350

Reservoir pressure (psi): 11,600

Typical stimulation/hydro-frac: 150,000 gal crosslinked gel and 450,000 lb interprop

Production rate:

prestimulation (Mcfd): 1,200–1,700

poststimulation (Mcfd): 2,700

Average recovery per completion (Bcf): 2.8

Decline rate: 58%/yr

1988) (table 15). Core permeabilities are equally low, averaging 0.006 md in Starr County (Railroad Commission of Texas, 1980c).

On the McAllen Ranch field B lease, water saturations ranged from 35 to 55 percent, averaging 43 percent (fig. 61). Other Vicksburg fields average 55 percent water saturation (Railroad Commission of Texas, 1988). During the McAllen Ranch study, a comparison was made between water saturations from capillary-pressure curves and measured core water saturations. Agreement was good except in some of the zones of higher water saturation where evaporation or blowdown losses, caused by extraction of the core from in situ to surface conditions, have occurred (Langford and others, 1992). Formation salinities range from 6,000 to 50,000 ppm. Large salinity variations make log interpretation difficult.

Vicksburg sandstone reservoirs are overpressured, reservoir pressure gradients ranging from 0.86 to 0.92 psi/ft (Railroad Commission of Texas, 1980c). Average reservoir pressure on McAllen Ranch B lease is 11,600 psi (Langford and others, 1992). Temperatures range from 250°F at 9,000 ft to 350°F at 14,000 ft (table 15).

Fracture-stimulation treatments are common in Vicksburg sandstones. Whitehead (W. Whitehead, written communication, October 21, 1992) recommends fracture stimulating with 150,000 gal of crosslinked gel and 450,000 lb of interprop. The extreme pressure makes sand proppant crushing a problem.

Production History

Extrapolated ultimate recovery of individual Vicksburg S completions is 2.8 Bcf, which is typical of other Vicksburg sandstones (Langford and others, 1992). Average well spacing is 80 acres. Initial pre-fracture flow rates are 1.2 to 1.7 MMcf/d (Railroad Commission of Texas, 1980c, 1988). Average production after fracture stimulation is 2.7 MMcf/d for the first 12 months (Langford and others, 1992). Water is produced with gas at an average of 25 bbl per MMcf. Condensate is produced at an average of 11 bbl per MMcf. Vicksburg S wells show a harmonic decline of 58 percent per year with recovery efficiency of 55 percent (Langford and others, 1992). The average life of a Vicksburg well is 16 years.

FORT WORTH BASIN

The Fort Worth Basin of North-Central Texas (fig. 1) is a north-south-trending, asymmetric foreland basin that was downwarped during Early Pennsylvanian time in response to the same tectonic stresses that produced the Ouachita thrust belt (summarized in Walper, 1982, and Johnson and others, 1988). It formed in front of the advancing Ouachita thrust belt on a continental shelf underlain by shelf carbonates of earlier Paleozoic age. The axis of the Fort Worth Basin is about 200 mi long along the front of the buried Ouachita terrane; the basin attains a maximum width of about 100 mi. It is bounded by the Red River Arch and Muenster Arch to the north, by the broad Bend Arch to the west, and by the Llano Uplift to the south (fig. 62).

The Davis sandstone is an informal stratigraphic unit within the thick succession of interbedded sandstone, chert-pebble conglomerate and granite wash, shale, and thin limestone that composes the Atokan Series in the Fort Worth Basin (Ng, 1979; Lovick and others, 1982). Although Atokan stratigraphic relationships are highly complex, Thompson (1982) and Johnson and others (1988) defined five lithogenetic sedimentary packages in the northern part of the Fort Worth Basin: (1) lower Atoka unit, (2) upper Atoka "Davis" subunit, (3) upper Atoka "post-Davis" subunit, (4) Red River unit, (5) Atoka-Caddo unit (fig. 63). The Atokan series is as much as 5,900 ft thick near the leading edge of the Ouachita thrust belt, the region of greatest Pennsylvanian subsidence (Johnson and others, 1988). The lower Atokan lithogenetic unit is inferred to be a fluvially dominated fan-delta system in which contemporaneous faulting influenced facies distribution, whereas the upper Atoka "Davis" lithogenetic subunit was deposited as a system of coalesced wave-dominated deltas that now have a thick, strike-oriented sandstone geometry (Thompson, 1982). Fluvially dominated fan-delta depositional

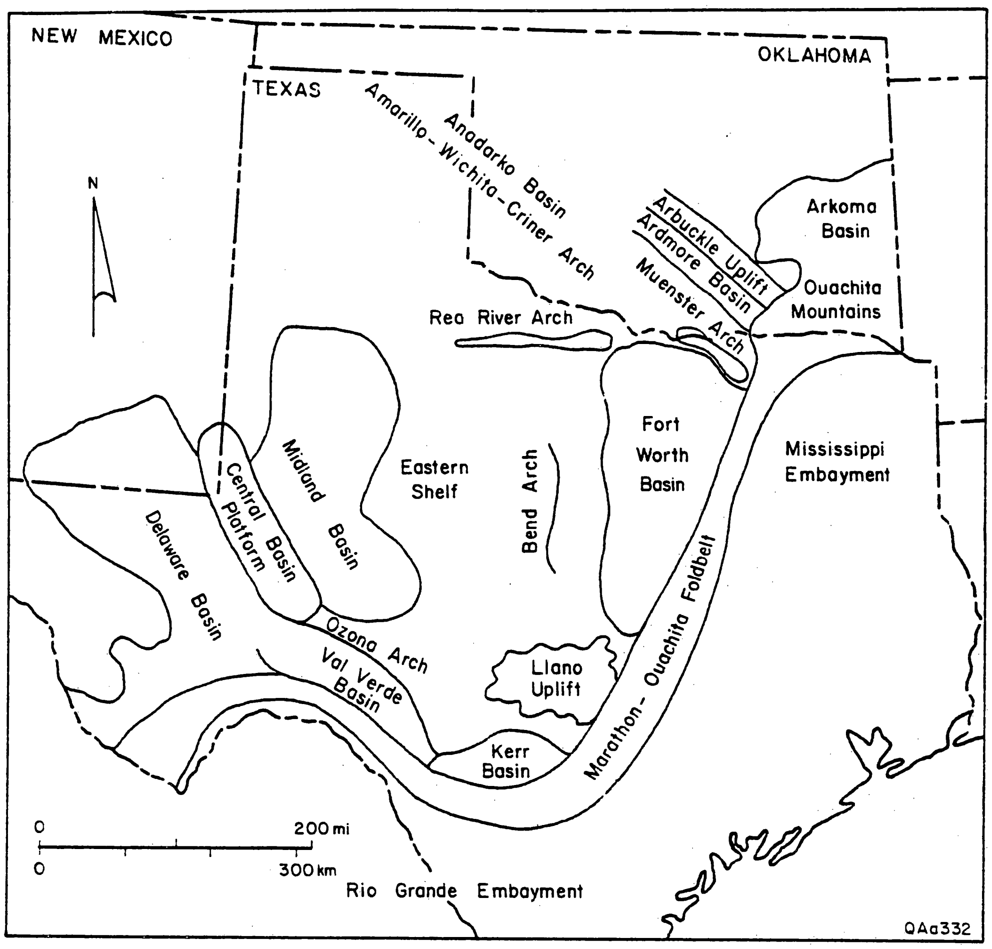


Figure 62. Map of late Paleozoic tectonic features of the southern Midcontinent region.

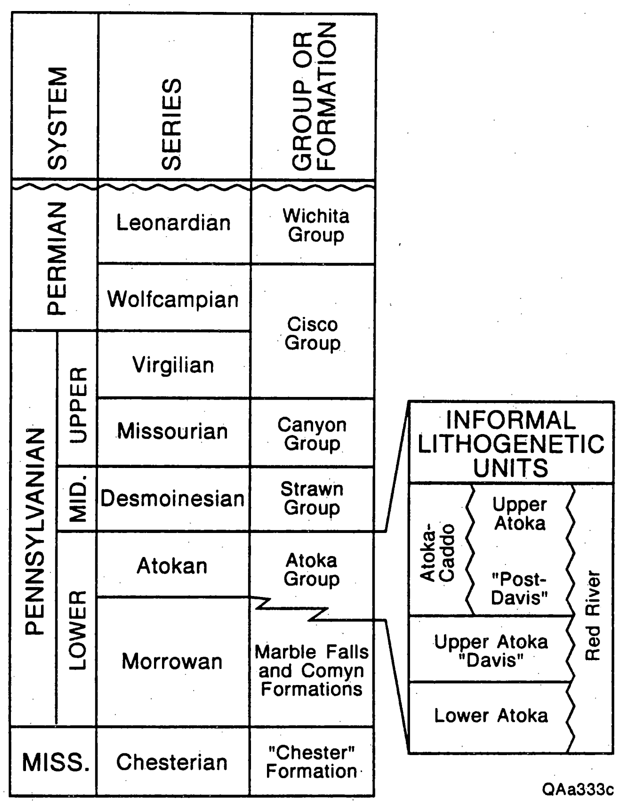


Figure 63. Stratigraphic column of upper Paleozoic strata in the Fort Worth Basin. From Johnson and others (1988).

conditions resumed during accumulation of the upper Atoka "post-Davis" lithogenetic subunit. Units 1 to 3 had primary sediment sources to the east off the Ouachita thrust belt with a subsidiary source to the north off the Muenster Arch. Only siliciclastic units 1 to 3 have regional areal extent in the northern part of the Fort Worth Basin. The Red River unit is a thick interval of arkosic conglomerate localized near, and derived from, the Red River Arch. The Atoka-Caddo unit roughly correlates with the Caddo reef facies and is contemporaneous with upper Caddo deposition.

On a regional scale, maximum horizontal stress in the Fort Worth Basin is inferred to trend northeastward (Zoback and Zoback, 1989). Local data from three GRI cooperative wells support this interpretation (CER Corporation, 1992a; Collins and others, 1992). A stress test conducted in shale above the Davis sandstone in the HFTS Data Well No. 1 created a fracture striking 036 degrees, whereas a stress test within Davis sandstone in the Sallie Hill "A" No. 1 well created a fracture striking 008 degrees. Results from HFTS Data Well No. 1 broadly agree with maximum horizontal stress directions inferred from wellbore breakouts, which range from 038 to 040 degrees, and with the north to north-northeast strike of fractures induced by drilling and coring. Although this direction is consistent with stress directions in the mid-plate stress province, according to recent reevaluations of stress data (Zoback and Zoback, 1991), the Fort Worth Basin is an extensional tectonic environment, with close affinities to the Gulf Coast Basin.

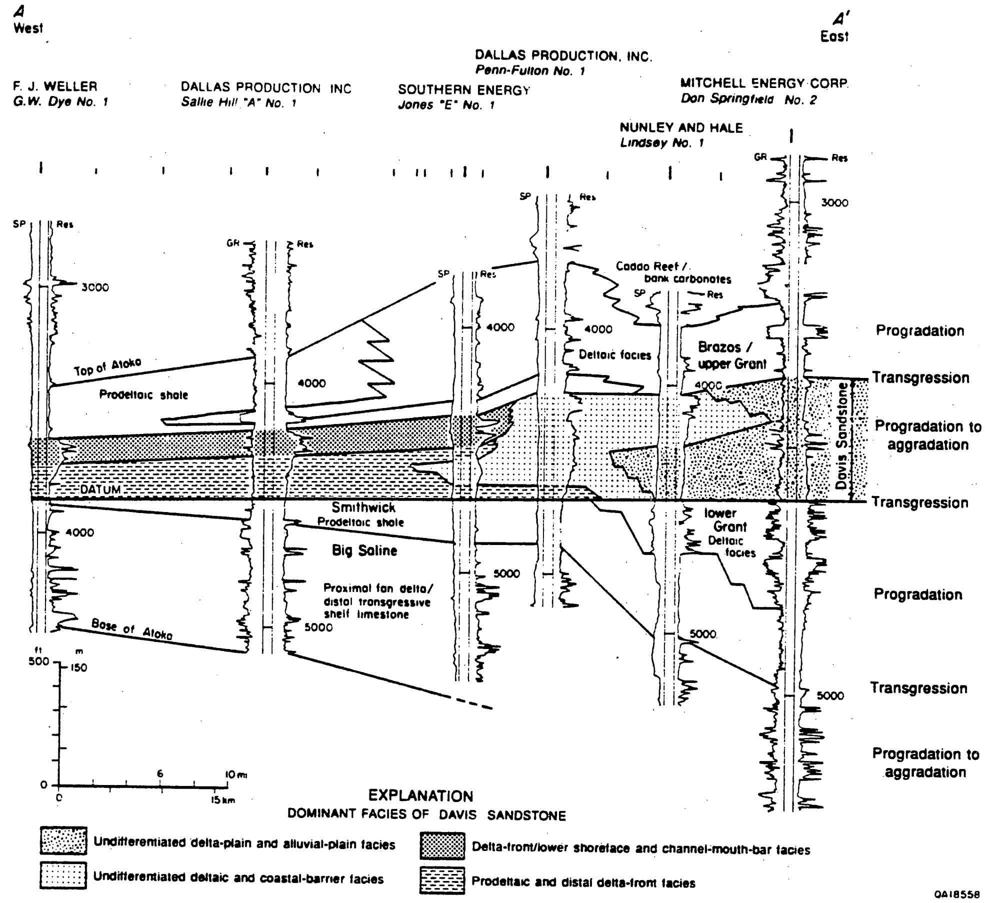
Davis Sandstone

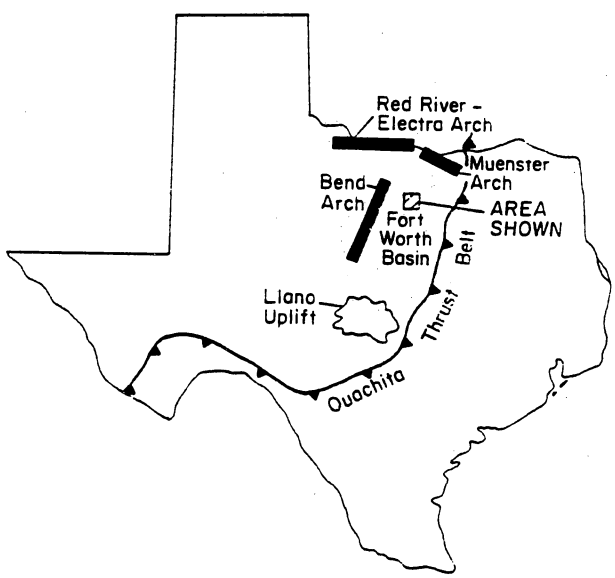
Introduction

The Middle Pennsylvanian (upper Atokan) Davis sandstone is a low-permeability, gas-bearing unit of the Atoka Group in the northern Fort Worth Basin of North-Central Texas (fig. 63). The Davis sandstone is not a formally designated tight-gas formation recognized by

FERC, unlike the other units described in this report. However, the Davis reservoirs have typical in situ permeabilities of 0.1 md or less (CER Corporation, 1992a) and must be fractured for gas production (Herkommer and Denke, 1982). Moreover, the Davis was studied by the GRI Tight Gas Sands program as a potentially suitable formation to test hydraulic-fracture-treatment methods for improved production from low-permeability, gas-bearing sandstone reservoirs (CER Corporation, 1992a). From these initial assessment studies and the results of subsequent GRI-sponsored coring operations, much information regarding Davis reservoir characteristics was generated. These new data offer an opportunity to present a well-documented case study of reservoir facies, stress regime, and engineering characteristics of a tight-gas sandstone in a notably productive depositional basin.

Among operating companies, the Davis is more commonly known as the Pregnant shale (for example, Lahti and Huber, 1982); producing "Davis" gas reservoirs are known by several local names (Conglomerate 4400, Meeker conglomerate, and Upper Atoka). Variation in the gas-field terminology applied to the siliciclastic Davis is a reflection of the complex stratigraphic relations among the regionally correlative, commonly partly coeval, Atokan sedimentary packages in the northern Fort Worth Basin (Ng, 1979; Thompson, 1982; Johnson and others, 1988) (figs. 63 and 64). The log signature of the Davis interval varies regionally, ranging from a generally upward-coarsening, shale-to-sandstone sequence where it overlies the lower Atokan Smithwick Shale and Big Saline Formation to a thicker, variable but mostly shale sequence where it overlies the lower Grant deltaic facies of the Smithwick (fig. 64). In the Davis gas-producing area of northeastern Palo Pinto and northern Parker Counties (Thompson, 1982, her fig. 23), the upward-coarsening log pattern predominates (Thompson, 1982, her cross section D–D'; Collins and others, 1992) (fig. 64). The Davis interval is overlain by the shale-prone Brazos/upper Grant deltaic facies (Lahti and Grant, 1982; Collins and others, 1992) (fig. 64). Gas production in the Davis sandstone is from the upper sandstone that caps the upward-coarsening sequence (fig. 65).





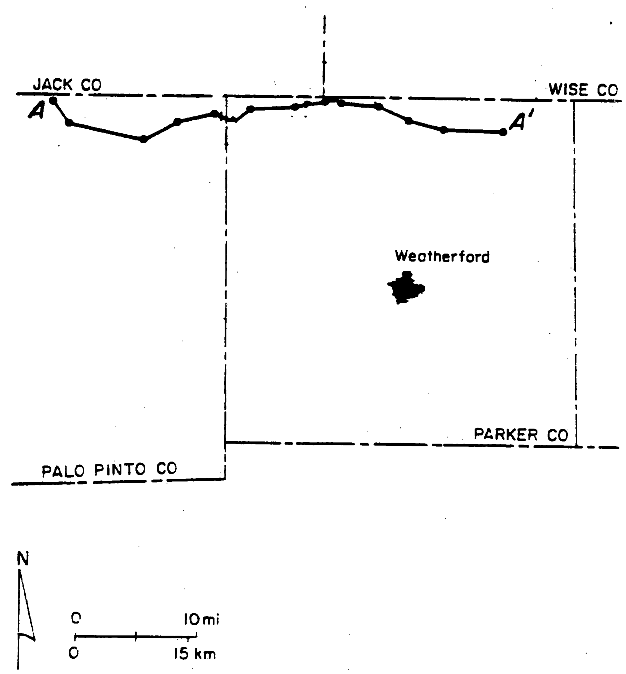


Figure 64. Regional cross section depicting generalized depositional facies of Davis sandstone and adjacent Atokan deposits. Inset maps show regional structural setting of the Fort Worth Basin and location of cross section A–A′ in Palo Pinto and Parker Counties, North-Central Texas. Modified from Collins and others (1992).

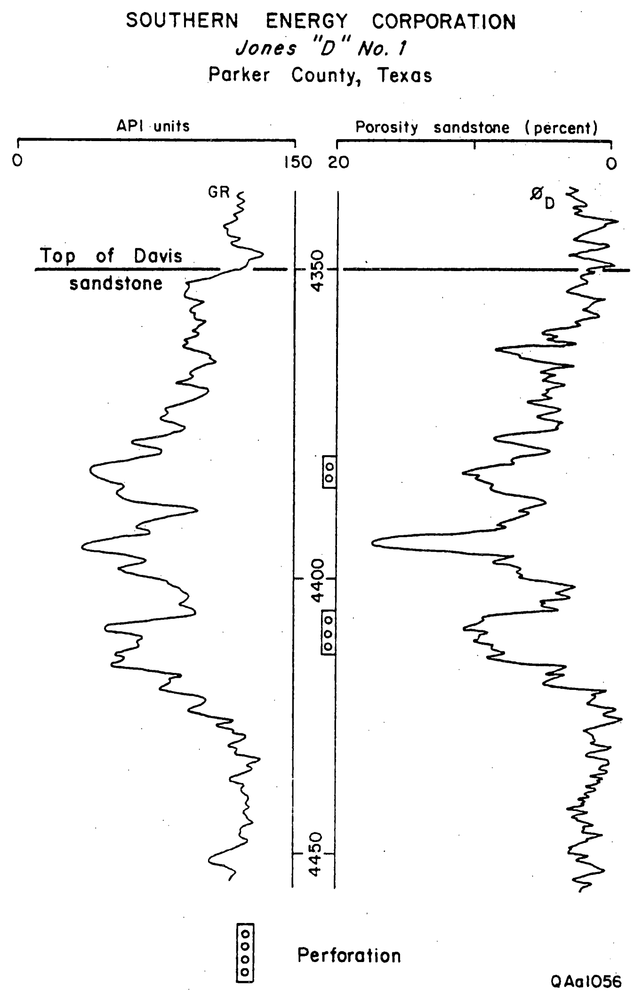


Figure 65. Well log of pay zones in the Davis sandstone.

The Davis sandstone thickens southeastward from less than 20 ft along the northern and western flanks of the Fort Worth Basin to as much as 1,200 ft in Parker and Dallas Counties, near the Ouachita thrust belt where subsidence in the basin was most pronounced (Thompson, 1982). In the two-county producing area, the unit is about 250 to 420 ft thick, with sandy reservoir facies near the top of the Davis varying from 50 to greater than 100 ft thick. Within the entire area of Davis sandstone distribution, net-sandstone thickness is less than 5 ft where the formation is thinnest to more than 700 ft in southwestern Parker County (Thompson, 1982, her plate XVI). Depth to the top of the formation in the gas-producing area is about 3,600 to 4,400 ft (fig. 64).

Depositional Systems and Reservoir Facies

Atokan siliciclastic deposits accumulated in the Fort Worth Basin, a late Paleozoic foreland basin formed along the front of the advancing Ouachita thrust belt (Walper, 1982). The Davis sandstone (Pregnant shale) interval is one of several Atokan lithogenetic units defined by Thompson (1982) that prograded generally westward from a tectonically active source area, the Ouachita thrust belt. The transition from the lower Atokan Big Saline and lower Grant siliciclastic facies to the upper Atokan Davis interval represents a change from a fluvially dominated fan-delta system whose facies distribution was influenced by contemporaneous faulting to a system of coalesced, wave-dominated deltas deposited during a period of relative tectonic quiescence (Thompson, 1982; Johnson and others, 1988). Fan-delta depositional conditions resumed in post-Davis time. Davis delta systems are composed principally of coastal barrier facies. Analysis of Davis cores from northern Parker and southwestern Wise Counties indicates that sandstone-rich reservoir facies of the upper Davis (fig. 64) were deposited in mostly delta-front and channel-mouth-bar environments (fig. 66) (Collins and others, 1992).

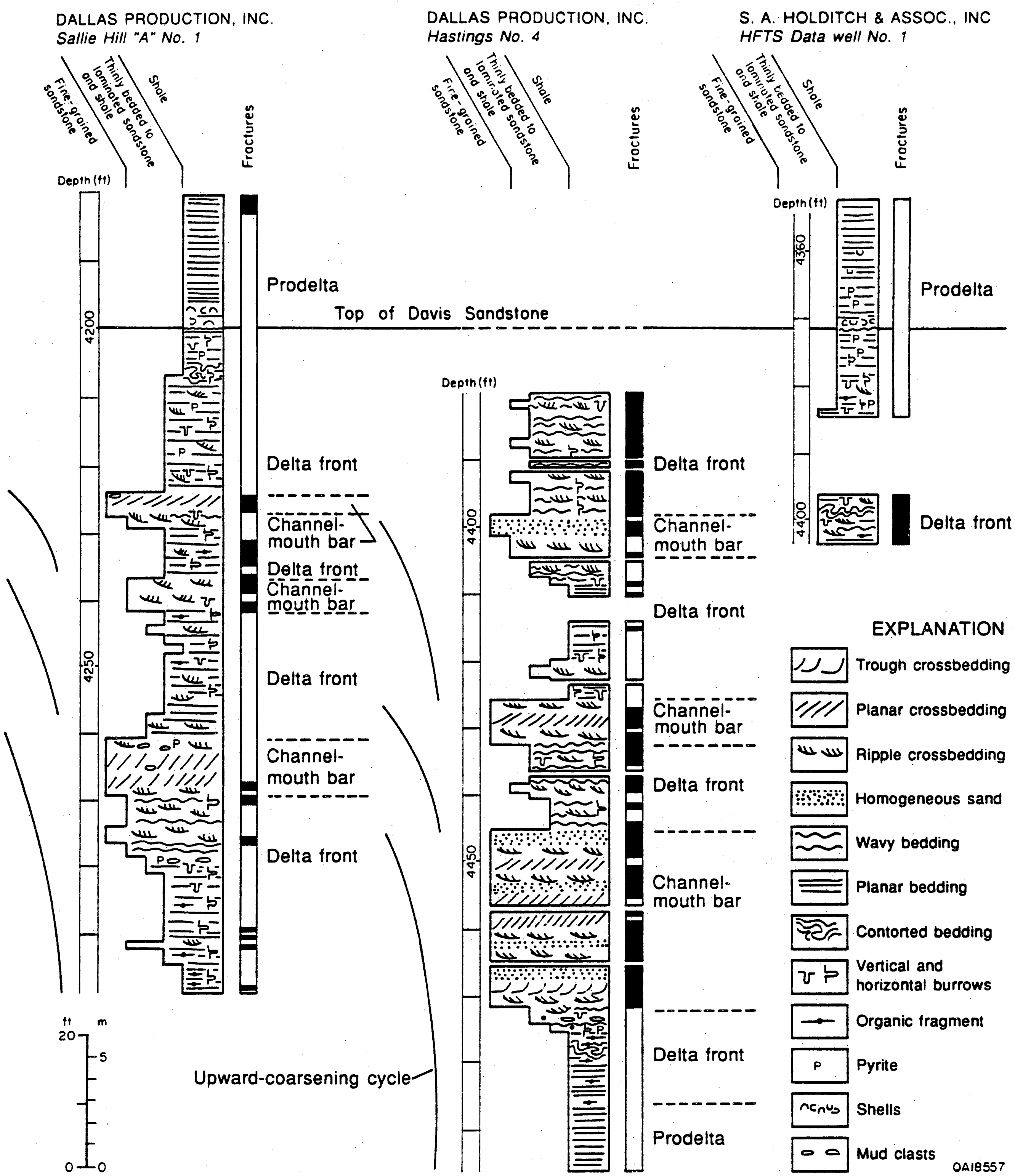


Figure 66. Core logs and interpreted depositional environments of the Davis sandstone. Two cores on left are from northern Parker County; right core from southwestern Wise County. From Collins and others (1992).

The Davis reservoir interval in the two-county producing area consists of multiple upward-coarsening cycles (10 to 40 ft thick) of interbedded sandstone and shale and clean, locally cross-bedded sandstone (fig. 66) (Collins and others, 1992). Upper Davis sand-rich facies of the coalesced Davis deltas and coastal barriers are subregionally continuous, especially along depositional strike (fig. 67). Bounding the Davis sandstone reservoirs are generally shale-rich prodeltaic intervals of variable thickness. Primary exploration targets for tight-gas production in the Davis sandstone are along the axis of the principal fluvial feeder channel to the delta systems and in the deltaic facies (Thompson, 1982). The trapping mechanism of Davis reservoirs is poorly documented but is probably primarily stratigraphic (Ng, 1979).

Composition of Reservoir Facies

Davis reservoir sandstones are very fine to fine grained, mineralogically mature, and classified as sublitharenites, with an average composition of $Q_{84}F_5R_{11}$; details of petrologic characteristics of the Davis in cores from the producing region of northern Parker County are described in Collins and others (1992). Typical sandstones contain abundant shale interbeds and clay drapes along ripples. Plagioclase is the most abundant feldspar; low-rank metamorphic rock fragments such as slate and phyllite are the most common lithic grains. Detrital organic matter constitutes as much as 8 percent of the volume of mudstones and muddy sandstones. Detrital clay matrix is composed of illite, chlorite, kaolinite, and clay-size quartz. Authigenic cements and replacive minerals constitute as much as 25 percent of the whole-rock volume in Davis sandstones and include quartz, calcite, ankerite, siderite, chlorite, illite, kaolinite, and pyrite. Quartz, the most abundant cement, has an average volume of 11 percent in clean (<2 percent clay matrix) sandstones. Chlorite-cement volume averages 3 percent, whereas carbonate cements, which are unevenly distributed, are generally less than 2 percent of rock volume. The relative order of major diagenetic events is (1) precipitation of chlorite flakes

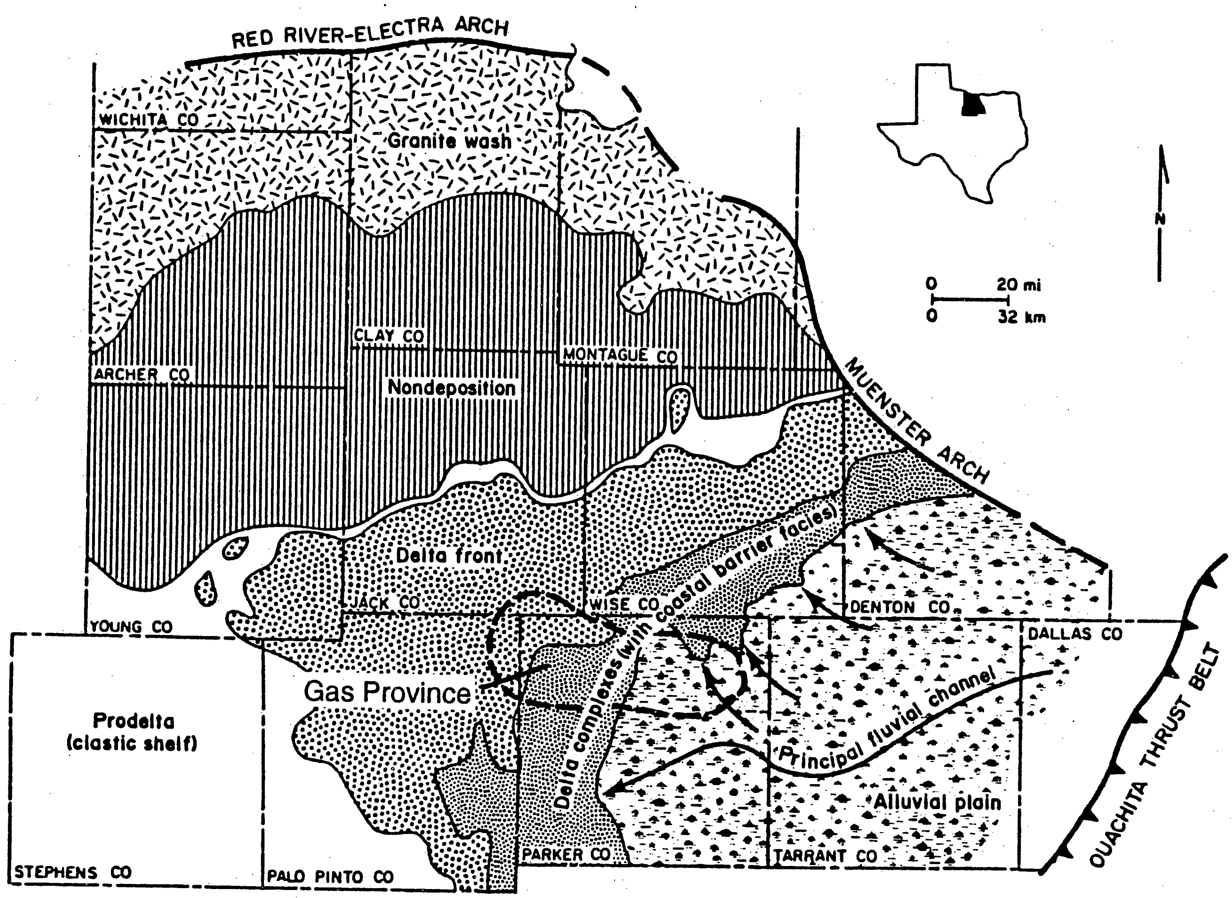


Figure 67. Generalized areal distribution of depositional facies and limits of gas province of the Davis sandstone in the Fort Worth Basin. Modified from Thompson (1982).

oriented perpendicular to detrital grains, (2) precipitation of quartz overgrowths, (3) development of secondary porosity by dissolution of feldspars, (4) precipitation of illite and kaolinite in primary and secondary pores, and (5) precipitation of pore-filling and grain-replacing iron-bearing calcite and ankerite.

Collins and others (1992) observed a porosity range of 0 to 6 percent in thin sections of Davis reservoir sandstones, with both primary and secondary pores present. The average volume of primary porosity is 1 percent, and the average volume of secondary porosity is 0.6 percent. Most secondary pores formed by partial or complete dissolution of framework grains, particularly feldspars. Microporosity occurs in detrital and authigenic clays, and partial dissolution of framework grains forms secondary micropores within grains. Whole-core porosity measured at the depths from which the thin sections were taken averages 5.7 percent in clean sandstones. Permeability in cores studied by Collins and others (1992) in the Davis producing region is 0.1 md or less.

Natural Fractures

Natural fractures are common in three Davis sandstone cores studied by Collins and others (1992). Fractures are vertical to subvertical extension fractures that are typically short (4 inches or less) and vertically discontinuous. A few fractures and fracture swarms are as much as several feet tall. Fractures are narrow (commonly less than 0.25 mm wide) and partly to completely filled with calcite. Fractures have northerly strikes (359° to 020°) (Collins and others, 1992), similar to a prominent fracture set in outcrop (Hoskins, 1982). Davis sandstone fractures are most common in clean sandstone but also occur in interbedded sandstone and shale intervals, where they occur primarily in the sandstone-rich interbeds.

Fracture abundance in the three cores is high but variable (Collins and others, 1992). The percentage of core containing natural fractures ranges from about 10 percent to more than 80 percent. In the HFTS Data Well No. 1 core, there is a swarm of closely spaced and interconnected fractures (fig. 68); elsewhere, fractures are less plentiful, and connectivity of fractures appears to be low. Fractures are not evenly spaced, and the distribution of large fractures and fracture swarms could not be determined.

During drilling through the top of the Davis sandstone, lost circulation has been observed by several operators in the Fort Worth Basin, and some operators ascribed this to the presence of conductive natural fractures. During coring and drilling of the HFTS Data Well No. 1, about 1,000 bbl of drilling mud and circulation-loss inhibitors was abruptly lost. From part of the upper Davis where circulation was initially lost, 7.5 ft of sandstone and interbedded shale core was recovered. Natural fractures are abundant in this core, and lost circulation material is imbedded in several of the fracture strands, clear evidence that fractures were open or were dilated during coring. Collins and others (1992) described fractures in this interval in detail. Lost circulation has been reported in several areas of Davis production in the Fort Worth Basin, but other than an association with the upper part of the Davis, any regional pattern that may exist has not yet been documented.

In 1991, GRI sponsored an experimental horizontal well in the Davis sandstone to test the feasibility of enhancing production from natural fractures in this unit. Dallas Production (Pitts Oil Company) air-drilled a 2,000-ft lateral well segment across the Davis sandstone near Weatherford in Parker County. The west-directed horizontal wellbore encountered the predicted set of north-south-striking natural fractures. A significant part of the wellbore, however, penetrated nonreservoir rock after drilling through the Davis section. The wellbore was then drilled to angle upward to reintersect the Davis.

The Davis was completed open-hole to take advantage of the production from the natural fracture system. Evaluation of the reservoir suggests that reservoir heterogeneity in the form of short and discontinuous fractures and numerous shale interbeds (which tend to vertically partition the reservoir) as well as damage from fluid imbibition during drilling and logging operations may have a negative impact on completion of this well (R. E. Peterson, CER

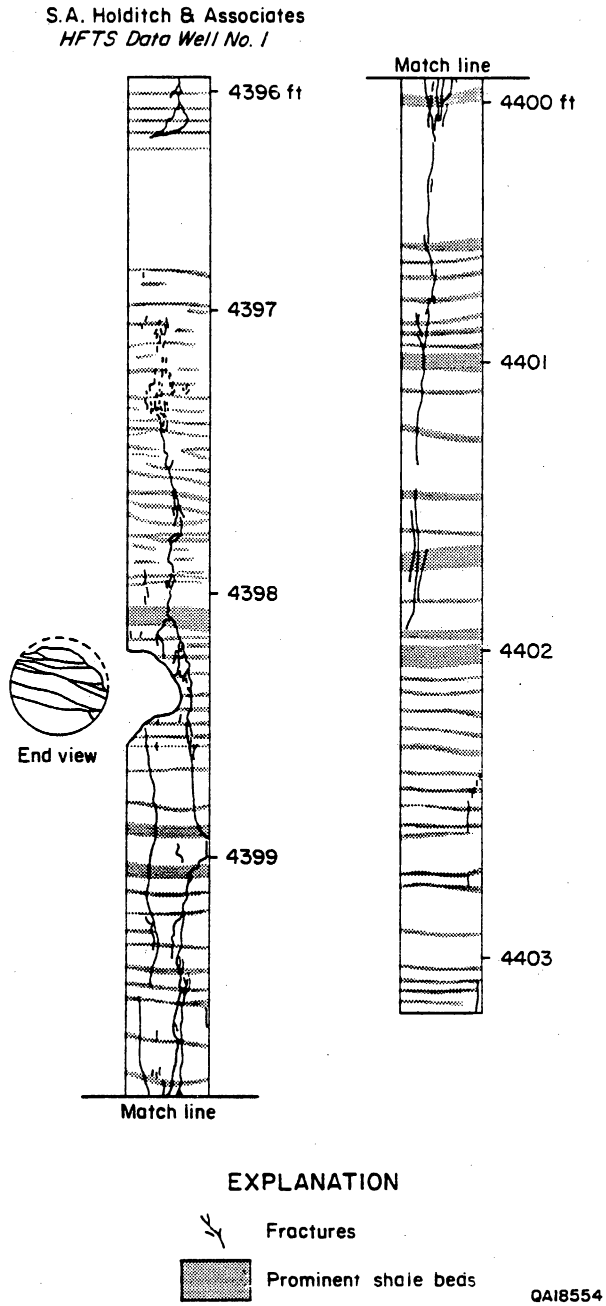


Figure 68. Sketch of fractured Davis sandstone core from Holditch HFTS Data Well No. 1, Wise County, Texas. From Collins and others (1992).

Corporation, personal communication, 1992). In late 1992, flow and buildup testing were still in progress.

The abundance of fractures in core described by Collins and others (1992) and in the experimental horizontal well, as well as the rapid loss of circulation in some fractured intervals, suggests that fractures are an important reservoir element in Davis sandstone. The close association of many fractures with stylolites implies that the processes of fracturing and diagenesis interacted.

Engineering Characteristics

As part of the GRI evaluation of low-permeability formations, a study was made of 10 wells completed in the Davis sandstone in Parker and Jack Counties, Texas (table 16, fig. 64). Log-calculated porosities from these wells indicate maximum porosities, depending on the location of the wells, to range from 7.5 to 12 percent. Average porosity throughout the gas-producing area is in the 5 to 7 percent range. This is consistent with the average whole core porosity of 5.7 percent determined by Collins and others (1992). Other core data taken in two wells in the Davis suggest porosities may be as high as 9 percent in the better reservoirs.

Gas production is best in the cleanest sandstone reservoirs. Davis sandstones typically contain abundant shale interbeds and clay drapes along ripples (CER Corporation, 1992a). The average gas permeability from well-test analysis in the 10-well study is 0.08 md, with the range from 0.021 to 0.31 md.

Net pay in the gas-producing area ranges from approximately 40 to 65 ft. This usually occurs in several discrete sandstones in a section that is 50 to 100 ft thick (fig. 65). The average net pay for the 10 wells examined for the GRI study was 53 ft.

Water saturations in the cleanest gas productive sandstones in the Davis range from 15 to 20 percent. In shaly sandstones, water saturations increase to 30 percent or more. Capillary pressure response will change according to the shaliness of the sample. Reservoir pressure

Table 16. Davis Sandstone, Fort Worth Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: No data

Cumulative production from tight completions 1970–1988 (Bcf): No data

Estimated ultimate recovery from tight areas (Bcf): No data

Net pay thickness (ft): 40–65

Porosity range and average (%): 0–9/5.7

Permeability range and average (md): 0.021–0.31/0.08

Water saturation (%): 15–30

Reservoir temperature (°F): 130

Reservoir pressure (psi): 1,000–1,500

Typical stimulation/hydro-frac: 21,000 gal fluid and 36,000 lb sand

Production rate:

  prestimulation (Mcf/d): No data

  poststimulation (Mcf/d): 2,020

Average recovery per completion (MMcf): 200–1,900

Decline rate: No data

ranges from 1,000 to 1,500 psi, depending on the degree of depletion in the area. Reservoir temperature is approximately 130°F.

Although the Davis contains several discrete sandstone beds, the interbedded shale layers are thin, so that the sandstones collectively behave as a single unit during fracture stimulation (CER Corporation, 1992a). In addition the stress contrast between the Davis sandstone and the shales immediately above and below it is significant. In stress tests conducted in the GRI study average sandstone fracture pressure gradient was 0.44 psi/ft. Average fracture pressure gradient in the shale below the Davis was 0.78 psi/ft. Average fracture pressure gradient in the shale above the Davis was 0.93 psi/ft. This stress contrast would make the Davis an ideal candidate for fracture stimulation. However, as discussed earlier, natural fractures are abundant, which may complicate normal fracturing operations. A typical fracture stimulation treatment in the Davis sandstone is about 21,000 gal fluid and 36,000 lb sand.

Production History

Estimated ultimate recovery per well in the eight productive wells of the 10-well GRI study ranges from 176 to 1,854 MMcf (table 16). The average for the eight wells was 576 MMcf. Examination of other data from Dallas Production Incorporated (the cooperating operator in the GRI study) indicates that these numbers are typical of Davis production. Post-fracture stimulation production rate averages 2,020 Mcf/d. The average drainage radius in the 10 wells is 48.7 acres.

ANADARKO BASIN

The Anadarko Basin (figs. 1 and 69) of the Southern Midcontinent is the deepest Phanerozoic sedimentary basin within the North American craton. Much of the basin's present

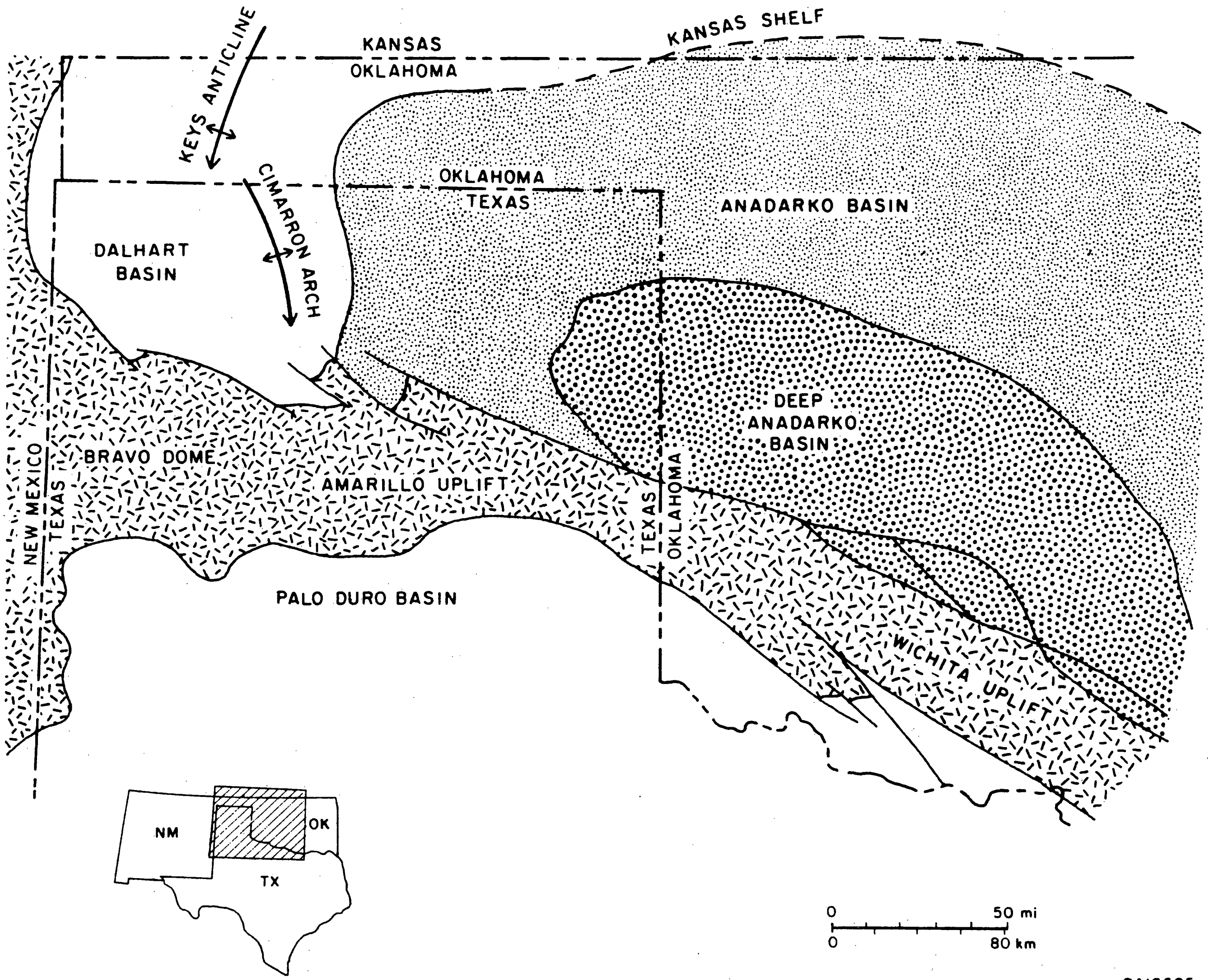


Figure 69. Regional geologic setting of the western and central parts of the Anadarko Basin. Modified from Hentz (1992).

structural configuration was the result of the prominent Pennsylvanian orogenic episode that affected a large region of the south-central United States (Ham and Wilson, 1967). FERC-designated, gas-producing, low-permeability sandstones in the Anadarko Basin are restricted to the Atokan, Desmoinesian, and Missourian Series of the Pennsylvanian System. The major tight gas sandstone reservoirs in the Anadarko Basin occur in the Granite Wash Formation, which spans most or all of the Pennsylvanian System, the Cherokee Group, and the Cleveland Formation of the Skiatook Group (fig. 70).

During the Pennsylvanian orogenic period, the active Wichita and Amarillo Uplifts (fig. 69) were separated from the Anadarko Basin by a series of large-displacement, moderate- to high-angle reverse faults. The adjacent basin subsided markedly; large volumes of coarse arkosic sediment of the primarily fan-deltaic Granite Wash Formation were deposited throughout the Pennsylvanian Period along the southern margin of the rapidly subsiding Anadarko Basin adjacent to the granitic Wichita and Amarillo highlands. During the Desmoinesian Epoch, fluvial-deltaic systems represented by the Cherokee Group (fig. 70) prograded generally southwestward into the northern part of the Anadarko Basin across the Kansas Shelf. Fluvial-deltaic Cleveland Formation systems were sourced to the west of the western margin of the Anadarko Basin and prograded generally eastward parallel to the axis of the basin.

Granite Wash and Cleveland Formation reservoirs are in the western Anadarko Basin, in the mid-plate stress province of Zoback and Zoback (1980, 1989). This stress province is a region characterized by northeast-trending maximum horizontal stress. Stress directions in this area are defined by hydraulic fracture treatments and stress measurements (for example, Haimson, 1977), earthquake focal mechanisms (Hermann, 1979), and wellbore breakouts (Dart, 1989). One of the most prominent young tectonic features in the Midcontinent 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 that the latest movement is fault is as young as Quaternary (Gilbert, 1983) and possibly late Holocene (Madole, 1988). The fault displays reverse sense-of-

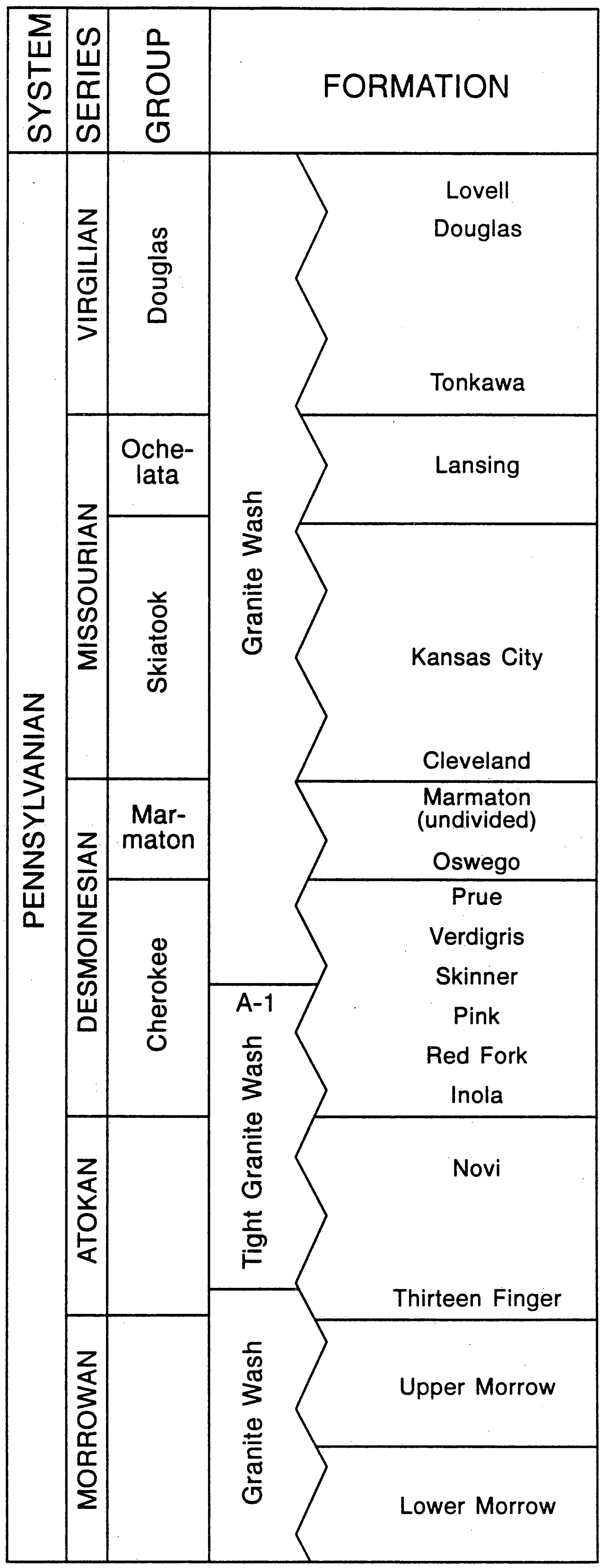


Figure 70. Generalized stratigraphic column of the Pennsylvanian System in the western part of the Anadarko Basin.

motion and a component of left-lateral slip (Ramelli and Slemmons, 1986; Myers and others, 1987), consistent with northeast-directed maximum horizontal compression. A stress profile from the Cleveland Formation is shown in figure 71.

Other formations in the Anadarko Basin that have been formally designated as tight by FERC include (1) undifferentiated sandstones of the Atokan Series and (2) the Missourian upper Marchand sand, primarily an oil producer (Baker, 1979).

Granite Wash

Introduction

The thick Pennsylvanian Granite Wash interval of the western Anadarko Basin (fig. 70) is composed of coarse, arkosic, synorogenic sediment derived from the granitic Amarillo Uplift (fig. 69), a tectonically active structure during most of the Pennsylvanian orogenic episode of the greater Anadarko Basin area. The Granite Wash is areally restricted close to the northern flank of the Amarillo Uplift in the southern part of the Anadarko Basin (fig. 69) and composes a vertically continuous succession through all or most of the Pennsylvanian System (fig. 70), a preserved record of the rapid subsidence that occurred in the Anadarko Basin as the adjacent Amarillo Uplift was elevated. Localized tongues of Granite Wash extend northward away from the major locus of accumulation (Handford and others, 1981).

Although the Granite Wash is generally characterized by moderate to high permeabilities (Dutton, 1990), it is locally tight with permeabilities of 0.1 md or less (Railroad Commission of Texas, 1982). In all of Roberts and Hemphill Counties and parts of Ochiltree, Lipscomb, and Wheeler Counties in the northeastern part of the Texas Panhandle (fig. 72), a portion of the Granite Wash interval approximately equivalent to most of the Atokan Series and part of the Desmoinesian Series (fig. 70) has been formally designated as a tight-gas-producing interval by FERC. The 31 fields that produce natural gas from the tight

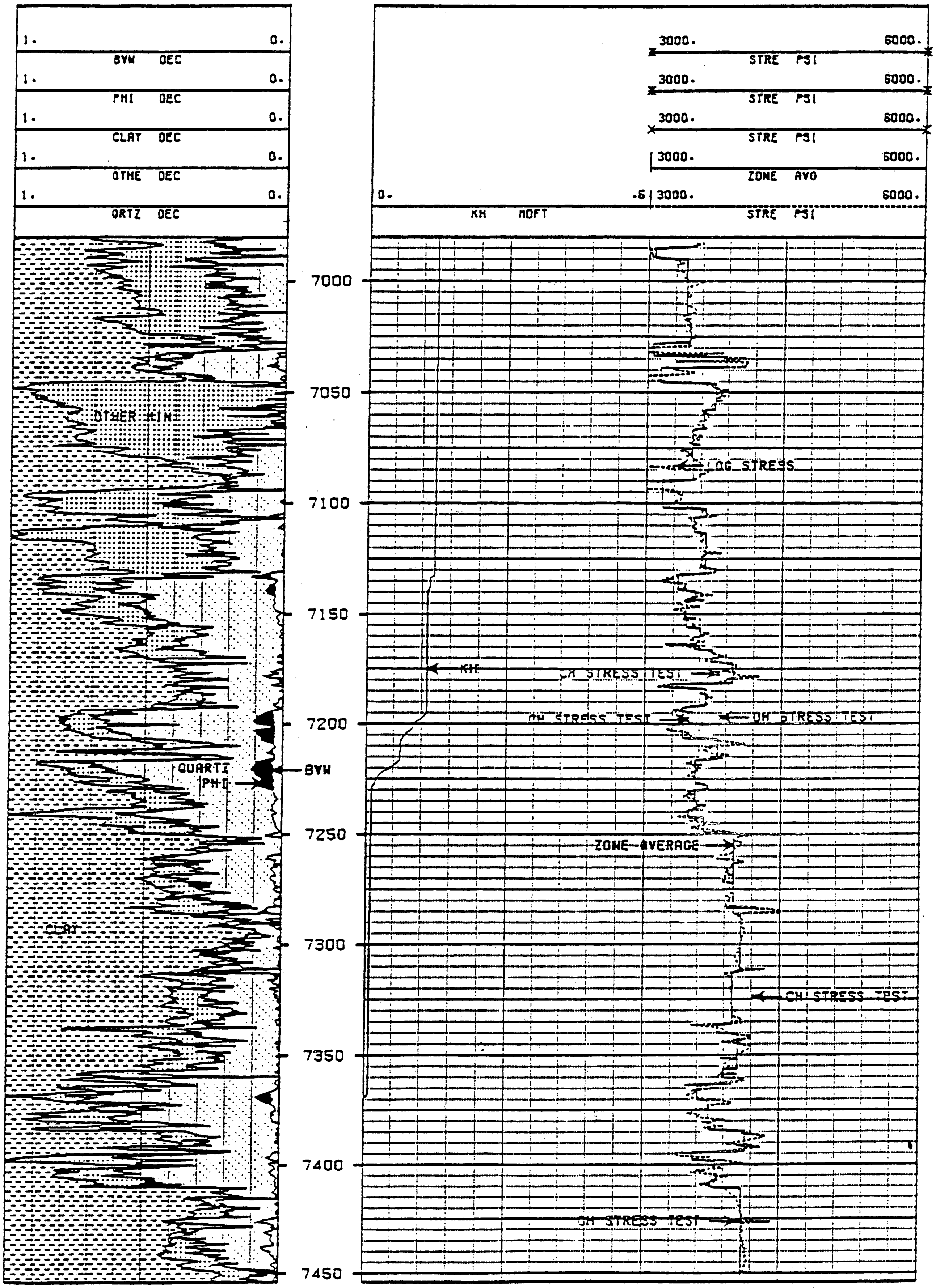


Figure 71. Stress profile, Cleveland Formation stress-profile example (W. Whitehead, personal communication, 1992).

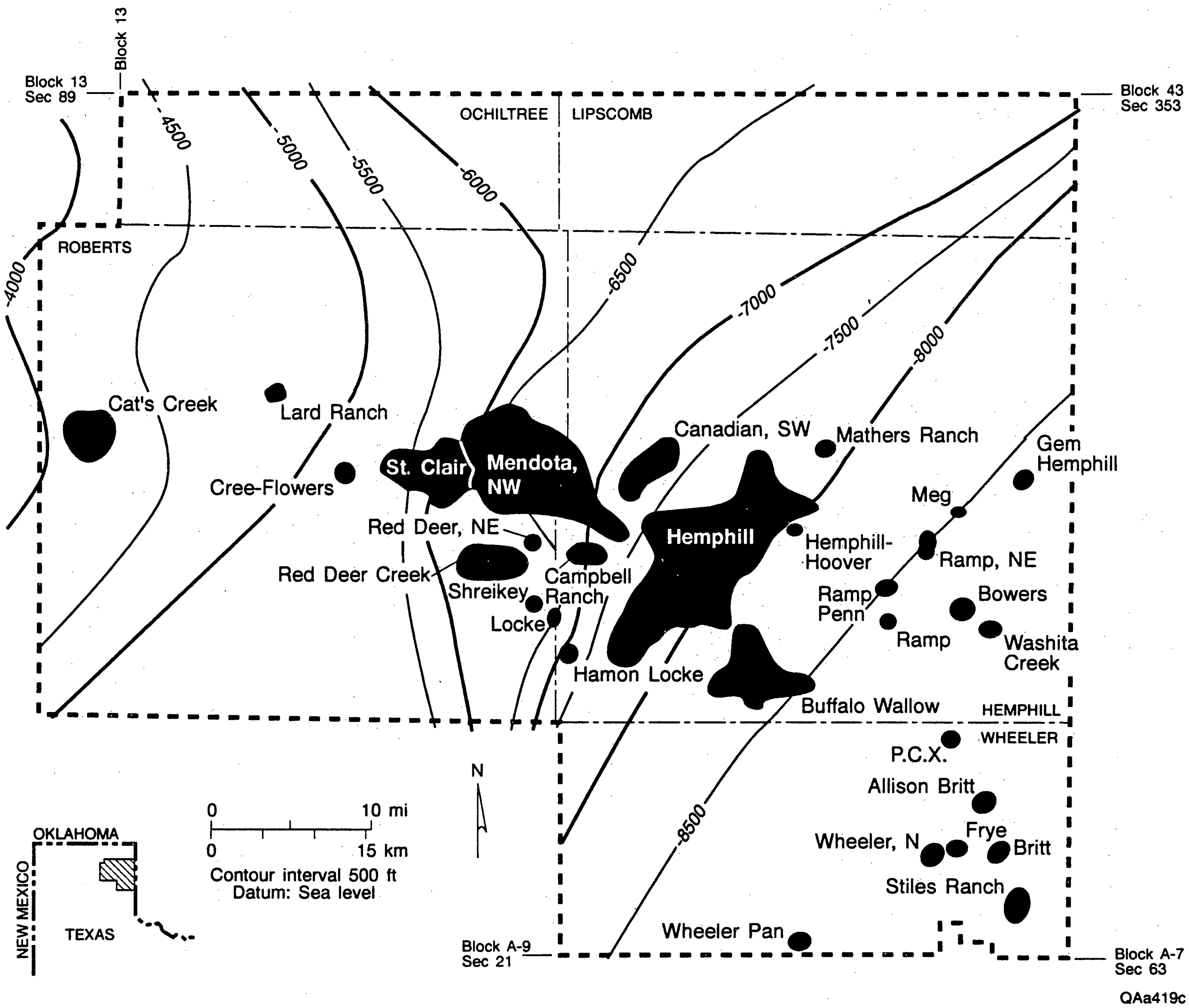


Figure 72. Map of fields producing natural gas from low-permeability intervals of the Granite Wash Formation superimposed on structure-contour map of top of A-1 zone in the Granite Wash interval (fig. 73). Perimeter of area shown defines the formally designated tight gas area. Modified from Railroad Commission of Texas (1982a).

Granite Wash interval (fig. 72) have yielded more than 540 Bcf of gas as of January 1991 (Railroad Commission of Texas, 1991a). The largest tight Granite Wash field by far is the Hemphill field (Hemphill County) with cumulative production of 399.6 Bcf as of January 1991; Northwest Mendota (Roberts County) and Stiles Ranch (Wheeler County) fields follow distantly with 44.7 Bcf and 24.7 Bcf cumulative production (to January 1991), respectively (Railroad Commission of Texas, 1991a). These production statistics may include some commingled gas production from nontight (permeability >0.1 md) Granite Wash reservoir intervals within these 31 fields.

Geologic and engineering information of the tight Granite Wash interval is limited to that presented in a petition to FERC by the Texas Railroad Commission for granting of formal tight formation designation (Railroad Commission of Texas, 1982a) and in published field descriptions (Cast, 1977; Parker and Gibson, 1977; Kosters and others, 1989). Other Granite Wash studies cited in this summary detail the depositional setting and reservoir conditions of non-tight intervals in the younger part of the thick Granite Wash section. It is presumed that similar conditions of deposition of the Granite Wash sediments prevailed at the southern margin of the Anadarko Basin during most of the Pennsylvanian Period.

The tight Granite Wash interval contains nine informal stratigraphic intervals (zones A-1 and A through H) (fig. 73), which can be correlated throughout most of the designated tight-gas area, although individual zones pinch out locally (Railroad Commission of Texas, 1982a). The tight Granite Wash ranges in thickness from about 860 ft in southern Lipscomb County (possibly thinner in southern Ochiltree County) to about 3,170 ft in northern Wheeler County where syndepositional subsidence was greatest along the axis of the deep Anadarko Basin (fig. 69). Depth to the top of the formation in the five-county, tight-gas area varies from about 6,900 ft (about 4,000 ft subsea) in Roberts County to 11,400 ft (about 9,000 ft subsea) in Wheeler County (fig. 72).

Most of the tight Granite Wash section is composed of coarse, arkosic sandstone and conglomerate, the reservoir lithologies. Abrupt vertical textural changes are characteristic.

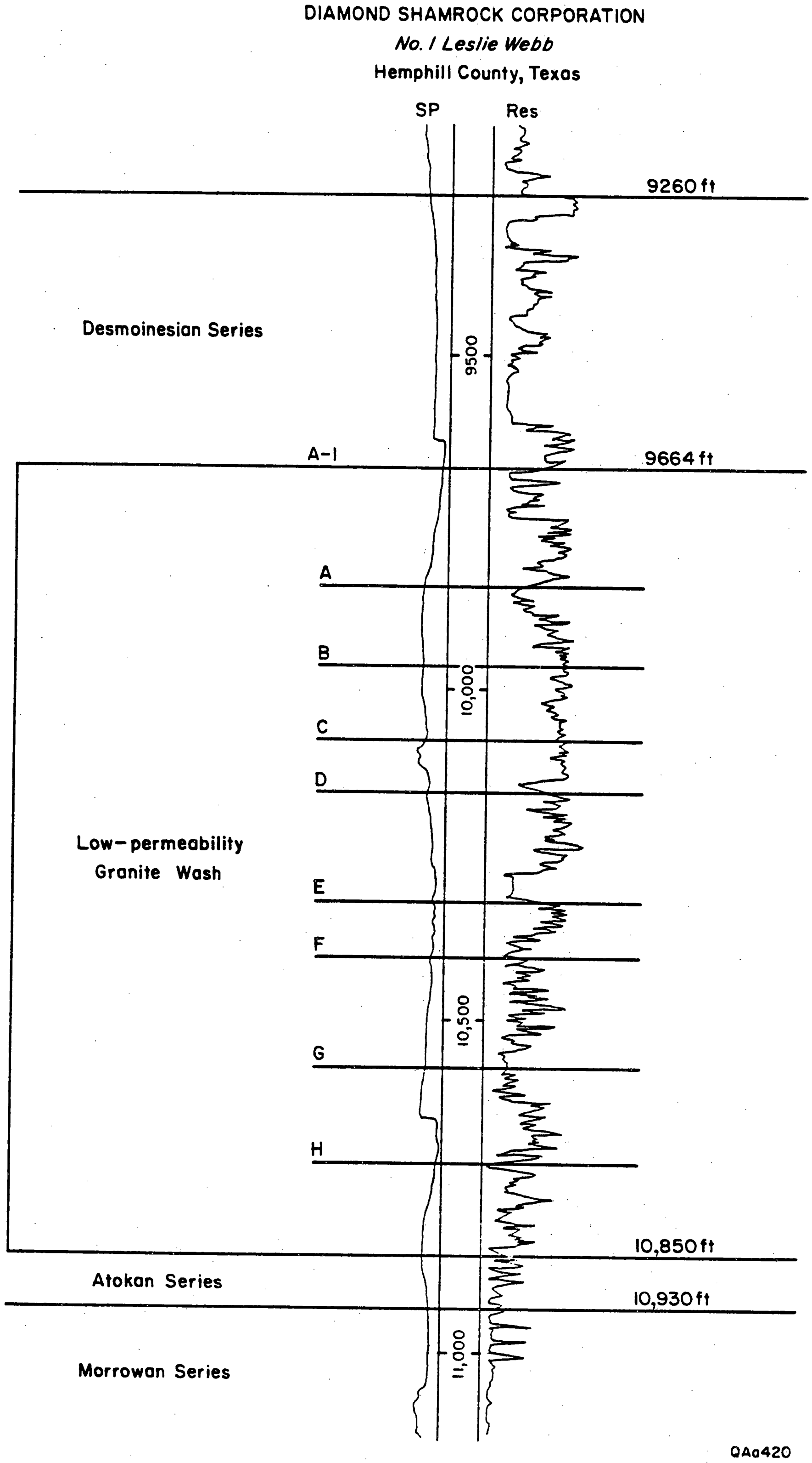


Figure 73. Representative log of the tight Granite Wash, showing all stratigraphic zones of the interval. Modified from Railroad Commission of Texas (1982a).

Shale sections as much as 30 to 40 ft thick, or possibly more in the deep Anadarko Basin region (fig. 69) of northeastern Wheeler County, occur sporadically in the interval and locally segregate potential reservoirs. The Granite Wash occurs in intervals 10 to greater than 120 ft thick (fig. 73). The log signature of the tight Granite Wash section varies regionally within the tight-gas area. The log expressions of the Granite Wash in the nine stratigraphic zones are variably upward coarsening, upward fining, blocky, and spikey (fig. 73). Most zones in the tight-gas area are upward coarsening or blocky, but their log character may change laterally within any one zone.

Depositional Systems and Reservoir Facies

The Railroad Commission of Texas (1982a) interpreted the tight Granite Wash to have been deposited in braided-stream, alluvial-fan, and fan-delta environments during the extended period of pronounced elevation of the Amarillo Uplift. Rapid erosion of this currently buried fault-bounded highland caused deposition of a large volume of generally coarse terrigenous detritus in a localized area at the southern margin of the Anadarko Basin. Non-tight Granite Wash of Missourian age in the southern part of the tight-gas area is locally interbedded with marine shales and limestones that indicate marine transgression interrupted episodes of fan-deltaic progradation (Dutton, 1982, 1990a). Only shale tongues occur in the older, tight-gas section, also recording episodic marine inundation of the fan systems. Tongues of tight Granite Wash that extend northward probably in part represent distal-fan deposition in nearshore-marine bars reworked by longshore currents. Much of the most distal parts of the Granite Wash facies tract may also represent coarse-grained, subaqueous gravity-flow deposits similar to those described by Surlyk and Ineson (1992).

The upward-coarsening log character of many of the tight Granite Wash stratigraphic zones (fig. 73) indicates progradation, probably generally northward, of Atokan and Desmoinesian fan deltas in the medial to distal parts of the fan-delta facies tract. Upward-fining and blocky intervals suggest aggradational processes, perhaps by braided streams in the more proximal parts of the fan plain. In turn, thinner zones with spikey log expressions possibly represent cyclically repeated deposits of destructional, nearshore bars or of submarine, debris-flow fans in the more distal parts of the fan-delta facies tract.

Available reservoir data on four tight Granite Wash fields (Hamon Locke, Hemphill, Northwest Mendota, and Saint Clair) indicate that trapping mechanism is stratigraphic, which is locally modified by folding (anticlines, faulted anticlines, and structural noses) (fig. 74) (Cast, 1977; Parker and Gibson, 1977; Kosters and others, 1989). Average net pay within these fields varies from 16 ft in the B and C zones to 60 ft or more in the A zone (fig. 73). The E, F, and G zones also produce gas (figs. 74 and 75) (Parker and Gibson, 1977), but data on average pay thicknesses within these zones are not available. Areal extent of all Granite Wash gas fields ranges from about 2,900 to 163,000 acres (Kosters and others, 1989).

Composition of Reservoir Facies

Reservoir lithologies of the tight Granite Wash are sandstone and conglomerate. Sandstones are typically fine to very coarse grained, poorly sorted, and mineralogically immature. Framework grains are generally subangular to angular. The low-permeability sandstones are classified as arkoses, with an average composition of 50.4 percent potassium feldspar, 24 percent quartz, 16.3 percent clay (mostly sericite and chlorite), 7 percent dolomite (as a cement), 2 percent accessory minerals, and 0.3 percent rock fragments (Railroad Commission of Texas, 1982a). Other cements in the tight intervals include calcite and siderite (Parker and Gibson, 1977). As much as 35 to 40 percent of the feldspar grains are highly altered to sericite. High clay content (largely from in situ sericitization of feldspars), dolomite cement, poor sorting, and grain angularity all contribute significantly to porosity and permeability reduction in the tight Granite Wash (Railroad Commission of Texas, 1982a). Missourian non-tight Granite Wash consists primarily of detrital grains of granite and granodiorite,

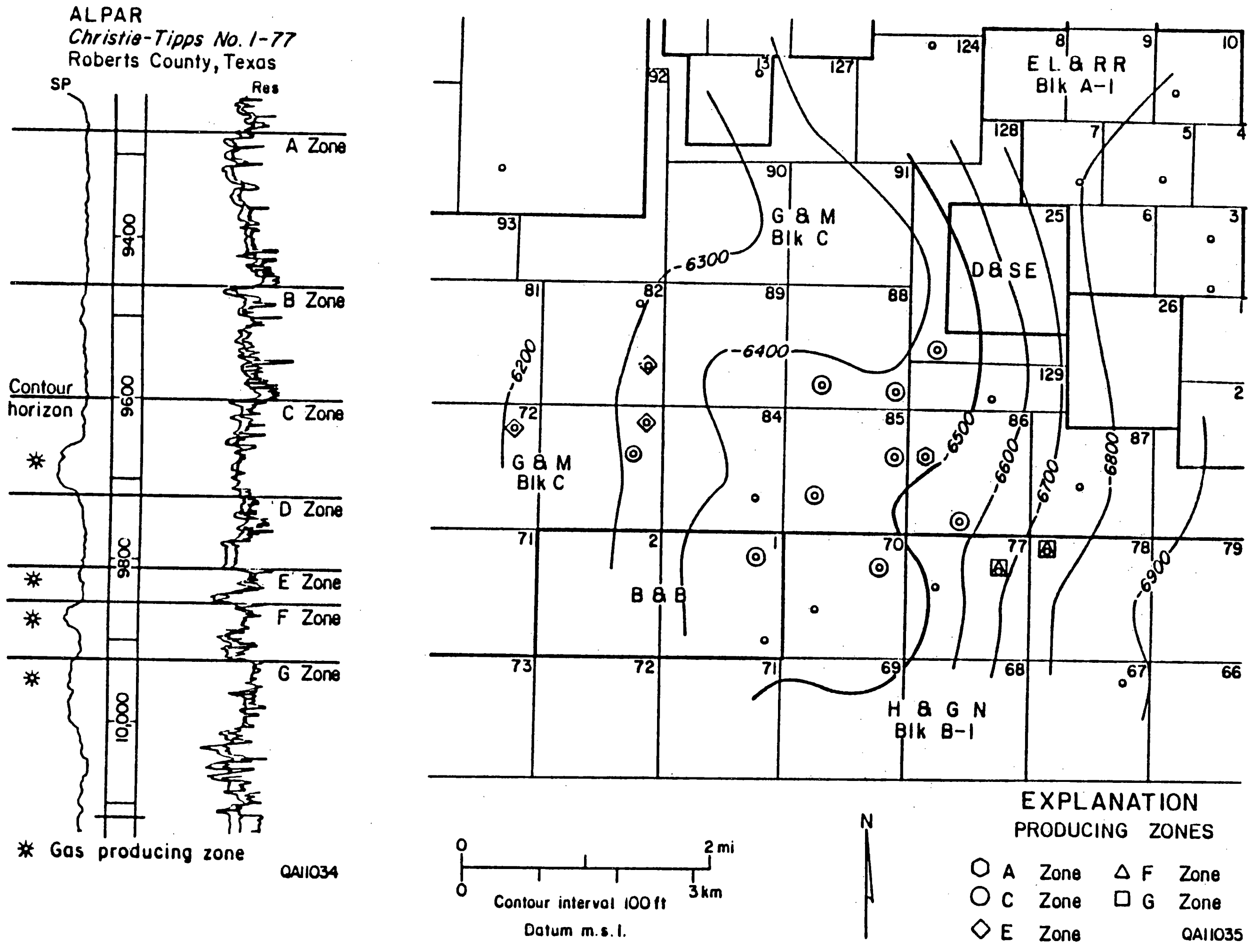


Figure 74. Structure-contour map and representative log showing producing intervals from the Saint Clair field in east-central Roberts County. See figure 72 for field location. Modified from Parker and Gibson (1977).

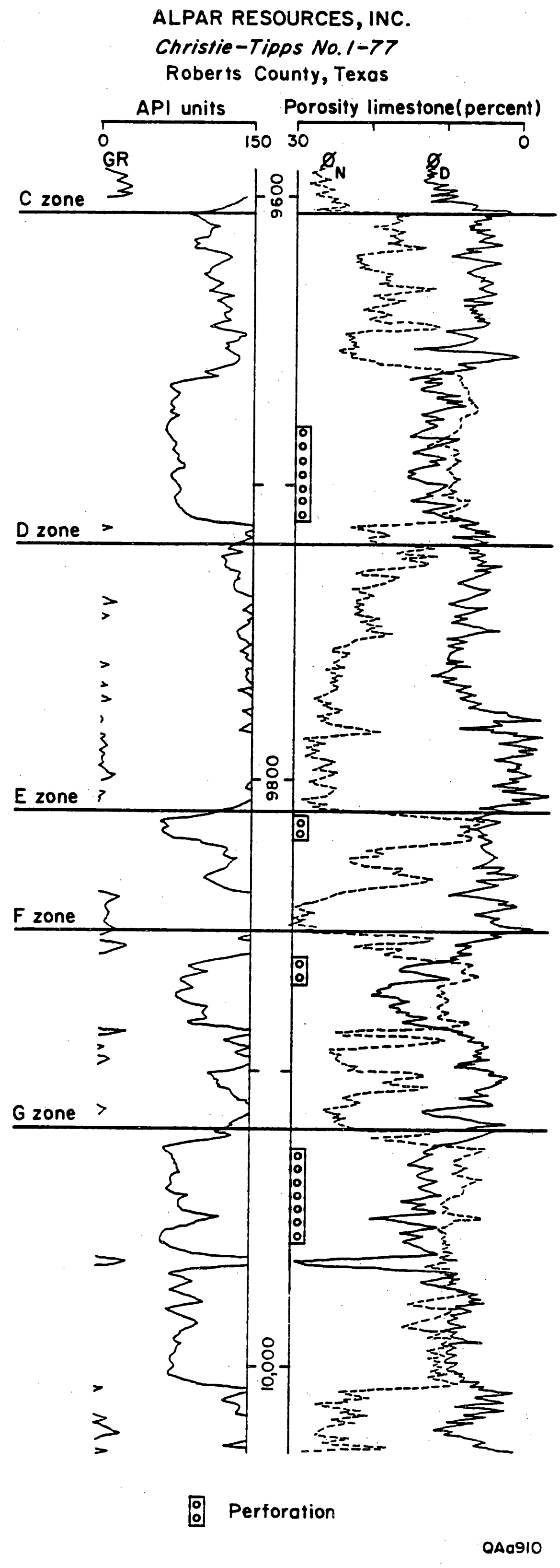


Figure 75. Well log of pay intervals in the C, E, F, and G zones of the tight Granite Wash. SP and resistivity logs are shown in figure 74.

microperthite, quartz, plagioclase, and orthoclase (Dutton and Land, 1985). The most common cements are chlorite, calcite, quartz, ankerite, and anhydrite, but the volume of calcite cement is the main control on porosity and permeability (Dutton, 1990).

Natural Fractures

No published information on naturally occurring fractures in Granite Wash reservoirs was found in the course of our review. The Granite Wash was deposited during rise of the Amarillo Uplift, a setting in which regional fractures would be expected to form.

Engineering Assessment

Porosity in the Granite Wash ranges from 4 to 12 percent with an average of 8.5 percent (Railroad Commission of Texas, 1982a) (table 17). Permeabilities are low, ranging from 0.0009 to 1.37 md. The mean permeability is 0.012 for the Granite Wash (Railroad Commission of Texas, 1982a). However, there are some better quality Granite Wash reservoirs that have average porosities as high as 11.5 percent and average permeabilities of 0.0342 md (Cast, 1977).

Composition of a typical Granite Wash sample is 50 percent potassium feldspar, 24 percent quartz, 16 percent clay, 7 percent dolomite, and 3 percent other. The atypically high feldspar content makes log interpretation and identification of potential pay zones difficult.

Net pay thickness ranges from 10 to greater than 60 ft. As in many of the formations discussed in this report, Granite Wash sandstones contain abundant shale stringers that lower the overall permeability.

Water saturations range from 22 percent to 35 percent in the gas productive sandstones (Cast, 1977; Parker, 1977). Formation waters in the Granite Wash average 140,000 ppm total dissolved solids, which corresponds to a resistivity of 0.042 Ω·m at 100°F. Formation

Table 17. Granite Wash Formation, Anadarko Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 506

Cumulative production from tight completions 1970–1988 (Bcf): 468.0

Estimated ultimate recovery from tight areas (Bcf): 698

Net pay thickness (ft): 10–60

Porosity range and average (%): 4–12/8.5

Permeability range and average (md): 0.0009–1.37/0.012

Water saturation (%): 22–35

Reservoir temperature (°F): 160–210

Reservoir pressure (psi): 1,800–2,000

Typical stimulation/hydro-frac: 102,000 gal fluid and 75,000 lb sand

Production rate:

prestimulation (Mcf/d): 0.1–4,335

poststimulation (Mcf/d): 100–3,400

Average recovery per completion (Bcf): 1.5

Decline rate: No data

temperature in the Granite Wash is 160° to 210°F. Reservoir pressures range from 1,800 to 2,000 psi.

Hydraulic fracture treatments are not large. A typical fracture-stimulation treatment in the Granite Wash uses 2,000 gal 15 percent HCl, 100,000 gal gelled salt water, and 70,000 to 75,000 lb sand proppant.

Production History

The average recovery per completion in the Granite Wash is 1.5 Bcf. Estimated ultimate recovery for the 408 wells completed in the tight Granite Wash is 698 Bcf (table 17). To date 31 fields have yielded 540 Bcf. The field with the highest yield is Hemphill field in Hemphill County, which has produced 399.6 Bcf.

Pre-fracture stimulation rates are typically quite low. After fracture, producing rates range from 100 to 3,400 Mcf/d stabilized flow.

Cherokee Group (Red Fork Formation)

Introduction

The Desmoinesian Cherokee Group of the western Anadarko Basin, Oklahoma, contains low-permeability, natural gas reservoirs in several formations. The entire group is formally designated to be tight by FERC in Beckham, Custer, Roger Mills, and Washita Counties of west-central Oklahoma. In this region of the western Anadarko Basin the Cherokee is divided into five formations (in ascending order): Inola Limestone, Red Fork Formation, Pink Limestone, Skinner Sandstone, Verdigris Limestone, and Prue Sandstone (fig. 70). Using pre-1989 production statistics, Hugman and others (1992) estimated the ultimate recovery for natural gas from the entire tight Cherokee to be 1.04 Tcf. They attributed the majority of this resource base, or

876 Bcf, to the Red Fork Formation (fig. 76), whereas other siliciclastic and carbonate units of the Cherokee Group accounted for only 165 Bcf of the total ultimate recovery. However, as of early 1992, total cumulative production from major (>10 Bcf cumulative production) Red Fork and other Cherokee (Skinner Sandstone, Prue Sandstone, and other unspecified units of the Cherokee Group) gas reservoirs in the four-county tight-gas area was 943 Bcf and 258 Bcf, respectively (Bebout and others, in press). As is evident, the recent cumulative production figures of Bebout and others (in press) already exceed the ultimate recovery estimates of Hugman and others (1992), thus highlighting the high production potential of the Cherokee tight-gas reservoirs.

This chapter focuses on the geology and reservoir characteristics of the Red Fork Formation (fig. 76) because it is the principal and best-documented gas producer in the Cherokee Group. However, geologic and reservoir characteristics of the Red Fork are not necessarily directly comparable to those of the other Cherokee reservoirs. There are 13 major Red Fork fields in the four-county tight-gas area: Butler-West Custer, North Canute, Carpenter, Northeast Carpenter, West Cheyenne, Clinton, East Clinton, East Hammon, Northeast Moorewood, Stafford, Strong City District, South Thomas, and Weatherford. Strong City District and East Clinton field are the largest with 246 Bcf and 153 Bcf cumulative Red Fork production, respectively (Bebout and others, in press).

The Cherokee Group is composed of thick sandstone and shale intervals separated by much thinner limestone units. The Cherokee thickens greatly from 200 to 300 ft in the northern and eastern shelf areas to greater than 4,000 ft along the axis of the Anadarko Basin (Whiting, 1984). In the tight-gas area, the Cherokee is about 1,500 ft to greater than 3,000 ft thick, thickening southward and westward toward the axis of the Anadarko Basin (Clement, 1991, his figures 6 and 18). Depth to the top of the Cherokee in the tight-gas area varies from about 9,900 to more than 13,000 ft; the top of the Red Fork in the same area ranges from less than 10,000 to more than 13,700 ft deep (Whiting, 1984; Clement, 1991; Bebout and others, in press). Depth of major reservoirs ranges from 10,640 ft (South Thomas field) to 13,930 ft (Carpenter

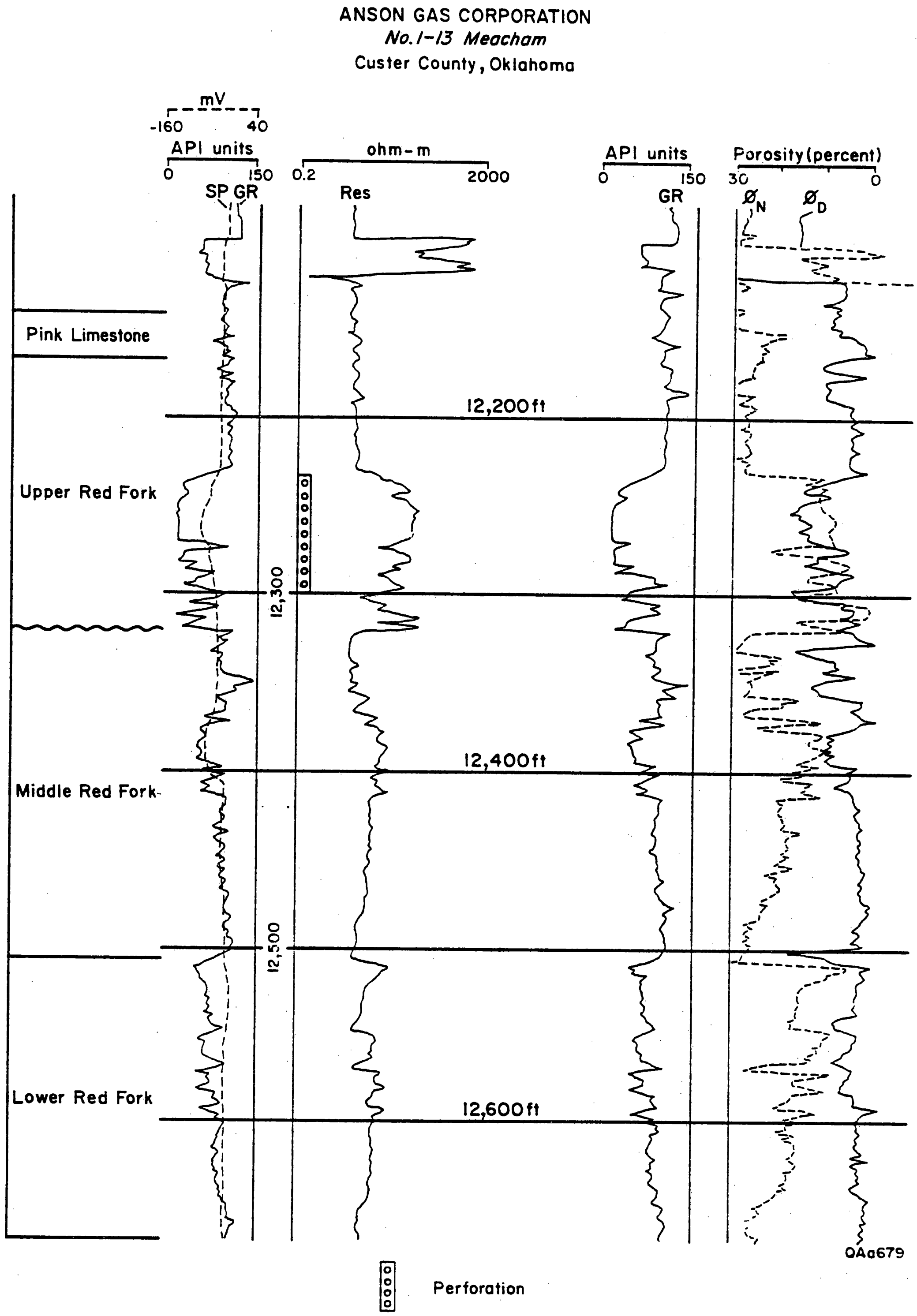


Figure 76. Representative log of the Red Fork Formation showing pay zones in the East Clinton field, Custer County, Oklahoma. Modified from Clement (1991).

field) in Custer and Mills Counties, respectively (Clement, 1991; Bebout and others, in press). The Red Fork Formation composes most of the lower part of the Cherokee Group in west-central Oklahoma and is informally divided into lower, middle, and upper members (fig. 76). Various combinations of the three members and the Cherokee Group (undifferentiated) are produced in the tight-gas area (Cornell, 1989). The entire Red Fork is about 500 to more than 1,400 ft thick in the tight-gas area (Clement, 1991).

Depositional Systems and Reservoir Facies

In the four-county tight-gas area, the Red Fork Formation facies tracts comprise fluvial-channel, fluvial-deltaic, and submarine-fan deposits (Clement, 1991). The siliciclastic Red Fork section is regionally variable in facies stacking patterns. In general, basinal facies in downdip areas, especially within the axial parts of the deep Anadarko Basin area, are thick successions (as much as 700 ft) of shale and siltstone and thinly interbedded sandstones and shales, expressed as thick intervals of subdued to spikey gamma-ray and resistivity log signatures. These facies predominate in the lower and middle Red Fork in downdip positions and are interpreted to represent submarine turbidite and slope and basinal mud accumulations (Clement, 1991). In an alternative viewpoint, Whiting (1984) postulated that all reservoir sandstones in the upper Red Fork throughout the tight-gas area originated as deep-marine, channelized submarine-fan deposits. However, Clement (1991) concluded that turbidite facies described by Whiting (1984) are distal prodeltaic components of the upper Red Fork delta. In updip positions all three Red Fork members generally contain more sandstone, and log signatures are upward-coarsening, upward-fining, and blocky (fig. 76). These deposits record fluvial and deltaic sedimentation (Hawthorne, 1985; Clement, 1991). Subregionally, especially in a localized, narrow, east-west trend in southern Custer County (fig. 77), the middle and upper Red Fork contain stacked incised-valley fluvial-channel deposits that range from less than 10

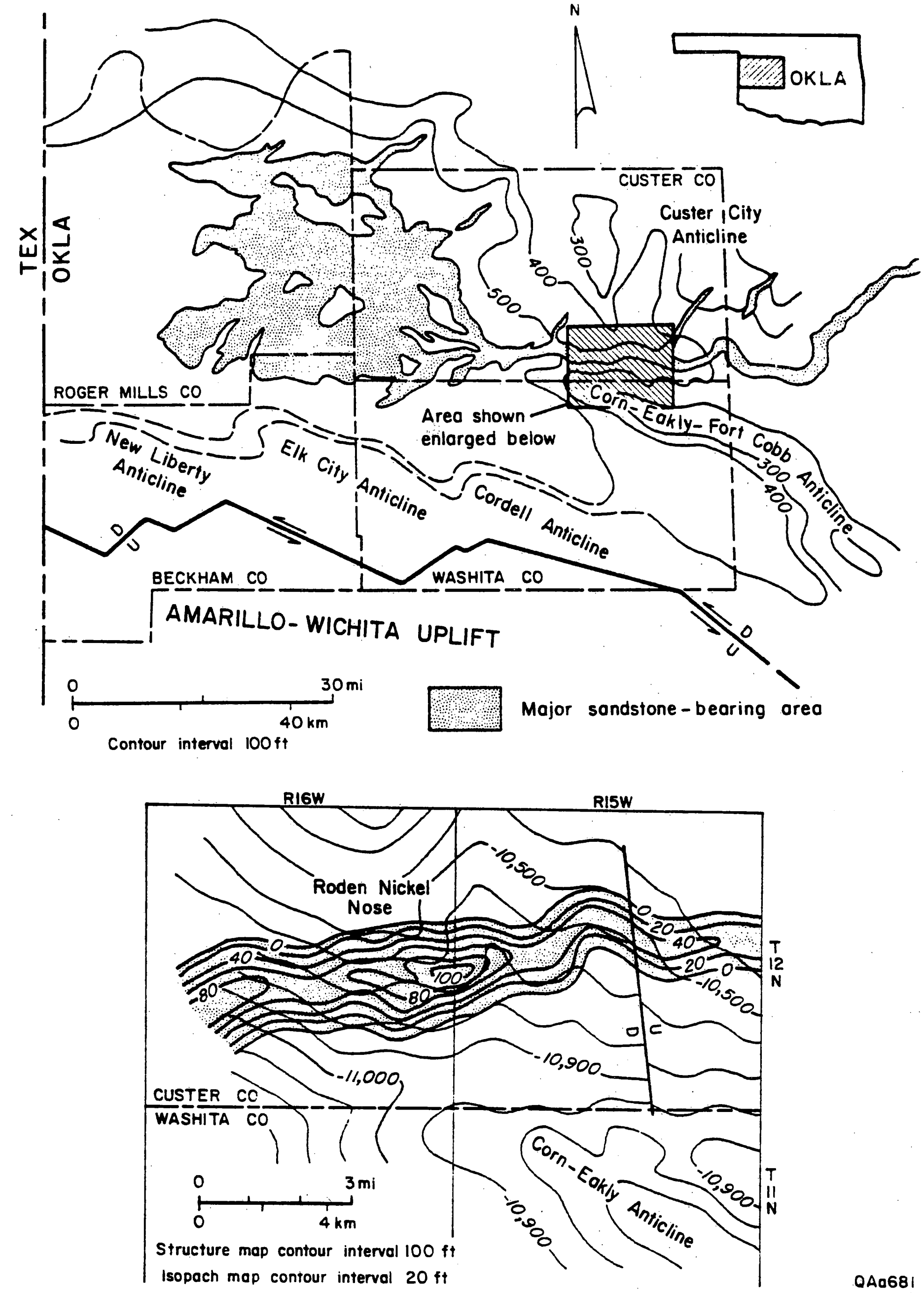


Figure 77. Sandstone-distribution and isopach map of the middle and upper Red Fork Formation. Also shown are major structures that existed during middle-upper Red Fork deposition. Inset is gross-sandstone isopach map of the upper Red Fork superimposed on structure-contour map of the top of the Red Fork in the East Clinton field, southeastern Custer County. Modified from Clement (1991).

to greater than 150 ft thick and that exhibit as much as 300 ft of erosional relief (fig. 78) (Clement, 1991).

Natural gas is produced from sand-rich fluvial, deltaic, and turbidite facies of the Red Fork Formation (Cornell, 1989), particularly in the upper lower, middle, and upper members. Several of the major Red Fork fields (Clinton, East Clinton, Stafford, Weatherford) contain valley-fill reservoirs producing from multiple pay zones comprising stacked fluvial channel fills (fig. 78) (Clement, 1991). Butler-West Custer field and Strong City District are examples of Red Fork fields that produce from low-permeability delta-front and submarine-fan (turbidite) facies, respectively (Cornell, 1989). In the same region, conventional gas resources occur in underlying Mississippian and Pennsylvanian (Springer and Morrow) reservoirs. Trapping mechanism in most Red Fork fields is stratigraphic with local enhancement by positive structural position (Clement, 1991; Bebout and others, in press). In East Clinton field, for example, incised fluvial channel sandstones are trapped laterally against older marine shales and siltstones or contemporaneous terrigenous shales and vertically by younger terrigenous shales and shaly valley fills (fig. 78) (Clement, 1991). Along the valley-fill trend in southern Custer County, fluvial reservoirs are typically abnormally pressured and encasing shales acted as source rock for gas (Clement, 1991). On average, major Red Fork gas reservoirs are about 22,000 acres in areal extent (range: 5,100 to 104,000 acres) (Bebout and others, in press).

Composition of Reservoir Facies

Reservoir characteristics vary within the tight Red Fork area, largely because of differences in depositional environment (Cornell, 1989). However, some generalizations can be made. Reservoir sandstones of the Red Fork Formation, which are typically very fine to fine-grained, are classified as sublitharenites, litharenites, and feldspathic litharenites, with an average composition of $Q_{68}F_{19}R_{13}$ (Levine, 1984). Quartz constitutes 58 to 70 percent of the essential framework grains in core samples from throughout the tight-gas area, whereas

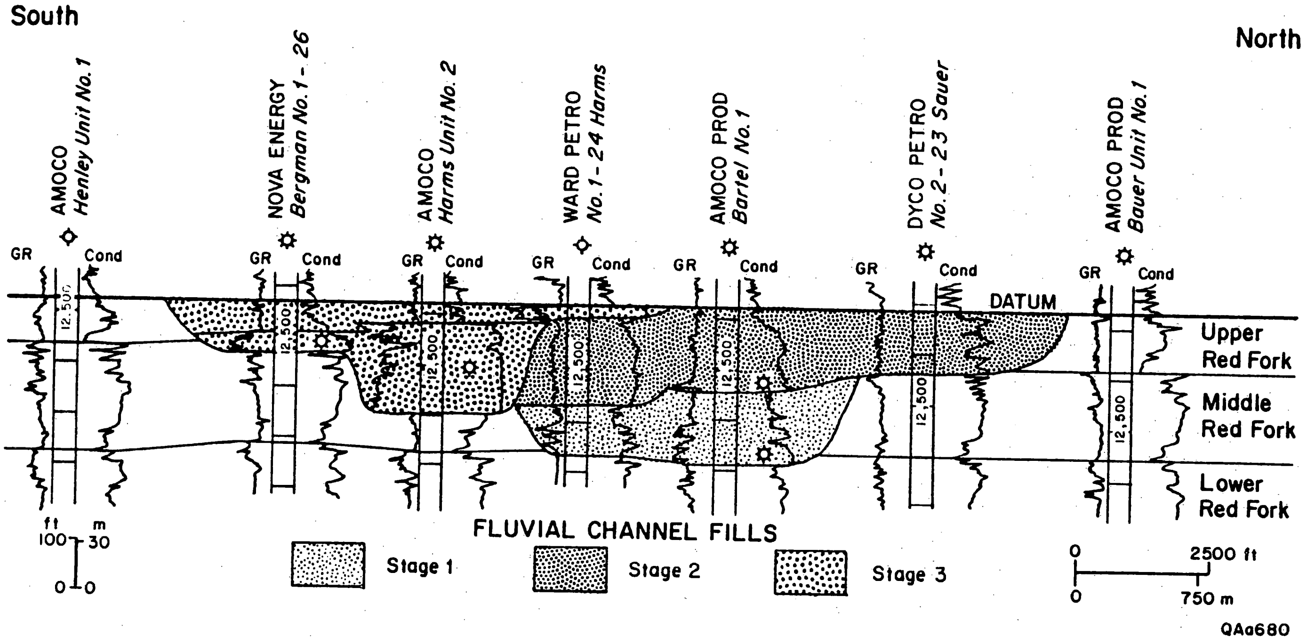


Figure 78. North-south stratigraphic cross section of the Red Fork Formation across the East Clinton field, illustrating superimposition of three fluvial-channel-fill reservoirs. Modified from Clement (1991).

feldspar and rock fragments range from 14 to 21 percent and 10 to 17 percent, respectively (Levine, 1984). Feldspars, which are commonly dissolved or partially/wholly replaced, are chiefly orthoclase and plagioclase; microcrystalline volcanic grains are the most common rock fragments. Clay matrix in Red Fork sandstone samples varies between 7 and 18 percent of the whole rock volume, with an average of 12 percent. Sandstone cements include (1) carbonate (calcite, ankerite, and dolomite), with an average of 9 percent of the whole rock volume, (2) quartz (as overgrowths), with an average of 3 percent of the whole rock volume, and (3) authigenic clay (illite, chlorite, and kaolinite), with an average of 2 percent of the whole rock volume (Levine, 1984; Clement, 1991).

The relative order of events in Red Fork Formation diagenesis is (1) growth of clay rims on framework grains, (2) calcite cementation, (3) partial feldspar and rock fragment dissolution, (4) formation of authigenic clays and quartz overgrowths, (5) grain replacement by calcite and ankerite, and (6) partial dissolution of calcite cement (Levine, 1984).

Red Fork reservoir porosity is almost entirely secondary and developed by dissolution of authigenic cements and detrital framework grains; average Red Fork porosity is 9.0 percent (Levine, 1984). Average porosity values of the Red Fork increase northward in the tight-gas area, varying from 5 percent or less in most of Beckham and Washita Counties to 10 percent or greater in northern Custer and Roger Mills Counties (Levine, 1984).

Natural Fractures

Naturally occurring fractures have not been described from Cherokee/Red Fork reservoirs. Natural fractures are indirectly indicated by high leakoff in some wells; successful stimulation of Red Fork reservoirs requires proper selection of a fluid-loss additive to control leakoff to natural fractures (Cornell, 1991). Appropriate leakoff-inhibitor concentrations can be identified with calibration treatments. In view of their apparent effects on stimulation, analysis of natural fracture attributes in these units is warranted.

Stress

Northeast-trending maximum horizontal stress is predicted in the mid-plate stress province of Zoback and Zoback (1980, 1989), where Cherokee/Red Fork reservoirs are located. Limited results from two Cherokee/Red Fork wells in western Oklahoma (Cornell, 1991) are inconsistent with this prediction, however. The methods used to find maximum horizontal stress orientation in these wells were anelastic strain recovery and the strike of coring-induced fractures, but actual measurements were not presented by Cornell (1991). According to Cornell, strain-recovery methods gave limited information that suggests east-trending maximum horizontal stress, but the data are imprecise because of rapid core relaxation. The strike of coring-induced fractures agrees with this interpretation of the strain-recovery results (Cornell, 1991). No published stress profiles for Cherokee/Red Fork reservoirs are currently available.

Engineering Assessment

Most engineering data that have been acquired for the Cherokee Group are from the upper Red Fork Formation (table 18). However, the lower and middle Red Fork sandstones, as well as the other sandstone formations within the Cherokee Group, are probably similar to the poorer quality upper Red Fork sandstones. Levine (1984) described Red Fork sandstones (including those of the upper Red Fork) as having porosities averaging 9 percent. Whiting (1984) described Red Fork porosities as ranging from 1 to 17 percent, which is consistent with Levine's data. The higher porosities occur in East Clinton field, where the majority of published data have been collected. In East Clinton field, porosities are as high as 18 percent, with averages in some of the pay sections as high as 15 percent (Clement, 1991). Skinner sandstones, stratigraphically above the Red Fork, have average porosities of 6.2 percent. Permeabilities in the Red Fork range from less than 0.1 to as high as 20 md in the higher porosity reservoirs. Log-calculated values generally agree with those from core analyses.

Table 18. Cherokee Formation, Anadarko Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 507

Cumulative production from tight completions 1970–1988 (Bcf): 566.3

Estimated ultimate recovery from tight areas (Bcf): 1,041

Net pay thickness (ft): 7–206

Porosity range and average (%): 1–18/9

Permeability range (md): 0.1–20

Water saturation (%): 20–35

Reservoir temperature (°F): 210–225

Reservoir pressure (psi): 2,500–10,000

Typical stimulation/hydro-frac: Limited data; sand/bauxite mix may be required in high-pressure reservoirs.

Production rate:

- prestimulation (Mcf/d): 500–2,500
- poststimulation (Mcf/d): 3,800–7,600

Average recovery per completion (Bcf): 2.2–8.8 (12–16 in Red Fork)

Decline rate: 27% (Red Fork)

Water saturations range from 20 percent in the cleaner sandstones to 35 percent in shaly intervals (Clement, 1991). Net pay varies from 7 to about 206 ft (Clement, 1991). Formation water salinity is 35,000 to 45,000 ppm total dissolved solids. This corresponds to a resistivity value of 0.045 to 0.055 at a reservoir temperature of 210° to 225°F.

Reservoir pressure is 2,500 to 10,000 psi (table 18). The low pressures are recorded at East Clinton where production has occurred since 1975. There is no observable water drive at East Clinton.

Gas completions may be natural (not requiring stimulation) in the higher quality reservoirs or may require stimulation. Some of the natural completions are among the most prolific producers. The Amoco Adler No. 2 well in East Clinton field was completed naturally at a rate of 12 MMcf/d. In Red Fork reservoirs outside of East Clinton field and in other Cherokee sandstones, fracture stimulations are generally a necessity. Because of the great depth of the Cherokee reservoirs and the high reservoir pressures, it may be necessary to use bauxite or other proppant material in addition to sand during the fracture stimulation. In one of the early wells, the fracture stimulation consisted of 100,000 lb of sand and 27,000 lb of bauxite as the proppant.

Overall, recovery per completion ranges from as low as 0.25 Bcf to as high as 16 Bcf. At East Clinton field 65 wells have produced 273 Bcf and 5.4 MMbbl of condensate. Per-well average annual production is 71 Bcf and 24,000 bbl of condensate (Clement, 1991). Estimated ultimate recovery at East Clinton field is 480 Bcf and 10.5 MMbbl of condensate.

Well spacing for Red Fork wells is 640 acres but may decrease to 320 if approved by the state of Oklahoma. Decline rate for the Red Fork overall is 27 percent, but for the upper Red Fork sandstones at East Clinton it is 20 percent (table 18).

Cleveland Formation

Introduction

The Upper Pennsylvanian (lower Missourian) Cleveland Formation is a moderately prolific natural gas producer, having yielded more than 435 Bcf as of January 1991 from sandstone reservoirs in the western part of the Anadarko Basin, northeastern Texas Panhandle (Railroad Commission of Texas, 1991a). The siliciclastic Cleveland Formation is the lowest unit of the Missourian Skiatook Group, which also includes the Kansas City Formation; the Desmoinesian Marmaton Group, comprising undivided siliciclastic strata and the Oswego Limestone, underlies the Cleveland (fig. 70). The stratigraphic boundaries of the Cleveland Formation are well constrained by thin, regionally correlative high-gamma-ray black shale marker beds (fig. 79). The Cleveland extends in the subsurface from the western terminus of the Anadarko Basin at least as far east (basinward) as west-central Oklahoma and probably farther. To the south in the tight-gas area, Cleveland sandstones interfinger with coarse-grained arkosic rocks (fan-deltaic granite wash) along the northern flank of the Amarillo Uplift. Equivalent Cleveland carbonate facies of the Kansas Shelf exist to the north in the northernmost part of the tight-gas area and in the Oklahoma Panhandle (fig. 79).

The formally designated tight-gas-producing region includes all or parts of seven Texas counties: Hansford, Hemphill, Hutchinson, Lipscomb, Ochiltree, Roberts, and Wheeler Counties (Railroad Commission of Texas, 1981a). However, in 1983 FERC also designated the Cleveland as tight in a portion of Ellis County, Oklahoma, located just east of Lipscomb County, Texas. Most natural gas fields occur in only Lipscomb and Ochiltree Counties (fig. 80). The formation also produces moderate amounts of oil in these areas. Many conventional oil and gas reservoirs also occur in other Pennsylvanian and older Paleozoic strata in the Cleveland producing region.

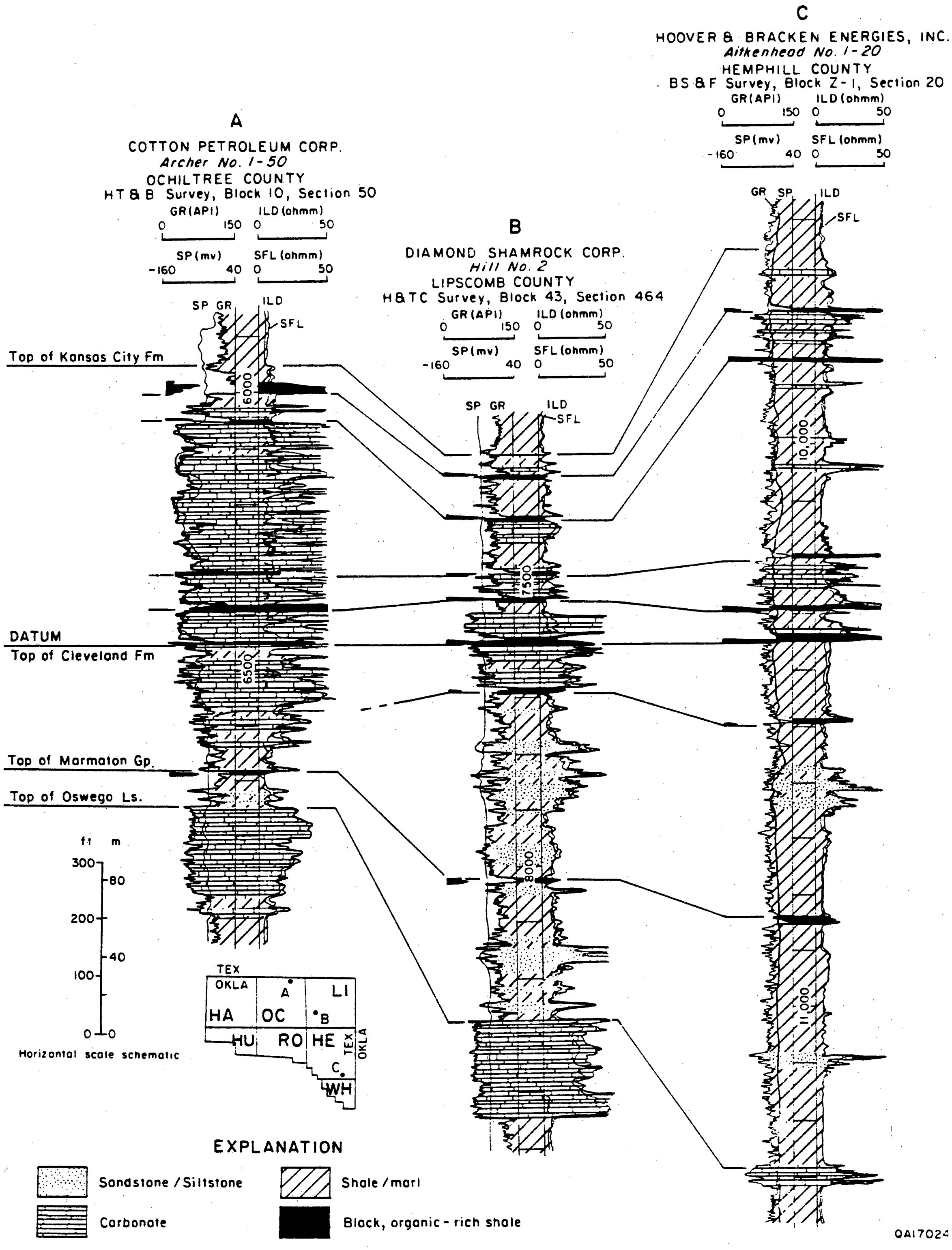


Figure 79. Representative shelf-to-basin cross section of the Cleveland Formation and adjacent units. Index map shows formally designated Cleveland tight-gas area in the northeastern Texas Panhandle. HA, OC, LI, HU, RO, HE, and WH identify Hansford, Ochiltree, Lipscomb, Hutchinson, Roberts, Hemphill, and Wheeler Counties, respectively. From Hentz (1992).

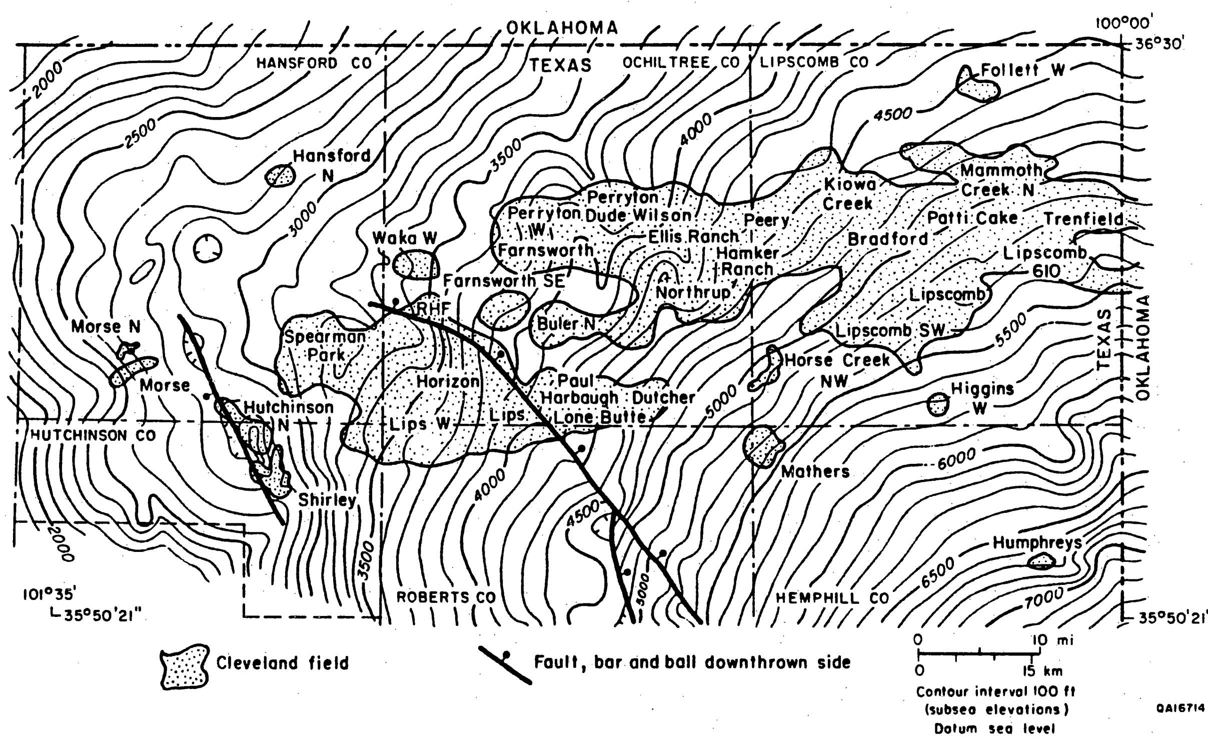


Figure 80. Map of major Cleveland hydrocarbon fields superimposed on structure-contour map of top of Cleveland. From Hentz (1992).

The Cleveland Formation generally thickens and descends southeastward in the subsurface toward the deeper, central part of the Anadarko Basin in Oklahoma. In the formal tight-gas area, Cleveland thickness ranges from a feather edge in the west to about 590 ft in shaly, basinal facies in southern Hemphill County. In the two-county producing area, the unit is about 60 (central Ochiltree County) to 480 ft (south-central Lipscomb County) thick, and net sandstone thickness locally exceeds 160 ft, attaining a maximum net thickness of 215 ft in south-central Lipscomb County (Hentz, 1992). Depth to the top of the formation in the seven-county area varies from about 5,800 to 11,800 ft. In the tight-gas-producing area, the Cleveland is about 6,600 (west) to 8,000 ft (east) deep; subsea depths range from about 3,600 (west) to 5,400 ft (east) (fig. 80).

Recent regional and field-specific studies of the Cleveland Formation have largely been funded by the Gas Research Institute (GRI) as part of a program to locate and drill experimental wells to conduct geologic and engineering research on this low-permeability, gas-bearing unit. Drilling of two GRI/Maxus Exploration Company cooperative gas wells in the Ellis Ranch field of Ochiltree County, the premier Cleveland gas field, allowed down-hole investigation of primary reservoir characteristics. Other data are available in published and unpublished sources, most of which are cited in this discussion. Older published accounts of the Cleveland are more limited in scope; most are field descriptions or collections of field isopach and net-sandstone maps (Stevens and Stevens, 1960; Wagner, 1961; National Petroleum Bibliography, 1965).

Depositional Systems and Reservoir Facies

Throughout most of the seven-county tight-gas area, the Cleveland Formation contains mostly sandstone and shale. Carbonates are generally restricted to the upper part of the unit, except in the northern part of the tight-gas area where they are the dominant lithology (fig. 79). Siliciclastics of the Cleveland section form mostly stacked, upward-coarsening (progradational) marine successions containing deltaic facies (in ascending order within each cycle): prodelta, distal delta front, and proximal delta front (fig. 81) (Hentz, 1992; Hentz, in press). A prominent, upward-fining, westerly sourced fluvial sandstone within an entrenched valley fill occurs in one stratigraphic zone in the middle to upper Cleveland in most of the seven-county, tight-gas area. Cleveland delta systems prograded eastward and were fed by sediment sources west of the Anadarko Basin.

Placed in a sequence-stratigraphic context, the superimposed Cleveland deltaic cycles form a highstand systems tract overlying a downlap or maximum flooding surface at the top of a transgressive systems tract in the underlying Marmaton Group (fig. 81) (Hentz, in press). The maximum flooding surface occurs in an areally extensive condensed section, a thin, high-gamma-ray, organic-rich black shale that forms the stratigraphic boundary between the Marmaton and Cleveland and may have been a primary source rock for Cleveland gas. Entrenchment of the valley-fill sandstone lying above the highstand systems tract occurred during an abrupt fall in relative sea level of a Late Pennsylvanian eustatic lowstand phase. The base of the valley-fill system is a sequence boundary that can be correlated throughout the tight-gas area and possibly over much of the Midcontinent.

Cleveland reservoirs trap natural gas mostly in the tight, relatively matrix-free, proximal delta-front sandstones capping deltaic cycles (figs. 81 and 82) but also locally in the fluvial valley-fill sandstones (Hentz, 1992). Trap styles of most fields are either combination (stratigraphic and structural) or stratigraphic types. Combination traps typically involve pinch-out of reservoir facies within small (4 to 8 mi long) southeast-plunging anticlines (structural noses) in central Ochiltree and Lipscomb Counties (fig. 80). Structural closures aligned along the axes of these anticlines also form traps in some fields. Facies termination of, and porosity/permeability pinch-out within, northwest-trending proximal delta-front sandstones along the northern flanks of the Cleveland delta systems compose the stratigraphic traps in the producing area.

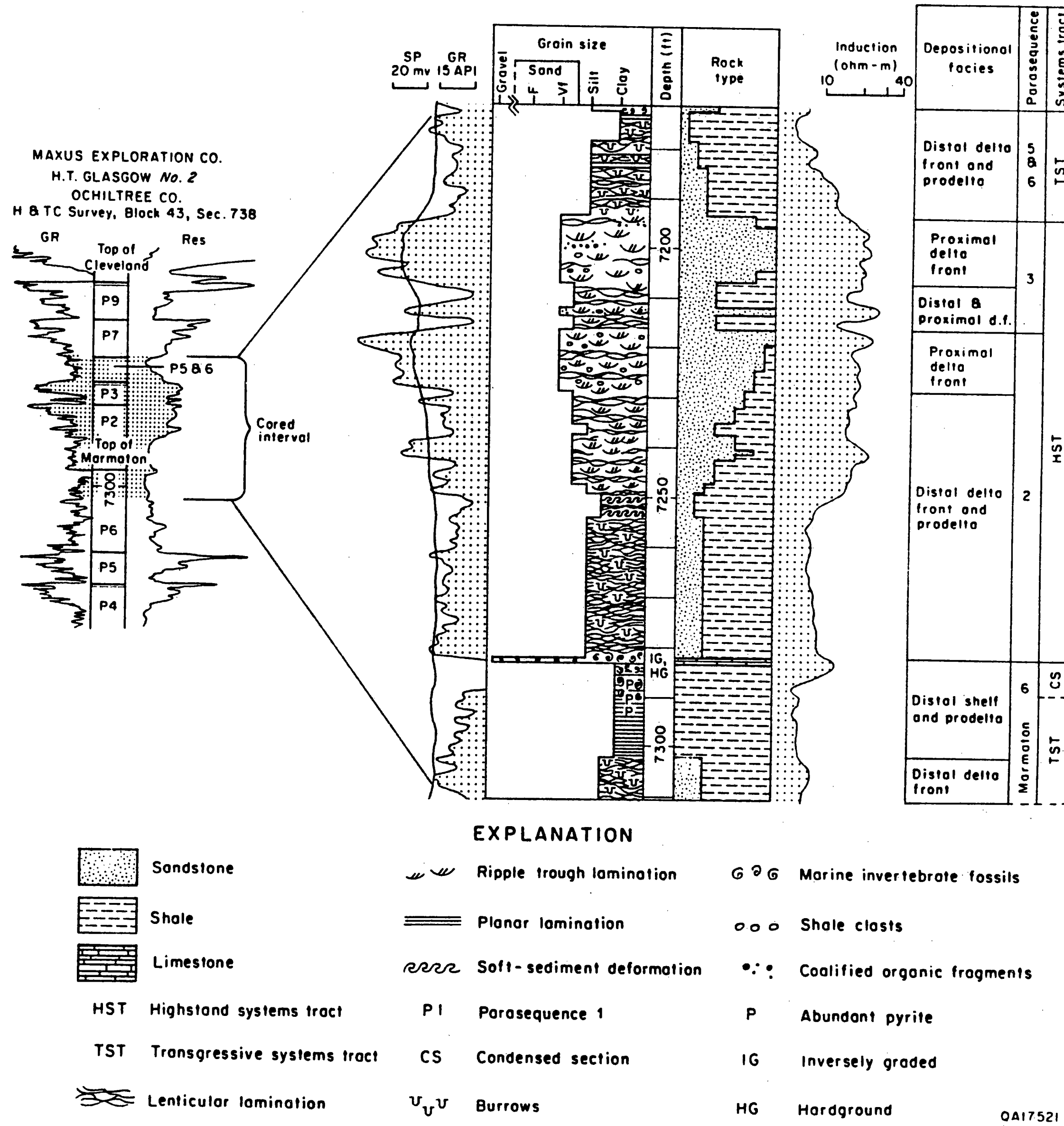


Figure 81. Core log of the upper Marmaton Group (undivided) and lower and middle Cleveland Formation from the Maxus Glasgow No. 2 well of the highly gas-productive Ellis Ranch field in east-central Ochiltree County. Tight gas is produced mostly from relatively clean delta-front sandstones capping upward-coarsening deltaic cycles of a highstand systems tract (see fig. 82). The Cleveland entrenched valley-fill system does not occur at the site of this well; however, a sequence boundary exists at the correlative horizon at the top of the highstand systems tract. From Hentz (1992).

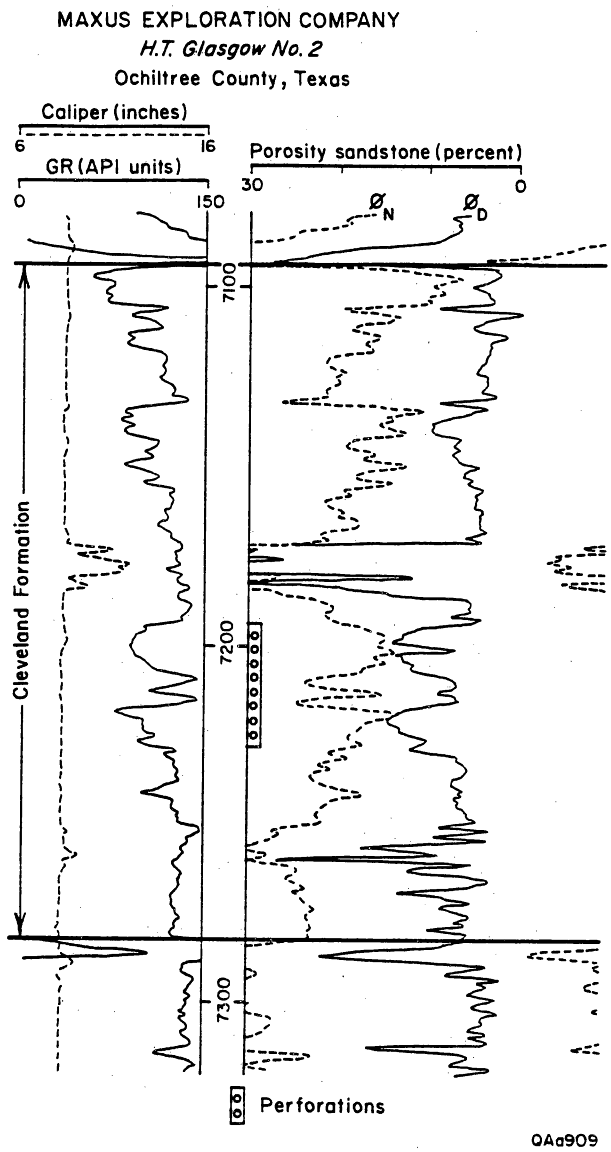


Figure 82. Well log of pay zone in the Cleveland Formation, Ellis Ranch field. Core log of part of the Cleveland interval from the same well shown in figure 81.

On average, Cleveland gas reservoirs are about 25,700 acres in areal extent (range: 5,000 to 57,350 acres) (Kosters and others, 1989). Potential reservoir sandstones are as much as 65 ft thick but are locally 90 to 100 ft thick where there is superposition of delta-front sandstones from two deltaic cycles (Hentz, 1992). Within fields and subregionally, reservoir sandstones are generally continuous with sheet-like geometries, especially in the northwest-southeast direction parallel to the Cleveland deltaic paleo-shoreline in the producing area. Reservoir thickness increasingly varies northward and westward in Ochiltree County and northward and eastward in Lipscomb County with progressive pinch-out of deltaic sandstone facies. Bounding facies of Cleveland sandstone reservoirs are well-indurated, largely calcite-cemented distal shelf, prodelta, and distal delta-front shales and silty/sandy shales that are typically less than 25 ft thick above and no more than 60 ft thick below the reservoir sandstones.

Composition of Reservoir Facies

Reservoir sandstones of the Cleveland Formation are typically very fine grained, mineralogically immature, and classified as feldspathic litharenites and lithic arkoses, with an average composition of $Q_{59}F_{21}R_{20}$ (S. P. Dutton, personal communication, 1991; Hentz, 1992). In the Maxus Glasgow No. 2 core from Ellis Ranch field (Hentz, 1992), quartz constitutes 50 to 71 percent of the essential framework grains. Feldspar ranges from 13 to 32 percent of the framework grains. Rock fragments, varying from 12 to 24 percent of the framework grains, are mostly pelitic metamorphic lithologies (low-rank phyllite and slate to high-rank schist). Authigenic cements and replacive minerals constitute between 10 and 34 percent of the whole rock volume. Cored Cleveland reservoir sandstones are typically ripple cross-laminated, containing numerous shale laminae and shale rip-up clasts. Clean (matrix-free) sandstones occur but are minor by volume. Illite, kaolinite, and chlorite compose most of the detrital clay matrix (S. P. Dutton, personal communication, 1991; Hentz, 1992). The sandstone cements, as determined from several Cleveland cores, are (1) quartz (as overgrowths), with an average of

7.3 percent of the whole rock volume, (2) carbonate (calcite, ankerite, and siderite), with an average of 6.2 percent of the whole rock volume, and (3) authigenic clay (chlorite, illite, and kaolinite), with an average of 3.0 percent of the whole rock volume (Hentz, in press).

Natural Fractures

With the limited evidence then available, Finley (1984) found no definitive proof for contributions of natural fractures to production in the Cleveland Formation. The structural setting of this unit adjacent to the Cimarron Arch, the fault-bounded Amarillo Uplift, and the regional Lips fault system suggests that natural fractures need to be taken into account in planning Cleveland exploration and development. Fractured reservoirs are recognized in carbonate units in the Anadarko Basin (Landes, 1970), and Bradshear (1961) interpreted fractures to contribute to reservoir permeability in some Cleveland Formation wells. However, no definitive production evidence of naturally occurring conductive fractures has been presented in the literature.

In two GRI research wells in the northeastern Texas Panhandle, three natural fractures were encountered in approximately 201 ft of core; these fractures were also visible on FMS logs (CER Corporation, 1991b). Fractures are short (less than 1 ft), subvertical, mineralized (closed) extension fractures. Three fractures have northwesterly strikes (300°–320°). CER Corporation (1991b, 1992c) presented core fracture descriptions for these wells.

The Cleveland was deposited during rise of the Amarillo Uplift. The setting of Cleveland deposition and early burial is one in which regional fractures would be expected to have formed. Moreover, syndepositional or early post-depositional folding and faulting is evident from regional maps (Hentz, 1992). Several major Cleveland reservoirs are on small, southeast-plunging anticlines (noses) where fractures might be expected, but fracturing in these areas has not been documented. Some Cleveland reservoirs in southwestern Ochiltree, southern Hansford, and northern Hutchinson Counties are associated with the northwestern end of the northwest-trending Lips fault and associated subsidiary faults. The Lips fault has had a protracted history of movement that could have produced fractures in Cleveland reservoir rocks; the northwest strike of this fault is subparallel to the few known fractures from Cleveland reservoirs.

Engineering Characteristics

Available analyses of porosity and permeability in Cleveland reservoir sandstones (fig. 83) indicate a moderate degree of uniformity within parts of the producing area. Porosity in the two GRI/Maxus research wells, which are typical Cleveland wells, ranges from 3 to 14 percent, with an average of 7 to 9 percent (table 19). In general this agrees with Finley (1984, 1986), who showed a range for the Cleveland of 4 to 14 percent. Average porosity in the Maxus Glasgow No. 2 well (Ellis Ranch field) through the pay interval was 10.0 percent, which is typical of Cleveland sandstones. Grain density of the sandstones in the wells averaged 2.69 g/cc. The difference from a normal sandstone density of 2.65 is caused by occurrences of chlorite and calcite within the sandstones.

Permeability values of core samples from wells in Ellis Ranch field range from 0.003 to 4.55 md. The arithmetic average permeability from individual cores is typically 0.15 md or less. The Railroad Commission of Texas (1981a) documented the arithmetic average in situ permeability for Cleveland sandstones in 501 wells in the two-county producing area as 0.140 md; values range from a high of 19.55 md to a low of <0.001 md. The permeability is affected by significant amounts of clay.

Well-test analysis after perforations indicated a permeability-thickness (kh) of 2.73 md-ft. This corresponds to an average permeability of 0.1 md across the pay interval of 27 ft (S. A. Holditch & Associates, Inc., 1992) in the Maxus Glasgow No. 2 well. Net pay in major Cleveland gas fields typically ranges from 6 to 54 ft (Stevens and Stevens, 1960; Wagner, 1961; Kosters and others, 1989).

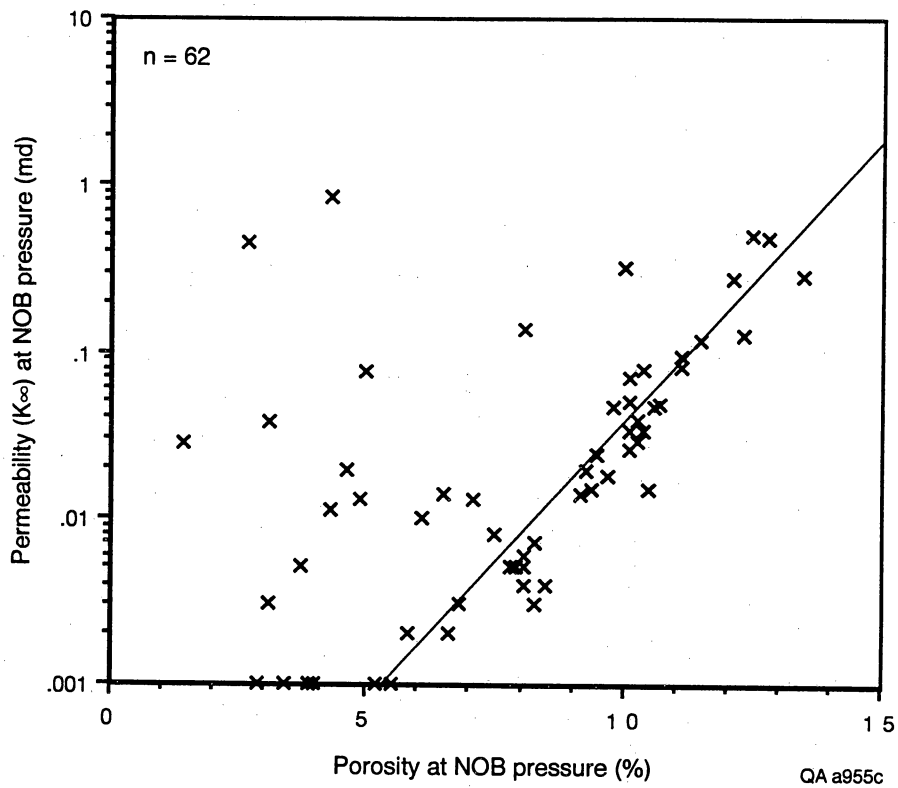


Figure 83. Semi-log plot of porosity measured at net overburden pressure vs. Klinkenberg-corrected gas permeability measured at net overburden pressure for 62 Cleveland sandstone samples. Line is approximate trend line for porosity-permeability relationship, ignoring data interpreted to be of poor quality.

Table 19. Cleveland Formation, Anadarko Basin: production data and engineering parameters.

Estimated resource base (Tcf): 38

No. tight completions: 770

Cumulative production from tight completions 1970–1988 (Bcf): 383.3

Estimated ultimate recovery from tight areas (Bcf): 721

Net pay thickness (ft): 6–54

Porosity range and average (%): 3–14/8

Permeability range and average (md): 0.001–19.55/0.14

Water saturation range and average (%): 30–40/35

Reservoir temperature (°F): 145–160

Reservoir pressure (psi): 2,200–2,700

Typical stimulation/hydro-frac (hundred thousand): 90,000 gal fluid and 250,000 lb sand

Production rate:

prestimulation (Mcf/d): 70

poststimulation (Mcf/d): 220

Average recovery per completion (MMcf): 969

Decline rate: 56% in first yr, then 11%/yr

Water saturation in productive Cleveland sandstones, calculated using log analysis, averages 35 percent (Finley, 1984). The lowest water saturation measured in the core from the Maxus Glasgow No. 2 well is 45 percent. No published capillary pressure data for the Cleveland exist to explain the differences between log-calculated and core-measured water saturations, but the high core water saturations may be caused by flushing of the core during core acquisition. Cementation and saturation exponents were measured at 2.05 and 1.44, respectively.

Reservoir pressure in the Cleveland ranges from 2,200 to 2,700 psi (table 19). Reservoir temperature is 145°–160°F. Virtually all wells have to be fracture stimulated. Pre-fracture production may range from zero to as high as 50 to 70 Mcf/d. Large but not massive fracture stimulations are conducted. Public-domain data suggest an average hydraulic fracturing job of 250,000 lb of sand proppant. The GRI research well, Maxus Glasgow No. 2, was perforated over 25 ft and fractured with 140,000 gal of 40 lb/gal gel and 595,000 lb of 20/40 sand. Initial flow rate after fracturing in this well was 700–800 Mcf/d, significantly higher than average Cleveland post-fracture production of 220 Mcf/d (Finley, 1984). The well had sustained production of 300 Mcf/d 3 months after being placed on production. This indicates that a larger hydraulic fracturing job may improve production rate. Data from this well indicate that vertical height growth may be a problem because of the lack of stress contrast between zones.

Production History

Well spacing in the Cleveland is 320 to 640 acres, depending on the field. The estimated resource base of the Cleveland is 38 Tcf (Haas and others, 1988) (table 19). Estimated ultimate recovery from currently producing wells is 721 Bcf (Hugman and others, 1992). The number of completed wells in the Cleveland is 770. Average recovery per completion is 969 MMcf. Decline rates average 56 percent for the first year and 11 percent per year for the life of the well.

PERMIAN BASIN

The Permian Basin of West Texas and southeastern New Mexico (fig. 1) produces natural gas from low-permeability carbonate and siliciclastic formations ranging in age from Middle Silurian to Early Permian (Leonardian); however, major FERC-designated, tight-gas sandstones are restricted to the Pennsylvanian and Permian Systems of the Northwest Shelf and northern Delaware Basin (figs. 84 and 85). These sandstone reservoirs occur in the Lower Pennsylvanian Morrow and Lower Permian Abo Formations (fig. 84). The Morrow is designated tight and produces gas from the Northwest Shelf and from the northern Delaware Basin of east-central and southeastern New Mexico, respectively. Gas production from areas in which the Abo is designated tight occurs only on the Northwest Shelf of east-central New Mexico.

The Delaware Basin, Central Basin Platform, Midland Basin, and Northwest Shelf collectively compose the Permian Basin (fig. 85). Differentiation of these structural elements began in Middle Pennsylvanian time, when vertical movement along zones of weakness inherited from late Precambrian faults induced formation of an elevated partition between the Delaware and Midland Basins (Hills, 1984; Frenzel and others, 1988). Pre-Pennsylvanian strata in this region were deposited in the Tabosa Basin, the predecessor of the Delaware and Midland Basins. The predominantly siliciclastic facies tract of the Morrow Formation extends from the Northwest Shelf into the Delaware Basin, and gas-producing reservoirs are represented by a range of continental to marine depositional environments: fluvial-deltaic, tidal channel, nearshore bar, and strandplain. In contrast, the Abo Formation produces tight gas only from fluvial and possibly delta-plain sandstone reservoirs and only on the Northwest Shelf.

Other formations in the Permian Basin have been formally designated as tight by FERC. In New Mexico, these include (1) undifferentiated Mississippian units and (2) the Atoka Group. In Texas, FERC-approved tight formations in the Permian Basin include (1) the Middle Silurian Fusselman Formation, (2) undifferentiated Devonian units, (3) the Desmoinesian

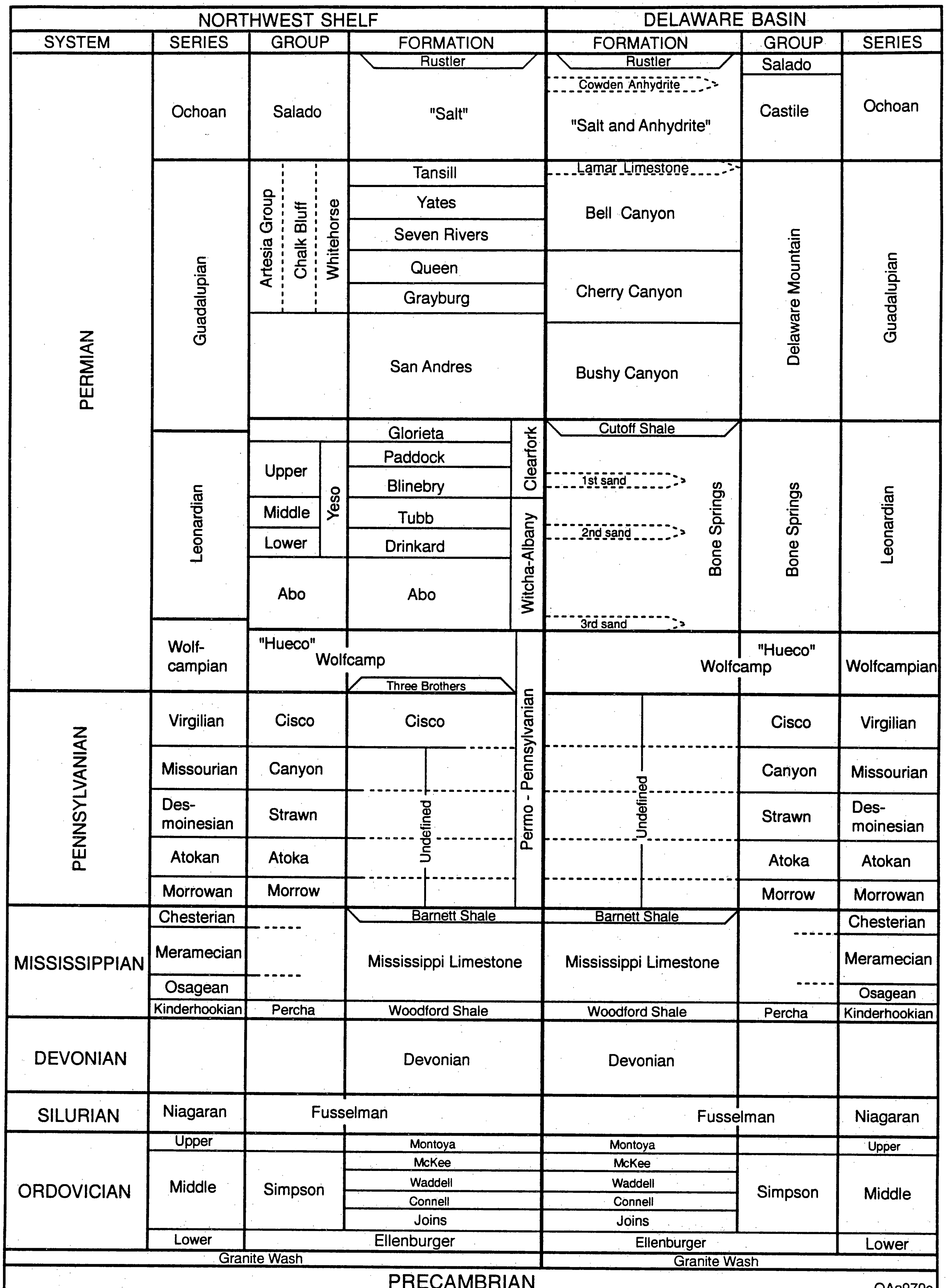


Figure 84. Stratigraphic column of the Paleozoic units of the Northwest Shelf and Delaware Basin.

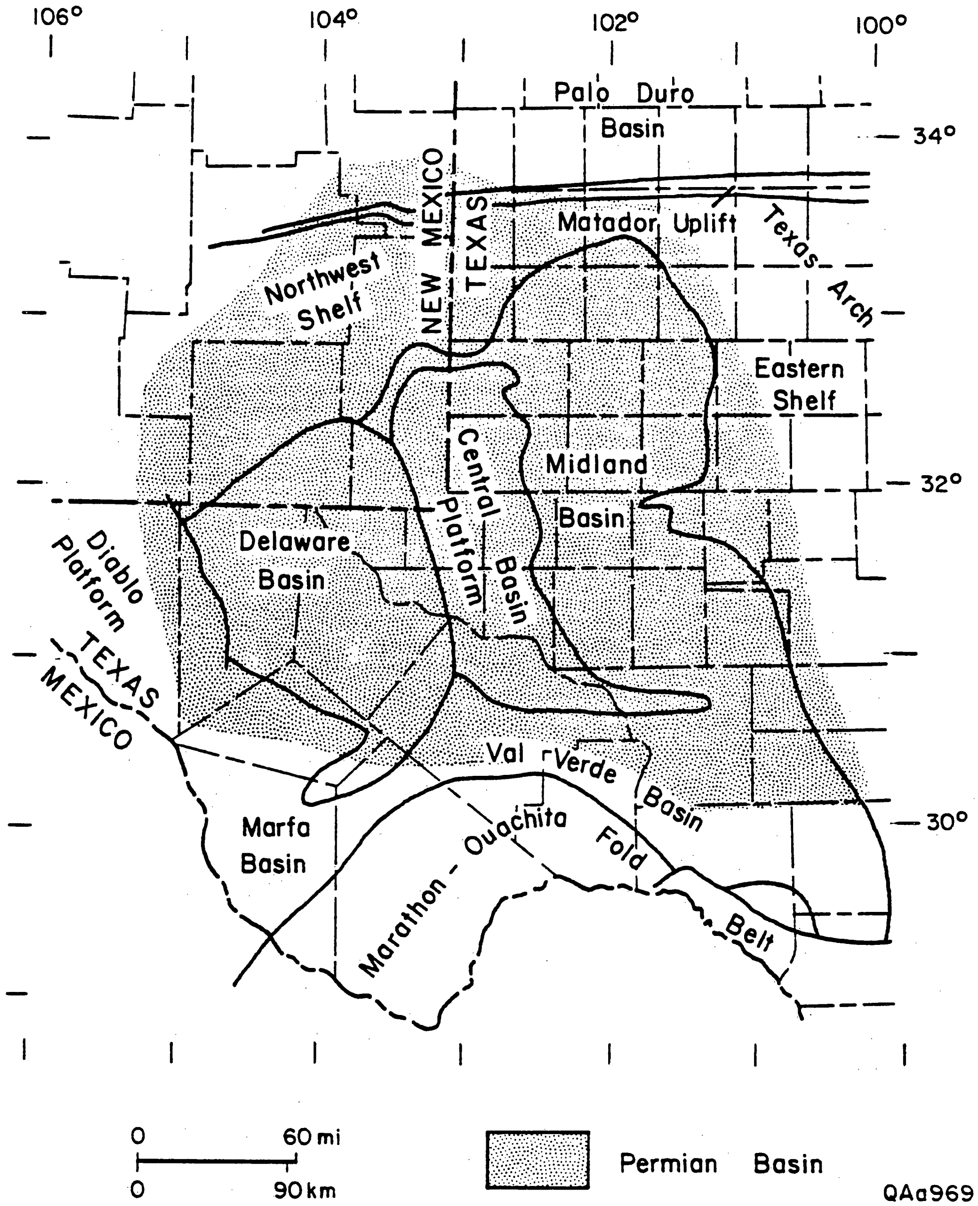


Figure 85. Geologic provinces of the Permian Basin of West Texas and southeastern New Mexico.

Strawn Group, (4) the Missourian Canyon Group, (5) the Virgilian Cisco Group (see chapter on Canyon Sandstone, Val Verde Basin), (6) Wolfcamp strata, and (7) the Leonardian Clear Fork Group.

Morrow Formation

Introduction

The Morrow Formation is the basal Pennsylvanian unit of the Permian Basin in southeastern New Mexico. The formation overlies Mississippian shelf carbonates (Chester Limestone) and basinal black shales (Barnett Shale) and is overlain by the Pennsylvanian Atoka Limestone (fig. 86). The Pennsylvanian sequence consists of interbedded carbonates and siliciclastics. Carbonate accumulation in the basin was interrupted by intermittent clastic deposition, shed from uplift and erosion of the ancestral Pedernal highland to the north and northwest. This clastic input reached a maximum during Morrow time (Mazzullo and Mazzullo, 1984). The Morrow Formation can be divided into lower, middle, and upper units, and the clastic-to-carbonate ratio is highest in the lower and middle units. A north–south gradation from coarse-grained clastics to basinal shales is apparent in the lower and middle units, and progradation reached a maximum during the middle Morrow when coarse-grained clastics extended farthest basinward. The upper unit was deposited in a transgressive regime and consists of alternating limestone and shale with minor sandstone. The Morrow Formation is extensive in the subsurface throughout Eddy and Lea Counties, southeast New Mexico, but the formally designated tight-gas-producing area covers only a small part of the subsurface distribution (New Mexico Oil Conservation Division, 1983a, b, 1984, 1992b; fig. 87). A unit stratigraphically above the Morrow Formation, the Atoka-Morrow, has also been designated as tight gas producing (New Mexico Oil Conservation Division, 1982b; fig. 87).

The Morrow Formation is approximately 900 ft thick in the north and thickens to in excess of 1,800 ft to the southeast. Depth to the top of the formation in the designated tight-gas

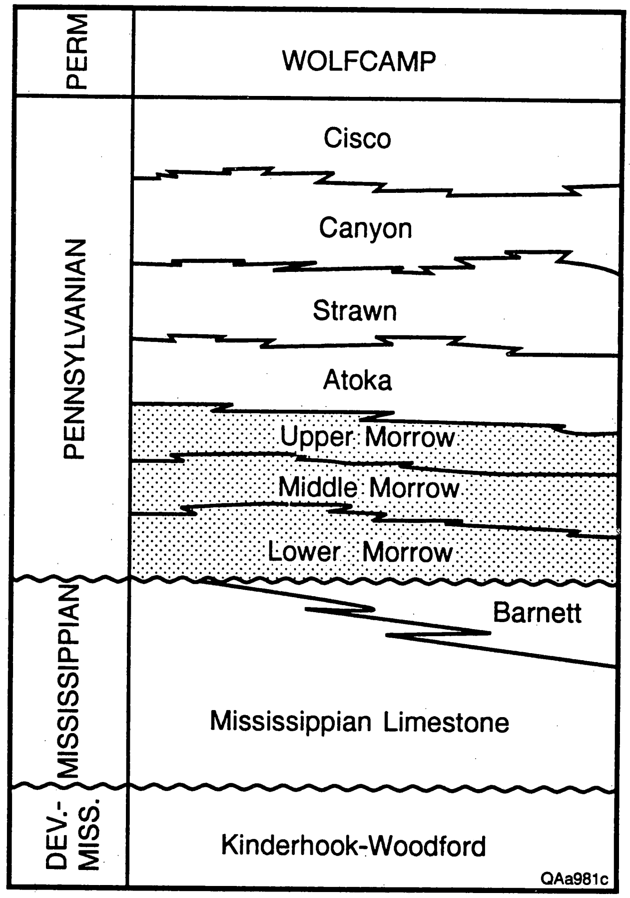


Figure 86. Stratigraphy of the Mississippian and Pennsylvanian in the Permian Basin of southeastern New Mexico (from Mazzullo and Mazzullo, 1985).

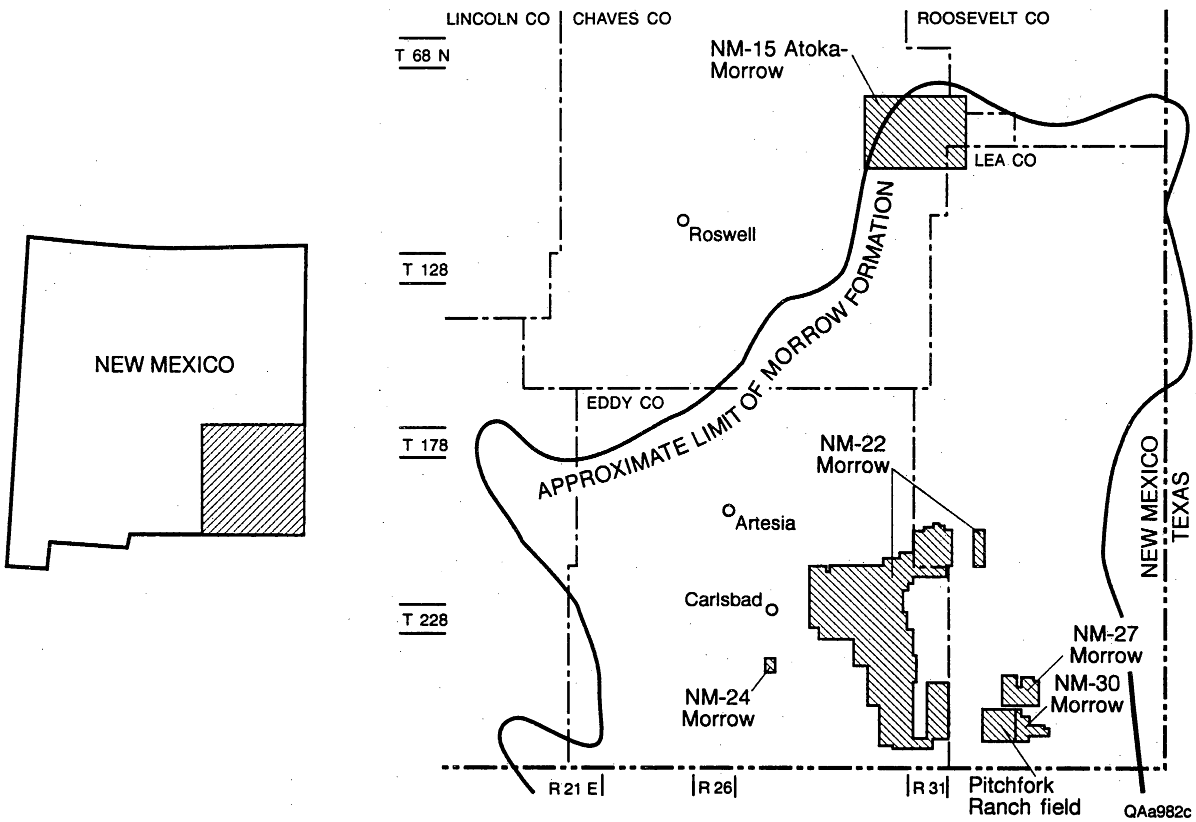


Figure 87. Subsurface distribution of the Morrow Formation and area designated as tight gas producing (data from Hillis, 1985; New Mexico Oil Conservation Division, 1982d, 1983a, b, 1984, 1992b).

areas is typically from 11,500 to 14,700 ft. The data base on the Morrow Formation is fair and based on information from a number of local field studies (Mazzullo, 1983a; James, 1984; Hillis, 1985), tight formation applications (New Mexico Oil Conservation Division, 1983a, b, 1984, 1992b), and several brief subregional summaries (Mazzullo, 1983b; Mazzullo and Mazzullo, 1984; Mazzullo and Mazzullo, 1985). No regional studies have been published. Little is known about the Atoka-Morrow except that in the application for tight gas designation, the unit was described as a 60- to 115-ft-thick, very fine-grained sandstone that occurs at a depth of 8,720 ft. Porosity of this unit ranges from 7 to 8 percent and permeability is less than 0.01 md.

Depositional Systems and Reservoir Facies

Depositional systems of the Morrow Formation are not well defined because of a lack of comprehensive regional studies. The unit has been attributed to a wide variety of depositional settings ranging from fluvial to basinal marine (James, 1984; Hillis, 1985; Mazzullo and Mazzullo, 1985), and a number of inconsistencies are apparent among these published accounts. However, a general picture of Morrow deposition is illustrated in figure 88. Repetitive cycles of nonmarine to nearshore siliciclastics and subordinate carbonates were deposited on a gently southward sloping shelf and pass farther south into basinal shales of the Delaware Basin (Hanson and others, 1991). Mazzullo and Mazzullo (1984) documented the strong lithological transition in the lower and middle Morrow units from medium to coarse-grained sandstone and intercalated shales in the north, to interbedded glauconitic sandstones, gray shales and limestones farther south, and finally thick dark shales with minor fine-grained sandstone lenses in the most basinward position. The coarse-grained lithologies extended farthest south during middle Morrow deposition (fig. 89).

The principal hydrocarbon reservoirs include fluvio-deltaic, tidal-channel, nearshore-bar, and strandplain sandstones (Hanson and others, 1991). Lower Morrow reservoirs in the updip areas, such as Parkway-Empire South field (James, 1984; fig. 90), consist of dip-oriented,

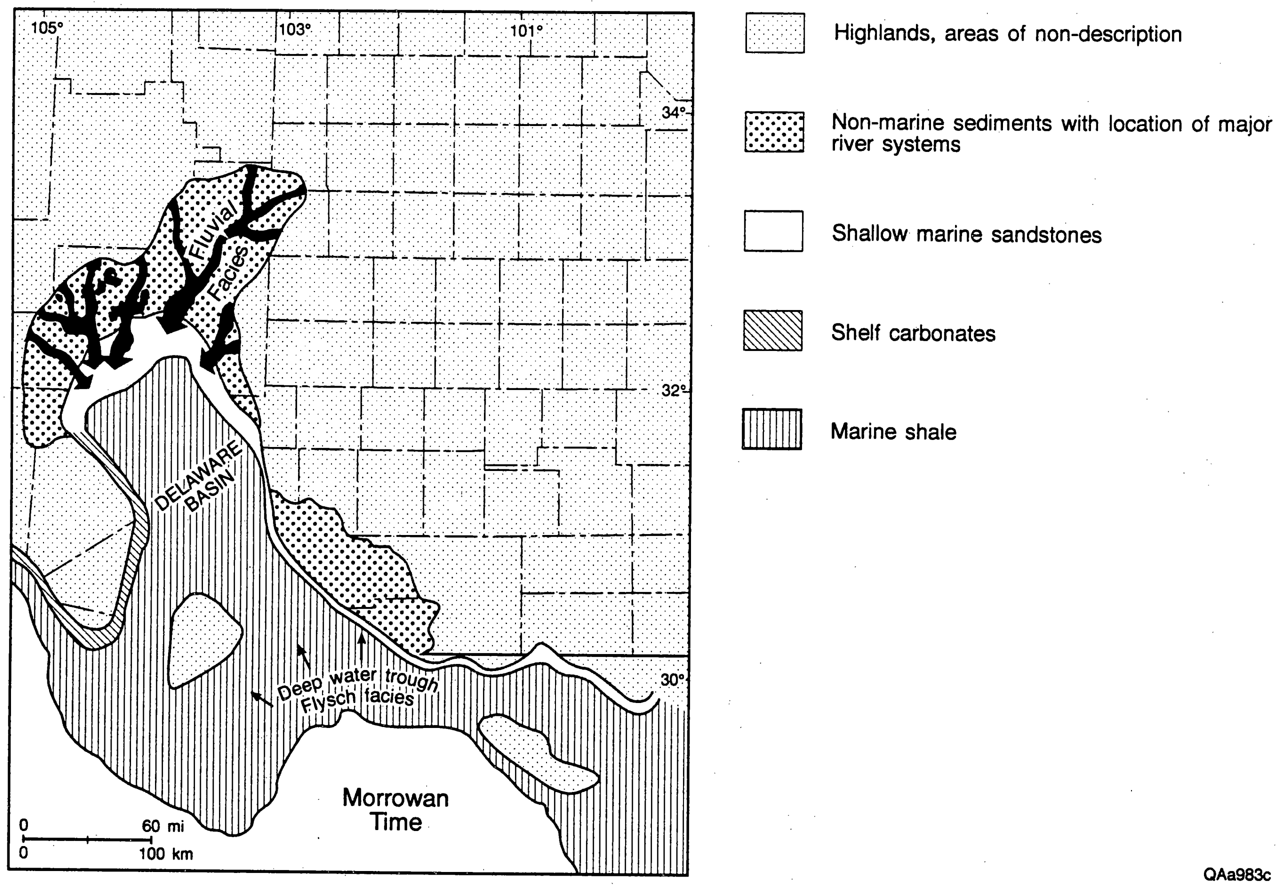


Figure 88. Generalized model of Morrow deposition (from James, 1985; Hanson and others, 1991).

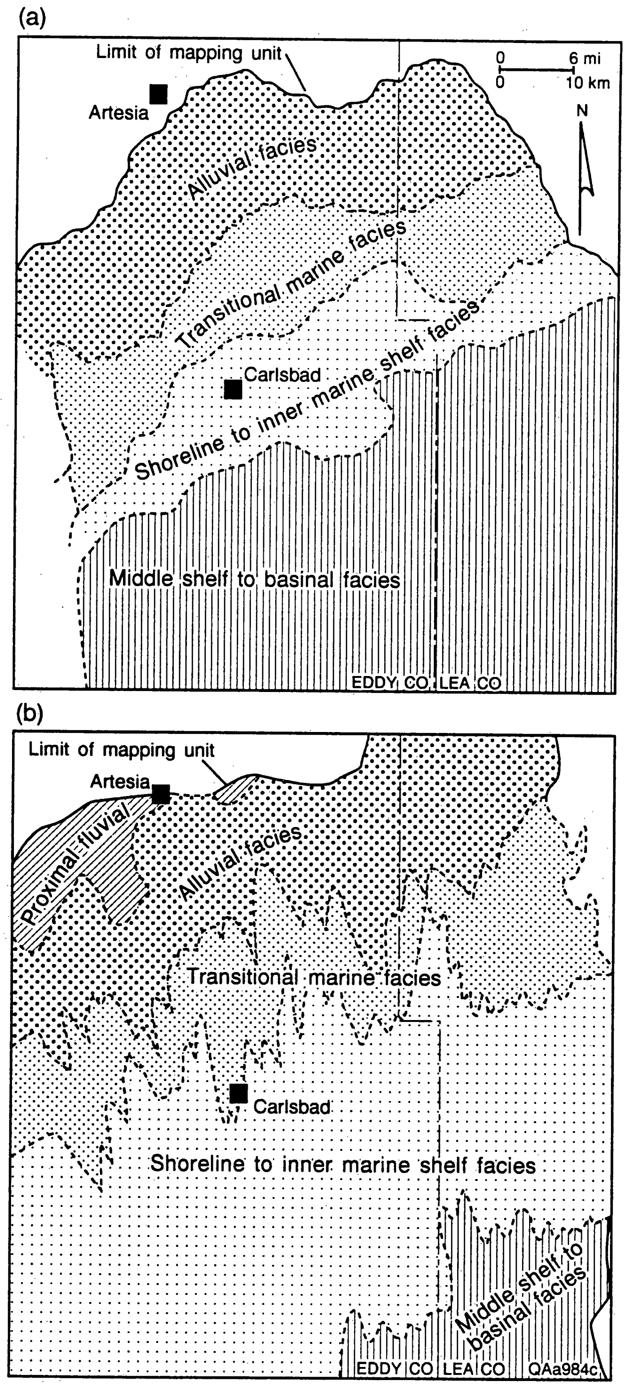


Figure 89. Schematic of the depositional environments of the lower (A) and middle (B) Morrow units (from Mazzullo, 1985).

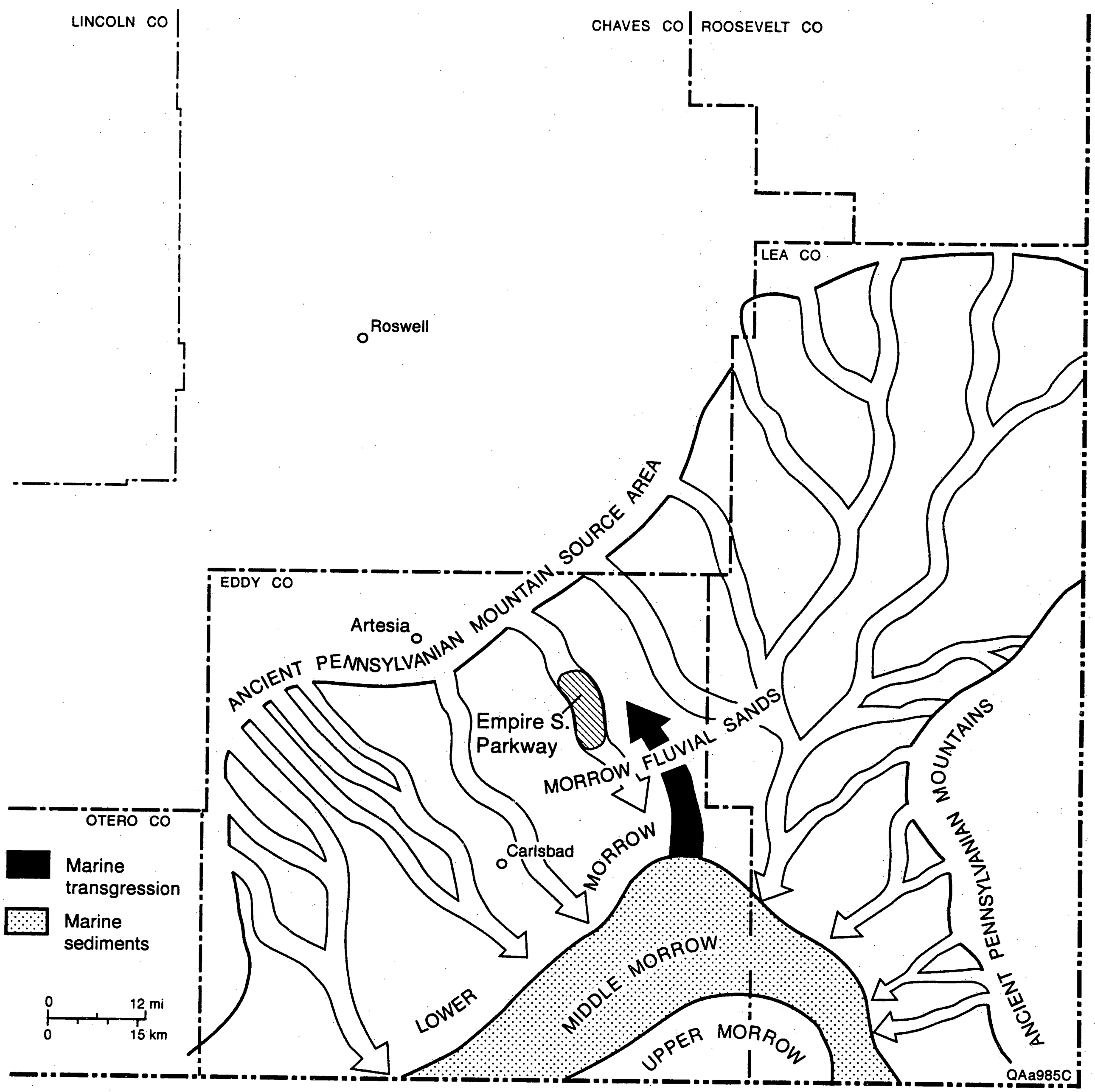


Figure 90. Depositional setting of lower and middle Morrow reservoir sandstones in the updip areas (modified from James, 1984).

locally sinuous channel, point bar, and stream mouth bar complexes from 2 to 5 mi wide. Net sandstone thickness in these complexes ranges from 10 to 60 ft. Downdip, the reservoir facies are strike-oriented (east), linear shoreline to inner marine shelf sandstones (Jons and Stanley, 1981) that typically range from 10 to 40 ft (Zones B and C of Mazzullo, 1983a).

Middle Morrow reservoirs in Parkway-Empire field are interpreted to be beaches deposited parallel to the ancient northeast-trending shoreline (James, 1985). These sandstones are from 10 to 50 ft thick and arranged in successive strike-oriented ridges approximately 1 to 2 mi wide.

Although clastic input was least in the upper Morrow unit, important reservoir sandstones are developed. Upper Morrow reservoirs are dominant in Pitchfork Ranch field (New Mexico Oil Conservation Division, 1992b; fig. 87) where lensoidal marine sandstones occur within marine shales. The Pitchfork Ranch area is located in a distal position.

Composition of Reservoir Facies

Petrographic data on Morrow Formation sandstones are scarce. Hillis (1985), using nine thin sections, described the sandstone composition as averaging 86 percent quartz (both as detrital grains and cement), 7 percent clays, and 3 percent calcite, with the remainder consisting of chert, siderite, muscovite, pyrite, and heavy minerals.

Data on the clay mineralogy are more comprehensive because of the sensitivity of the sandstones to drilling and completion fluids (Mazzullo and Mazzullo, 1984). The lower and middle Morrow Sandstones contain major amounts of kaolinite and chlorite, moderate amounts of illite, and minor smectite and mixed-layer illite-smectite (Mazzullo and Mazzullo, 1985). The kaolinite and chlorite are authigenic in origin whereas the smectite, illite, and illite-smectite are generally detrital in origin. Authigenic smectite and illite are rarely found in the Morrow sandstones.

Natural Fractures

We are aware of no studies that describe naturally occurring fractures in Morrow sandstones. Anomalously high initial bottom-hole pressures have been reported from some Morrow Formation reservoirs (Craddock and others, 1983), and these may correspond to wells that intersect naturally fractured intervals.

Engineering Assessment

The Morrow sandstones are characterized by having low porosity, low permeability, and extreme sensitivity to formation damage. Porosities in the Morrow sandstones range from a low of 3 percent at Pitchfork Ranch (New Mexico Oil Conservation Division, 1991) to a high of 17 percent (Hillis, 1985) at Big Eddy field. Averages for these two areas are 7 and 9.5 percent, respectively (table 20). James (1984) estimated the average porosity of the lower and middle Morrow reservoir sandstones to be between 8 and 14 percent at Parkway-Empire South field. For log porosity determinations, a grain density of 2.67 g/cc should be used (Hillis, 1985). Permeabilities are less than 0.1 md except in some localized areas. Well test permeability in 11 wells at Pitchfork Ranch field was 0.076 md (New Mexico Oil Conservation Division, 1991). Enron Oil and Gas Company calculated an in situ permeability of 0.07 md for the Morrow reservoir in the Vaca Draw/Pitchfork Ranch area (New Mexico Oil Conservation Division, 1991). A type log (fig. 91) illustrates the potential pay zone of Morrow reservoir sandstones.

Water saturations in the productive sandstones are generally less than 50 percent. The average water saturation in the producing wells at Pitchfork Ranch field is 27 percent and ranges from 8 to 57 percent, with only one well above 50 percent. Formation water resistivity is 0.065 Ω·m at 200°F (Hillis, 1985).

Net pay footages are 20 to 100 ft, with an average of 53 ft (New Mexico Oil Conservation Division, 1991) (table 20). Porosity cutoff is 3.5 percent for potential production. Water

Table 20. Morrow Formation, Permian Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 280

Cumulative production from tight completions 1970–1988 (Bcf): 500.2

Estimated ultimate recovery from tight areas (Bcf): 771.9

Net pay thickness range and average (ft): 20–100/53

Porosity range and average (%): 3–17/7–9.5

Permeability average (md): 0.07

Water saturation range and average (%): 8–57; 27

Reservoir temperature (°F): 120–200

Reservoir pressure (psi): 2,815–9,100

Typical stimulation/hydro-frac: <20,000 lb sand

Production rate:

prestimulation (Mcf/d): 0–120 Mcf/d

poststimulation (Mcf/d): 1,339

Average recovery per completion (Bcf): 2.8

Decline rate: No data

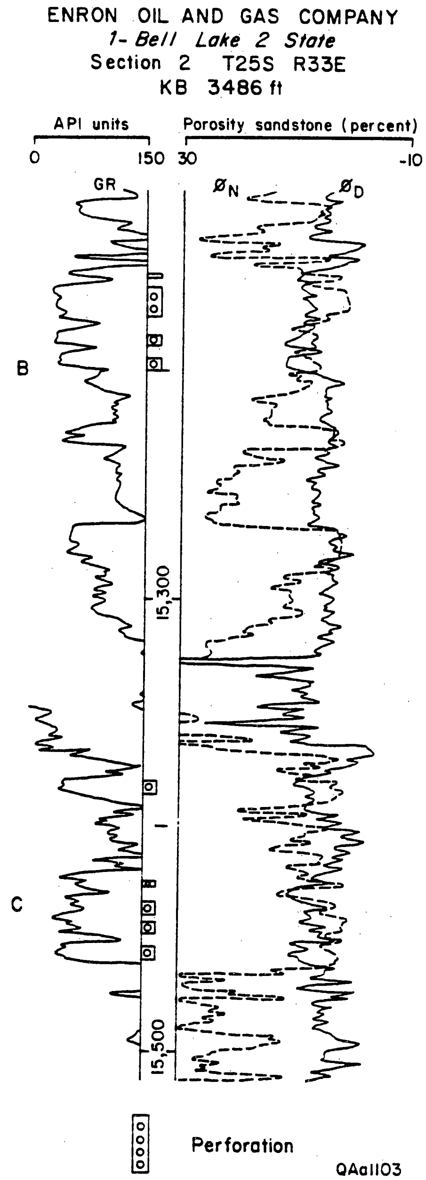


Figure 91. Representative log of the Morrow Formation.

saturation cutoff is 50 percent. Reservoir temperature in the Morrow ranges with depth from 120°F at 7,000 ft in Chaves County to 200°F at 12,000 ft at Big Eddy field (Hillis, 1985). Reservoir pressure averages 9,100 psi in 13 wells at Pitchfork Ranch (New Mexico Oil Conservation Division, 1991). Reservoir pressure in Chavez County is 2,815 psi (New Mexico Oil Conservation Division, 1982).

Fracture-stimulation treatments are routinely small, using less than 20,000 lb sand proppant (New Mexico Oil Conservation Division, 1982). There is a danger of formation damage from drilling and completion procedures in the Morrow sandstones (Mazzullo and Mazzullo, 1984). Authigenic kaolinite and chlorite occur abundantly. Use of high water loss drilling muds is not recommended because of the potential for breaking off unstable kaolinite crystals and blocking pore throats. Similarly, use of acid in completing Morrow sandstones may result in the precipitation of ferric hydroxide from iron rich chlorite, also blocking pore throats. This can be avoided by using the proper drilling and completion strategies.

Production History

Tight gas ultimate recovery in Morrow sandstones is 772 Bcf (table 20). Average recovery per completion is 2.834 Bcf per well. Pre-stimulation flows are quite variable. Some wells at Pitchfork Ranch have pre-stimulation flows of 2.5 Mcf/d (New Mexico Oil Conservation Division, 1992b). Most have no flow (or too small to measure) and require a small acid or fracture-stimulation treatment. Wells in the Chavez County tight gas classification hearing ranged in pre-stimulation flow rate from 100 to 120 Mcf/d (New Mexico Oil Conservation Division, 1982). The average stabilized flow rate after stimulation at Pitchfork Ranch is 1,339 Mcf/d (New Mexico Oil Conservation Division, 1992b).

Abo Formation

Introduction

The Lower Permian (Wolfcampian to lower Leonardian) Abo Formation (fig. 84) produces natural gas from low-permeability sandstones on the Northwest Shelf of the Permian Basin in east-central New Mexico (fig. 85). The red beds of the Abo Formation are well studied where they are exposed in uplifts of the late Tertiary Basin and Range province throughout much of New Mexico (for example, Hatchell and others, 1982; Speer, 1983). However, the gas-productive Abo Formation is restricted to the Pecos Slope, a gently eastward-dipping (0.5° to 1°), locally faulted and folded, Laramide-age (Late Cretaceous to Tertiary) homocline immediately east of the Pedernal Uplift (Kelly, 1971; Broadhead, 1984a, b) (fig. 92). In the producing area, the Abo onlaps and overlies the granitic and metamorphic core of the Pedernal Uplift, interfingers downdip with Hueco Formation limestones and is overlain by dolostone and anhydrite of the Yeso Formation (figs. 92 and 93). The Abo is formally designated to be tight by FERC in all or parts of Chaves, De Baca, Guadalupe, Lincoln, San Miguel, and Torrance Counties of east-central New Mexico (New Mexico Oil Conservation Division, 1981c, 1982d) (fig. 94). Cumulative gas production from the tight Abo from 1977 (discovery) through 1988 was 222.7 Bcf (Hugman and others, 1992). Six fields produce natural gas from Abo low-permeability reservoirs: Pecos Slope, South Pecos Slope, West Pecos Slope, North Pecos Slope, Border Hill, and Pine Lodge (R. F. Broadhead, personal communication, 1992) (fig. 94). The premier tight-gas Abo field is Pecos Slope field; cumulative production from this field alone was 272.7 Bcf as of January 1991 (Bentz, 1992).

In the gas-producing area east of the Pedernal Uplift, the Abo Formation is subdivided into three informal stratigraphic units: a lower granite wash interval, a middle unit of red mudstone, and an upper unit of interbedded sandstone and red mudstone (Broadhead, 1983, 1984a, b). Lenticular, areally restricted sandstones of the upper Abo are the reservoirs in the

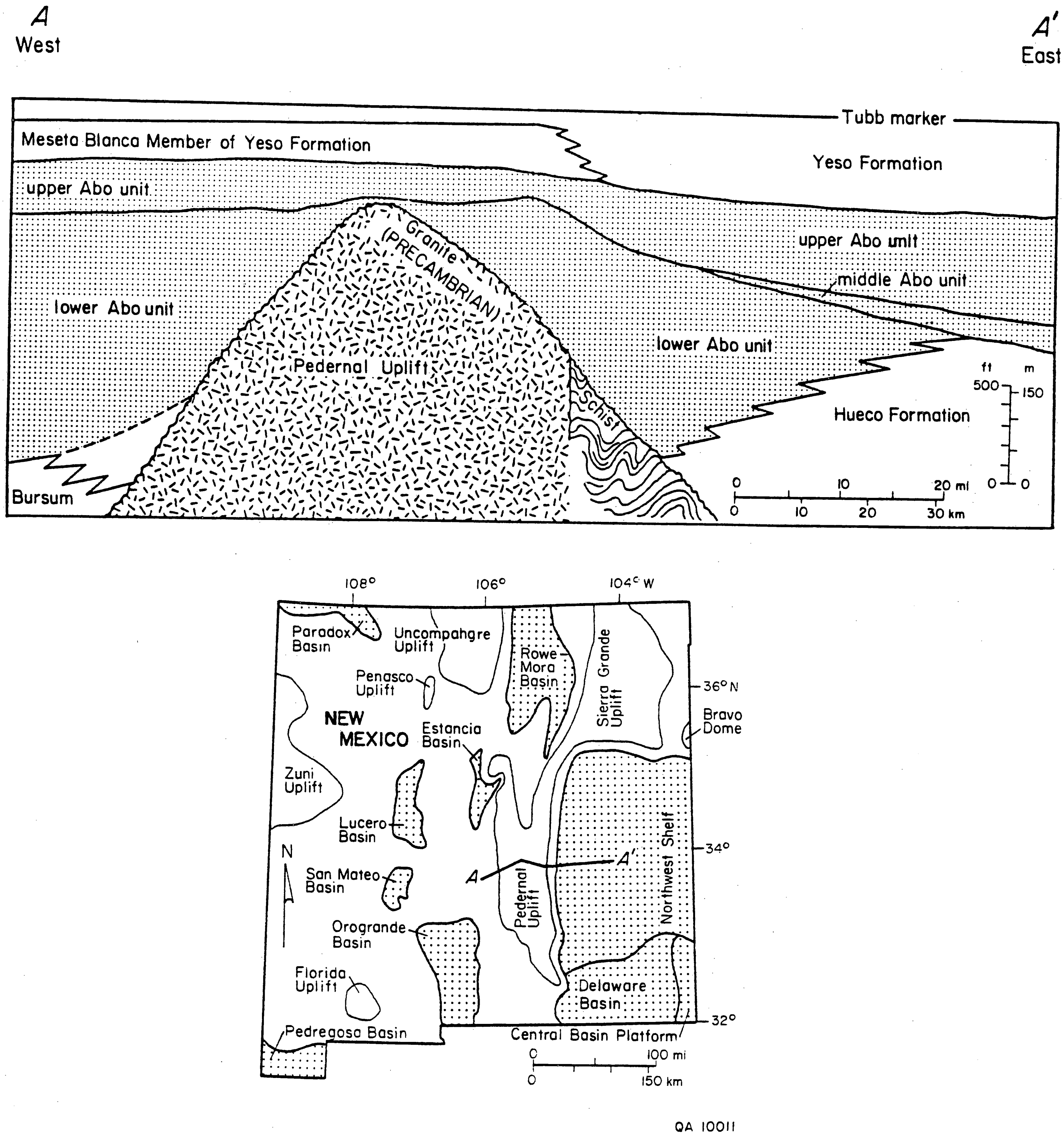


Figure 92. Regional schematic west–east cross section of the Abo Formation and adjacent units in east-central New Mexico. Cross section location shown on map of major geologic features of New Mexico. Modified from Broadhead (1984b).

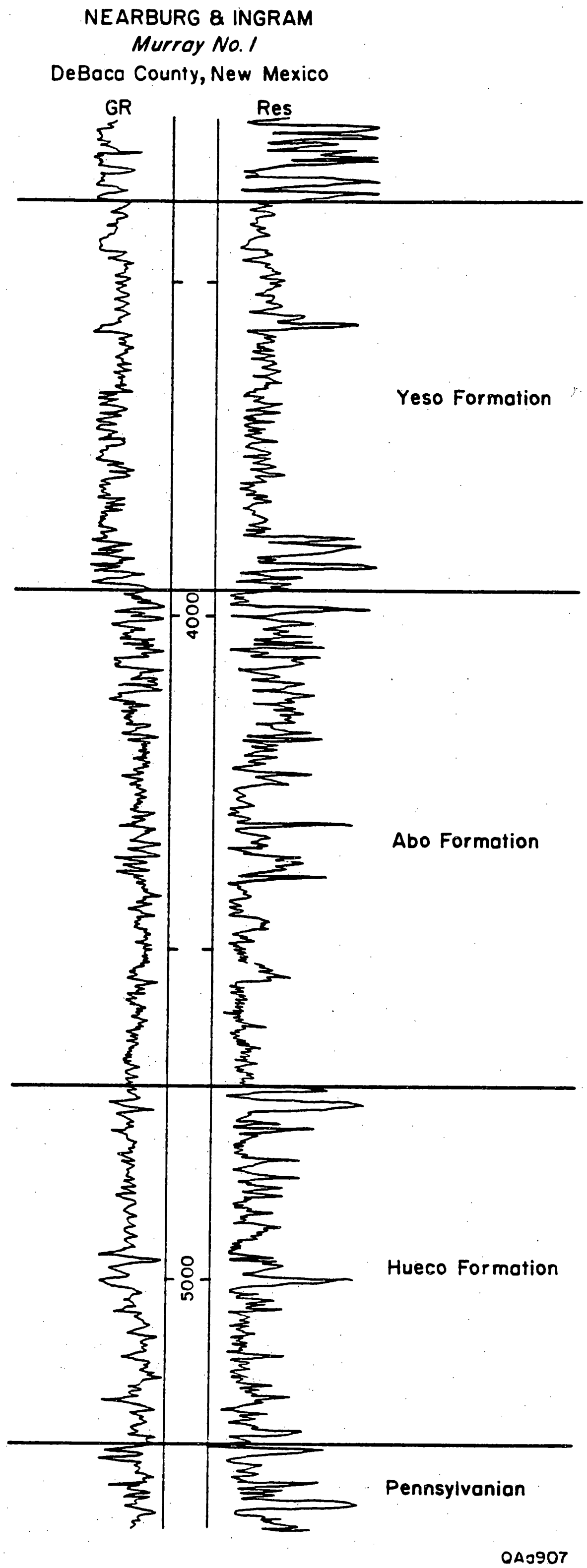


Figure 93. Representative log of the Abo Formation.

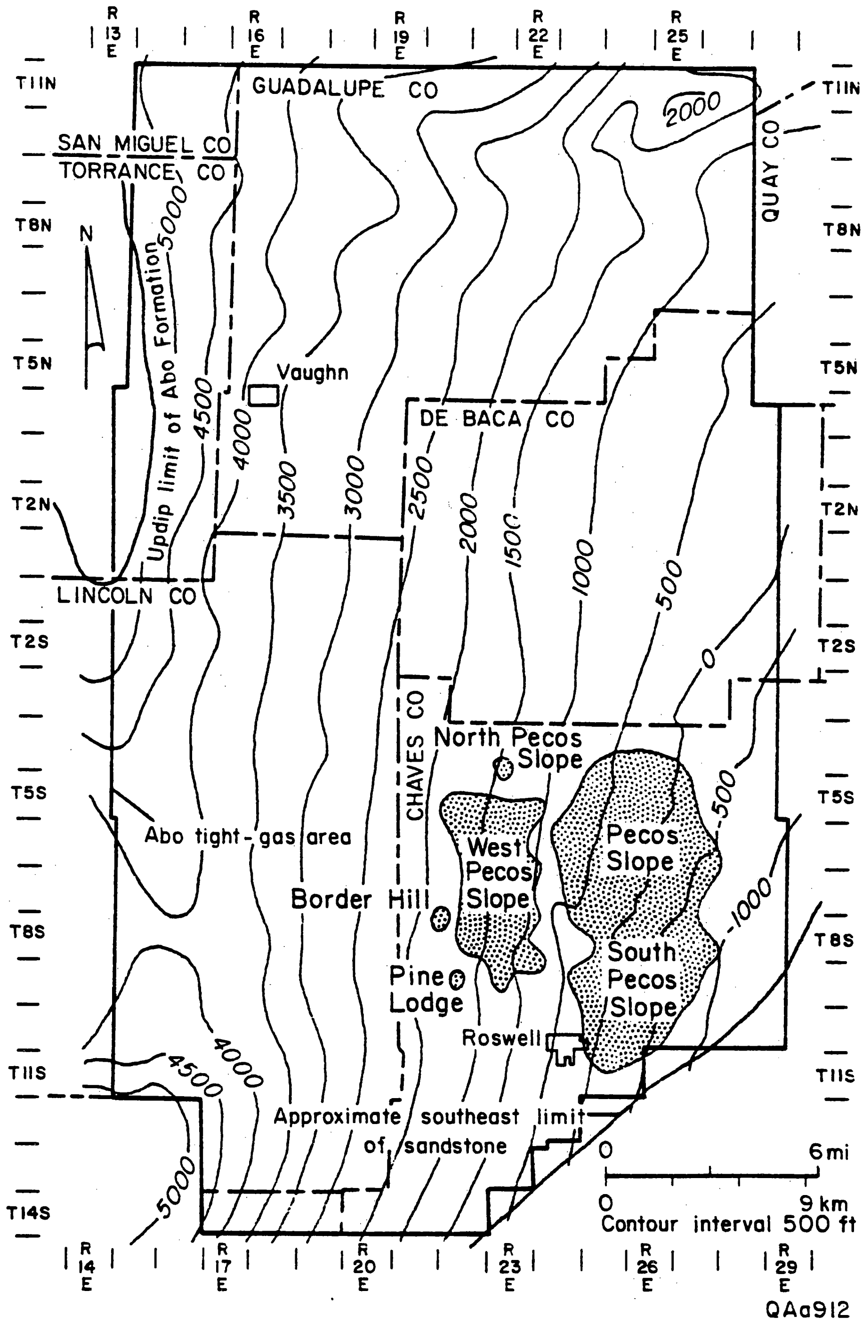


Figure 94. Structure-contour map of top of Abo Formation in the Pecos Slope area of east-central New Mexico, showing tight-gas Abo fields. Map border depicts limits of Abo tight-gas area. Modified from New Mexico Oil Conservation Division (1982d). Field-location data provided by R. F. Broadhead (personal communication, 1992).

six-county tight-gas area. Depth to the top of the Abo Formation increases eastward on the Pecos Slope (fig. 94), ranging from about 1,560 ft in the west to 4,500 ft in the east. Depth of pay zones (top of perforations) varies from less than 3,375 ft in updip areas to more than 5,221 ft in the east (Petroleum Information Corporation, 1983). Abo thickness is about 240 to 2,090 ft (New Mexico Oil Conservation Division, 1982d). The productive upper Abo ranges from less than 100 ft to about 900 ft thick, generally thinning to the south (Broadhead, 1984b).

Depositional Systems and Reservoir Facies

Reservoir sandstones of the upper member of the Abo Formation originated in a predominantly fluvial-deltaic depositional setting (Scott and others, 1983; Broadhead, 1984b), whereas the lower granite wash and middle mudstone-rich Abo members represent alluvial-fan and shallow-marine depositional environments, respectively (Broadhead, 1984b). However, Bentz (1992) postulated that all of the productive Abo channel-fill sandstones are fluvial and found that there is no conclusive evidence of deltaic sedimentation. Reservoirs are restricted to channel-fill sandstones; productive sandstones in individual wells range from 10 ft to greater than 50 ft thick (Scott and others, 1983). Net pay varies from about 6 ft to 80 ft (Broadhead, 1984b; Bentz, 1992), with highest net pay found in wells in which more than one producing channel sandstone was penetrated. Broadhead (1984b) interpreted channel fills to be components of southward-flowing meandering-river (northern area) and delta-distributary (southern area) systems. Individual anastomosing channel systems of the upper Abo that were stratigraphically differentiated and mapped by Scott and others (1983) include (in ascending order) the McConkey, Dee, and Savage zones; portions of more than one of these channel zones are commonly perforated within Abo gas wells (fig. 95). The log expression of the Abo Formation in the tight-gas area varies locally, primarily reflecting the localization of channel-fill sandstones. Gamma-ray and resistivity log traces of Abo red mudstones are

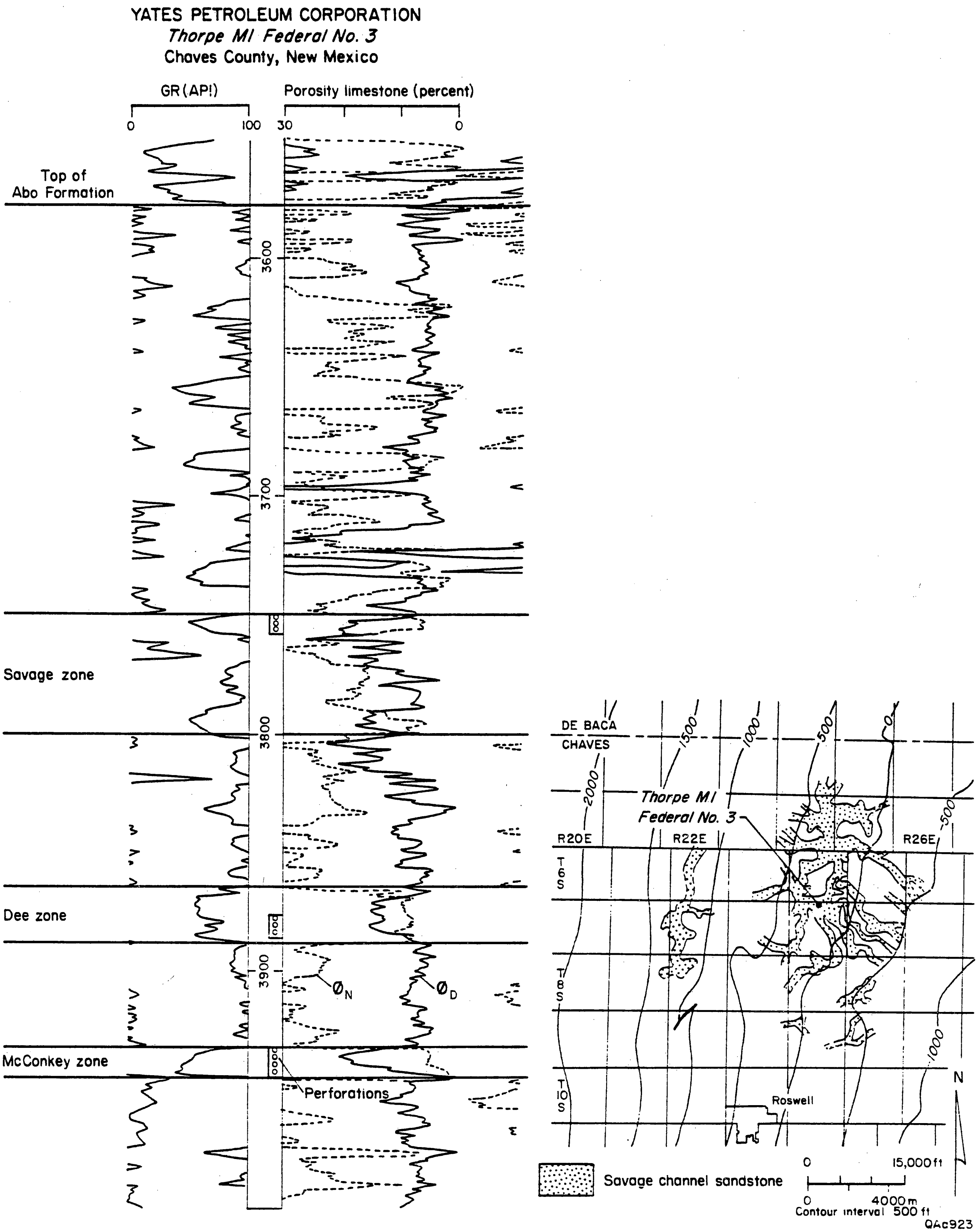


Figure 95. Well log of pay zones in the Abo Formation. Map illustrates location of well from which log shown was taken and areal configuration of the Savage zone channel sandstone superimposed on structure-contour map of the top of the Abo Formation. Map modified from Scott and others (1983).

typically subdued, whereas those of channel-fill sandstones are blocky to spikey and upward fining (figs. 93 and 95).

The trapping mechanism in Abo fields is stratigraphic, primarily facies change at channel-fill margins and updip terminations; gas traps are consistently found where reservoir sandstones are overlain by thick (as much as 100 ft) mudstone seals (Scott and others, 1983; Broadhead, 1984a, b). Most Abo gas production comes from the distal portions of the upper Abo fluvial-deltaic systems where sandstone-to-mudstone ratios are relatively low but where thick channel-fill sandstones occur (Broadhead, 1984b). Both reservoir and sealing strata are commonly fractured; however, unlike the gas-bearing sandstones, the mudstone seals contain either closed or anhydrite- and carbonate-cement-filled fractures (Broadhead, 1984a, b; Bentz, 1992). Although there is about 2,400 ft of elevation difference between the highest and lowest reservoirs in Pecos Slope field, bottom-hole pressures throughout the field are consistently similar and subnormal (1,000 to 1,200 psi), suggesting (1) fracture communication among the separate channel-fill reservoirs (Scott and others, 1983) and (2) a regional hydrodynamic and/or tectonic influence on gas accumulation (Bentz, 1992). Fracture treatment increases gas flow rates in producing Abo wells by as much as tenfold, ostensibly by opening and enhancing existing natural reservoir fractures (Bentz, 1992).

Composition of Reservoir Facies

Reservoir sandstones of the upper Abo Formation are fine to very fine grained, with average grain size increasing slightly northward toward the proximal parts of the Abo fluvial systems (Broadhead, 1984b). Sandstones are uniformly composed of quartz and feldspar (plagioclase and orthoclase), which constitute 61 to 90 percent and 10 to 39 percent, respectively, of essential framework grains (New Mexico Oil Conservation Division, 1982d; Petroleum Information Corporation, 1983; Broadhead, 1984b), and are classified as arkoses and subarkoses. Quartzarenites (>95 percent quartz) occur in the southern part of the producing area.

Feldspars are angular and mostly unweathered, showing only minor alteration to clays along cleavage planes, although replacement of framework grains by cement is evident (Broadhead, 1984b). Detrital clay matrix (illite and chlorite) and heavy minerals are generally absent or occur in trace amounts.

Abo sandstone cements include (1) carbonates (calcite and dolomite), ranging from a trace to 50 percent of whole rock volume, (2) anhydrite, ranging from a trace to 10 percent (rarely as much as 40 percent), (3) quartz (as overgrowths), only locally in trace amounts, and (4) authigenic clay and hematite, which are ubiquitous in trace amounts as thin rims around framework grains (Broadhead, 1984b). Anhydrite is an early, pre-compaction cement that occludes primary porosity and replaces framework grains. Carbonates are late, post-compaction cements that occlude primary porosity and replace framework grains and anhydrite cement. Quartz overgrowths project into post-compaction pore space not occluded by other cements, indicating a late diagenetic origin.

Abo reservoir porosity was reduced by development of clay-hematite rims, compaction, and precipitation of cements; thin-section porosity is rare, but that which is visible is secondary and the result of intrastratal solution (Broadhead, 1984b). Local fracture porosity is probably quite high.

Natural Fractures

The area of Abo production is transected by a zone of northeast-trending folds and faults known as the Pecos buckles (figs. 96 and 97). The buckles are primarily strike-slip fault zones and associated folds (fig. 98), and a range of natural fractures and minor faults can be expected in this setting (fig. 99). Fractures and, locally, brecciation are evident in the central parts of some buckles. Core data suggest that the upper unit of the Abo is fractured in De Baca and Guadalupe Counties (Broadhead, 1984b). Because Abo cores are commonly fractured and because of the general consistency of subnormal bottom-hole pressures in some areas, Broadhead (1984b)

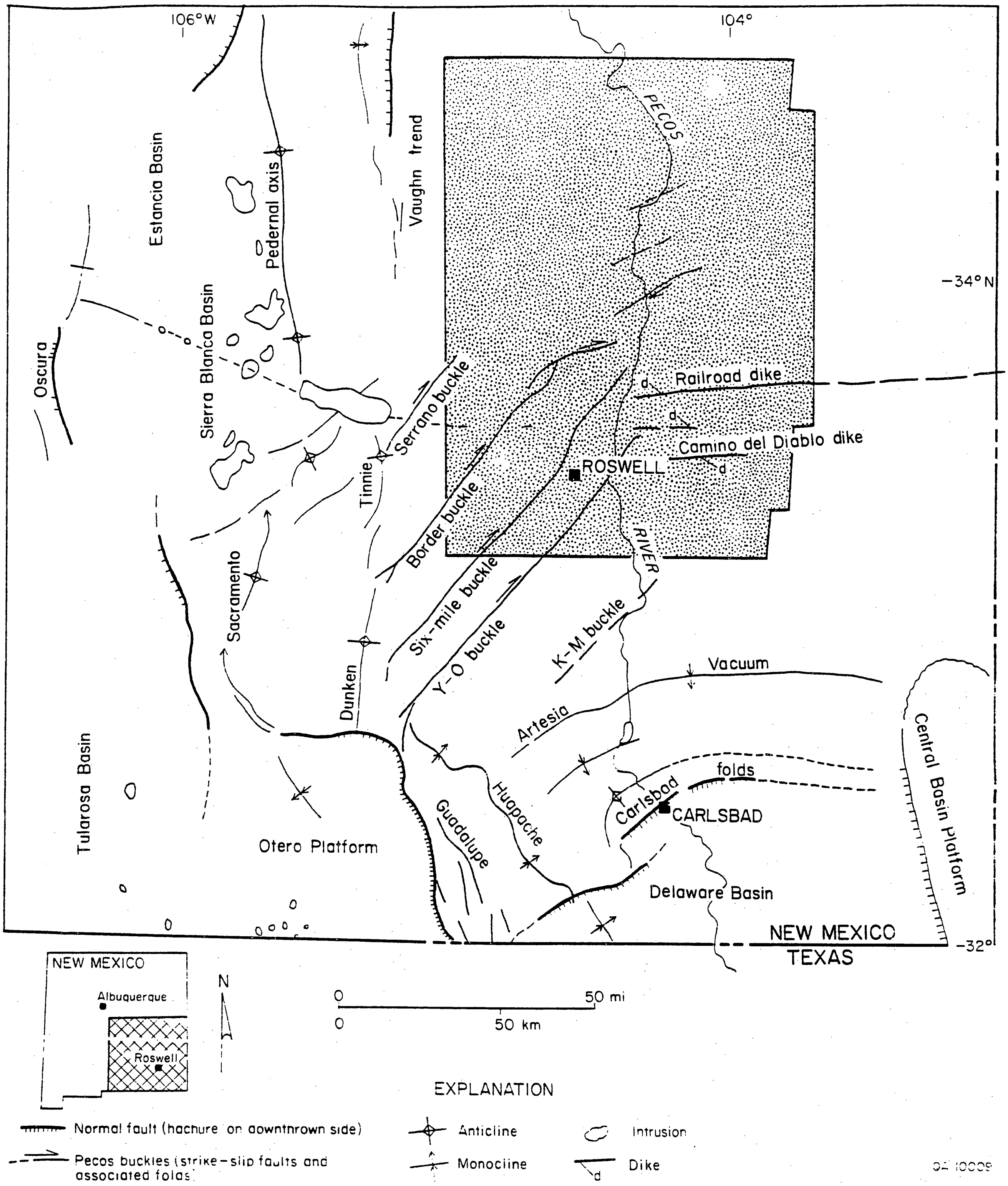


Figure 96. Structure map of southeastern New Mexico. Modified from Kelley (1971). Stippled box shows area of Abo production reviewed by Baumgardner and others (1988).

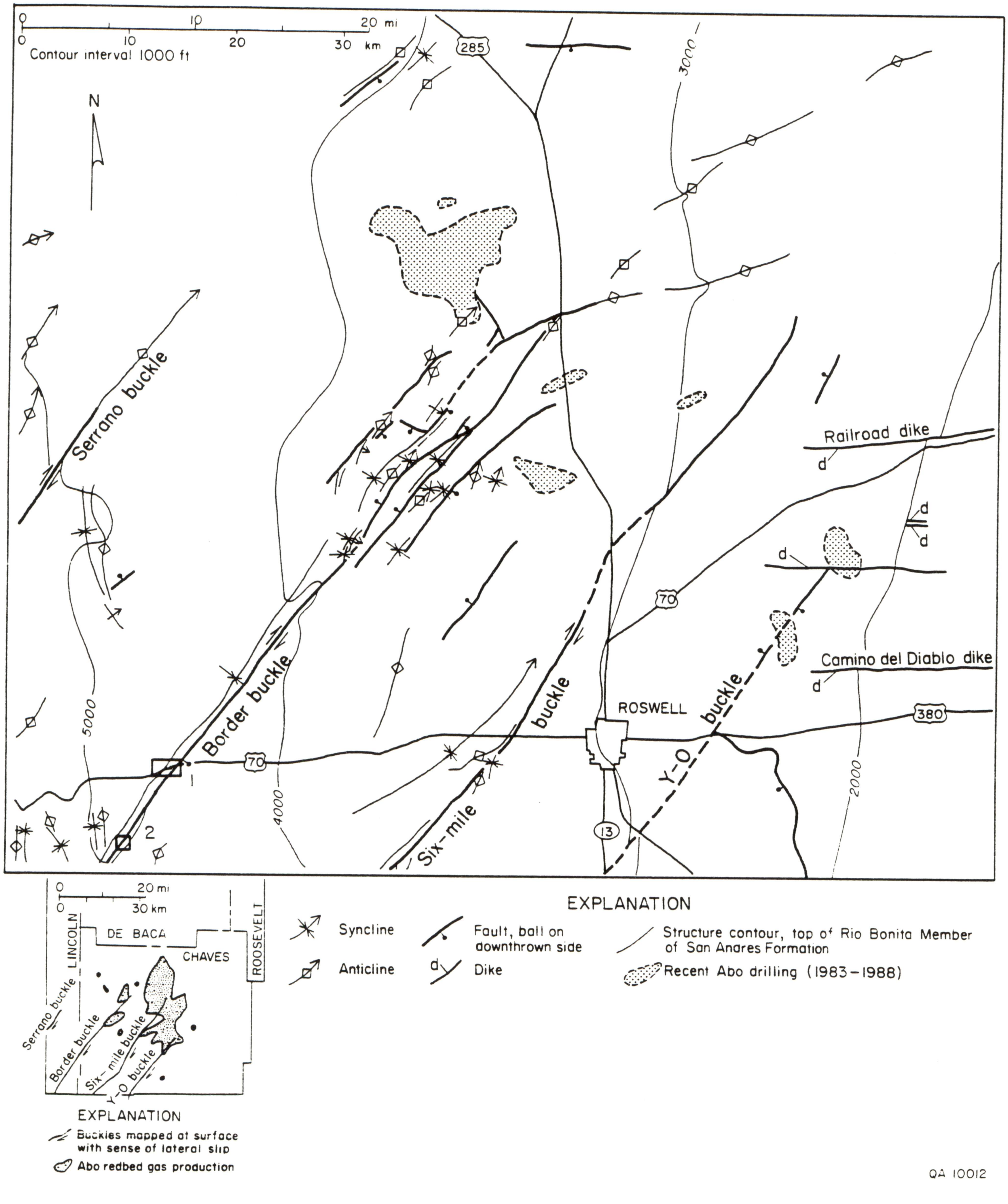


Figure 97. Structural map of buckle terminations. 1 = Location of figure 98a. 2 = location of figure 98b. Inset map from Broadhead (1984b) shows major surface structures (Pecos Slope buckles) mapped by Kelley (1971) and their relation to Abo gas production (Baumgardner and others, 1988).

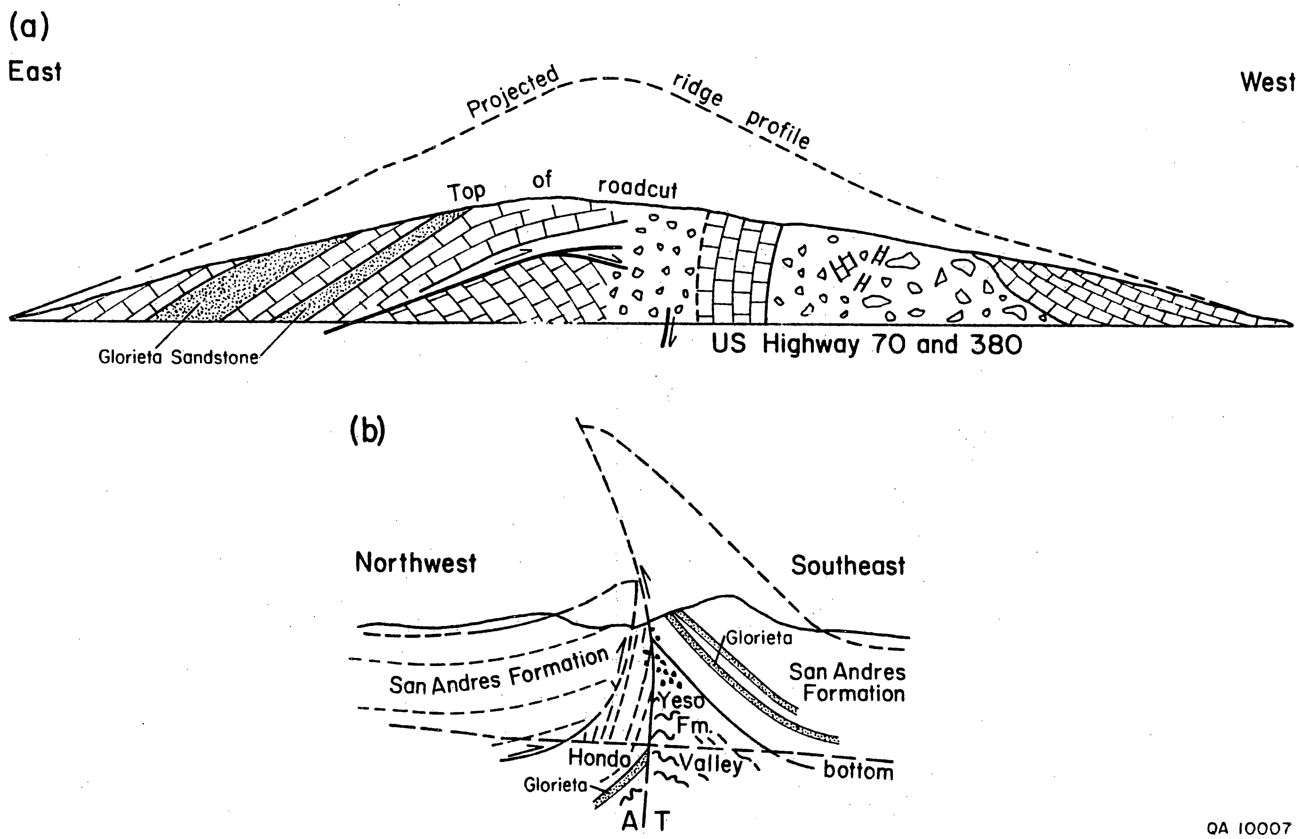


Figure 98. Structural sketches of cross sections through Pecos Slope buckles. (a) Fold and wide fault zone. (b) Tight fold and narrow fault zone. From Kelley (1971). See figure 97 for approximate location of exposures.

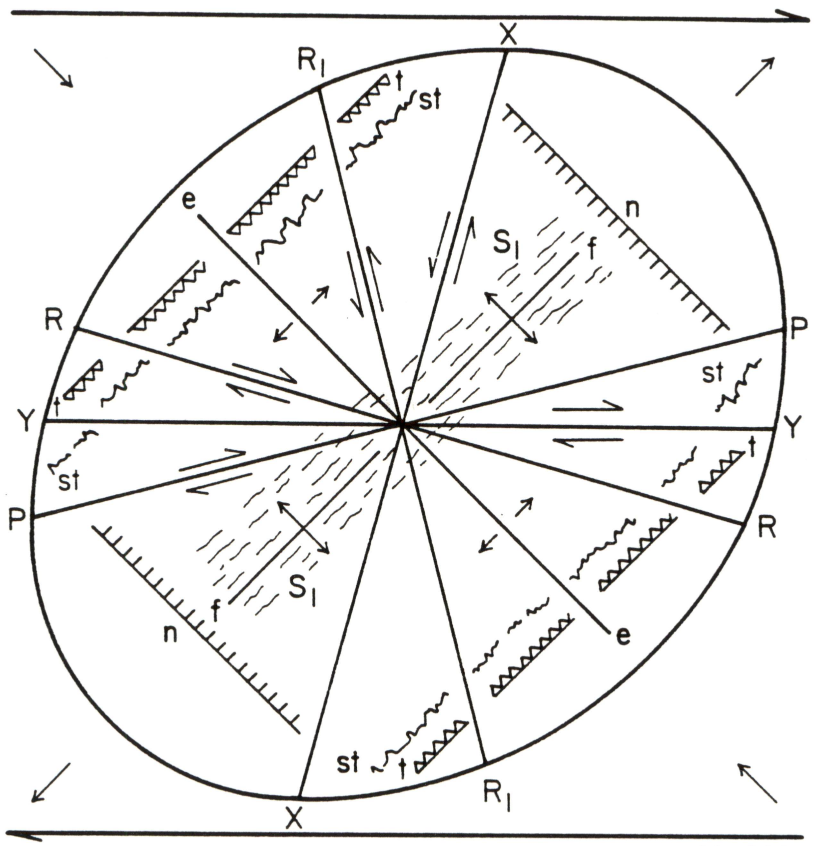


Figure 99. Compilation diagram illustrating en echelon structures characteristic of strike-slip fault zones evolving during simple shear. R and R1, Reidel and conjugate Reidel shears; P, X, and Y, P-, X-, and Y-shears; e, extension fracture, fissure, or vein; n, normal fault; t, thrust; st, stylolite; f, fold; s1, foliation. From Hancock (1985).

and Bentz (1992) concluded that Abo gas is probably produced from fractures that are pervasive at field scale. Fractures in mudstones are either closed or filled with anhydrite or carbonate.

The Pecos buckles and associated folds, faults, and fractures could affect Abo reservoir characteristics, but fracture-related production has not been documented with published engineering studies. 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. The role of fractures in structurally complex areas of Abo production has not been established (Broadhead, 1984b). According to Scott and others (1983) and Broadhead (1984b), Abo production is not directly controlled (localized) by faults or folds, and production is not limited to fracture zones within the buckles (Broadhead, 1984b). Nevertheless, production is spatially associated with the terminations of the Border, Six-mile, and Y-O buckles (fig. 97, inset) (Baumgardner and others, 1988) where fractures can be expected to be prevalent.

Eastern New Mexico is in the Southern Great Plains stress province (fig. 5), a part of the larger Cordilleran extensional stress province of the western United States (Zoback and Zoback, 1980, 1989). In the Southern Great Plains stress province, the maximum horizontal stress trends northwestward, based on fracture orientations in hydraulically fractured wells in the Permian Basin of West Texas (Zemanek and others, 1970) and from alignment of post-5 m.y. volcanic edifices in northern New Mexico.

Engineering Assessment

The Abo red beds are an enigma to log analysts in evaluating wells for porosity. Density logs yield log-calculated porosities in the Abo sandstones of 2 to 15 percent (Baumgardner and others, 1988), averaging 14 percent (Petroleum Information Corporation, 1983) (table 21). Porosity determined from neutron logs ranges from 6 to 18 percent. This contrasts with core analysis, which shows average porosities to be 5 percent. Broadhead (1984b) concluded that

Table 21. Abo Formation, Permian Basin: production data and engineering parameters.

Estimated resource base (Tcf): 3

No. tight completions: 864

Cumulative production from tight completions 1970–1988 (Bcf): 222.7

Estimated ultimate recovery from tight areas (Bcf): 344

Net pay range and average thickness (ft): 6–80/30

Porosity range and average (%): 2–15/14

Permeability (md): 0.01–0.19

Water saturation range and average (%): 25–60/35

Reservoir temperature (°F): No data

Reservoir pressure (psi): 950–1,200

Typical stimulation/hydro-frac: 60,000 gal fluid and 87,000 lb sand

Production rate:

- prestimulation (Mcf/d): 50–70
- poststimulation (Mcf/d): 400–700

Average recovery per completion (MMcf): 511

Decline rate: 35% in first yr, then 19%/yr density porosities are high because of clays and because of micropores in the clay/hematite cements. Other industry experts believe that core has been taken from poorer quality sandstones and that the true porosities range from 10 to 15 percent (Petroleum Information Corporation, 1983). At Pecos Slope field, one of the largest Abo producing fields (1,030 wells), porosities average from 12 to 14 percent (Bentz, 1992).

Permeabilities in the Abo are low. Permeability measurements at Pecos Slope field are 0.03 to 0.05 md. Data from the New Mexico Oil Conservation Division (1982d) indicate a permeability range of 0.01 md to about 0.19 md regionally in the Abo. Natural fractures are common, which may improve deliverability (Scott and others, 1983; Broadhead, 1984b; Bentz, 1992).

Water saturation ranges from 25 to 60 percent and averages 35 percent (Petroleum Information, 1983) (table 21). Bentz (1992) noted that the average water saturation at Pecos Slope field is 38.5 percent. Irreducible water saturation can be high in the Abo due to bound water associated with the hematite-rich clay surfaces. Net pay ranges from 6 to 80 ft and averages 30 ft (Broadhead, 1984b; Bentz, 1992). Net pay footages are usually calculated using a 9 percent porosity cutoff.

Baumgardner and others (1988) reported in a study of 94 Abo wells drilled from 1986 to 1988 that three-fourths were hydraulically fracture stimulated. Fracture treatments consisted of 13,000 to 181,000 gal of fluid (averaging 60,000 gal) and 19,000 to 292,000 lb of sand (averaging 87,000 lb). Reservoir pressure in the Abo is 950 to 1,200 psi.

Production History

ICF-Lewin Energy Division (1988) estimated that the ultimate resource base of the Abo is 3 Tcf (table 21). Well spacing is 160 to 320 acres per well (Finley, 1984). Pecos Slope is the most active field in the Abo play. Ultimate recovery is 344 Bcf (Hugman and others, 1992). Primary reserves estimates range from 500 MMcf per well (Baumgardner and others, 1988) to 600 MMcf

(Bentz, 1992). Top producers will recover more than 2,000 MMcf, whereas poor producers will recover less than 100 MMcf. The typical pre-fracture-treatment Abo wells produce 50 to 70 Mcf/d (Petroleum Information Corporation, 1983) which improves to 600 Mcf/d (Bentz, 1992) after fracture-stimulation treatment. Although no source has been found, trace amounts of arsenic are found in Abo gas. Treatment facilities must exist at the surface. Decline rate for Abo wells is 35 percent for the first year and 19 percent per year thereafter.

VAL VERDE BASIN

The Val Verde Basin is a northwest-trending foreland basin within the Permian Basin region, which also encompasses the Midland and Delaware Basins and adjacent uplifts (Hills and Galley, 1988). The basin forms an asymmetric trough; its deepest part (foredeep) is adjacent to the Ouachita structural belt in the south (fig. 100). Cambrian- to Cretaceous-aged sedimentary fill in the foredeep reaches 28,000 ft, most of which is Pennsylvanian and Lower Permian (National Petroleum Council, 1980). The basin is bounded on the north and east by shelf-like positive structural features: Central Basin Platform, Ozona Arch, and Eastern Shelf (fig. 100). Lower and middle Paleozoic shallow-marine carbonates and clastics fill a shallow cratonic basin, the Tobosa Basin, which was ancestral to the Permian Basin (Hills and Galley, 1988). The Val Verde Basin became distinct during late Mississippian time, when the Tobosa Basin began to separate into several basins and uplifts. Following widespread carbonate deposition in the middle Pennsylvanian (Desmoinesian Strawn Group), the Val Verde Basin began to subside rapidly, creating a deep basin in the south adjacent to a shallow shelf in the north (fig. 101). Upper Pennsylvanian (primarily Virgilian) clastic slope wedges prograded the shelf margin southward, but because of increasing tectonic activity in the Ouachita orogen to the south, Lower Permian (primarily Wolfcampian) clastics filled the foredeep from south to north. Cretaceous carbonate rocks unconformably overlie the Wolfcamp and extend to the surface of the Val Verde Basin. Well, seismic, and vitrinite reflectance data suggest that

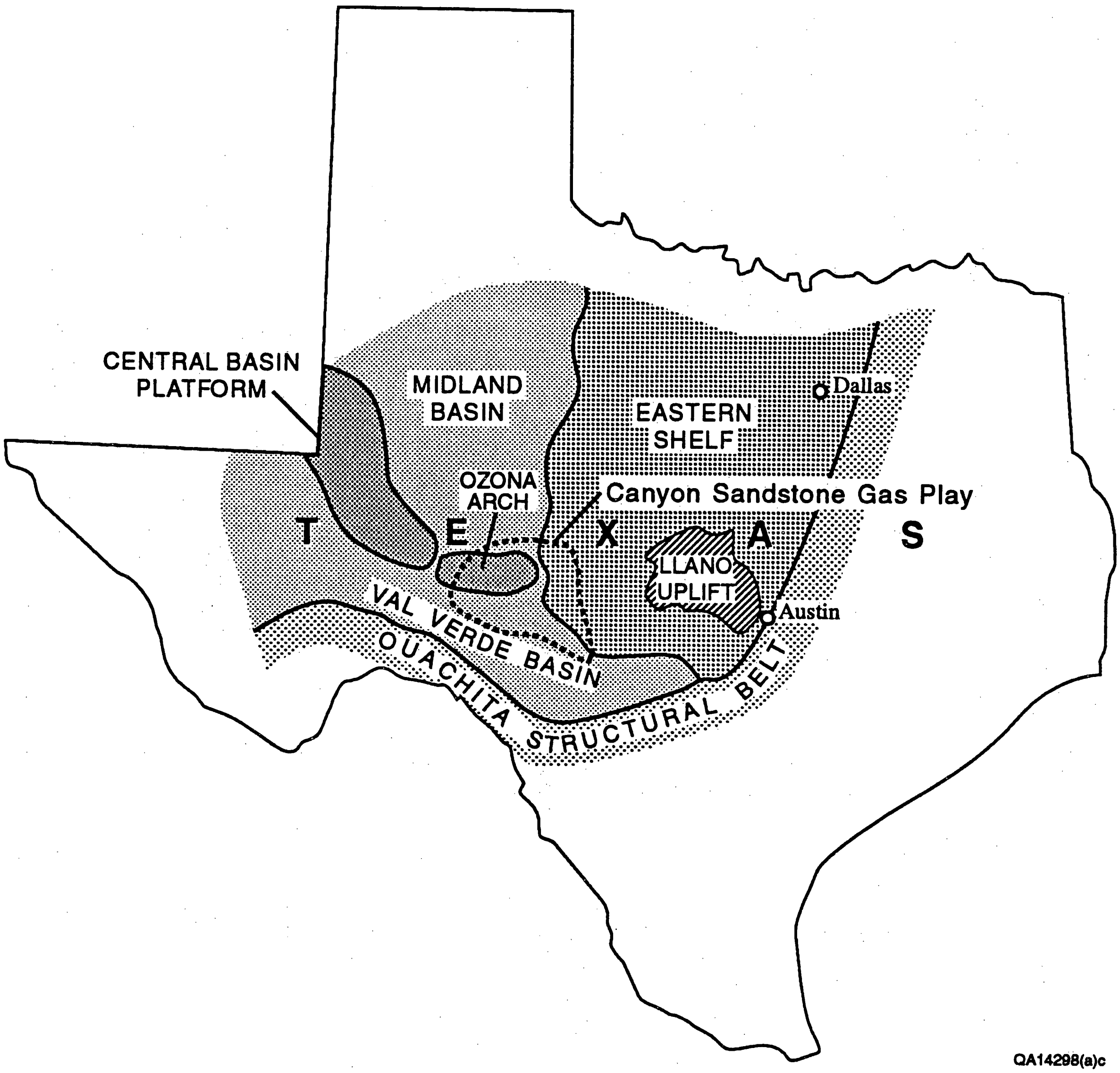


Figure 100. Principal Late Pennsylvanian–Early Permian tectonic elements and paleogeography in southwest Texas. From Hamlin and others (1992a).

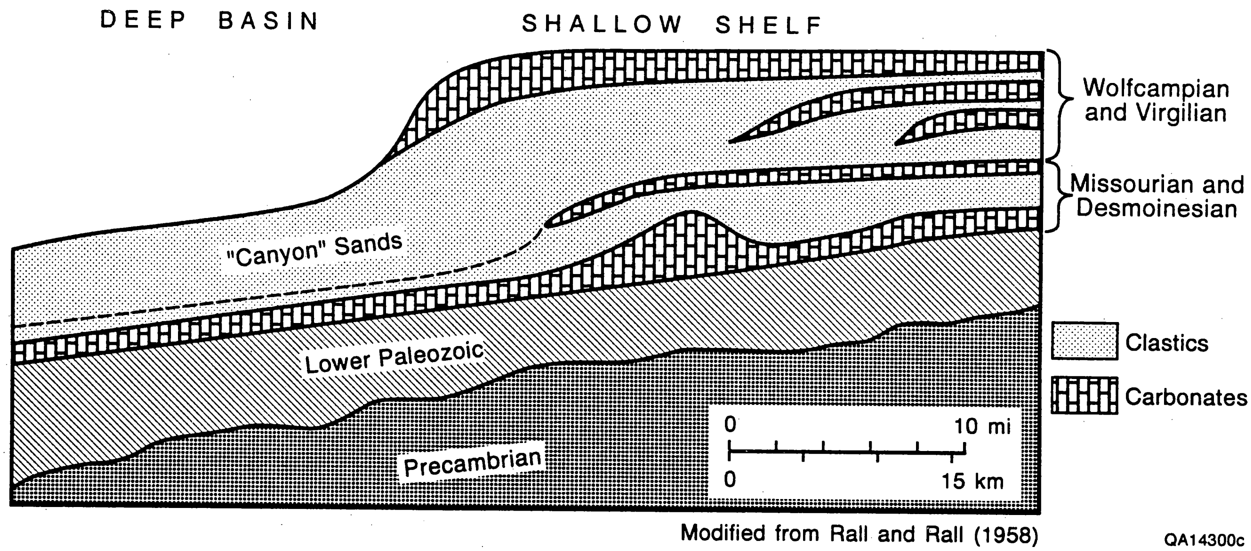


Figure 101. Schematic cross section showing Late Pennsylvanian–Early Permian stratigraphy and depositional topography, northeast Val Verde Basin. Modified from Rall and Rall (1958).

thousands of feet of Permian rocks may have been eroded before deposition of the Cretaceous (Sanders and others, 1983).

Low-permeability gas-bearing sandstones in the Val Verde Basin occur within the Upper Pennsylvanian/Lower Permian clastic slope wedges. These tight-gas formations are called Canyon or Cisco-Canyon Sandstones and generally comprise thick intervals of interbedded sandstone and shale. Strawn and Wolfcamp carbonates also produce tight gas in the Val Verde Basin (Hugman and others, 1992). Conventional oil and gas reservoirs occur in Ordovician through Permian sedimentary rocks.

Canyon Sandstones

Introduction

The Canyon sandstones tight gas play is located mainly in the north and east parts of the Val Verde Basin in southwest Texas but also extends across the Ozona Arch, the south end of the Midland Basin, and the southwest margin of the Eastern Shelf (fig. 100). Several distinct Canyon intervals are formally designated as tight-gas producers: the Sonora Canyon in Crockett, Edwards, Schleicher, and Sutton Counties; the Ozona Canyon in Crockett, Terrell, and Val Verde Counties; the lower (Epps) Canyon in Edwards, Sutton, and Val Verde Counties; and undifferentiated Canyon sandstones in Irion and Tom Green Counties. The stratigraphically equivalent Cisco-Canyon sandstones are also designated tight in local areas in Glasscock, Reagan, and Sterling Counties. Cumulative gas production from Canyon sandstone reservoirs in these areas is almost 2 Tcf (Bebout and Garrett, 1989; Hugman and others, 1992) (table 2).

Canyon sandstones were deposited in shelf-edge, slope, and basin-floor environments during the late Pennsylvanian and early Permian (Virgilian–Wolfcampian) (fig. 101) (Rall and Rall, 1958; National Petroleum Council, 1980; Hamlin and others, 1992a, b). The Canyon interval, which is predominantly siliciclastic, is enclosed in Permo-Pennsylvanian carbonates and shales. The Canyon is a wedge-shaped interval, thickening toward the deep Val Verde and Midland Basins from the more positive areas that rim these basins (fig. 102). On the Eastern Shelf and Ozona Arch, the Canyon interval is less than 1,000 ft thick and comprises isolated sandstones in thick shales; net sandstone in shelf areas is 0 to 200 ft. Where shelf-margins slope down into deep basins, the Canyon is 1,000 to 3,000 ft thick and comprises complexly interbedded sandstones and shales (net sandstone reaching 1,000 ft). The largest and most prolific Canyon fields, such as the Ozona, Sawyer, and Sonora fields, produce from thick sandstones in slope settings. In the deep Val Verde and Midland basins, the Canyon interval comprises greater than 3,000 ft of shales and thin sandstones (net sandstone 200 to 400 ft).

Post-Pennsylvanian northwest tilting has modified original depositional topography and caused the shallowest Canyon sandstones to be in the southeast. Depth to Canyon sandstone is less than 3,000 ft across most of Edwards County and northern Val Verde County; 4,000 to 6,000 ft in Sutton County, east Schleicher County, and south Crockett County; and generally greater than 6,000 ft in the rest of the area (National Petroleum Council, 1980; Bebout and Garrett, 1989; Hamlin and others, 1992a). Traps are stratigraphic, resulting from updip (south and east) porosity loss attributable to depositional, erosional, and diagenetic processes (National Petroleum Council, 1980).

With the exception of a broad-based report by the National Petroleum Council (1980), most published descriptions of Canyon sandstone reservoirs are of limited scope. Early regional studies include brief descriptions of Canyon sandstones based on limited data (Rall and Rall, 1958; Holmquist, 1965; Hills, 1968). More recent studies include core-based descriptions of reservoir facies and sandstone petrography in parts of the Ozona and Sonora Canyon intervals (Mitchell, 1975; Berg, 1986; Huang, 1989). Recent support by the GRI Tight Gas Sands project led to the drilling of two cooperative wells in the Sonora Canyon in Sutton County and to the collection of data necessary for formation evaluation and hydraulic-fracture-treatment design (CER Corporation, 1991a, c; Miller and others, 1991; NSI Technologies, Inc., 1991a–d; Hamlin

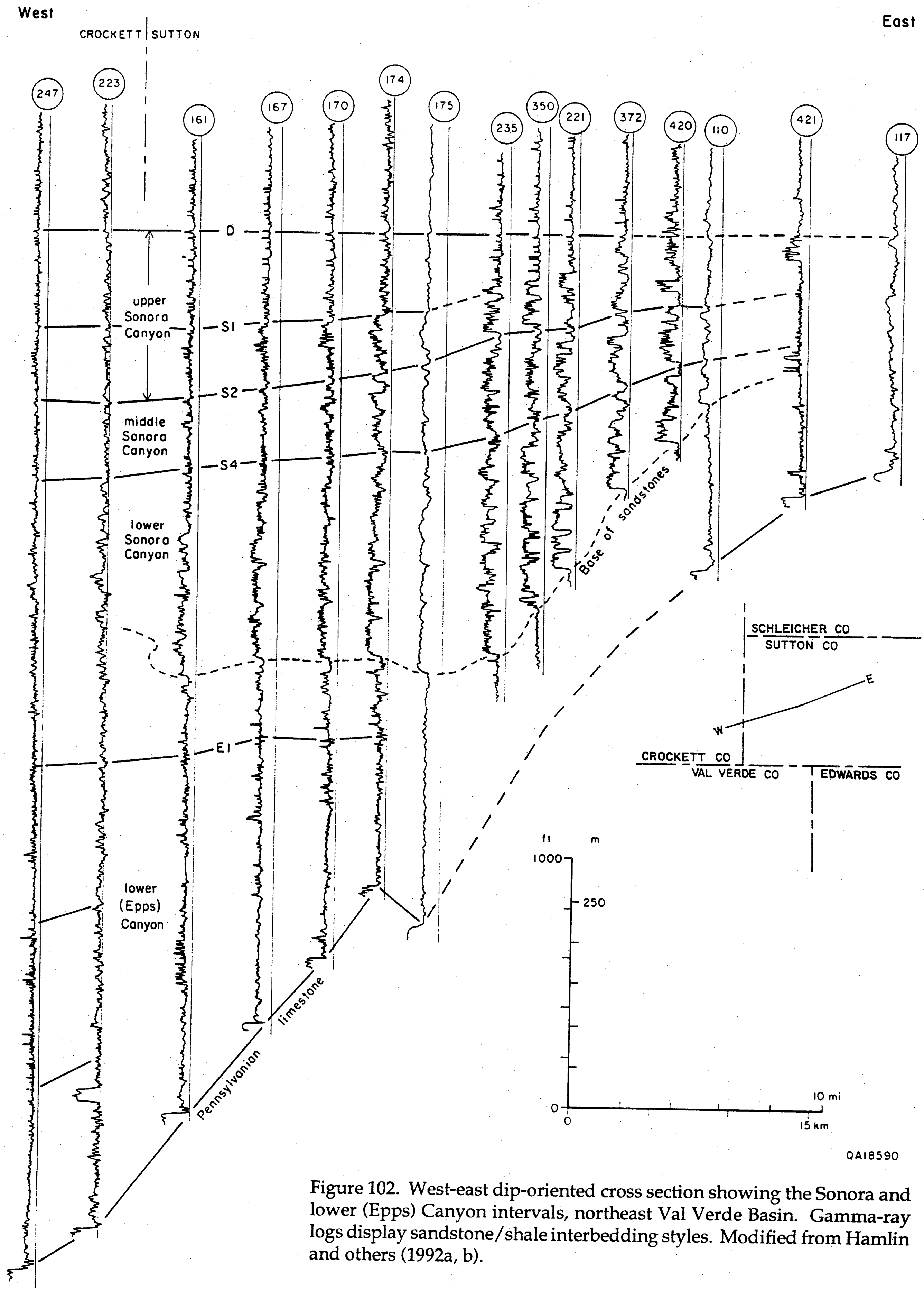


Figure 102. West-east dip-oriented cross section showing the Sonora and lower (Epps) Canyon intervals, northeast Val Verde Basin. Gamma-ray logs display sandstone/shale interbedding styles. Modified from Hamlin and others (1992a, b).

and others, 1992b). The GRI also supported regional and field-scale geologic studies of the Sonora Canyon interval using logs from 500 wells and 820 ft of core (Hamlin and others, 1992a).

Depositional Systems and Reservoir Facies

Most Canyon sandstones were deposited in submarine fan systems (fig. 2). During sea-level lowstands fluvial-deltaic systems transported sediments across exposed shelf areas and deposited them directly into basinal areas. Sediment input occurred at many locations along the shelf margins, forming wedge-shaped slope aprons composed of small, laterally coalesced submarine fans. The oldest intervals, such as the lower (Epps) Canyon, lie the farthest basinward (fig. 102), but younger intervals extend progressively farther updip, onlapping the underlying Desmoinesian–Missourian carbonate slope and shelf margin and suggesting deposition during rising sea level (Hamlin and others, 1992a). Deposition of Canyon slope aprons prograded the shelf margins, constructing platforms for overlying Wolfcampian carbonate and fine-grained-clastic shelf deposits (fig. 101).

In Canyon submarine fan depositional systems, the primary reservoir facies are channel-fill and fan-lobe sandstones (fig. 103) (National Petroleum Council, 1980; Berg, 1986; Hamlin and others, 1992a, b). On the inner or proximal part of the fan, isolated channel-fill sandstones, 20 to 100 ft thick and less than 0.5 mi wide, are enclosed in thick slope mudstones (fig. 102, log 421). The middle fan comprises a complex crosscutting network of channel-fill and proximal fan-lobe sheet sandstones and interchannel mudstones. The prolific Sawyer and Sonora fields produce from thick but laterally discontinuous sandstones (fig. 102, log 350) that probably represent channelized proximal fan lobes within coalesced middle fans (fig. 103). The distal fan-lobe margins are composed of thinner but more laterally continuous sandstones interbedded with basinal mudstones (fig. 102, log 247).

Turbidites are the main sedimentary features of Canyon reservoirs. A turbidite, which may be simply characterized as massive to laminated sandstone overlain by laminated

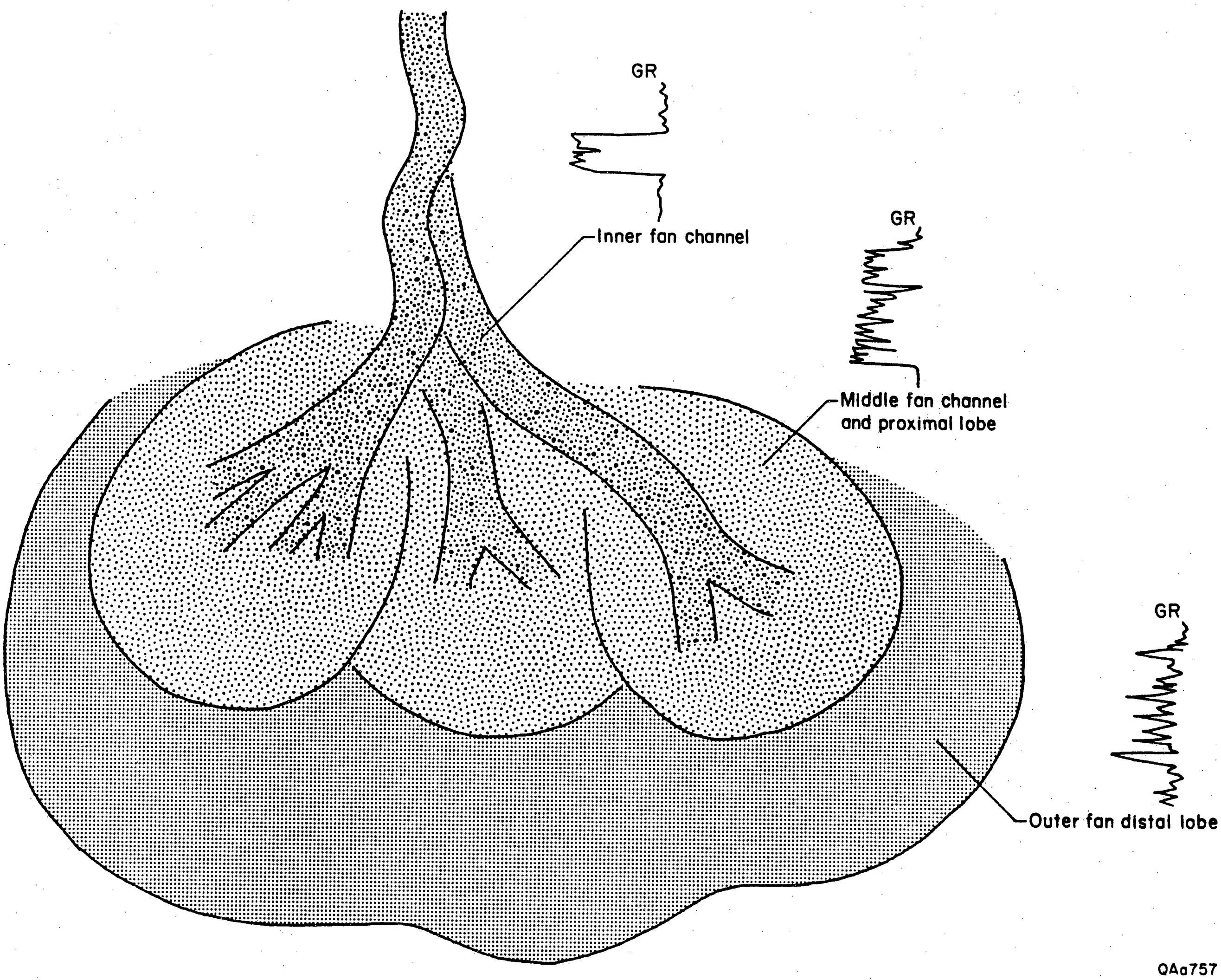


Figure 103. Submarine fan model showing typical gamma-ray log responses caused by Canyon fan channel and lobe facies. Model simplified from illustrations and descriptions in Shanmugam and Moiola (1988).

mudstone, records deposition by a waning turbidity flow. Thick-bedded turbidites, having sandstone components 1 to 5 ft thick and mudstone components <0.5 ft thick, result from higher flow energies in fan channels and on proximal parts of fan lobes, whereas thin-bedded turbidites, having subequal sandstone and mudstone components <1 ft thick, result from lower flow energies in interchannel areas and on distal fan lobes. Wells in the Sawyer and Sonora fields commonly penetrate up to 1,000 ft of gross sandstone that is composed of hundreds of turbidites (fig. 104). Thus, many Canyon reservoirs, although thick, are compartmentalized vertically by the fine-grained components of the turbidites.

Composition of Reservoir Facies

Canyon reservoirs are typically composed of very fine to medium grained sandstone, although coarser, locally conglomeratic sandstone is present in the channel-fill facies. Intergranular matrix, composed primarily of detrital and authigenic clay, averages 20 percent in selected Sonora and Ozona Canyon sandstones (Mitchell, 1975). Most clean (<2 percent clay matrix) are moderately well sorted. Sonora Canyon clean sandstones are mineralogically immature and are classified as sublitharenites and litharenites; framework grain average composition is 77 percent quartz, 4 percent feldspar, and 19 percent rock fragments. Authigenic cements and replacive minerals constitute between 7 and 52 percent of rock volume in Sonora Canyon sandstone samples (Hamlin and others, 1992a).

Major diagenetic events in Sonora Canyon sandstones were (1) siderite and chlorite cementation, (2) mechanical compaction, (3) quartz cementation, (4) feldspar dissolution and illite and kaolinite precipitation, and (5) ankerite cementation (Hamlin and others, 1992a). Early precipitation of siderite cement was an important diagenetic event in Sonora Canyon sandstones because siderite cemented sandstones apparently have lost less porosity by compaction and quartz cementation than have sandstones without siderite (Berg, 1986; Huang, 1989; Hamlin and others, 1992a; Dutton and others, in press). Siderite cement has not been noted

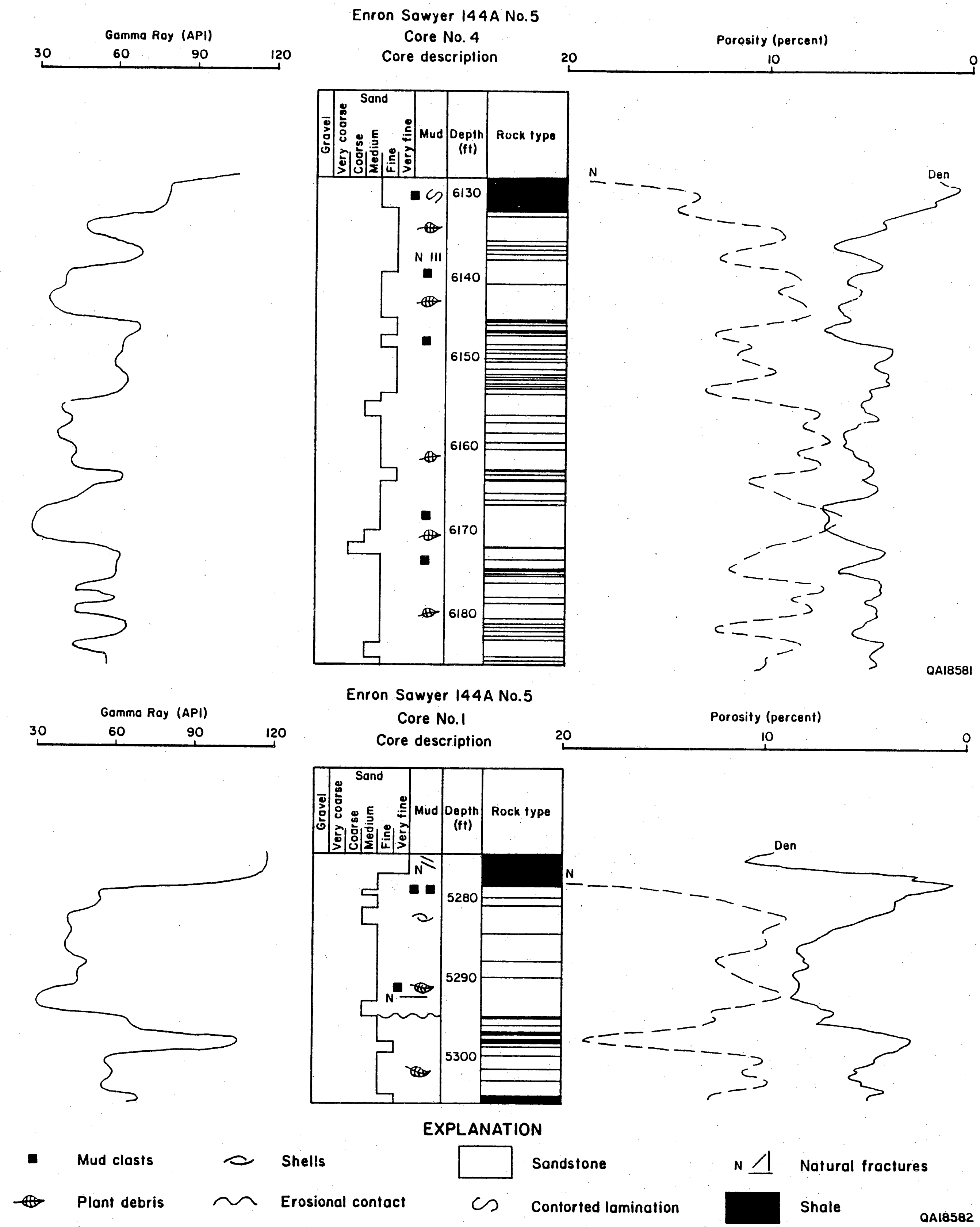


Figure 104. Core description and log responses from the Enron Sawyer 144A No. 5 GRI cooperative well, Sutton County. (a) Interbedded sandstones and mudstones are thick- and thin-bedded turbidites. (b) Sandstone between 5,278 and 5,294 ft is probably a small channel fill. The underlying thin sandstones are turbidites.

in Ozona Canyon sandstones, although calcite cement is more abundant in the Ozona Canyon than in the Sonora Canyon (Berg, 1986). Quartz cement is common in all Canyon intervals.

The National Petroleum Council (1980) reported that the highest porosity in Canyon sandstones occurs in association with abundant siderite, and data from the GRI cooperative wells support this observation. Average porosity of siderite-rich sandstones (>10 percent siderite) is 7.9 percent, compared with 6.4 percent in siderite-poor sandstones. High permeability in siderite-cemented Canyon sandstones was noted by the National Petroleum Council (1980), Berg (1986), Huang (1989), and Hamlin and others (1992b). Siderite-rich sandstones have higher geometric mean unstressed permeability (0.069 md) than do siderite-poor sandstones (0.014 md) (Hamlin and others, 1992a). Similarly, stressed permeability is higher in siderite-rich than in siderite-poor sandstones (0.042 vs. 0.009 md). Therefore, the best matrix reservoir quality in Canyon sandstones apparently occurs in siderite-cemented zones in some areas of Canyon production.

Natural Fractures

The potential importance of natural fractures for augmenting production from Sonora Canyon sandstone reservoirs was noted by Finley and others (1990). Until recently, natural fractures had not been described in published accounts of Canyon reservoirs. At this time the possible effects of natural fractures on production and stimulation have not been studied in detail.

Abundant natural fractures occur in three cored Sonora Canyon sandstone wells in Sutton County, Texas (Hamlin and others, 1992a; Marin and others, in press). This core shows that at least three distinct natural fracture types coexist that have contrasting distributions, characteristic sizes, and mineral fills.

The most abundant fracture type comprises clay- or carbonate-filled and partly open fractures that are confined to siderite-cemented zones in sandstones (fig. 105). These fractures

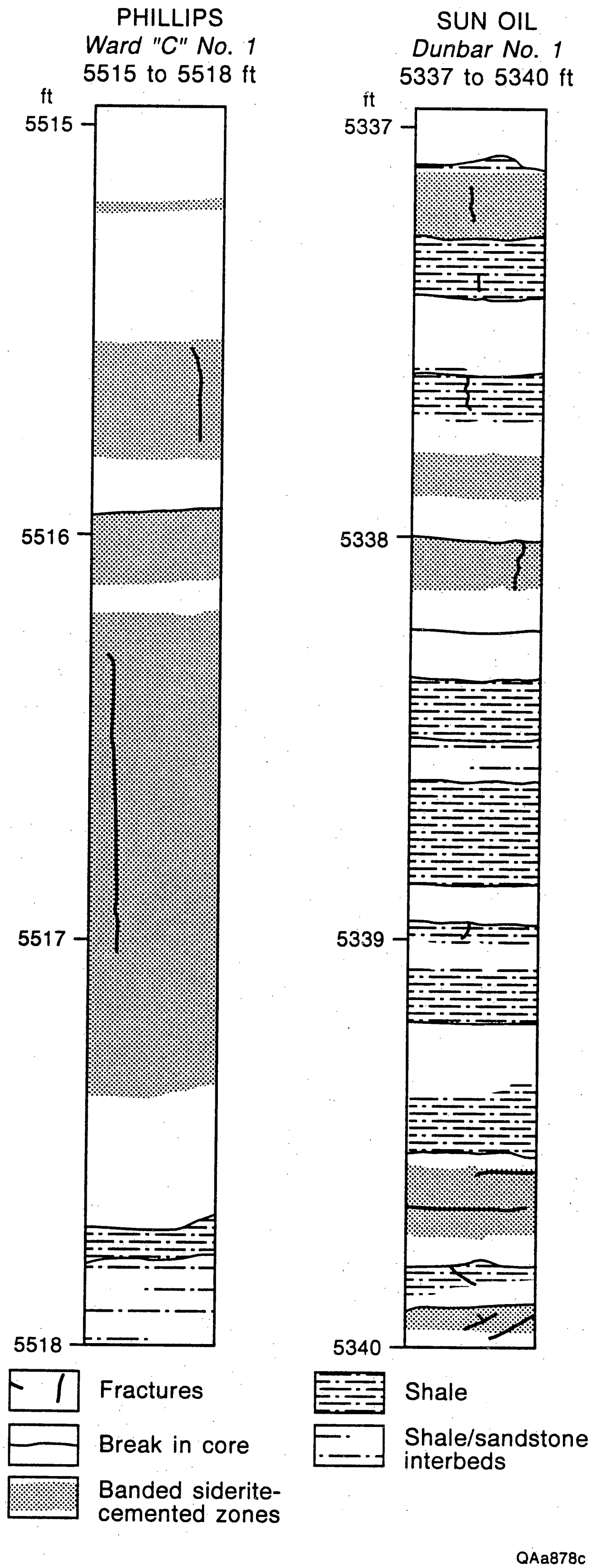


Figure 105. Fractures in Canyon Sandstone core, Phillips Ward C No. 1 and Sun Oil Dunbar No. 1. Maps show fracture traces, rock type, and location of siderite-cemented zones (from Marin and others, in press).

typically have the same vertical extent as layers of siderite cement, which are generally less than 4 inches thick. Owing to their clay (dickite) content, many of these fractures locally may be barriers to fluid flow, and their presence could promote reservoir heterogeneity and anisotropy without necessarily augmenting production. Moreover, although not filled with swelling clay minerals, clay-filled fractures may be sensitive to fluids introduced during completion and stimulation (possibly including fines migration). Furthermore, the highly variable degree of occlusion of fracture porosity by infilling minerals suggested to Marin and others (in press) that flow channeling *within* some Canyon fractures may occur.

In core, calcite- and quartz-cemented fractures are less common than clay-filled fractures but they are larger (greater vertical extent) and are partly open as a result of diagenetic propping (vein-filling minerals holding fractures open; Dyke, 1992). Although less common, the open pore space in these fractures and their stable mineral assemblage of quartz and calcite may make this set of fractures important fluid conduits. Because they are vertically extensive and are not confined to siderite layers, these fractures could link discontinuous areas of high reservoir quality. In a GRI cooperative well a wireline formation test measurement of one of these fractures showed that it was sufficiently open to conduct fluids (R. E. Peterson, personal communication, 1992).

There is some evidence that natural fractures can also affect the outcomes of Canyon Sandstone hydraulic fracture stimulations. In hydraulic fracture treatments in GRI experimental wells, observed inconsistencies between hydraulic fracture strike and maximum horizontal stress direction (NSI Technologies, Inc., 1991a; Miller and others, 1991) may be due to natural fractures guiding hydraulic fracture growth (Marin and others, in press). High treatment pressures that occur in some Canyon sandstone stimulations (NSI Technologies, Inc., 1991a; Miller and others, 1991) may be due to propagation of multiple fracture strands in the near-wellbore region during hydraulic fracture treatment, a phenomenon promoted by the presence of natural fractures. These observations show that fractured zones in Sonora Canyon sandstones are possible reservoir elements that assist production. Natural fractures may also need to be accounted for in treatment design. A stress profile from the Canyon Sandstone is shown in figure 106.

Engineering Assessment

According to the National Petroleum Council (1980), Ozona Canyon sandstone porosities range from 1 to 12 percent and average 6.9 percent, and Sonora Canyon sandstone porosities range from 2 to 15 percent and average 7.4 percent (table 22). GRI research on wells in the Sonora sandstone in Sutton County indicates porosities ranging from 3 to 9 percent and averaging around 6 percent (ResTech, Inc., 1991). Log observations in the Sonora Canyon sandstones indicate zones where porosity is consistently as high as 14 percent. In Irion County, in situ gas permeability for Canyon sandstones is 0.027 md (Railroad Commission of Texas, 1983a). Weighted average core permeability in this same application was 0.09 md for four cored wells. Average in situ gas permeabilities for the Cisco-Canyon sandstones in Reagan County is 0.052 md (Railroad Commission of Texas, 1980a). In Tom Green County, the Canyon sandstones are divided into two intervals, with permeabilities of 0.037 md for the lower and 0.025 md for the upper interval (Railroad Commission of Texas, 1991c). Restored-state core analysis measurements for the GRI research in Sawyer field indicate that most permeabilities range from 0.001 to 0.03 md (NSI Technologies, Inc., 1991a–d) (fig. 107).

Net pay thicknesses in the Canyon sandstones can be in excess of several hundred feet per well (National Petroleum Council, 1980; Hamlin and others, 1992c). Because the permeability is extremely low, high net pay footages are necessary for making an economical completion. In some of the higher porosity wells, net pays of 20 to 30 ft may be economic (NSI Technologies, Inc., 1991a). Net pay porosity cutoff is 5 percent (ResTech, 1991).

Water saturations range from 20 percent upward (National Petroleum Council, 1980) (table 22). In Sawyer field, average water saturation in the pay sandstones averages 42 percent. Formation water resistivity is consistent over a wide area at 0.088 Ω·m at 75°F. Total dissolved

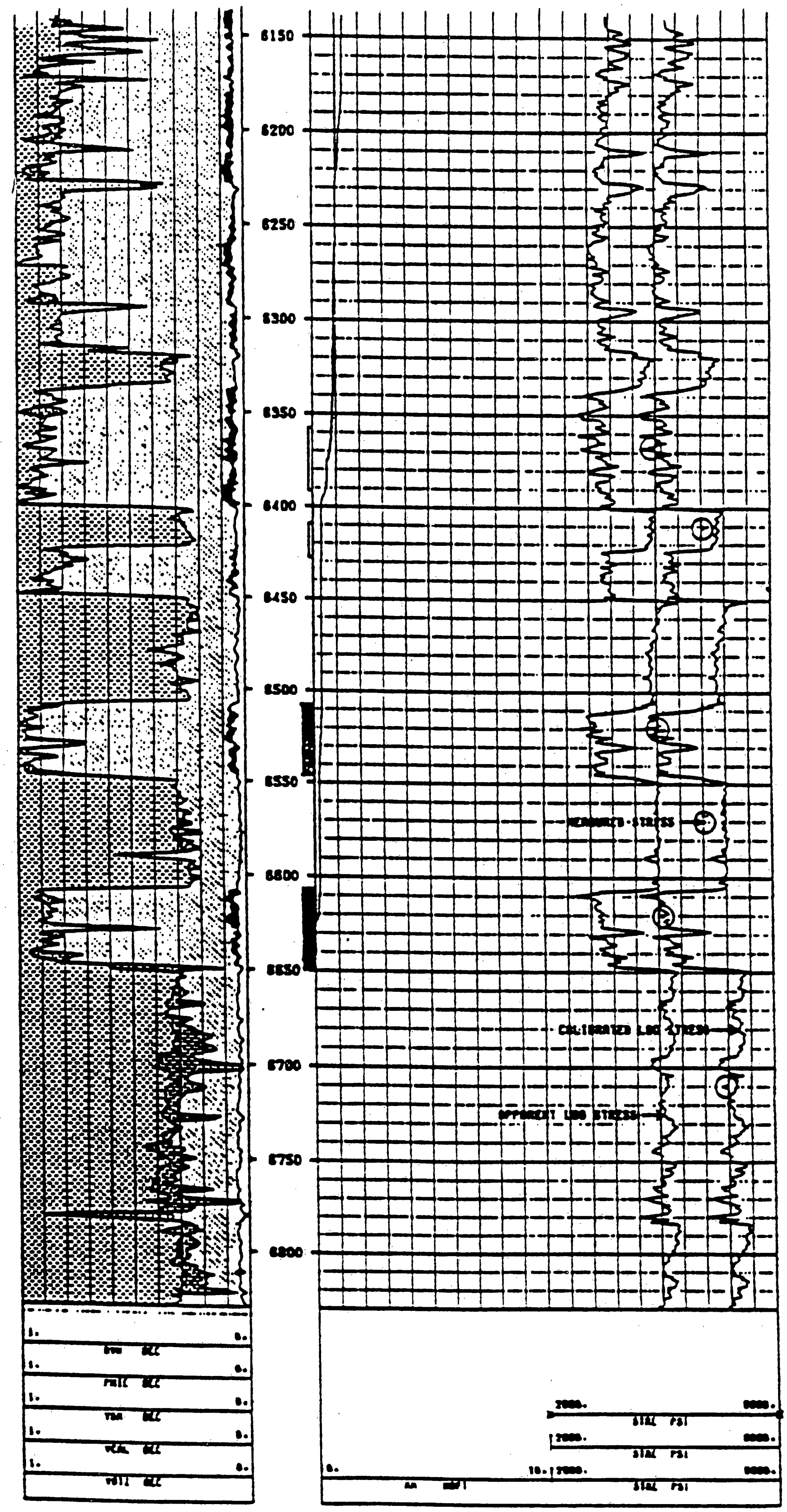


Figure 106. Canyon Formation stress-profile example, Phillips Ward C No. 11 (W. Whitehead, personal communication, 1992).

Table 22. Canyon Sandstone, Val Verde Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 4,560

Cumulative production from tight completions 1970–1988 (Bcf): 1,821.3

Estimated ultimate recovery from tight areas (Bcf): 3,370

Net pay thickness (ft): 20–300

Porosity range and average (%): 2–15/7.4

Permeability (md): 0.001–0.052

Water saturation range and average (%): >20

Reservoir temperature (°F): 150–185

Reservoir pressure (psi): 670–940

Typical stimulation/hydro-frac: 50,000 gal gel and 118,000 lb sand

Production rate:

  prestimulation (Mcf/d): 40

  poststimulation (Mcf/d): 339

Average recovery per completion (Bcf): 0.73

Decline rate: No data

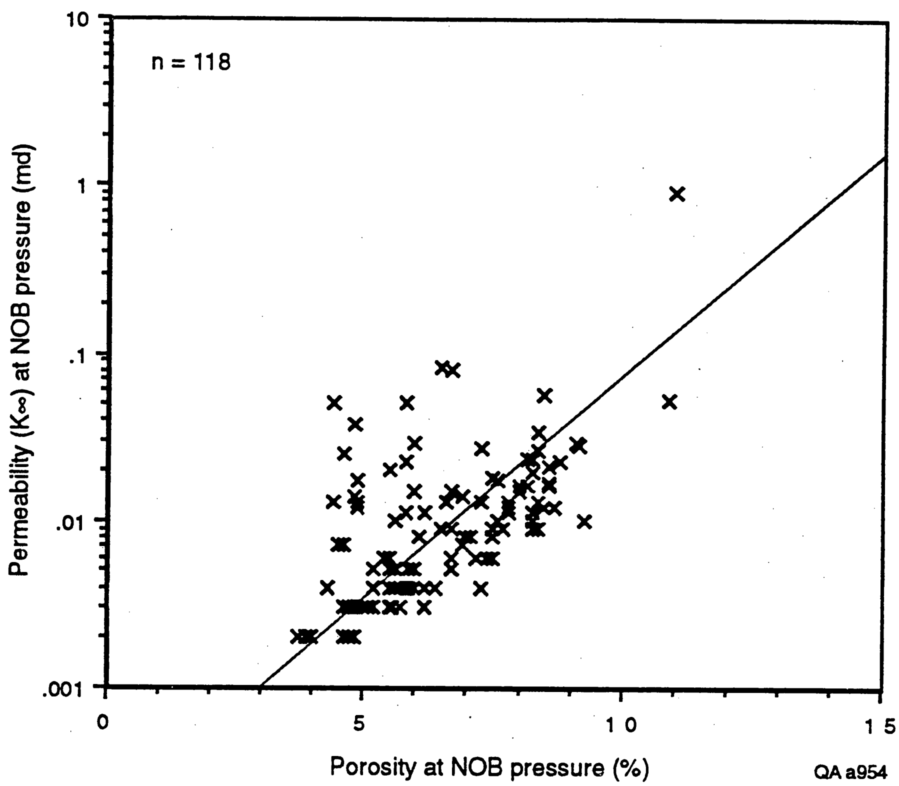


Figure 107. Semi-log plot of porosity measured at net overburden pressure vs. Klinkenberg-corrected gas permeability measured at net overburden pressure for 118 Canyon Sandstone samples. Line is approximate trend line for porosity-permeability relationship, ignoring data interpreted to be of poor quality.

solids are 80,000 ppm. Cementation and saturation exponents are 2.07 and 2.09, respectively (ResTech, Inc., 1991). Temperature ranges from 150° to 185°F.

A typical hydraulic fracture treatment consists of 50,000 gal of gel with 118,000 lb Ottowa sand (NSI Technologies, Inc., 1991a) One of the GRI research wells improved from a pre-fracture stimulation rate of 40 Mcf/d to a post-fracture stimulation rate of 339 Mcf/d 1 month after fracture. Stress gradient for the Canyon sandstone is .621 psi/ft in the sandstone itself and .778 psi/ft in the surrounding shales. Water production can be a problem with rates up to 100 bbl per 1,000 Mcf (National Petroleum Council, 1980). Some wells have been abandoned due to low gas production with high volumes of water.

Production History

In Canyon fields in Irion County, the average well density in acres per well is 310 (Railroad Commission of Texas, 1983a). Ultimate recovery for Canyon sandstone wells is 3,370 Bcf (Hugman and others, 1992) (table 22). Average recovery per completion is 0.73 Bcf for Canyon well completions and 0.49 Bcf for Cisco-Canyon completions.

Production rates vary according to the area but are not excessive. Ozona wells generally range from 10 to 250 Mcf/d (National Petroleum Council, 1980). In Irion County, average flow rate was 81.5 Mcf/d for 477 wells (Railroad Commission of Texas, 1983a). The Cisco-Canyon sandstone in Glasscock and Reagan Counties (Railroad Commission of Texas, 1980a) recorded average stabilized rate of 92 Mcf/d. Decline rate in Irion County was described at 20 to 50 percent the first year and 5 to 20 percent per year after 5 years.

SAN JUAN BASIN

The San Juan Basin occupies the east-central part of the Colorado Plateau in northwestern New Mexico and southwestern Colorado and is a major gas producing area (New Mexico Oil Conservation Division, 1981a). The depocenter and the synclinal axis of the basin occur near, and parallel, the north and the northeast margin of the basin (fig. 108) (Ayers and Ambrose, 1990). The basin is a roughly circular, asymmetrical structure that is approximately 80 mi long in a northwest-southeast trend and 40 mi wide from southwest-northeast (New Mexico Oil Conservation Division, 1981a). The southwest flank of the basin dips gently, and the north and northwest margins dip steeply (fig. 109).

The basin developed during the Late Cretaceous–Early Tertiary Laramide Orogeny. Principal structures that bound the basin include the Hogback Monocline (west, northwest), the San Juan-Archuleta Uplift (north), the Nacimiento Uplift (east, southeast), the Puerco Fault Zone (southeast), and the Chaco Slope and Zuni Uplift (south, southwest) (fig. 108). Epeirogenic uplift of the Colorado Plateau, including the San Juan Basin, took place in post-Laramide Tertiary time (Woodward and Callender, 1977).

The gas produced from the low-permeability sandstones in this area is found principally in reservoirs of the Mesaverde Group and Dakota Sandstone. Smaller volumes of gas have been produced from the Pictured Cliffs Sandstone (fig. 110).

The Pictured Cliffs sandstone and the Cliff House and Point Lookout sandstones of the Mesaverde Group represent regressive-transgressive-regressive cycles of part of the shoreline of the Western Interior Seaway during Late Cretaceous (Late Campanian) time (fig. 111). Both the Point Lookout and the Pictured Cliffs sandstones were deposited during regression of the Cretaceous sea, whereas the Cliff House represents an overall transgressive episode (fig. 111). The Pictured Cliffs and Point Lookout sandstones were deposited when sediment influx exceeded the subsidence rate of the slowly subsiding basin (Fassett, 1977). The Dakota

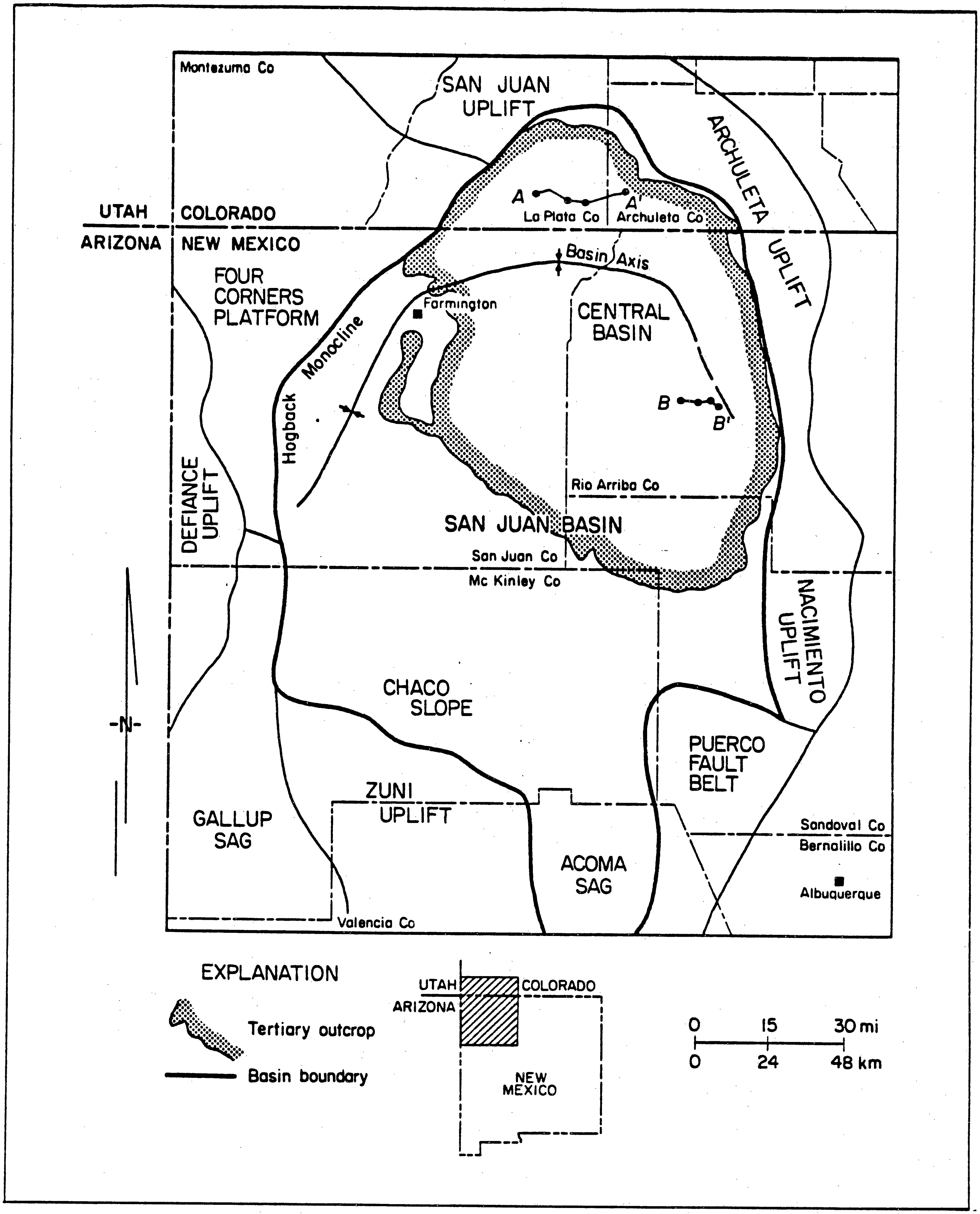


Figure 108. Location and generalized structure map, San Juan Basin (from Peterson and others, 1965; Finley, 1984). Cross section A–A′ shown in figure 114 and B–B′ in figure 117.

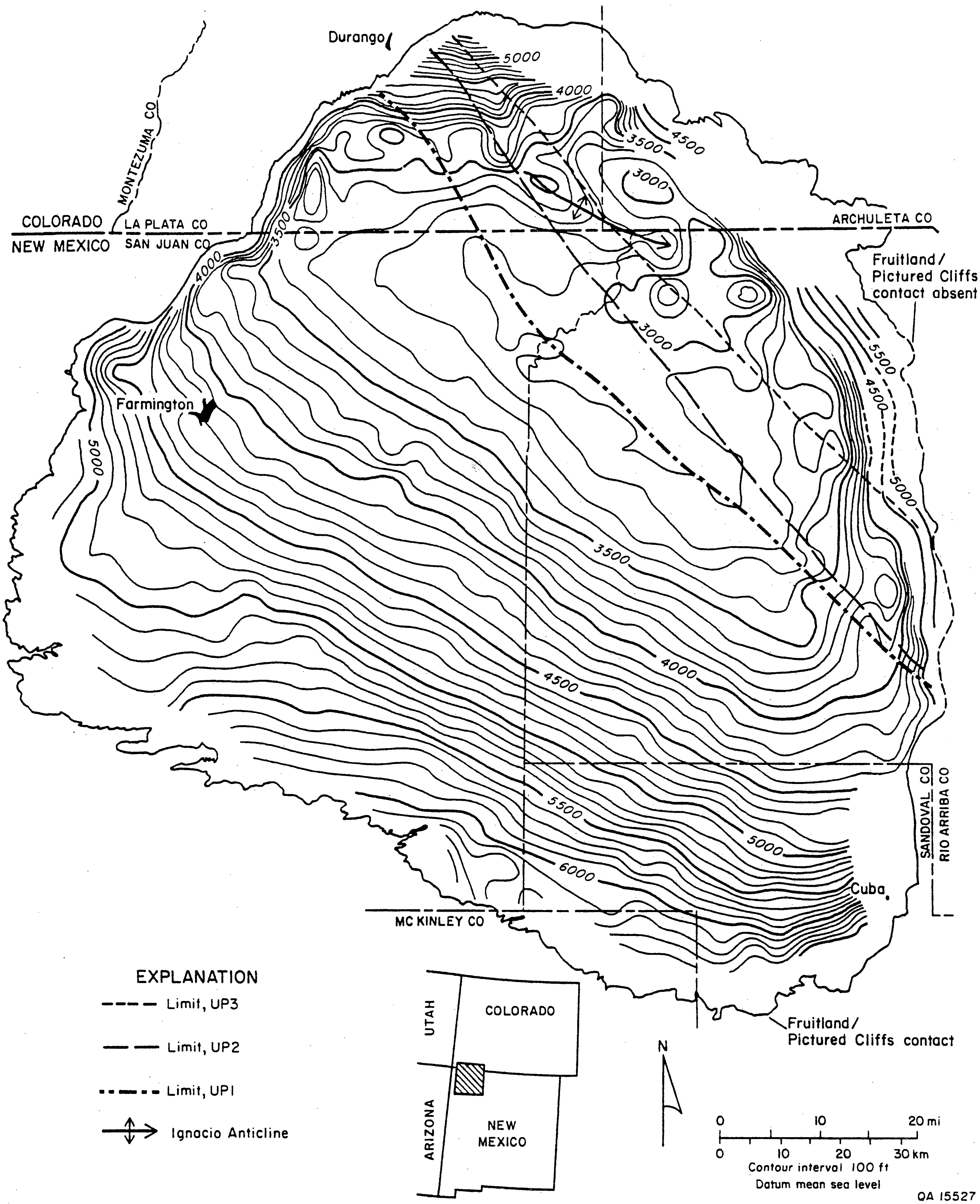


Figure 109. Elevation of the top of the Pictured Cliffs Sandstone, San Juan Basin. C–C′ is the southwest-northeast stratigraphic cross section through Pictured Cliffs Sandstone (modified from Ayers and Ambrose, 1990).

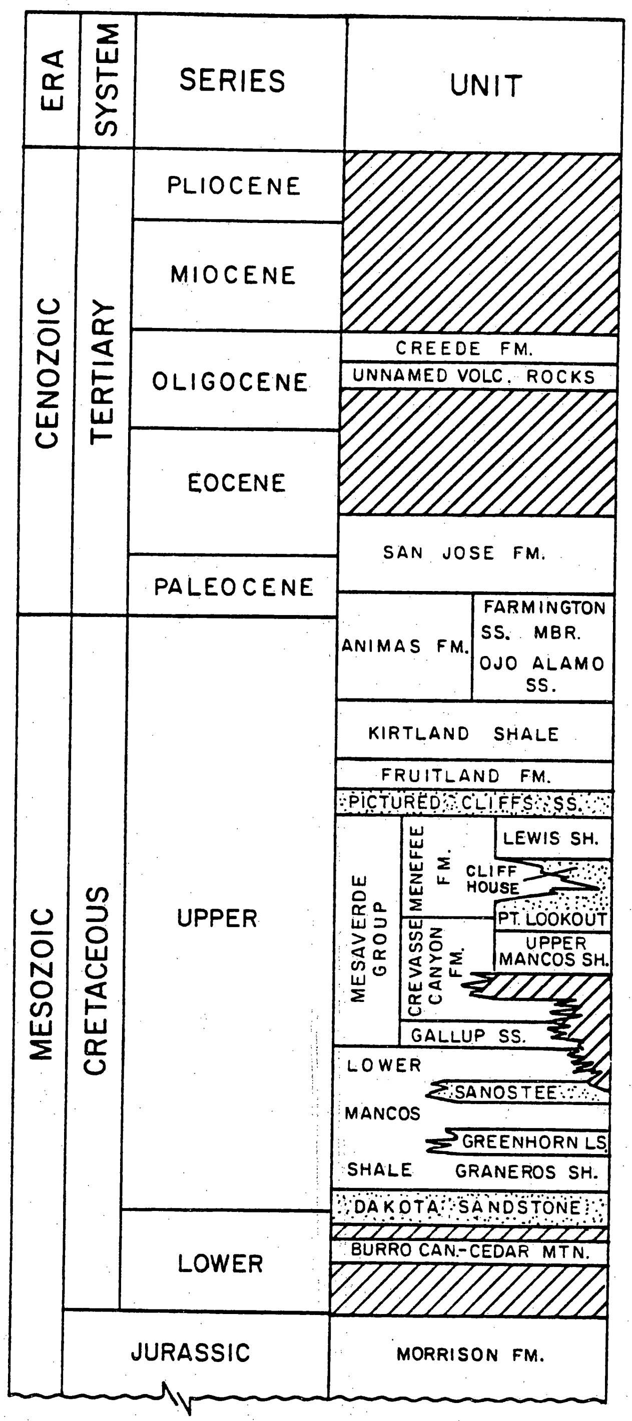


Figure 110. Stratigraphic column from the Upper Jurassic through the Pliocene, San Juan Basin (from Rocky Mountain Association of Geologists, 1977; Finley, 1984).

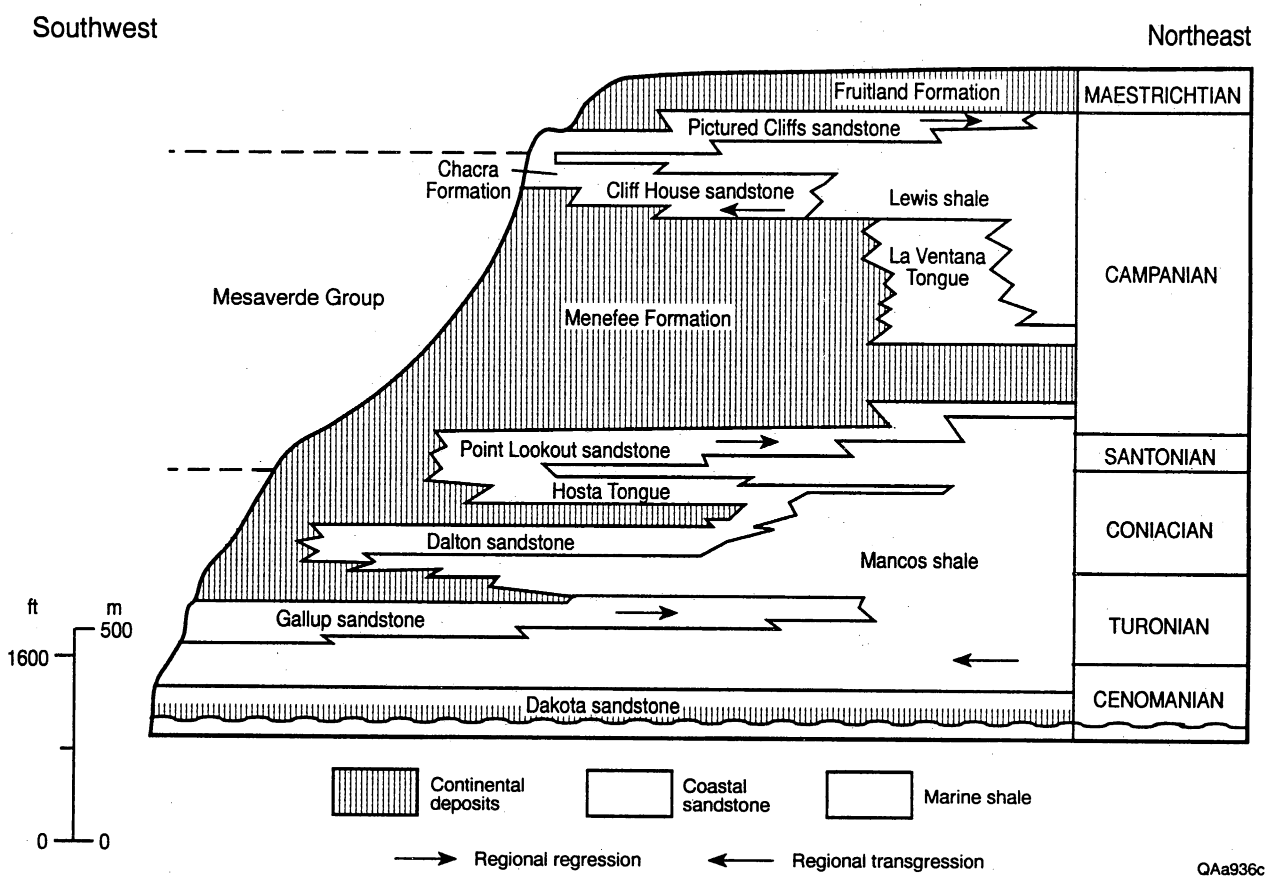


Figure 111. Lithostratigraphic relations of Late Cretaceous deposits in the San Juan Basin (modified from Beaumont and others, 1956; Donselaar, 1989).

Sandstone represents a basal transgressive sequence that was deposited during Late Cretaceous (Cenomanian) time (fig. 111) (Finley, 1984).

Other low-permeability formations include the Sanostee Member of the Mancos Shale (fig. 110). The Sanostee has been approved by FERC as a tight gas sandstone in the Ignacio area of La Plata and Archuleta Counties, Colorado, on the northern margin of the San Juan Basin (Colorado Oil and Gas Conservation Commission, 1980g). Described as a shelf deposit within the Mancos Shale, the Sanostee Member is a very fine grained, silty, clay-rich, calcareous sandstone (Finley, 1984). As of 1988, there have been no tight completions in the Sanostee, and there is no projected ultimate recovery in the designated tight gas area (Hugman and others, 1992).

The Gallup Sandstone records a major regressive episode in the Mesaverde Group (fig. 110). The Gallup designated tight gas areas are located in parts of Rio Arriba, Sandoval, and San Juan Counties, New Mexico. The Gallup is approximately 200 to 600 ft of interbedded, dark gray to black, calcareous, marine shales with light medium-gray siltstones and fine grained sandstones (Middleman, 1983). As of 1988, there have been 13 tight completions, and projected ultimate recovery in the designated tight gas area is 2 Bcf (Hugman and others, 1992).

The Fruitland Formation is located on the northeast flank of the San Juan Basin and is composed of coal seams, shales, and low-permeability sandstone lenses (New Mexico Oil Conservation Division, 1981b). The Fruitland designated tight gas areas are located in parts of San Juan and Rio Arriba Counties, New Mexico. As of 1988, there were no completions, and projected ultimate recovery in the designated tight gas area is 0 Bcf (Hugman and others, 1992).

The San Juan Basin is a prolific area of gas production from low-permeability sandstones. Almost half of the ultimate recovery of gas from tight formations in the United States (excluding the Appalachian Basin) will be in the San Juan Basin (Hugman and others, 1992). Ultimate recovery of gas from tight formations in the San Juan Basin is estimated to be 22,668 Bcf, and as of 1988, there were 7 designated tight fields, 21 designated tight reservoirs, and 13,549 tight gas completions in the San Juan Basin. Most of the development occurred in the

1970's and 1980's, and production has been declining since 1980. Most of the recent development activity has been infill development in the Mesaverde Group and the Dakota Sandstone on 160-acre spacing (Hugman and others, 1992).

Dakota Sandstone

The Dakota Sandstone in the San Juan Basin is the basal sequence formed by the southwesterly transgression of the Cretaceous Sea as it entered the western interior of North America and is probably Late Cretaceous in age (fig. 111) (Finley, 1984). The designated tight gas areas are located in parts of San Juan and Rio Arriba Counties in New Mexico (fig. 112) and in La Plata and Archuleta Counties in Colorado (Finley, 1984). Dakota Sandstone thickness in New Mexico ranges from 200 to 350 ft (Finley, 1984), and depths to the top of the formation range from 5,900 ft to 7,586 ft (Finley, 1984; New Mexico Oil Conservation Division, 1992a). In Colorado, Dakota Sandstone thickness ranges from 210 to 250 ft, and depths to the top of the formation range from 7,180 ft to 8,720 ft (Finley, 1984). Along with the Dakota Sandstone, the Graneros and the Morrison Formations have been added to the total Dakota producing interval in some areas that are designated tight in the San Juan Basin (figs. 113 and 114) (Bureau of Land Management, 1991; Colorado Oil and Gas Conservation Commission, 1981a). There were 4,728 tight completions in the Dakota Sandstone by 1988, and projected ultimate recovery is 7,322 Bcf (Hugman and others, 1992) (table 2).

Depositional Systems and Reservoir Facies

The Dakota represents the initial transgression across an erosional surface that formed on the fluvial and lacustrine rocks of the Lower Cretaceous Burro Canyon Formation in the northern part of the San Juan Basin (fig. 113) and the Upper Jurassic Morrison Formation in the southern part of the basin (Owen and Siemers, 1977; Dillinger, 1989). The Dakota Sandstone

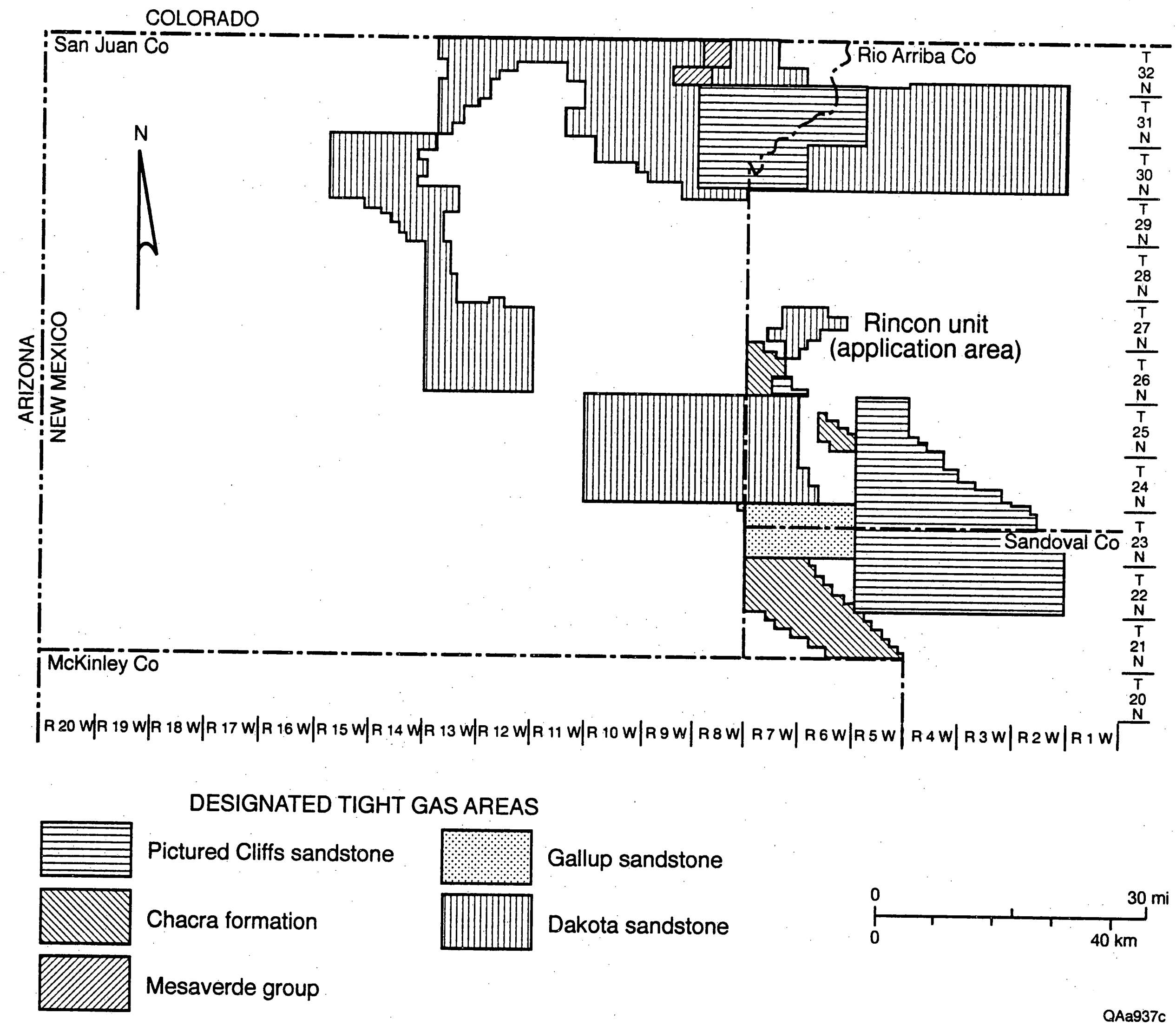


Figure 112. Map showing major designated tight gas areas in the San Juan Basin, New Mexico (modified from Bureau of Land Management, 1991).

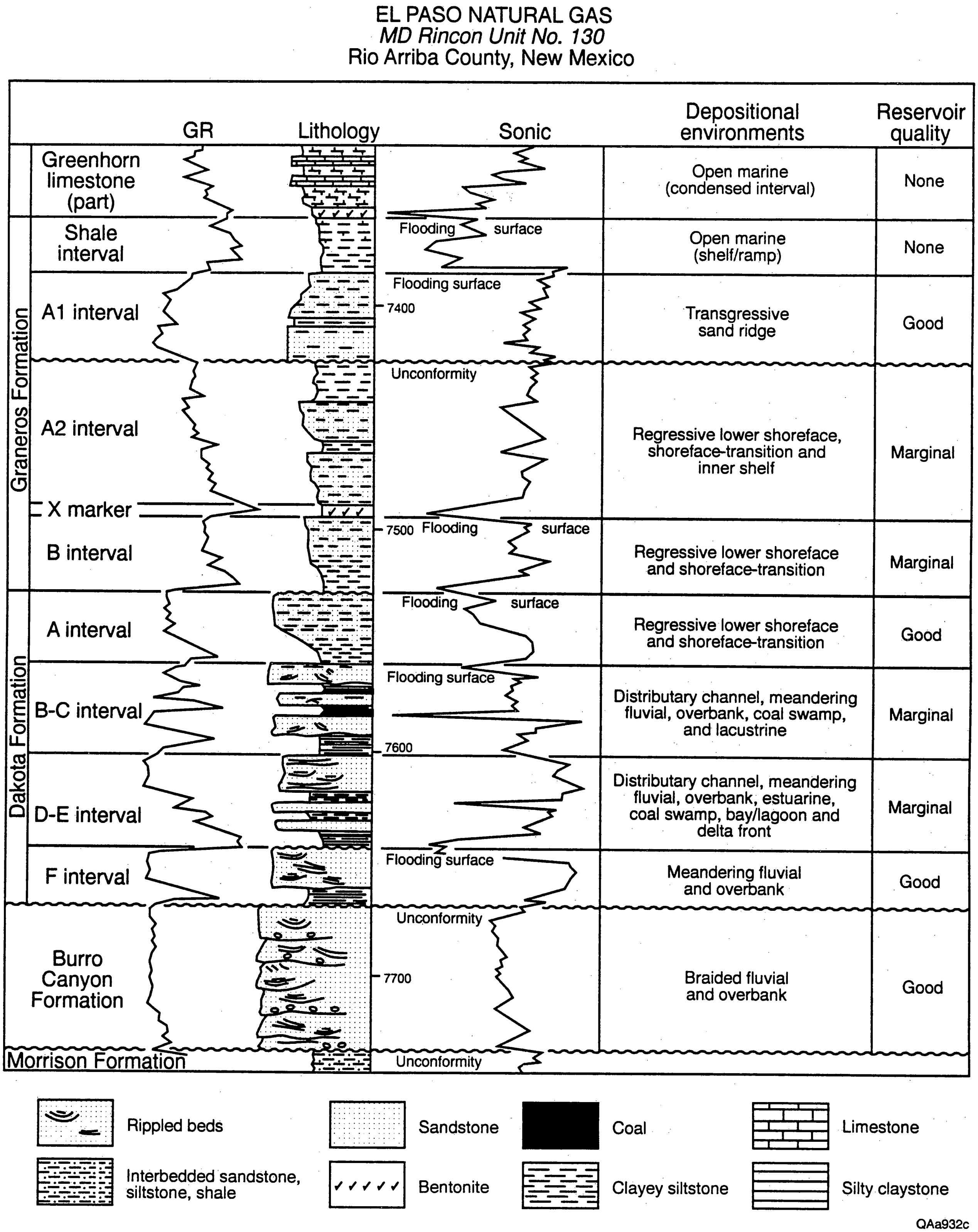


Figure 113. Type log from Dakota producing interval, San Juan Basin (from New Mexico Oil Conservation Division tight gas application file, 1992a).

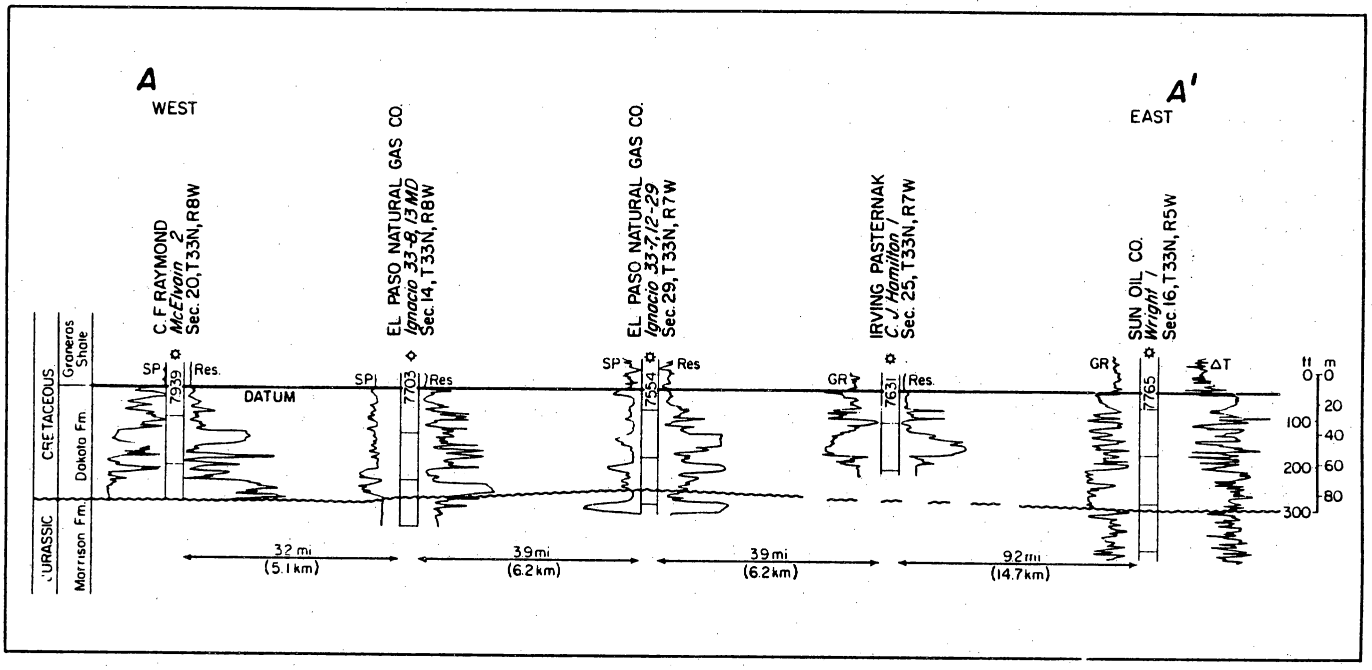


Figure 114. East-west stratigraphic cross section A–A' through the Dakota Sandstone (including the Burro Canyon Formation), San Juan Basin (from Colorado Oil and Gas Conservation Commission, 1981c). Line of section shown in figure 108.

underlies the marine Graneros Formation, the basal unit of the Lower Mancos Shale in this area (fig. 114) (Finley, 1984).

In the northwestern part of the San Juan Basin, the Dakota Sandstone is composed entirely of fluvial sandstones, and most of the marine sandstones and shales are in the southeastern part of the basin (Fassett and others, 1978). Intertonguing is common between these facies as shales wedge out to the north and west and regressive marginal marine sandstones wedge out to the south and east. The Dakota Sandstone includes fluvial through marine facies in the central basin area and in much of the productive tight sand areas along the northern to northeastern margin of the basin (Owen, 1973).

Fluvial sandstones deposited by meandering streams and associated floodplain deposits begin a vertical sequence upward through the Dakota Sandstone in the basin-margin areas (Finley, 1984). The floodplain deposits consist of carbonaceous shales, a few thinly bedded coals, and minor siltstones. Nonmarine facies are followed by transitional estuarine and lagoonal facies of mudstone and siltstone. Small amounts of sandstone represent tidal inlets, tidal channels, and washover fans. Minor episodic regressions and transgressions occurred within the upper part of the Dakota Sandstone, leading to deposition of barrier-strandplain facies (Owen, 1973; Hoppe, 1978). These barrier-strandplain facies are laterally persistent and are 40 to 60 ft thick. The uppermost Dakota sandstones consists of upward-coarsening deposits including lower and upper shoreface facies. The barrier-strandplain system includes less well sorted and less porous sands, which are interpreted to be offshore bars (Finley, 1984).

The Rincon Area of the Dakota Producing Interval (fig. 112) has two main reservoir units: the Graneros "A1" and the Dakota "A" intervals (fig. 113) (New Mexico Oil Conservation Division, 1992a). The Graneros "A1" producing interval is interpreted to be a transgressive sand ridge and the Dakota "A" producing interval is interpreted to be a regressive lower shoreface and shoreface transition facies (fig. 113) (New Mexico Oil Conservation Division, 1992a).

Composition of Reservoir Facies

The Dakota Sandstone is a very fine to fine-grained subarkose to sublitharenite (Franklin and Tieh, 1989). Monocrystalline quartz grains are subangular to well rounded and are moderately well sorted. Average composition is $Q_{65}F_{5}R_{30}$. Rock fragments in descending abundance are igneous (polycrystalline quartz represents 58 percent of the total rock fragments), sedimentary, and metamorphic (Franklin and Tieh, 1989).

The basal section of the "A" producing interval of the Dakota Sandstone consists of carbonaceous clayey siltstone and coarsens upward into a very fine to fine grained, slightly muddy sandstone (fig. 113). The Dakota muddy sandstone unit is very carbonaceous, pyritic, porous, and slightly calcareous (New Mexico Oil Conservation Division, 1992a).

The basal section of the "A1" producing interval of the Graneros Formation consists of a fine grained muddy sandstone and fines upward into a very fine to fine grained extremely muddy sandstone (fig. 113). The Graneros muddy sandstone is siliceous and nonporous. The extremely muddy sandstone is very carbonaceous, micaceous, slightly porous, and slightly glauconitic (New Mexico Oil Conservation Division, 1992a). Silt- and clay-sized matrix material is present throughout the Dakota sandstone sequence and represents a significant portion of the bulk rock composition. This matrix material reduces the effective permeability of the formation (New Mexico Oil Conservation Division, 1982c).

Natural Fractures

In the San Juan Basin, the Dakota Sandstone is considered by DuChene (1989) to be a naturally fractured reservoir, but detailed fracture descriptions and production analyses have not been published. Lacy and others (1992) report a horizontal Dakota well at a depth of 12,300 ft in the Denver Basin.

Engineering Assessment

The tight Dakota sandstones are similar throughout the San Juan basin. Porosities range from 2 to 16 percent (fig. 115) and average from 7.5 percent (Colorado Oil and Gas Conservation Commission, 1981c) to 9.5 percent (New Mexico Oil Conservation Division, 1982c) (table 23). Permeabilities are less than 0.1 md, ranging from 0.024 md in the Basin Dakota area in New Mexico (New Mexico Oil Conservation Division, 1981g) to 0.077 md in Ignacio Blanco field, Colorado (Colorado Oil and Gas Conservation Commission, 1981c).

Water saturations are 40 to 60 percent depending on the shaliness (Colorado Oil and Gas Conservation Commission, 1980f, 1981c) and clean sandstones will approach 40 percent. Formation temperature is 210° to 240°F, and reservoir pressure ranges from 2,500 to 3,400 psi (Finley, 1984). Net pay footages generally are 10 to 110 ft (New Mexico Oil Conservation Division, 1992a; Colorado Oil and Gas Conservation Commission, 1981c). A typical fracture stimulation treatment uses 60,000 gal fluid and 110,000 to 125,000 lb sand proppant (table 23).

Production History

The number of tight completions in the Dakota was 4,728 by 1988, and estimated ultimate recovery from existing wells is 7,322 Bcf (Hugman and others, 1992) (table 23). An additional 2.2 Tcf of recoverable gas is estimated to exist outside present field limits (National Petroleum Council, 1980). Well spacing ranges from 160 acres per well in New Mexico to 640 acres per well in Colorado, and average recovery per completion is 1.63 Bcf (Hugman and others, 1992). Prefracture stimulation production ranges from 6.7 Mcf per well to 152 Mcf per well, with an average of 101 Mcf/d and post-stimulation production is less than 400 Mcf/d in New Mexico designated areas. Dakota Sandstone completions decline at a rate of 5 to 9 percent per year (Finley, 1984).

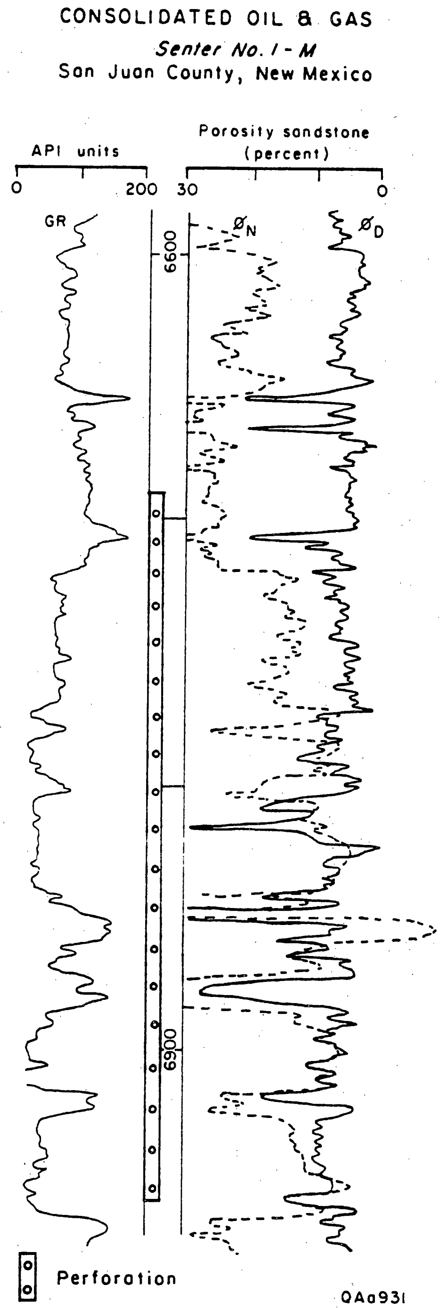


Figure 115. Neutron density log showing gross perforated zone through Dakota Sandstone, San Juan Basin (New Mexico Oil Conservation Division, 1981h).

Table 23. Dakota Formation, San Juan Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 4,728

Cumulative production from tight completions 1970–1988 (Bcf): 2,921.1

Estimated ultimate recovery from tight areas (Bcf): 7,322

Net pay thickness (ft): 10–110

Porosity (%): 7.5–9.5

Permeability (md): 0.024–0.077

Water saturation (%): 40–60

Reservoir temperature (°F): 210–240

Reservoir pressure (psi): 2,500–3,400

Typical stimulation/hydro-frac: 60,000 gal fluid and 110,000 to 125,000 lb sand

Production rate:

- prestimulation (Mcf/d): 6.7–152
- poststimulation (Mcf/d): <400

Average recovery per completion (Bcf): 1.63

Decline rate: 5–9%/yr

Mesaverde Group and the Chacra Formation

The Mesaverde Group, the largest low-permeability producer of gas in the San Juan Basin (Hugman and others, 1992), was deposited along the western margin of the Cretaceous Western Interior Seaway during the Late Cretaceous. The New Mexico Oil Conservation Division has determined that the vertical limits of the Mesaverde Group in the designated tight gas areas extend from the Huerfanito Bentonite in the overlying Lewis Shale to 500 ft below the top of the Point Lookout Sandstone (fig. 116) (Bureau of Land Management, 1991). This includes, in ascending order; (1) the Point Lookout Sandstone, (2) the Menefee Formation, and (3) the Cliff House Sandstone.

The Chacra Formation is "the time-stratigraphic equivalent of the upper Unnamed Tongue of the Cliff House beach sandstone" (fig. 111) (New Mexico Oil Conservation Division, 1981h). The Chacra has been designated as a separate tight gas formation by the New Mexico Oil Conservation Division (1981h) although it is considered the uppermost unit of the Cliff House Sandstone in the Mesaverde Group. The Chacra will be included in this chapter because it is part of the Cliff House Sandstone and will be called the Chacra Formation following the New Mexico Oil Conservation Division tight gas application file (1981h). Because the Menefee Shale is not an important reservoir unit, (New Mexico Oil Conservation Division, 1981f) this chapter will focus on the Point Lookout Sandstone, the Cliff House Sandstone, and the Chacra Formation.

The Mesaverde Group in the northeast part of the San Juan Basin forms a major regressive-transgressive wedge that interfingers with the marine Mancos Shale and Lewis Shale (fig. 111) (Palmer and Scott, 1984). The regressive Point Lookout Sandstone overlies the Mancos Shale and underlies the nonmarine Menefee Formation (Finley, 1984). The transgressive Cliff House Sandstone underlies the Lewis Shale (fig. 111). The Cliff House is part of a major transgressive-regressive cycle that includes the regressive Pictured Cliffs Sandstone that overlies the Cliff House (Donselaar, 1989).

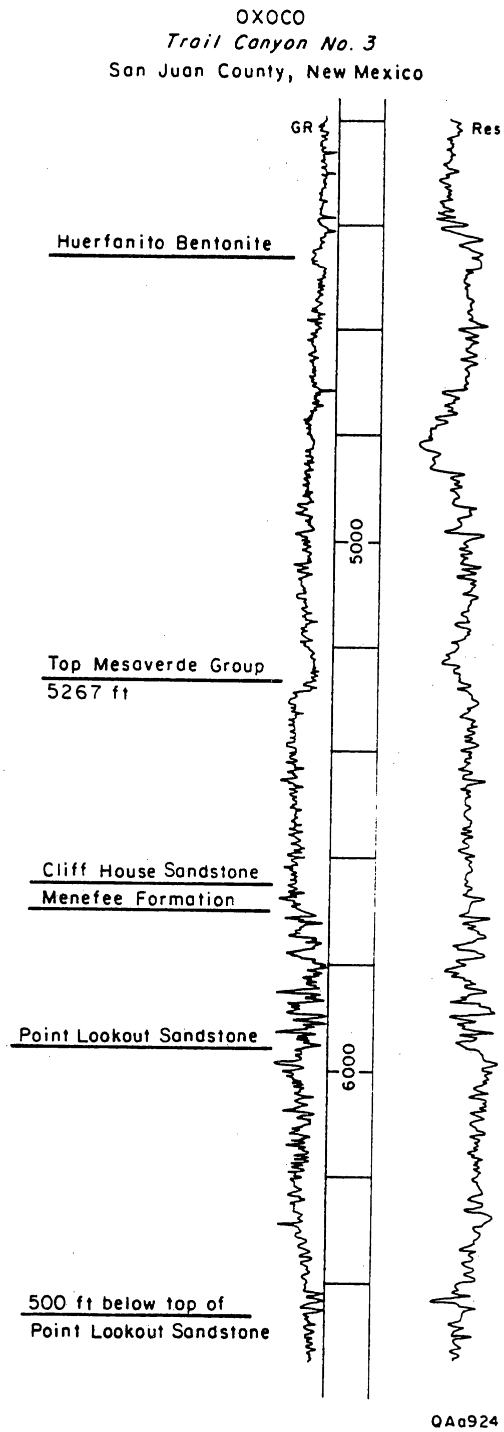


Figure 116. Mesaverde Group type log, San Juan Basin (New Mexico Oil Conservation Division tight gas application file, 1982e).

The Mesaverde Group, including the Point Lookout Sandstone, the Menefee Formation, and the Cliff House Sandstone, is designated tight in parts of San Juan County in northwestern New Mexico (fig. 112) and in La Plata and Archuleta Counties in southwestern Colorado. The Chacra is designated a tight gas reservoir in parts of Sandoval and Rio Arriba Counties, New Mexico (fig. 112).

In New Mexico designated tight gas areas, the average thickness of the Point Lookout is 150 to 200 ft, the Menefee is 230 to 290 ft, and the Cliff House is 50 ft (Bureau of Land Management, 1991). The average depth to the top of the Mesaverde Group ranges from 5,463 ft to 5,600 ft (Bureau of Land Management, 1991). The average thickness of the Chacra Formation ranges from 110 ft to 300 ft, and the average depth to the top of the Chacra ranges from 1,658 ft to 3,390 ft (Bureau of Land Management, 1991). In designated tight gas areas of the Ignacio Blanco field in La Plata and Archuleta Counties, Colorado, the total thickness of the Mesaverde Group is 900 ft and average depth to the top is 5,380 ft (Colorado Oil and Gas Conservation Commission, 1981d).

Depositional Systems and Reservoir Facies

The Point Lookout Sandstone

The Point Lookout Sandstone is the largest producer of natural gas in the Mesaverde Group (New Mexico Oil Conservation Division, 1981f). It is the basal unit of the Mesaverde Group (fig. 117) in the designated tight gas areas and consists of a series of strike-oriented, cuspate to linear sands that were deposited as strandplain and nearshore sands (Finley, 1984). The Point Lookout represents deposition associated with a shoreline advance interrupted by episodic transgressions (Devine, 1991).

The regressive phase is represented by offshore deposits that were overlain by shoreface deposits (Devine, 1991). Sediment was spread out from small, wave-dominated deltas that

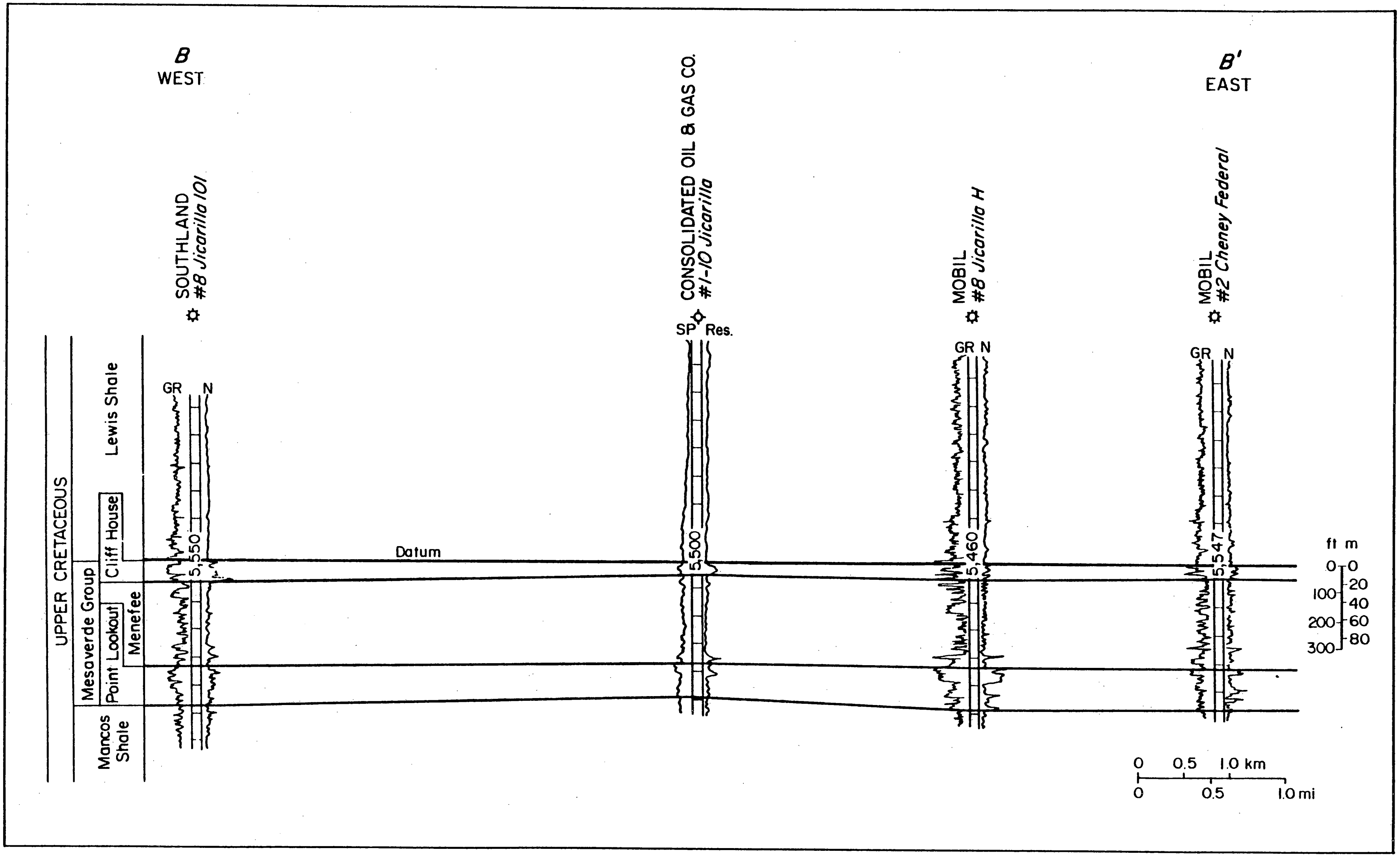


Figure 117. East–west stratigraphic cross section B–B' through the Mesaverde Group, San Juan Basin (New Mexico Oil Conservation Division tight gas application file, 1981e). Line of section shown in figure 108.

prograded northeastward. Beach ridges prograded seaward to successive shoreline positions, and shallow channels through these barriers were areas of input for sediment that was moved alongshore and incorporated into the ridges (Finley, 1984).

When relative sea level began to rise, sediment supply became insufficient to maintain shoreface advance, and the Point Lookout regressive phase gave way to a transgressing sea. The strandplain was flooded, and shallow lagoons surrounded the higher beach ridges (Devine, 1991). As the transgressive phase stabilized, the lagoonal area was gradually filled and the backbarrier area was changed into a channeled estuarine system (Devine, 1991).

Reservoir facies are medium-grained sandstones of the channeled estuary environment, the most landward component of the Point Lookout lateral facies tract (fig. 118) (Devine, 1991). Associated nonmarine (fluvial, coastal plain, paludal) deposits to the southwest of the Point Lookout are found in the Menefee Formation, which overlies the Point Lookout (fig. 111) (Finley, 1984).

The Cliff House Sandstone

Changes in sediment supply and changes in rates of subsidence and/or eustatic conditions caused the Point Lookout regression to halt, and the Late Cretaceous Seaway transgressed the area. Transgressive shoreline sands were deposited over the Menefee, and they compose the uppermost formation of the Mesaverde Group, the Cliff House Sandstone (fig. 117) (Finley, 1984). The Cliff House Sandstone consists of several linear sandstone complexes in ascending order from northeast to southwest (fig. 111) (Hollenshead and Pritchard, 1961; Fassett 1977; Molenaar, 1977, 1983). Although the Cliff House was deposited during an overall transgressive phase, the presence of thick, strike-elongate shoreline sandstones within the Cliff House Sandstone suggests that the transgressions were episodic in the San Juan Basin area. In the subsurface study of the northeastern San Juan Basin by Hollenshead and Pritchard (1961), these thick sandstones were called "benches." These benches formed during temporary stabilizations

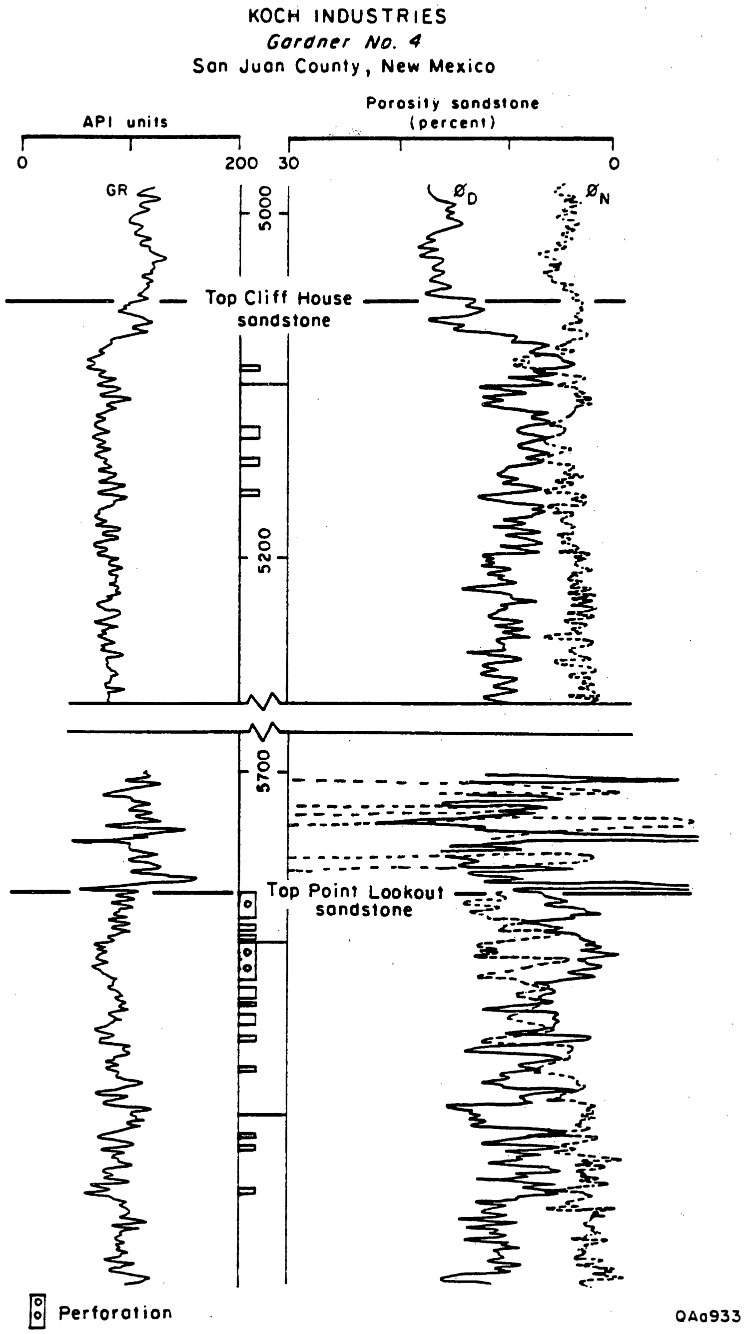


Figure 118. Neutron density log showing perforated zones in the Cliff House and Point Lookout sandstones (Mesaverde Group), San Juan Basin (New Mexico Oil Conservation Division, 1981f).

of the shoreline (Finley, 1984). The thicker parts of the Cliff House are connected by thin sandstone sheets; where these sheets are absent the Lewis Shale rests directly on the Menefee Formation (fig. 111) (Donselaar, 1989).

In the northern and eastern half of the San Juan Basin, the thick sandstone complexes of the Cliff House are called the La Ventana Tongue of the Cliff House Sandstone (fig. 111). These sandstones represent a wave-dominated coastline with cuspate deltas flanked by strandplains and coastal barriers (Palmer and Scott, 1984). Minor regressive and transgressive shifts in shoreline position throughout the depositional history were responsible for the interfingering of the La Ventana tongue with the Lewis Shale. The accumulation of this sandstone resulted from the stacking of many sandstone depositional units (Palmer and Scott, 1984). Reservoirs in the La Ventana Tongue occur in the shelf sandstones (Palmer and Scott, 1984) and delta front sheet sandstones (Mannhard, 1976).

The Chacra Formation

The Chacra Formation, the uppermost unit of the Cliff House Sandstone, is located in the southwestern part of the San Juan Basin. Chacra deposits formed at, or close to, the Cliff House-Pictured Cliffs transgression to regression turn-around point in a retrogradational shoreline depositional system (fig. 111) (Donselaar, 1989). The Chacra is a narrow, linear sandstone complex with an ESE–WNW elongation. The depositional environment of the Chacra indicates a storm-dominated, barrier island coast. Facies of the Chacra, in a downdip (seaward) direction are (1) lagoonal shales, (2) upper shoreface sandstones, and (3) lower shoreface/offshore sandstones. Transgressive phases are characterized by sharp erosional surfaces that formed during coastal retreat during a relative rise in sea level, and regressive phases are characterized by prograding barrier sands (Donselaar, 1989). Tight gas production in the Chacra is mainly from shaly sandstones and siltstones in the distal part of these facies (fig. 119) (New Mexico Oil Conservation Division, 1981h).

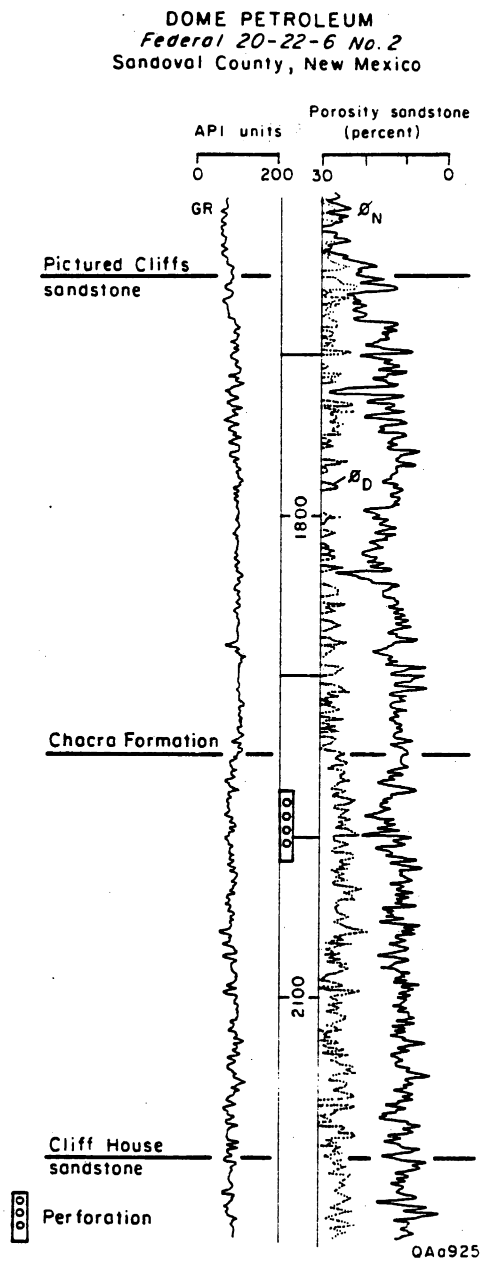


Figure 119. Type log from Chacra Formation, San Juan Basin (from New Mexico Oil Conservation Division tight gas application file, 1981h).

Composition of Reservoir Facies

The Point Lookout Sandstone

Point Lookout sandstones are very fine to medium grained, moderately well sorted to very well sorted sublitharenites. The grains are subangular to angular and have an average composition of $Q_{46}F_{16}R_{38}$ (Hunter, 1979). Rock fragments are dominated by chert, which averages 15 percent. Other rock fragments in descending abundance include polycrystalline quartz, clay fragments, volcanic rock fragments, metamorphic rock fragments, and quartz-feldspar plutonic rock fragments (Hunter, 1979).

There are two types of sandstones within the Point Lookout Sandstone in the San Juan Basin; updip sandstones located in the southwest part of the basin and downdip sandstones located in the northeast part of the basin (Hunter, 1979). Updip reservoirs are clean sandstones that were well cemented during diagenesis but only moderately compacted. Permeability is much higher in the updip reservoirs due to the development of secondary porosity. Downdip sandstones have undergone extreme compaction, developed only minor secondary porosity, and have very low permeabilities. These downdip sandstones are present in the designated tight gas areas. The downdip sandstones are quartz poor and enriched in rock fragments. They formed in low energy environments and have a finer grain size. The ductile grains were highly deformed and squeezed into pore throats. Downdip sandstones are rich in carbonate cement and illite and mixed-layer illite/smectite are the dominant clays. Permeability is low in this section of the Point Lookout Sandstone in part because of the pore blocking effect of authigenic illite fibers (Hunter, 1979).

The Cliff House Sandstone

Sediment in the Cliff House Sandstone was supplied in part from volcanic activity in Arizona during Campanian time. On average, Cliff House sandstones are fine grained, moderately to well sorted subarkoses and quartzarenites (Mannhard, 1976).

Average composition is $Q_{89}F_8R_3$ (Mannhard, 1976). Quartz content ranges from 30 percent to 70 percent and averages 52 percent of whole rock volume. Feldspar content ranges from 0 percent to 17 percent and averages 5 percent. Rock fragments range from 0.6 percent to 8 percent and average 2 percent. Volcanic rock fragments are most abundant, followed by sedimentary and metamorphic rock fragments (Mannhard, 1976).

Authigenic clay (kaolinite) is the dominant diagenetic component in Cliff House sandstones (Mannhard, 1976). Quartz overgrowths are a minor constituent but are most abundant in sandstones that contain low percentages of detrital or authigenic clay. The clay may have inhibited quartz overgrowth development by interfering with precipitation of dissolved silica on detrital quartz grains. The effect of kaolinite precipitation is a significant reduction in pore space of the Cliff House sandstones in the designated tight gas area (Mannhard, 1976).

The Chacra Formation

The Chacra Formation consists of very fine grained marine siltstones and sandstones. There are varying amounts of carbonaceous shale and clay matrix that contribute to the low permeability of the sandstone (New Mexico Oil Conservation Division, 1982a). Higher permeability values in figure 120 are due to data that were collected at ambient not in situ pressure. Because of the close stratigraphic relationship and similar depositional setting, the composition of the Chacra may be comparable to other units of the Cliff House Sandstone.

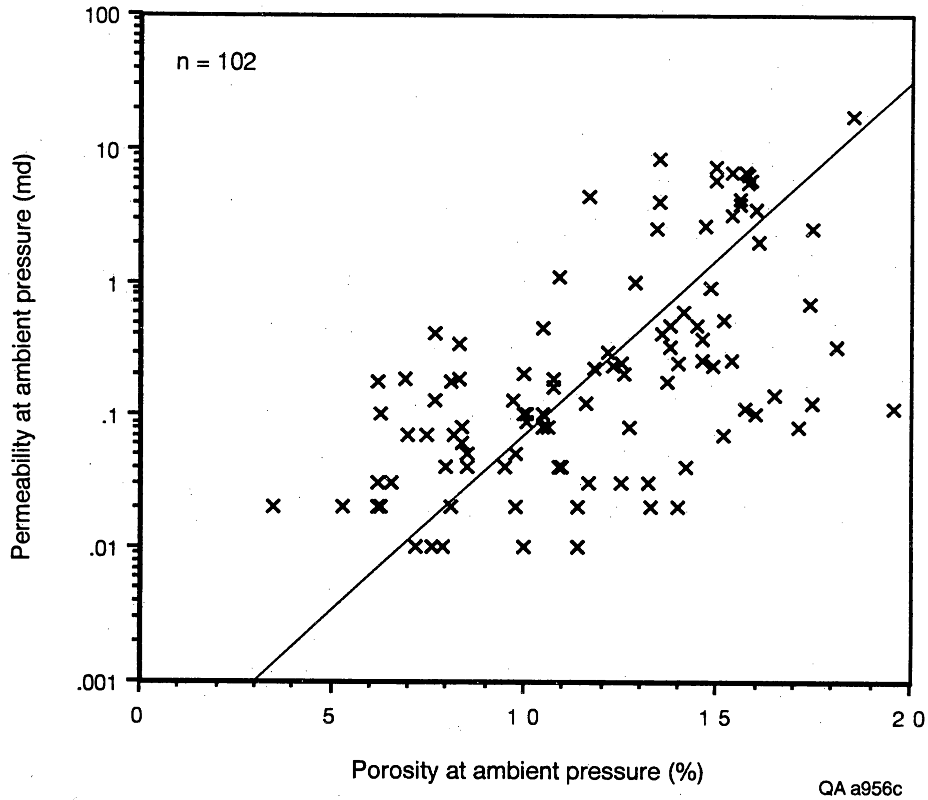


Figure 120. Semi-log plot of porosity measured at ambient pressure vs. gas permeability measured at ambient pressure for 102 Chacra Formation samples. Line is approximate trend line for porosity-permeability relationship, ignoring data interpreted to be of poor quality (from New Mexico Oil Conservation Division, 1981h).

Natural Fractures

Finley (1984) reported that natural fractures were encountered in some Cliff House and Point Lookout core but that no data were available on the distribution of fractures in relation to gas production. Where these units are exposed on basin margins, fractures are visible, but many of the most prominent of these appear to be related to near-surface processes such as weathering and spalling. Regional studies of fracture patterns in Pictured Cliffs sandstones and Fruitland Formation (described in the next section) could provide guidance for assessing general Cliff House/Point Lookout fracture trends.

Engineering Assessment

Porosities in the Mesaverde sandstones of the San Juan Basin generally decrease as sands thin (New Mexico Oil Conservation Division, 1981e) and Cliff House and Point Lookout sandstones are quite similar across the basin. In the Rattlesnake Canyon tight formation area of New Mexico, porosities range from 3 to 14 percent and average 8 percent (New Mexico Oil Conservation Division, 1981f) (table 24). In the Ignacio Blanco field of Colorado, porosities average 9.1 percent (Colorado Oil and Gas Conservation Commission, 1981d). Permeabilities in the Blanco Mesaverde and Rattlesnake Canyon aeas are low, with stabilized flow pre-fracture permeabilities ranging from 0.021 to 0.073 md (table 24) (New Mexico Oil Conservation Division, 1981e, f). Water saturations range from 35 to 65 percent (Colorado Oil and Gas Conservation Commission, 1981d), and they increase in the lower porosity finer grained sandstones.

In the Ignacio Blanco field (Colorado Oil and Gas Conservation Commission, 1981d), net pay thicknesses are 10 to 60 ft. In other areas, net pays may be as high as 250 ft (New Mexico Oil Conservation Division, 1981e, f). Reservoir pressure is 1175 to 1300 psi and reservoir temperature is 150° to 160°F (table 24).

Table 24. Mesaverde Group, San Juan Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 4,779

Cumulative production from tight completions 1970–1988 (Bcf): 4,473.9

Estimated ultimate recovery from tight areas (Bcf): 12,315

Net pay thickness (ft): 10–250

Porosity (%): 8–9

Permeability (md): 0.021–0.073

Water saturation (%): 35–65

Reservoir temperature (°F): 150–160

Reservoir pressure (psi): 1,175–1,300

Typical stimulation/hydro-frac: 476,000 to 1,028,000 lb sand in Ignacio Blanco field; smaller amounts in surrounding areas

Production rate:

prestimulation (Mcf/d): <150

poststimulation (Mcf/d): 2,290 (absolute open flow), 115 after 6 mo

Average recovery per completion (MMcf): 500

Decline rate: 37% in first year, 10% in 2nd–7th yr, then 5%

Fracture-stimulation treatments were reported on six wells in Rattlesnake Canyon (New Mexico Oil Conservation Division, 1981f). The average treatment was 170,000 gal gel and 166,000 lb sand. Fracture treatments described at the Ignacio Blanco field are much larger, ranging from 476,000 to 1,028,000 lb, averaging 652,000 lb (Colorado Oil and Gas Conservation Commission, 1981d).

Production History

Well spacing for Mesaverde sandstones is 160 acres per well (Hugman and others, 1992). Ultimate recovery is 12,315 Bcf (table 24) and average recovery per well is 0.5 Bcf. There were 4,779 tight completions in the Mesaverde Group by 1988. Natural absolute open flow rates are under 150 Mcf/d. After fracture stimulating, the wells may start out at high rates (>1 MMcf/d) then decline to lower rates after a short time. A typical well with absolute open flow after fracture stimulation of 2,290 Mcf/d had declined to 115 Mcf/d after 6 months. Generally, wells will produce 63 MMcf the first year (New Mexico Oil Conservation Division, 1981f). Decline rates are 37 percent the first year, 10 percent for years 2 through 7, and 5 percent for the life of the well (New Mexico Oil Conservation Division, 1981f).

Little engineering data exist on the Chacra sandstone (table 25). Porosity averages 11 percent (New Mexico Oil Conservation Division, 1981h) with some of the best reservoirs approaching 19 percent (New Mexico Oil Conservation Division, 1982a). Stabilized flow well test permeability is less than 0.02 md, and average core in situ permeabilities are 0.038 md (New Mexico Oil Conservation Division, 1982a). Average reservoir temperature is 160°F in the Rusty Chacra area (New Mexico Oil Conservation Division, 1981h).

Average pre-fracture production is 3.9 Mcf/d. Post-fracture production in one well averaged 45 Mcf/d for the year 1980 (New Mexico Oil Conservation Division, 1982a). Cumulative production in this same well was 565 MMcf, very similar to other Mesaverde sandstones. Well spacing in the Chacra is 320 acres per well. There were 598 tight completions

Table 25. Chacra Formation, San Juan Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 598

Cumulative production from tight completions 1970–1988 (Bcf): 123.8

Estimated ultimate recovery from tight areas (Bcf): 272

Net pay thickness (ft): No data

Porosity average (%): 11

Permeability average (md): 0.038

Water saturation (%): No data

Reservoir temperature (°F): 160

Reservoir pressure (psi): No data

Typical stimulation/hydro-frac (hundred thousand): No data

Production rate:

prestimulation (Mcf/d): 3.9

poststimulation (Mcf/d): 45

Average recovery per completion (MMcf): 565

Decline rate: No data

by 1988, and projected ultimate recovery is 272 Bcf in the Chacra Formation (Hugman and others, 1992).

Pictured Cliffs Sandstone

The Pictured Cliffs Sandstone was deposited along the western margin of the Cretaceous Western Interior Seaway during Late Campanian time (Cumella, 1981). The designated tight gas areas are located in San Juan, Rio Arriba, and Sandoval Counties in northwestern New Mexico (fig. 112). The gross Pictured Cliffs Sandstone package thickens basinward (southwest to northeast) from approximately 150 to 500 ft (fig. 121). In the designated tight gas area at the Northeast Blanco Unit in San Juan and Rio Arriba Counties, the thickness ranges from 75 to 140 ft in the Pictured Cliffs Sandstone. The thickness ranges from 65 to 115 ft in the Largo Canyon tight gas area in Rio Arriba County, and 91 ft is the average thickness (Finley, 1984). The tops of the Pictured Cliffs range in depth from 770 ft in the southwest part of the basin to 2,830 ft in the northeast part of the basin. Tops range in depth from 2,750 to 3,500 ft in the Northeast Blanco Unit (fig. 122) and 2,200 to 2,800 ft in the Largo Canyon tight gas area (Finley, 1984).

Recent studies of the Pictured Cliffs Sandstone have been incorporated into publications for coalbed methane studies of the Fruitland Formation, San Juan Basin. They include (1) Ayers and others (1991), (2) Ayers and Ambrose (1990), (3) Ayers and Zellers (1988), and (4) Choate and others (1984).

The San Juan Basin has approximately 17,000 oil and gas wells that have been drilled and logged (Ayers and others, 1991). This provides an exceptional data base for studying tight gas formations located in the basin. GRI drilled cores in the Pictured Cliffs Sandstone from the REI/Blackwood & Nichols N.E. Blanco Unit No. 403 and Mesa FC Federal No. 12 in Rio Arriba County.

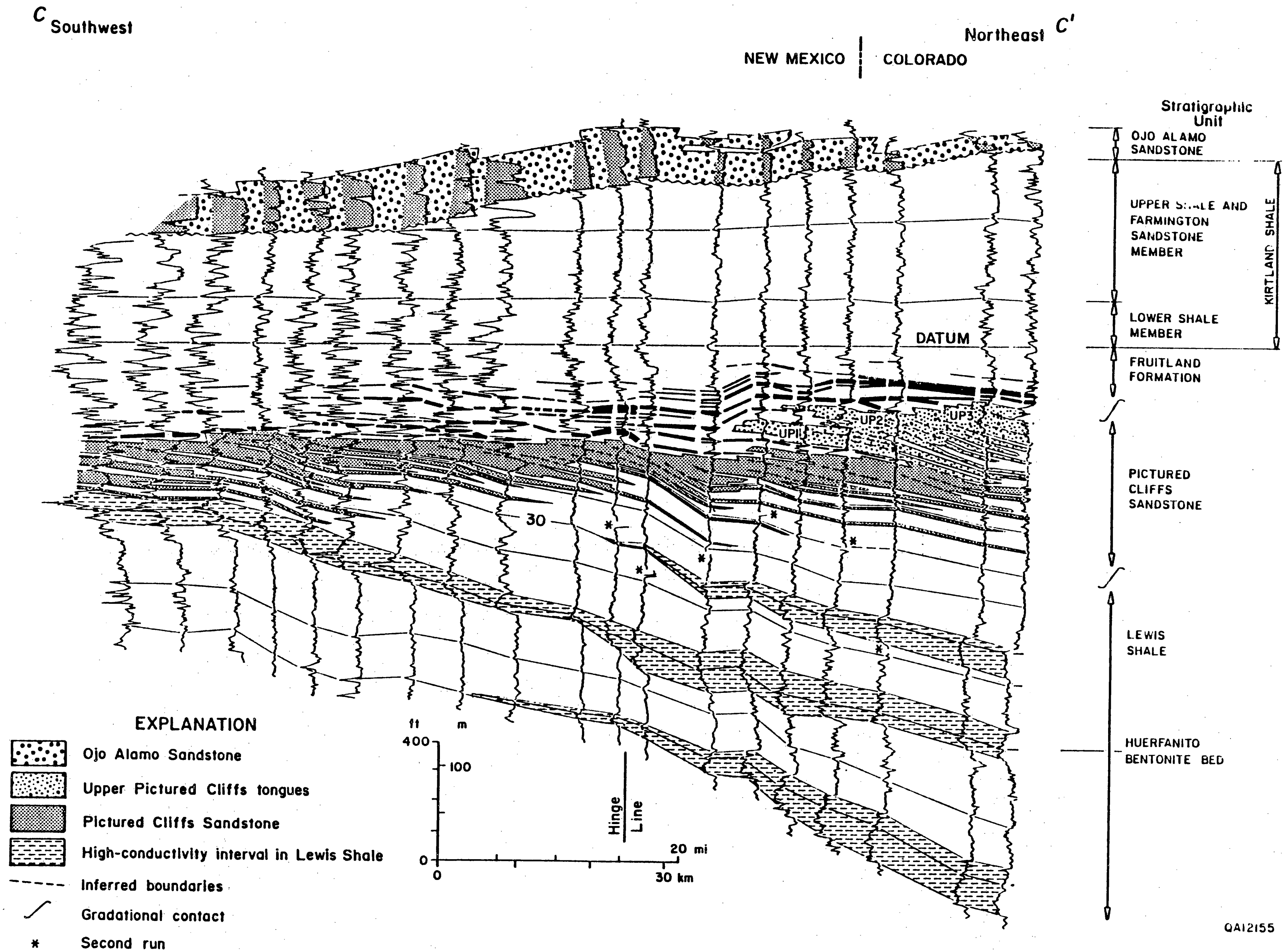


Figure 121. Southwest–northeast stratigraphic cross section C–C′ through the uppermost Cretaceous, San Juan Basin. Line of section shown in figure 109 (modified from Ayers and Ambrose, 1990).

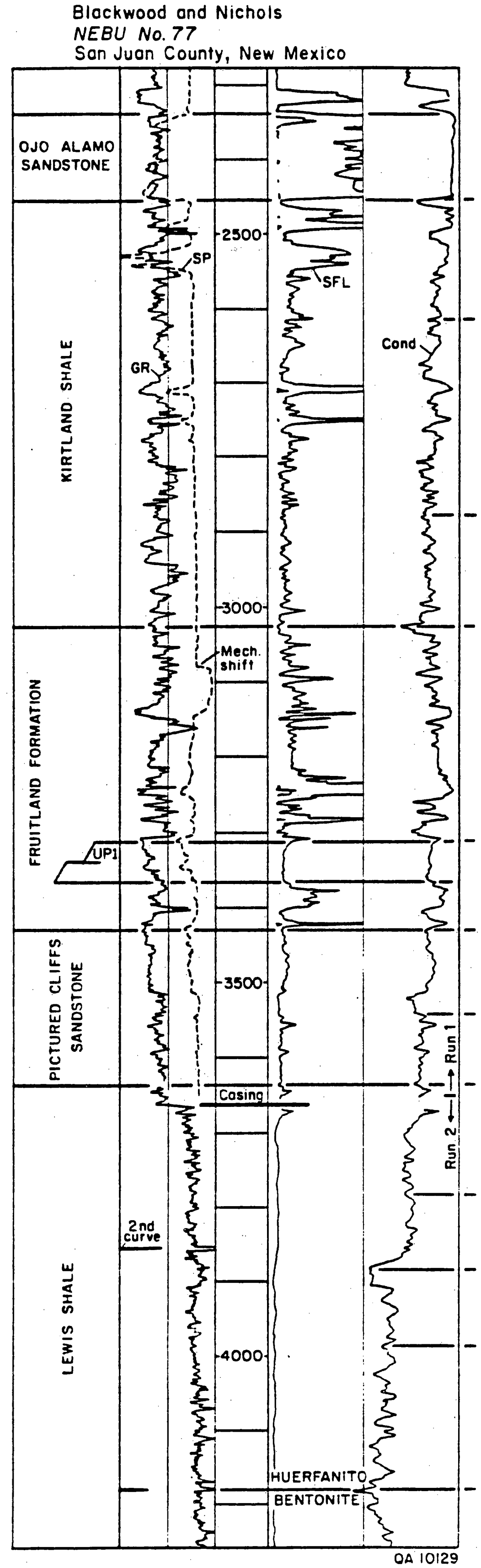


Figure 122. Type log showing upper Cretaceous in San Juan Basin (from Ayers and Ambrose, 1990).

Depositional Systems and Reservoir Facies

The Pictured Cliffs Sandstone is a coastal facies that was deposited when the Late Cretaceous shoreline prograded northeastward into the Western Interior Seaway. The Pictured Cliffs is interpreted as shelf, shoreface mudstone/sandstone interbeds and prograding barrier/strandplain depositional systems. The base of the Pictured Cliffs Sandstone intertongues with the Lewis Shale (fig. 111). The Pictured Cliffs Sandstone and equivalent marine units thicken basinward above the Huerfanito Bentonite Bed of the Lewis Shale (fig. 121) (Ayers and Ambrose, 1990).

The contact between the Pictured Cliffs Sandstone and the Fruitland Formation is "placed at the top of the massive sandstone below the lowermost coal of the Fruitland except in those areas where the Fruitland and Pictured Cliffs intertongue" (fig. 121) (Fassett and Hinds, 1971). Progradation of the Pictured Cliffs shoreline was intermittent, resulting in shoreline stillstands. Intertonguing of the Pictured Cliffs Sandstone and the Fruitland Formation resulted from temporary landward shifts of the shoreline during an overall regression of the Late Cretaceous shoreline (fig. 111). Ayers and others (1991) called the Pictured Cliffs sandstones that intertongue with the Fruitland Formation the "Upper Pictured Cliffs sandstones" or the "upper Pictured Cliffs tongues." Approximately 270 ft of stratigraphic rise of the Pictured Cliffs over a 25-mi distance in the northern third of the San Juan Basin is attributed to these tongues (fig. 121). The upper Pictured Cliffs tongues were deposited in a wave-dominated shoreline setting. Dip-elongate (southwest to northeast) and strike-elongate (northwest trending) sandstone bodies occur in the northeast part of the basin where the tongues exist (fig. 123). Dip-elongate sand bodies imply distributary channels. Strike-elongate sand bodies imply a strandplain-barrier system (Ayers and others, 1991).

The lateral continuity of the Pictured Cliffs beds is relatively good because of the sandstone's origin as a progradational sandy strandplain (Finley, 1984). Successive shoreline positions moved across the basin, resulting in steplike regressive sandstone deposits. In areas

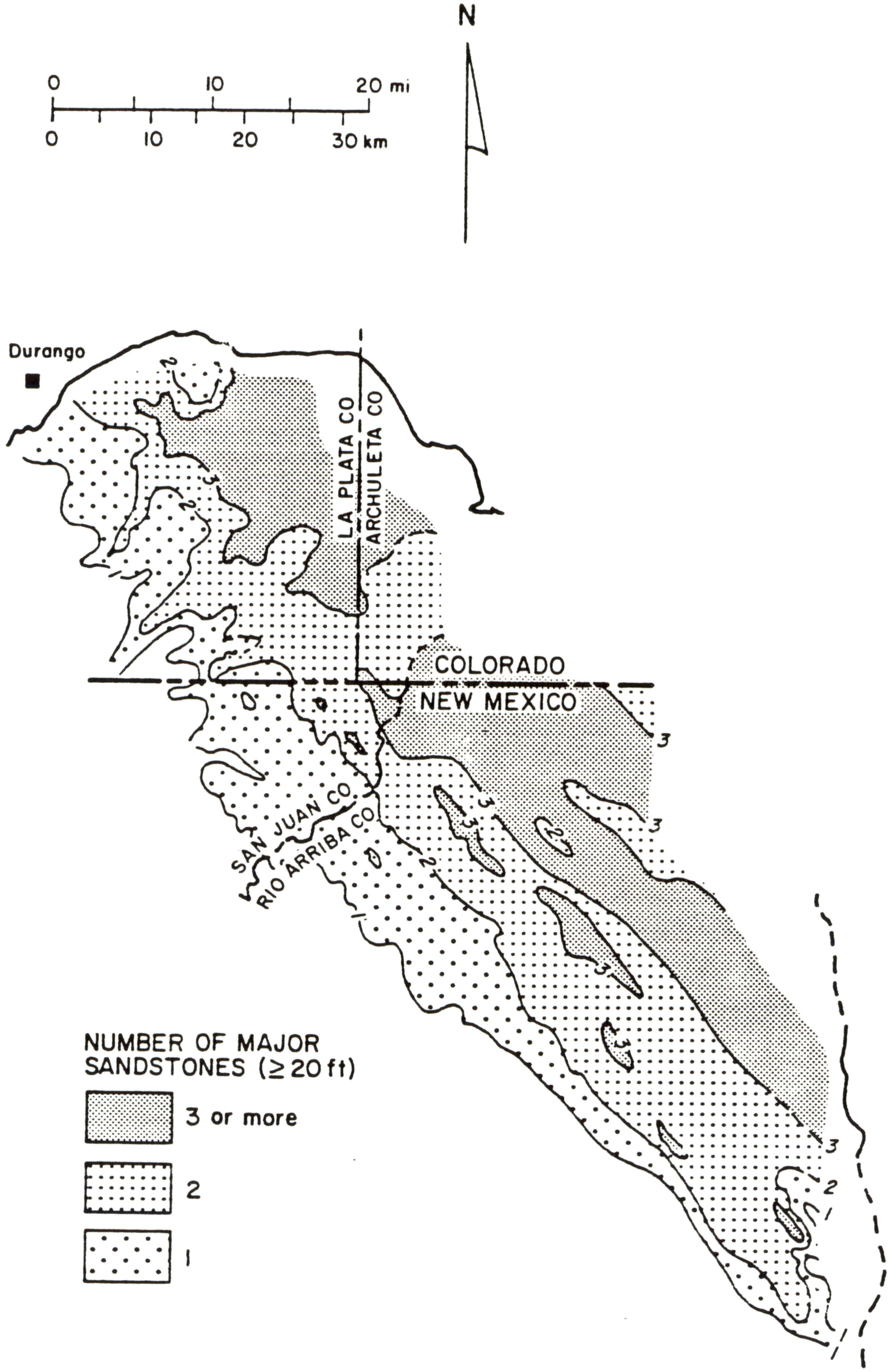


Figure 123. Map of major sandstones in the upper Pictured Cliffs tongues (from Ayers and Ambrose, 1990).

where the relative rates of subsidence and sediment supply remained in balance over a period of time, a thicker package of sand was deposited (Finley, 1984).

Composition of Reservoir Facies

Volcanic activity in Arizona during Campanian time apparently marked the beginning of the Laramide orogeny and supplied some of the sediments forming the Pictured Cliffs Sandstone (Cumella, 1981). Pictured Cliffs sandstones generally are very fine to fine grained, well sorted, subangular to subrounded litharenites and feldspathic litharenites (Cumella, 1981). Average composition is $Q_{38}F_{15}R_{48}$ (Cumella, 1981). Quartz content ranges from 18.5 to 55 percent, and averages 30 percent. Feldspar content ranges from 4 percent to 22 percent, and averages 12 percent. Average plagioclase is 6.5 percent and average K-feldspar is 5.5 percent. Rock fragments range from 21 percent to 50 percent, and average 38 percent. Volcanic rock fragments are most abundant, followed by metamorphic and sedimentary rock fragments. Minor amounts of mica (biotite, muscovite, and chlorite) and glauconite are present. Detrital dolomite grains are common (Cumella, 1981).

Siderite and dolomite precipitation occurred early in the Pictured Cliffs diagenetic history (Cumella, 1981). As burial proceeded (pre-Laramide), abundant illite-smectite and quartz overgrowths formed. Permeability was greatly reduced in the designated tight gas areas by extensive grain coatings of the authigenic illite-smectite. Throughout and following basin formation, locally extensive calcite and some kaolinite precipitated on the northeast basin margin (Cumella, 1981). Average porosity is 10 percent (fig. 124) (New Mexico Oil Conservation Division, 1981i).

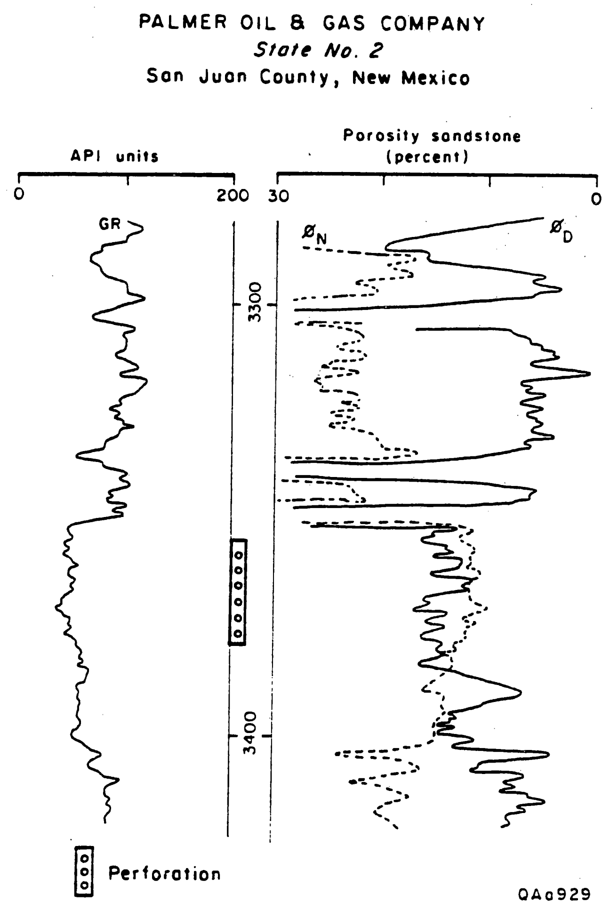


Figure 124. Neutron density log showing Pictured Cliffs perforated zones, San Juan Basin (New Mexico Oil Conservation Division tight gas application file, 1981a).

Natural Fractures

Local fracture-enhanced permeability in Pictured Cliffs reservoirs can be inferred from clusters of wells with high gas or water production and other differences in well performance that cannot be explained by other aspects of reservoir geology or completion practices. Considerations such as these led DuChene (1989) to interpret some Pictured Cliffs reservoirs to be naturally fractured.

Fractures are locally present in Pictured Cliffs sandstone core (Laubach and others, 1991). In core, Pictured Cliffs fractures are commonly subvertical extension fractures that are confined to individual sandstone beds. Fractures are typically partly to completely filled with secondary minerals such as calcite. A detailed study of fractured Pictured Cliffs core has not been published, but several recent studies have described aspects of fracture patterns in Pictured Cliffs outcrops on the margins of the San Juan Basin (Condon, 1988; Laubach and others, 1991). Findings from these studies are reviewed below. Recent publications also describe basement fault patterns in the San Juan Basin (Huffman and Taylor, 1991), fractures in coal interbedded with Pictured Cliffs sandstone (Laubach and Tremain, 1991; Laubach and others, 1992b), and linear features visible on high altitude imagery and their relationship to production (Baumgardner, 1991).

Production data have been used to identify areas of fracture-enhanced permeability within Pictured Cliffs fields in the San Juan Basin (fig. 125). Using the cumulative gas volume produced (MMcf) per net change in average reservoir pressure, Hower (1990) delineated areas of prolific production that he ascribed to natural fractures. Areas dominated by fracture porosity in the Pictured Cliffs have high depletion ratios. The northwest-trending (310 to 320 degrees) area of high fracture porosity identified by Hower is in the north-central San Juan Basin, parallel to but east of a major structural hingeline identified by Ayers and others (1991) (fig. 108). The trend of this area parallels fracture strikes observed in outcrop and in some cores. Areas of good production are also ascribed to naturally occurring fractures in the Trinidad

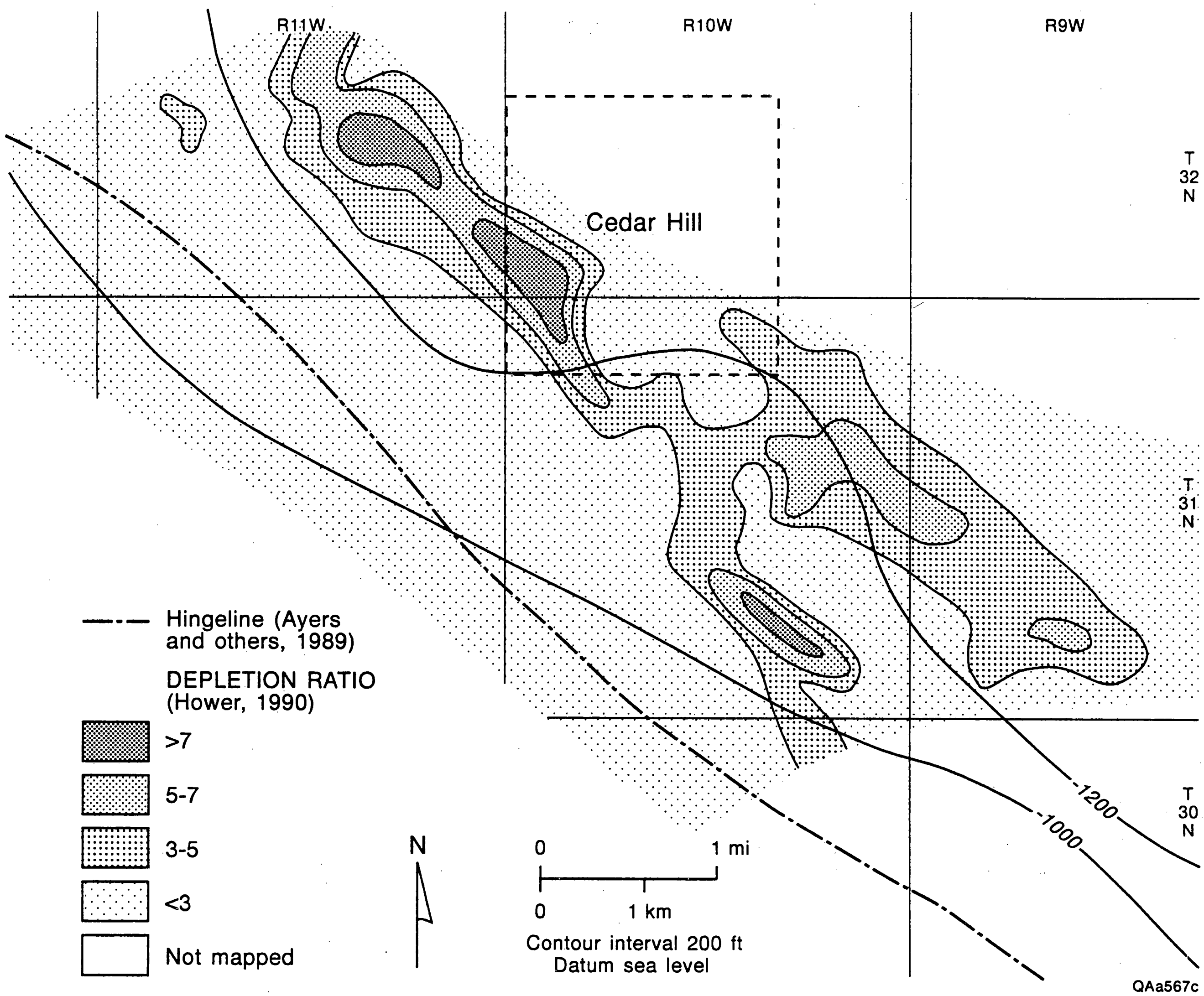


Figure 125. Map of inferred natural fracture production in San Juan Basin indicated by depletion ratio (modified from Hower, 1990; hingeline from Ayers and Zellers, 1988).

Sandstone (approximate age-equivalent of the Pictured Cliffs) of the Raton Basin (Rose and others, 1986).

Several joint sets exist in Pictured Cliffs sandstone along the northwest margin of the San Juan Basin (Condon, 1988; Laubach and others, 1991). Some are fracture sets that have near-constant orientation over wide areas; others are localized near specific folds or faults or topographic escarpments. Sets of northwest and northeast fractures have been interpreted to be representative of regional fractures in the subsurface, and detailed patterns of fracture density variations (fracture swarms) (fig. 126) and fracture-network connectivity that are visible in these outcrops can be used to help visualize the role of fractures in Pictured Cliffs production (Laubach, 1992a).

Fracture swarms are a key aspect of the Pictured Cliffs fracture pattern that is visible in outcrop. Pictured Cliffs fracture swarms are areas of fractured rocks separated by tens to several hundreds of feet of less-fractured or unfractured rock (fig. 126) (Laubach and Tremain, 1991). The wide spacing between swarms suggests that the swarms will only rarely be encountered by vertical wells. Moreover, fracture spacing within some swarms is on the order of tens of feet, a much wider spacing than is likely to be systematically encountered by vertical wells. Fractures within swarms are commonly confined to individual sandstone beds (as is the case for fractures observed in Pictured Cliffs cores), so fractured areas likely do not have large (more than several tens of feet) vertical extent. Evidence for the lateral extent (length and width) of swarms is limited by the size of outcrops, but some swarms are only a few hundred feet long.

The discontinuous nature of Pictured Cliffs fracture swarms has implications for drilling strategy and interpretation of production patterns. If regional fractures were laterally persistent over great distances, horizontal wells drilled perpendicular to the fracture trend could be expected to consistently encounter fractures or fracture swarms. Where swarms are discontinuous parallel to their strike (nonpersistent), as is the case for those fractures in Pictured Cliffs outcrops, even wells drilled in the most favorable direction, directly across fracture strike, may entirely miss such swarms. Because swarms can be vertically isolated in a

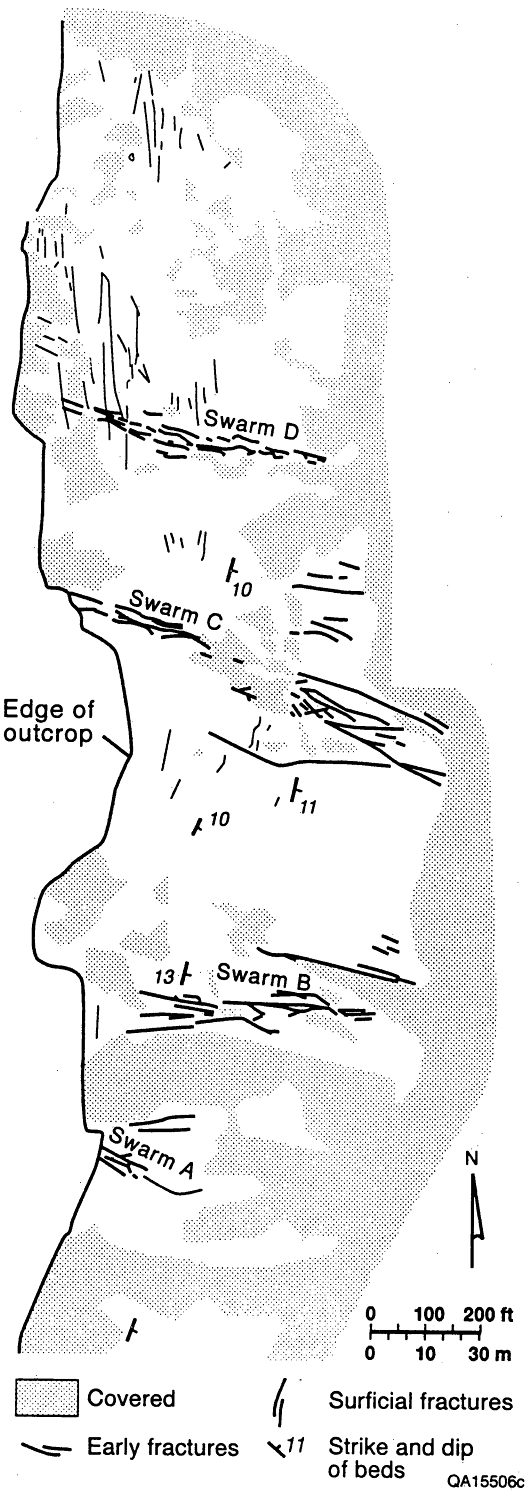


Figure 126. Simplified map of bedding-plane pavement and fracture network in Upper Cretaceous Pictured Cliffs Sandstone, Fort Lewis mine (from Laubach, 1992).

given sandstone bed, they can have limited height and may be narrow targets for horizontal wells. Alignment of highly productive wells must be used with caution to identify fracture swarms because wells may intersect parts of different fracture swarms, yet appear to be aligned, leading to erroneous deductions from production patterns of the likely location of highly productive areas.

Indirect geophysical methods to detect highly fractured areas in Pictured Cliffs sandstone have not been described in the literature. Remote sensing studies of the San Juan Basin (summarized by Baumgardner, 1991) suggest that, except for areas close to the Pictured Cliffs outcrop belt, fracture swarms that contribute to production are not readily detected on high-altitude imagery or air photographs.

Engineering Assessment

Pictured Cliff sandstones have average porosities of 10 percent (New Mexico Oil Conservation Division, 1981a) (table 26). Permeabilities calculated from production data at Largo Canyon are 0.02 md (New Mexico Oil Conservation Division, 1981i), and core measured permeabilities in the same wells average 0.007 md. Estimates of permeability at Northeast Blanco unit range from 0.012 to 0.003 md.

Water saturations range from 50 to 80 percent in the pay sandstones (table 26), and net pay footages in general range from 30 to 50 ft. Gross pay thickness in the Northeast Blanco unit is 70 to 140 ft, and net pay thickness is 40 to 50 ft. In the Largo Canyon tight gas unit, gross pay thickness is 75 to 80 ft. Reservoir temperature in the Pictured Cliff sandstones is 120°F, and reservoir pressure ranges from 1,375 to 1,500 psi (Finley, 1984). A fracture treatment recommended for Pictured Cliff sandstone consists of 100,000 gal of mini-max gel and 190,000 lb of 10/30 mesh sand (New Mexico Oil Conservation Division, 1981a).

Table 26. Pictured Cliffs Formation, San Juan Basin: production data and engineering parameters.

Estimated resource base (Tcf): 21

No. tight completions: 3,431

Cumulative production from tight completions 1970–1988 (Bcf): 1,086.9

Estimated ultimate recovery from tight areas (Bcf): 2,757

Net pay thickness (ft): 30–50

Porosity average (%): 10

Permeability (md): 0.003–0.02

Water saturation (%): 50–80

Reservoir temperature (°F): 120

Reservoir pressure (psi): 1,375–1,500

Typical stimulation/hydro-frac: 100,000 gal gel and 190,000 lb sand

Production rate:

  prestimulation (Mcf/d): ≤35

  poststimulation (Mcf/d): up to 350

Average recovery per completion (MMcf): 830

Decline rate: 7–14%/yr

Production History

Well spacing in Pictured Cliff sandstones is 160 to 320 acres per well. The estimated resource base is 21 Tcf (Haas and others, 1988) (table 26), and average recovery per completion is 0.83 Bcf (Hugman and others, 1992). Typical completions flow 35 Mcf/d or less naturally, then improve as much as tenfold after fracture stimulating (New Mexico Oil Conservation Division, 1981a). Decline rate ranges between 7 and 14 percent per year for Pictured Cliff sandstones.

DENVER BASIN

The Denver Basin is a long, asymmetrical trough of the central Rocky Mountain region (fig. 1). The basin's present structural configuration (fig. 127) is largely the result of Laramide deformation about 50 to 80 mya and is genetically related to uplift of the Front Range of the Rocky Mountains. FERC-designated tight gas sandstones in the Denver Basin are restricted to the Cretaceous System. The major tight gas reservoir in the Denver Basin is the J Sandstone of the Lower Cretaceous Dakota Group (fig. 128).

The Dakota Group and younger strata record part of the infilling of the Western Interior Basin, a foreland depression within which lay the future site of the Denver Basin (summarized in Baars and others, 1988). At its maximum extent, the Western Interior Basin extended from the Gulf of Mexico to the arctic regions. Primary sediment sources were in the rising Cordilleran mountains to the west, with minor sources to the east and from intrabasinal uplifts. Lowermost sandstones of the Dakota Group are mainly fluvial deposits of an extensive, northward-flowing system within the Western Interior Basin. The Skull Creek and Huntsman Shales (fig. 128) represent marine advances from the north, whereas the J and D Sandstones were deposited during regressive phases and are composed of coastal plain, fluvial, deltaic, and nearshore-marine facies.

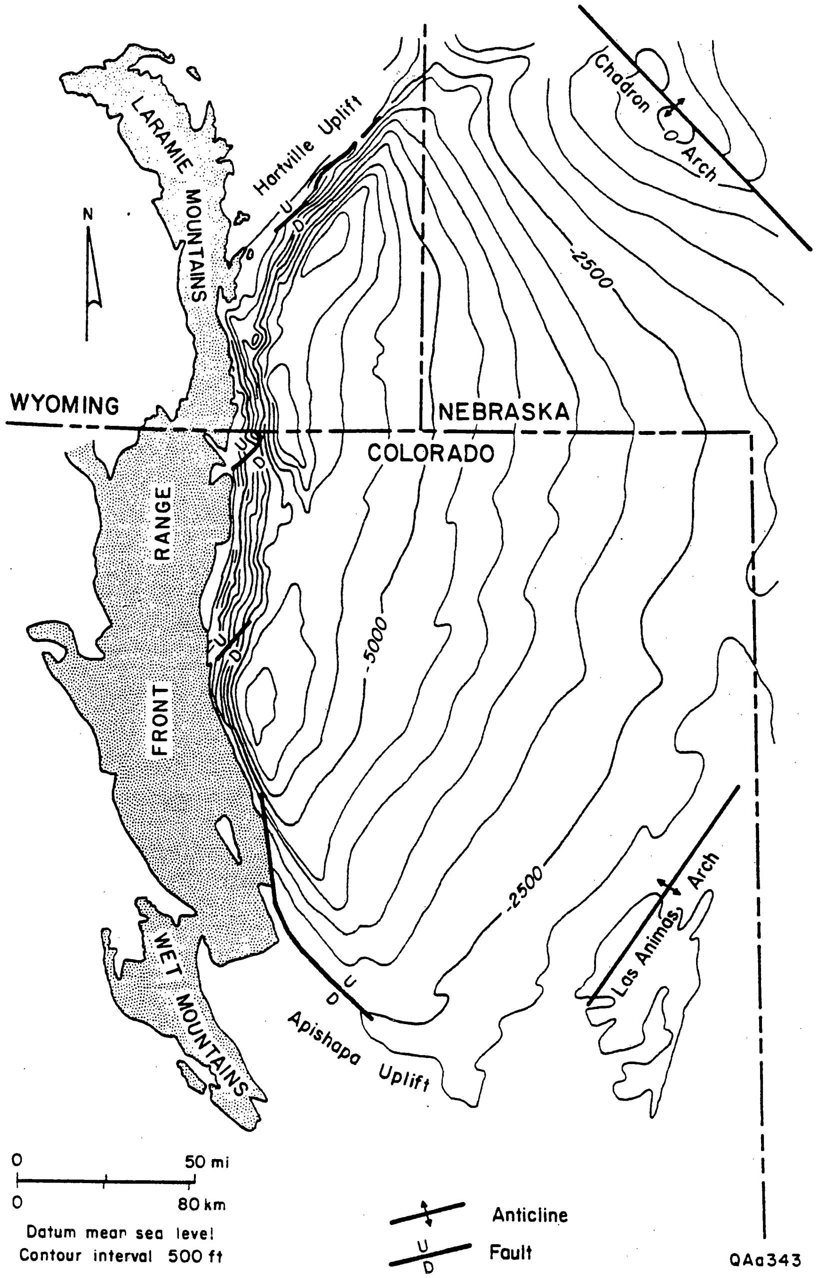


Figure 127. Structure-contour map of the top of Precambrian basement in the Denver Basin showing peripheral structures. From Kennedy (1983).

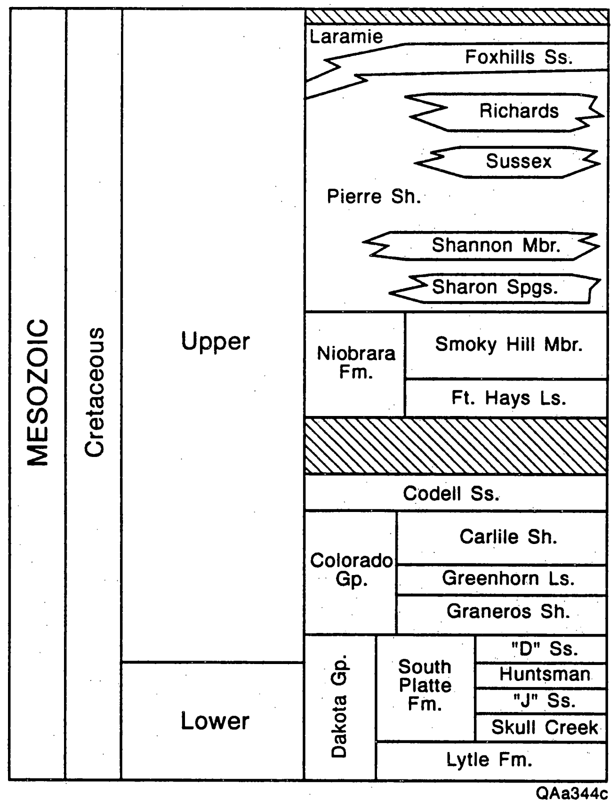


Figure 128. Stratigraphic column of the Cretaceous System in the Denver Basin. From Kennedy (1983).

The Denver Basin is currently undergoing extensional tectonism, which is marked by high subsurface geothermal gradients (Lachenbruch, 1979; Zoback and Zoback, 1980; Myer and McGee, 1985). Productive sandstones are reported to have lower modulus of elasticity than shales that bound reservoir intervals. Closure pressures are not high enough to warrant high-strength proppants (Roberts, 1981).

Other formations in the Denver Basin that have been formally designated as tight by FERC include (1) the Upper Cretaceous Codell Sandstone (Kennedy, 1983a; Weimer and Sonnenberg, 1983), (2) the Upper Cretaceous Niobrara Formation, which produces from tight carbonate reservoirs (Hollberg and others, 1985), (3) several sandstones of the Lower Cretaceous Dakota Group (identified as Dakota, Dakota-Morrison, and Dakota-Lakota in FERC list of tight gas formations), and (4) the Sussex Sandstone Member of the Upper Cretaceous Pierre Shale.

J Sandstone

Introduction

The low-permeability, gas-bearing J Sandstone is the primary petroleum-productive reservoir in the Denver Basin of Colorado. Estimated ultimate recovery for petroleum in the tight J Sandstone reservoir in the Wattenberg field, by far the largest tight J producing area, is 1.3 Tcf of gas and 30 MMbbl of condensate (Matuszczak, 1976; Momper, 1981). Hugman and others (1992) estimated total cumulative gas production from the tight J Sandstone to be 500.1 Bcf as of January 1989. However, this may be a conservative figure because Higley and Schmoker (1989) calculated cumulative gas production from the Wattenberg (J) field alone, from 1970 (discovery date) to January 1989, to be 566.2 Bcf. Areas producing from the tight

J Sandstone in the Denver Basin that are formally designated by FERC include parts of Adams, Arapahoe, Boulder, Elbert, Jefferson, Larimer, and Weld Counties in northeastern Colorado.

The J Sandstone (fig. 128) is the subsurface equivalent of the exposed Lower Cretaceous (upper Albian) Muddy Sandstone of the Dakota Group (MacKenzie, 1965). The Muddy (J) Sandstone and equivalent units occur in several structural basins in the central and northern Rocky Mountain region, and they have produced more than 1.5 Bbbl of oil-equivalent hydrocarbons from both tight and nontight reservoirs (Dolson and others, 1991). From outcrops along the western margin of the Denver Basin, MacKenzie (1965) divided the Muddy Sandstone into the Fort Collins and Horsetooth Members, which are separated by a widespread, markedly erosional unconformity (Weimer and others, 1986; Ethridge and Dolson, 1989). These members are readily correlated into the subsurface of the Denver Basin (fig. 129) (Weimer and others, 1986). The Fort Collins Member is the main tight-gas producer at Wattenberg field. However, minor amounts of gas are also produced from the younger Horsetooth Member in the eastern and northeastern parts of the field.

Wattenberg field, productive over an area of about 627,000 acres, straddles the axis of the Denver Basin, an asymmetric north–south-elongate Laramide foreland basin with a gently dipping eastern flank and a steeply dipping western flank. Depths of the J Sandstone reflect this structural configuration by being deepest (about 8,400 ft deep) in the western part of the field (fig. 130) (Weimer and Sonnenberg, 1989, their fig. 3). Depth to the top of the formation in the shallowest, eastern part of the field is about 7,600 ft. In Wattenberg field and surrounding area, the J Sandstone ranges in thickness from less than 75 to more than 150 ft (fig. 129); the Fort Collins Member is less than 5 to more than 80 ft thick (Weimer and others, 1986). Net pay varies considerably from 4 to 58 ft (Colorado Oil and Gas Conservation Commission, 1980) but locally composes a large percentage of the Fort Collins Member.

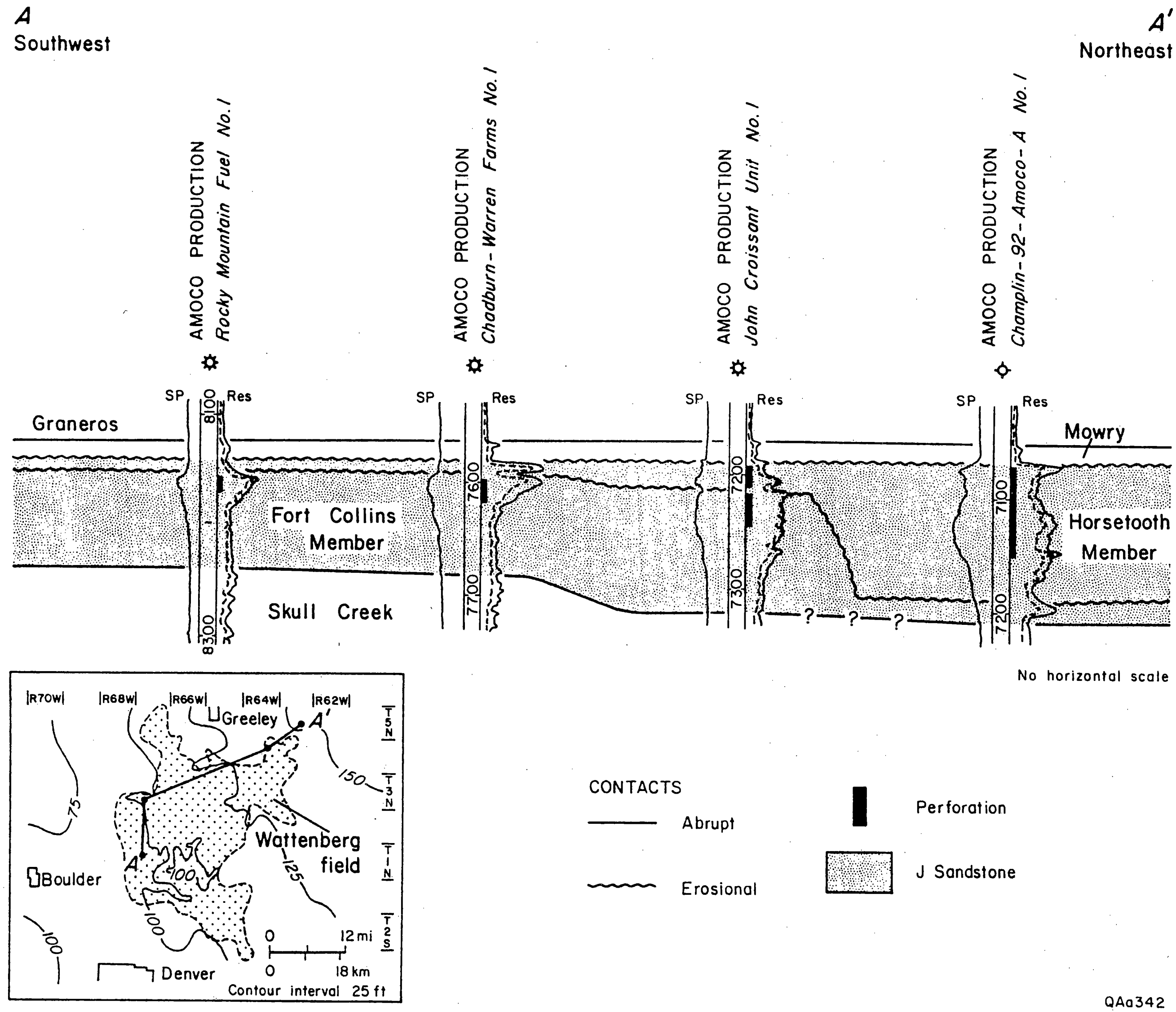


Figure 129. Regional cross section of the J Sandstone and adjacent units across the Wattenberg field showing erosional contact between, and productive zones within, the Fort Collins and Horsetooth Members. Inset is isopach map of the J Sandstone in the Wattenberg field area. Modified from Weimer and others (1986).

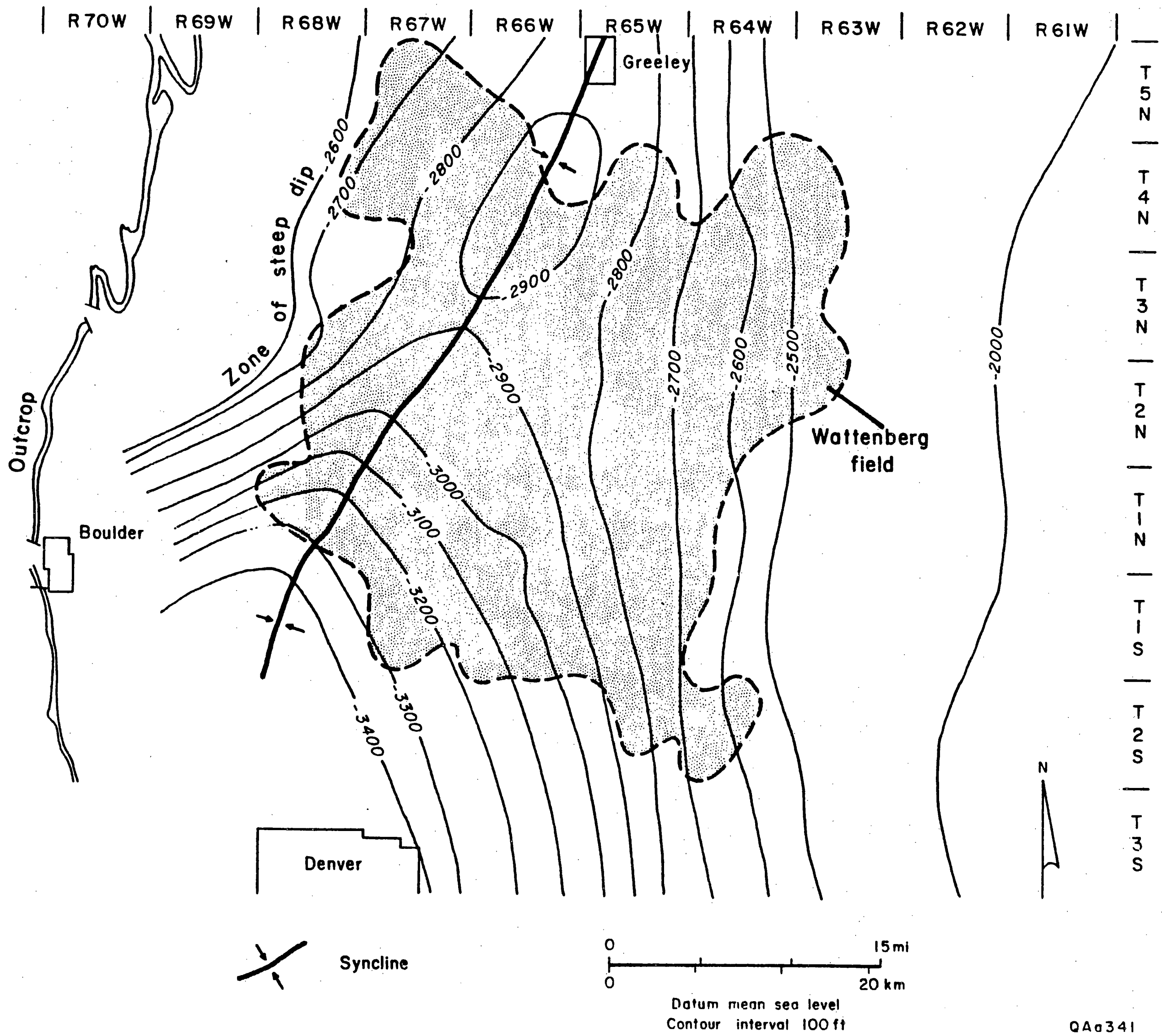


Figure 130. Structure-contour map contoured on top of the J Sandstone in the Wattenberg field area. Modified from Weimer and Sonnenberg (1989).

Depositional Systems and Reservoir Facies

The principal Muddy (J) reservoir sandstone, the Fort Collins Member, represents delta-front and nearshore-marine depositional processes, whereas the overlying Horsetooth Member is interpreted to consist of valley-fill fluvial and estuarine facies incised into the Fort Collins (MacKenzie, 1965; Weimer and others, 1986; Ethridge and Dolson, 1989; Higley and Schmoker, 1989). The log signature of the J Sandstone varies from upward-coarsening and bell-shaped, where the progradational Fort Collins deltaic/marine facies compose at least half of the J Sandstone interval, to blocky and irregular, where aggradational Horsetooth valley-fill facies predominate (figs. 129, 131, and 132). Weimer and Sonnenberg (1989), who interpreted J Sandstone facies relations in the context of sequence stratigraphic analysis, divided the Lower Cretaceous Series in the Denver Basin into three sequences bounded by unconformities, one of which occurs at the base of the Horsetooth Member of the Muddy (J) (fig. 129). The Fort Collins Member and underlying upper Skull Creek Shale comprise regressive deposits deposited during highstand conditions. The regionally erosional base of the Horsetooth Member records a eustatic drop and valley incisement about 97 to 98 mya. Valley-fill deposits of the Horsetooth Member, which are probably fluvial in the lower part and brackish to marine in the upper part, accumulated during subsequent rising sea level, reflecting aggradational fill and coastal onlap.

The main tight-gas-producing unit in Wattenberg field is the Fort Collins Member; pay-zone facies occur in the sandy, upper part of the member (figs. 129 and 132) and are interpreted to be mainly delta-front sandstones that occur beneath the unconformity at the base of the Horsetooth Member (Weimer and others, 1986). In areas of the field where valley incision is minor or nonexistent, the pay-zone sandstones are generally continuous. Elsewhere, the Fort Collins is thin or absent due to valley incision (fig. 129). Although currently in a structural low, the Wattenberg J reservoir was in a structural high during the Late Cretaceous, and natural gas that migrated into the J Sandstone at this time accumulated in a combined structural and

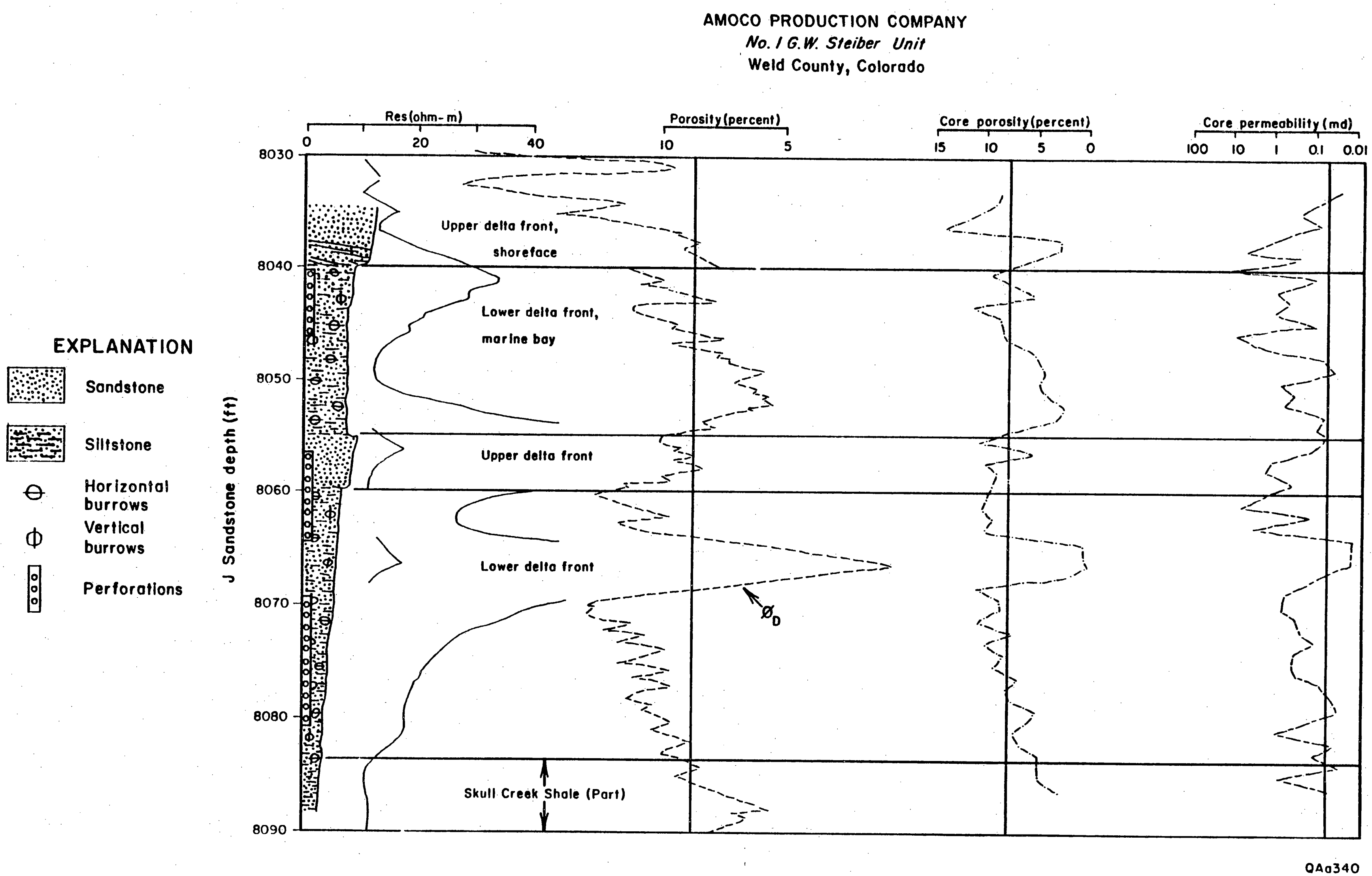


Figure 131. Lithology, producing intervals, log curves, and core analyses of the J Sandstone in the Amoco Production Company No. 1 G. W. Steiber Unit well, Weld County, Colorado, Wattenberg field. Modified from Higley and Schmoker (1989).

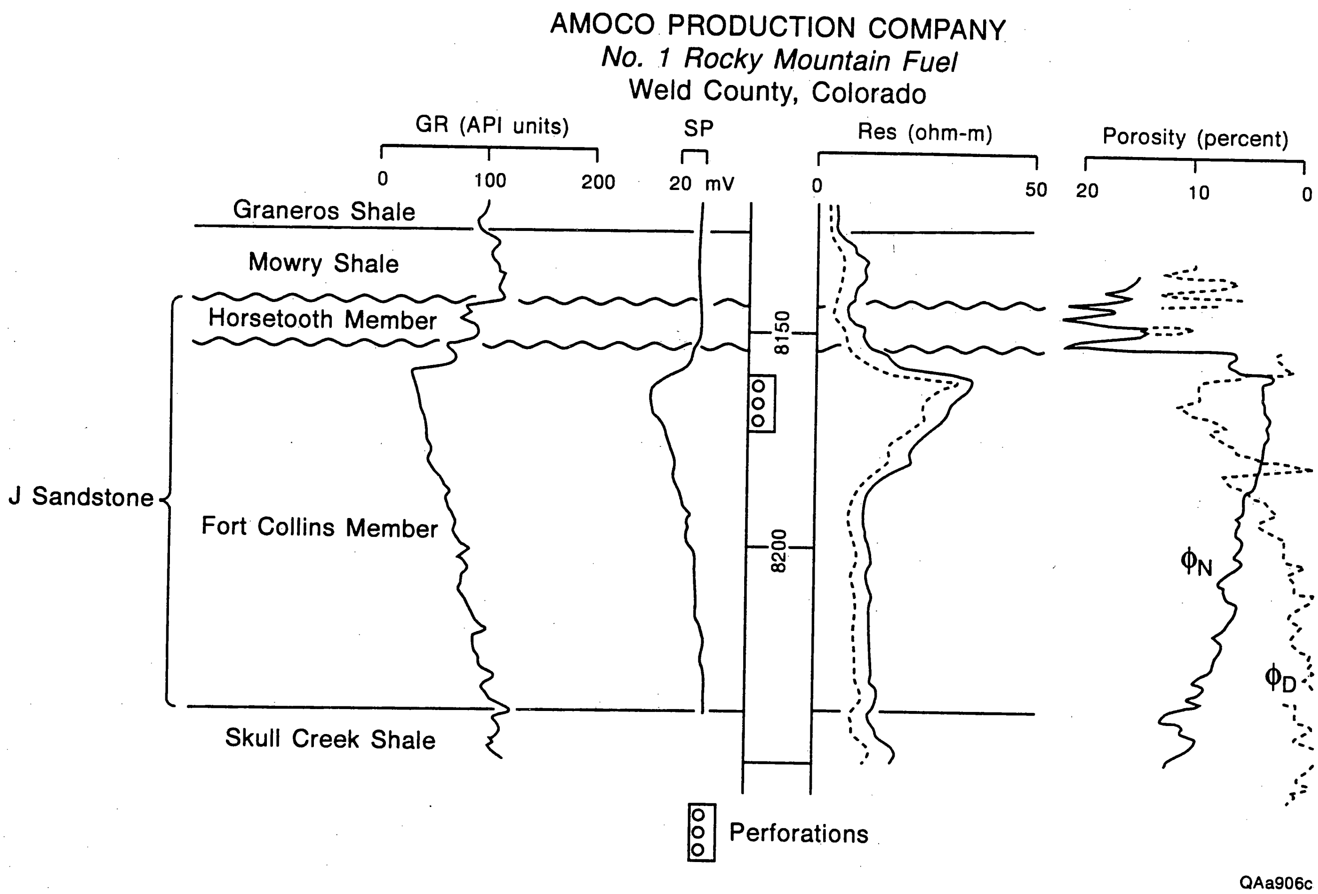


Figure 132. Well log of pay zone in the Fort Collins Member of the J Sandstone. Log also shown in figure 129. Modified from Weimer and others (1986).

stratigraphic trap (Weimer and others, 1986). This trap was subsequently downwarped into the present structural low (fig. 130). The present trapping mechanism in Wattenberg field is largely a combination of stratigraphic and diagenetic conditions, although subtle structure (small drape folds over basement fault blocks) probably plays a role.

Composition of Reservoir Facies

Reservoir sandstones of the gas-productive Fort Collins Member in Wattenberg field are very fine to fine grained, mineralogically mature, and classified as subarkoses to sublitharenites, with compositions varying slightly from about $Q_{90}F_5R_5$ (Weimer and others, 1986) to $Q_{91}F_1R_8$ (Higley and Schmoker, 1989). Composition of both members of the J Sandstone throughout the Denver Basin in Colorado ranges from quartzarenite to litharenite, with feldspar content being consistently low (Schmoker and Higley, 1991). The Fort Collins also contains about 6 to 10 percent argillaceous matrix, which decreases upward in abundance in the reservoir. Rock fragments are almost entirely mudstone clasts and chert. Authigenic cements and replacive minerals, which include quartz overgrowths, chert, calcite, chlorite, kaolinite, and illite, constitute as much as 26 percent of the whole rock volume of the undivided J Sandstone in Wattenberg field (Higley and Schmoker, 1989). Total silica, the most abundant cement, has an average volume of about 17 percent; quartz overgrowths (11 percent) compose most of this cement. Clay and calcite cements follow in abundance with average volumes of 6 and 3 percent, respectively (Higley and Schmoker, 1989).

The relative order of events in J Sandstone diagenesis is (1) growth of clay rims on framework grains, (2) precipitation of quartz overgrowths, (3) patchy to pervasive calcite cementation, which filled pores not occluded by quartz overgrowths, and contemporaneous feldspar and rock fragment solution, (4) calcite solution, (5) partial occlusion of secondary pores by authigenic kaolinite and chlorite, and (6) late-stage fracturing (Weimer and others, 1986; Ethridge and Dolson, 1989). Schmoker and Higley (1991) observed evidence of pressure solution as a source of quartz cement in the J Sandstone and interpreted the formation of quartz overgrowths to predate all other diagenetic stages.

Porosity in the Fort Collins Member of Wattenberg field is mainly intergranular with minor amounts of microporosity in the matrix and secondary intraparticle porosity formed by leaching of feldspars and rock fragments (Weimer and others, 1986). In general, both porosity and permeability increase upward in the deltaic/marine reservoir facies of the Fort Collins (Higley and Schmoker, 1989).

Natural Fractures

Published in-depth studies of the role of natural fractures in Muddy (J) Sandstone production in the Denver Basin are lacking, but fractures have been discussed as a possible source of enhanced permeability, and models for fracture distribution have been proposed. In the Denver Basin at the elevation of the Muddy (J) Sandstone, fold trends are northwest and east-northeast; minor changes in regional strike or dip result primarily from subtle bending of strata over basement fault blocks (Weimer and others, 1986; Weimer and Sonnenberg, 1989). Weimer and Sonnenberg (1989) recognized structural movement during and after deposition of the Muddy (J) sandstone. Regional fracture trends are east-west, northwest, and northeast (Weimer and Sonnenberg, 1989). Extension associated with drape folds has been interpreted to have produced a natural open fracture system, possibly localized near margins of basement blocks. Some fracturing is inferred to be late in the Muddy (J) Sandstone diagenetic sequence (Weimer and others, 1986; Higley and Schmoker, 1989).

Engineering Assessment

The largest FERC-designated tight gas field that produces from the J Sandstone in the Denver Basin is the Wattenberg field. The J Sandstone at Wattenberg has produced over half of all J Sandstone gas production and 47 percent of all gas in the Denver Basin (Higley and Schmoker, 1989). Wattenberg field encompasses almost all of the tight-gas area, with only a few small fields surrounding it.

Porosities in the Wattenberg "J" sandstones generally range from 8 to 12 percent (Weimer and others, 1986) (table 27). The Colorado Oil and Gas Conservation Commission (1980) reported porosities as high as 13.9 percent. Average porosity is 10.8 percent (Colorado Oil and Gas Conservation Commission, 1980). Permeability varies from 0.005 to 0.05 md (Matuszczak, 1973, 1976). Data presented to FERC indicate gas permeabilities calculated from well test analysis to be even lower, ranging from 0.0003 to 0.0306 md with an average of 0.0059 md.

Water saturations average 44 percent (Higley and Schmoker, 1989), and water saturation range is 27 to 56 percent (Colorado Oil and Gas Conservation Commission, 1980). Capillary pressure data presented by Weimer and Sonnenberg (1989) and displayed in figure 133 show a classic tight sand response with irreducible water saturation of about 40 percent. Net pay varies from 4 to 58 ft (Colorado Oil and Gas Conservation Commission, 1980) and averages 27 ft (table 27). Reservoir pressure in the J Sandstone is 3,000 psi (Colorado Oil and Gas Conservation Commission, 1980). Average reservoir temperature is 260°F (Weimer and others, 1986). Typical fracture stimulation treatment of the J Sandstone reservoir uses 180,000 gal cross-linked gel water with 832,000 lb of 20/40 mesh sand as a proppant. Cumulative production per well is directly proportional to the size of the fracture-stimulation treatment.

Production History

Estimated resource base of the J Sandstone is 10.5 Tcf (Hugman and others, 1992) (table 27). Well spacing per well ranges from 320 to 640 acres. Ultimate recovery from current wells is 1,019 Bcf. Cumulative production in the J Sandstone at Wattenberg field already has reached 566 Bcf. Average recovery per completion is 0.74 Bcf. Cumulative gas production is generally less than 500 Mcf per well (Weimer and others, 1986). Wells have produced greater

Table 27. J Sandstone, Denver Basin: production data and engineering parameters.

Estimated resource base (Tcf): 10.5

No. tight completions: 1,449

Cumulative production from tight completions 1970–1988 (Bcf): 500.1

Estimated ultimate recovery from tight areas (Bcf): 1,019

Net pay thickness range and average (ft): 4–58/27

Porosity range and average (%): 8–12/10.8

Permeability (md): 0.005–0.05

Water saturation range and average (%): 27–56/44

Reservoir temperature (°F): 260

Reservoir pressure (psi): 3,000

Typical stimulation/hydro-frac: 180,000 gal fluid and 830,000 lb sand

Production rate:

prestimulation (Mcf/d): 1–167

poststimulation (Mcf/d): 100–3,575

Average recovery per completion (Bcf): 0.74

Decline rate: 50% in first yr, then 10–20%/yr

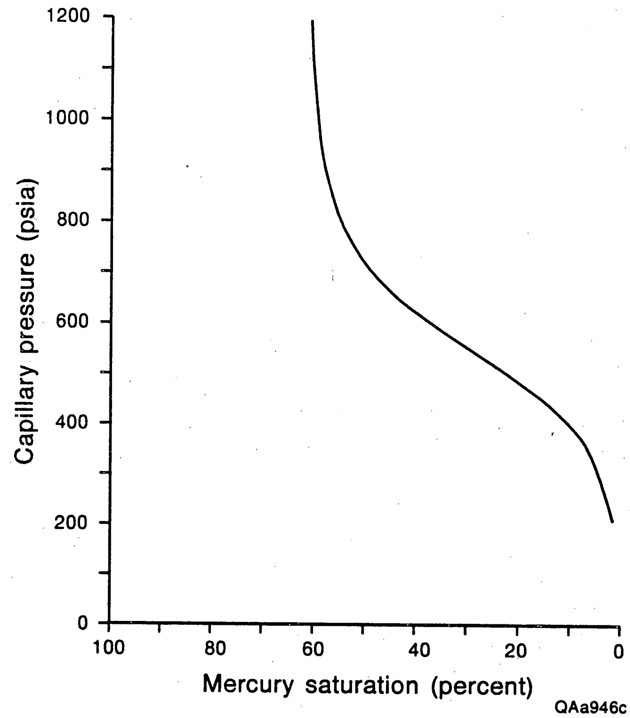


Figure 133. Capillary pressure curve for the J Sandstone in Wattenberg field. Note that irreducible water saturation is calculated to be about 40 percent. Porosity is 5.2 percent, and permeability is <0.1 md. From Weimer and Sonnenberg (1989).

than 1 Bcf in only a few small areas. Gas wells have a life of 20 years or more (Weimer and others, 1986).

Pre-fracture production rates range at Wattenberg field from 1 to 167 Mcf/d and average 19.9 Mcf/d (Colorado Oil and Gas Conservation Commission, 1980). Post-fracture rates as high as 3,575 Mcf/d have recorded (Hugman and others, 1992). The average Wattenberg well initially produces at 500 Mcfd. After 1 year, production typically declines to 90 Mcf/d. After 2 years, production has declined to 60 Mcf/d. Normally, production declines at a rate of 50 percent for the Mcf/d first 1 to 2 years, then at 10 to 20 percent for the life of the well (Weimer and others, 1986).

PICEANCE BASIN

Introduction

The Piceance Basin (also called the Piceance Creek Basin) of northwestern Colorado lies in the Rocky Mountain Foreland, a major tectonic element between the Overthrust Belt and the North American Craton. The basin formed as a result of breakup of the Foreland during the Laramide Orogeny in Late Cretaceous and early Tertiary times. The basin is bounded by the Uinta Mountain Uplift on the northwest, the Axial Arch on the north, the White River Uplift on the east, the Elk Mountains and Sawatch Uplift to the southeast, the Gunnison Uplift and San Juan volcanic field to the south, and the Uncompahgre Uplift to the southwest (fig. 134). It is separated from the Uinta Basin to the west by the Douglas Creek Arch.

Sedimentation in the basin is characterized by regressive and transgressive cycles initiated by tectonic uplift and loading of the Overthrust Belt, and eustatic sea-level fluctuations (Kauffmann, 1977). The basal sedimentary unit consists of conglomerate and coarse sandstones of the Cedar Mountain Group and fluvial and shore-zone deposits of the Dakota Group (National Petroleum Council, 1980) (fig. 135). Subsequent rapid subsidence caused a major

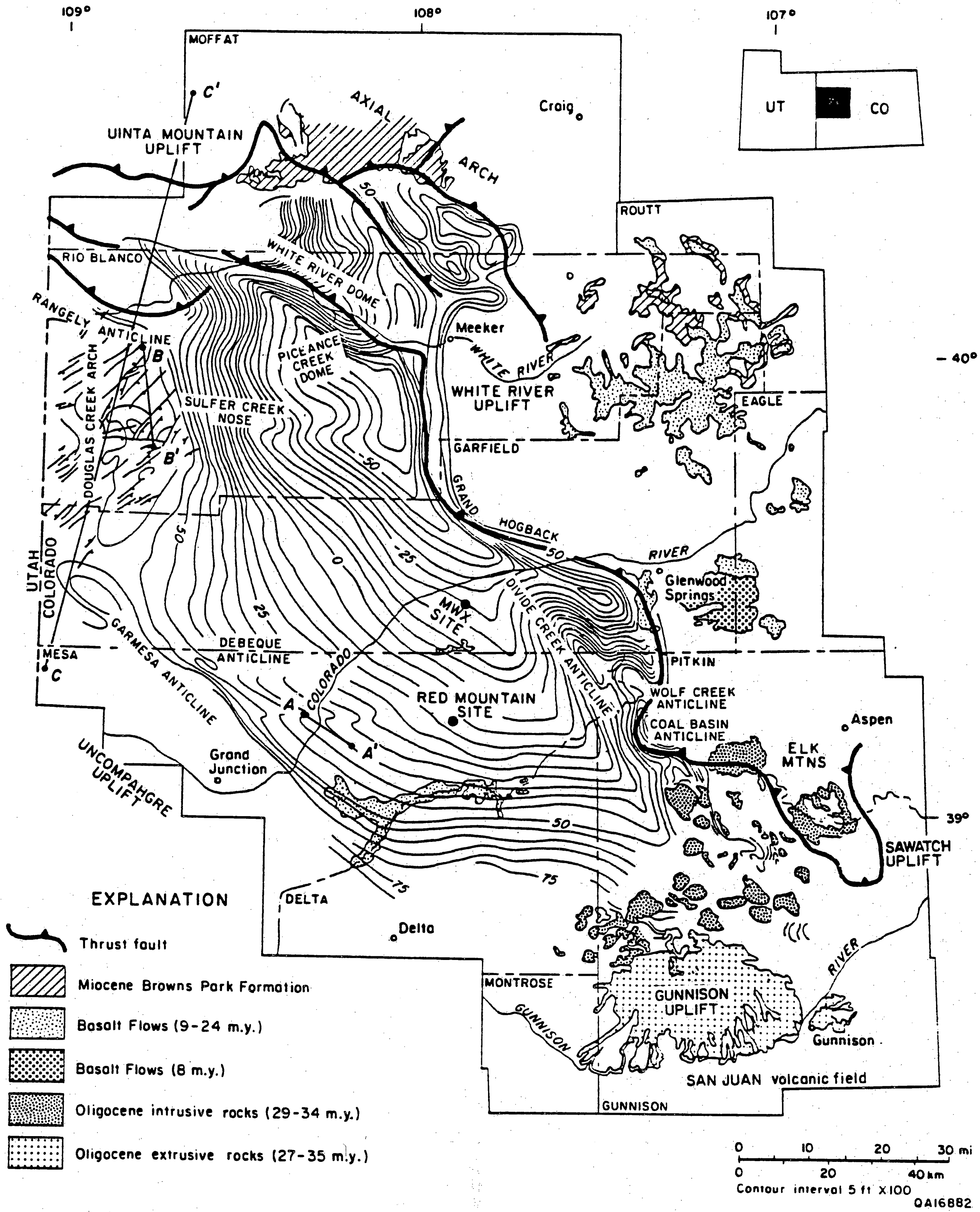


Figure 134. Structure map contoured on top of the Rollins and Trout Creek Sandstone Members, Piceance Basin. Contour interval is 500 ft. Modified from Johnson and Nuccio (1986). Cross section A–A′ shown in figure 136, B–B′ in figure 139, and C–C′ in figure 140.

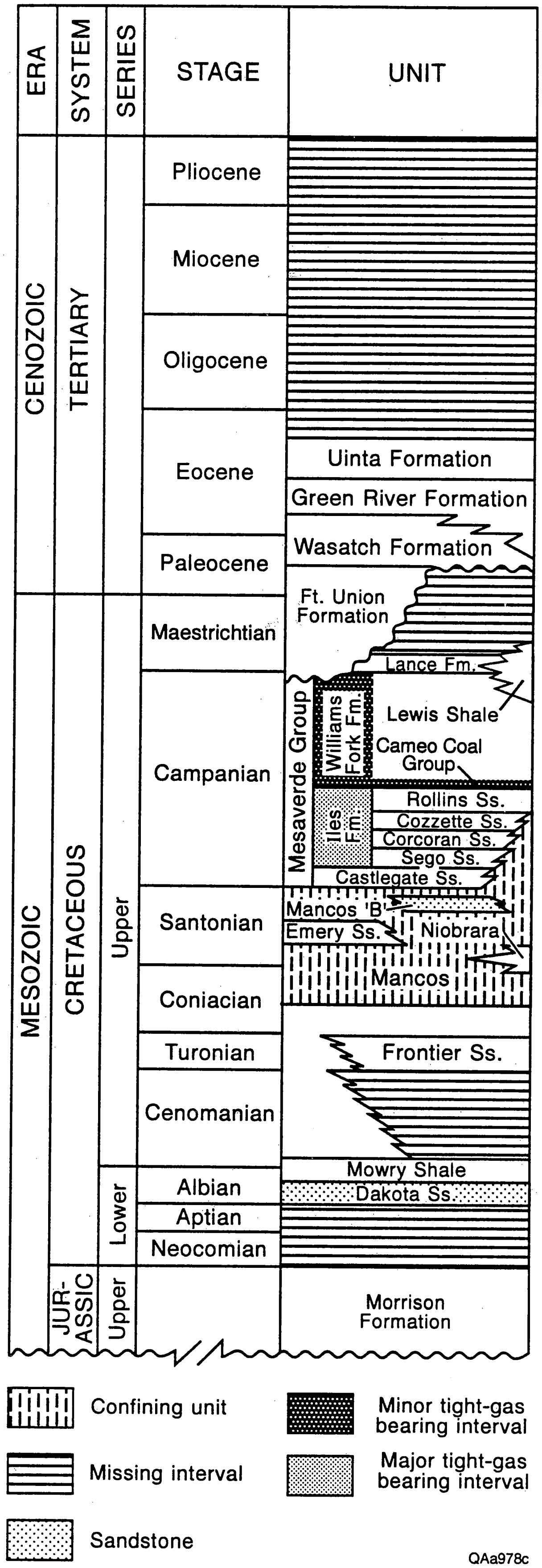


Figure 135. Stratigraphic units in the Piceance Basin (from Rocky Mountain Association of Geologists, 1977; modified from Finley, 1984).

marine incursion (Mancos Shale), and the Western Interior Seaway covered much of the Rocky Mountain foreland area (Tyler and others, 1991). Pulses of tectonic activity in the Overthrust Belt shed sediment eastward. Initially, sediment was concentrated along a fairly narrow zone adjacent to the Orogenic Belt (Frontier and Emery Sandstones and Niobrara Formation), but later, sediment was deposited much farther east as the shorelines advanced beyond the present-day eastern basin margin (upper Mesaverde Group). During the Tertiary the Piceance became a typical intermontane basin and thick continental clastic wedges flanked the basin, thinning and interfingering with lacustrine shales and marlstones in the basin interior (National Petroleum Council, 1980).

The tight gas formations of the Piceance Basin are Cretaceous age fluvial and shore-zone sandstones of the Dakota, offshore marine sandstones in the Mancos "B" Shale, barrier-strandplain deposits of the Corcoran, Cozzette, and Rollins Sandstones (lower Mesaverde Group), and overlying coastal/delta plain and fluvial sandstones in the upper Mesaverde Group (fig. 135). Most tight completions are in the Mancos "B" (409) with the Mesaverde (253) and Dakota (231) being secondary (table 2). Cumulative production is also dominated by the Mancos "B" (185.6 Bcf), ahead of the Dakota (66.3 Bcf) and Mesaverde Group (57 Bcf) (Hugman and others, 1992).

No low-permeability sandstones in the Uinta Basin to the west of the Piceance Basin are included in this atlas, but the Mancos "B" Shale, the Sego and Castlegate Sandstones in the Mesaverde Group, and the Wasatch Formation have all been designated tight in parts of the basin (Finley, 1984). Of these formations, the Eocene Wasatch Formation is the most prolific producer. There have been 257 tight completions in the Wasatch, and production from tight reservoirs was 179 Bcf through 1988 (Hugman and others, 1992). Estimated ultimate recovery for the Wasatch is 472 Bcf. Geologic information about low-permeability sandstones in the Uinta Basin was summarized by Fouch and others (1992).

Dakota Sandstone

The Dakota Sandstone in the Piceance Basin has been described as uppermost lower Cretaceous (fig. 135) or lowermost upper Cretaceous (Johnson and Finn, 1986) and is the transgressive unit that represents the initial invasion of the Cretaceous epeiric sea (Johnson and Finn, 1986). Designated tight gas areas include parts of Garfield, Mesa, and Rio Blanco Counties in Colorado. Along with the Dakota Sandstone, the upper Jurassic Morrison Formation has been added to the total Dakota producing interval in some areas that are designated tight in the Piceance Basin (Colorado Oil and Gas Conservation Commission, 1982c). Total thickness of the Dakota Sandstone ranges from 100 ft to 275 ft (Colorado Oil and Gas Conservation Commission, 1980j, 1981a), and depth to the top of the formation ranges from 2,026 to 9,225 ft (Colorado Oil and Gas Conservation Commission, 1980j, 1982c). Net sand thickness ranges from 10 to 60 ft (Colorado Oil and Gas Conservation Commission, 1980j). There were 231 tight completions in the Dakota and 17 tight gas completions in the Morrison by 1988 (Hugman and others, 1992).

Depositional Systems and Reservoir Facies

The Dakota Sandstone is composed of interbedded sandstone and siltstone and some beds of limestone and coal (fig. 136) (Colorado Oil and Gas Conservation Commission, 1981a). The Dakota unconformably overlies the upper Jurassic Morrison Formation and underlies the Upper Cretaceous Mowry Shale (fig. 135). The Dakota is represented by a series of transgressive deposits, and facies include (1) fluvial and floodplain environments; (2) nearshore continental and transitional environments, including salt marsh, tidal flat, and lagoon; (3) barrier island environments, including backshore and foreshore beach; and (4) shallow sublittoral environments (Lane, 1963). Coarser grained sandstones usually occur in northeasterly trending channels of lower alluvial plain and delta plain deposits (Colorado Oil and Gas Conservation

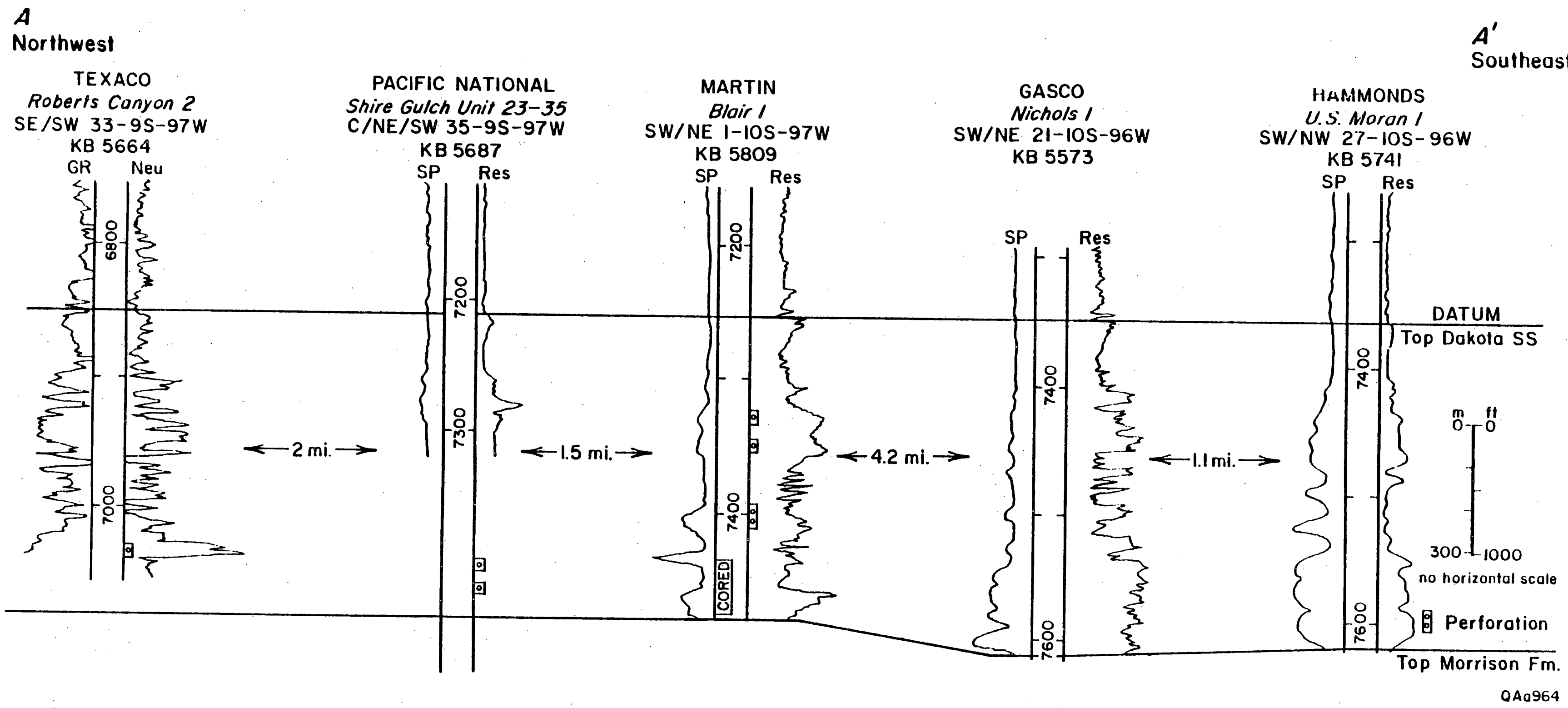


Figure 136. Northwest–southeast stratigraphic cross section through Dakota Sandstone, Piceance Basin (from Colorado Oil and Gas Conservation Commission, 1981a). Approximate line of section A–A′ shown in figure 134.

Commission, 1980d). These sandstones have an average porosity range of 12 to 14 percent. A natural flow of gas is sometimes obtained from these coarser-grained channel deposits, but fracture treatment is usually required to establish a sustained commercial flow of gas from these sandstones (Colorado Oil and Gas Conservation Commission, 1980d). Finer-grained sandstones, interpreted as overbank deposits, have an average porosity range of 8 to 12 percent in areas adjacent to the main channels. Wells in the overbank deposits rarely have a measurable natural flow of gas, and fracture treatment is necessary (Colorado Oil and Gas Conservation Commission, 1980d). The Dakota Sandstone is divided into three separate "benches" in some areas (Colorado Oil and Gas Conservation Commission, 1980j). The first bench is generally gas productive, the second is water productive, and the third is marginally gas productive (Colorado Oil and Gas Conservation Commission, 1980j). Areal extent of these sandstones ranges from a few hundred feet to 2 mi.

Composition of Reservoir Facies

The Dakota Sandstone is composed of submature to mature, fine- to medium-grained sandstone, siltstone, and shale (Colorado Oil and Gas Conservation Commission, 1981a). In outcrop studies conducted in northwestern Colorado, sandstone constituted 65 to 86 percent, siltstone 10 to 25 percent, and shale 0 to 15 percent of the rock units (Lane, 1963). Calcite, quartz overgrowths, and authigenic clays reduce the porosity and permeability in the Dakota Sandstone (fig. 137) (Colorado Oil and Gas Conservation Commission, 1981a).

Natural Fractures

Anecdotal evidence suggests that some operators consider natural fractures to play a role in Piceance Basin Dakota production, but published accounts are lacking. Fractures have been reported in Dakota Sandstone core of the Piceance Basin (T. Hemler, 1982, oral communication

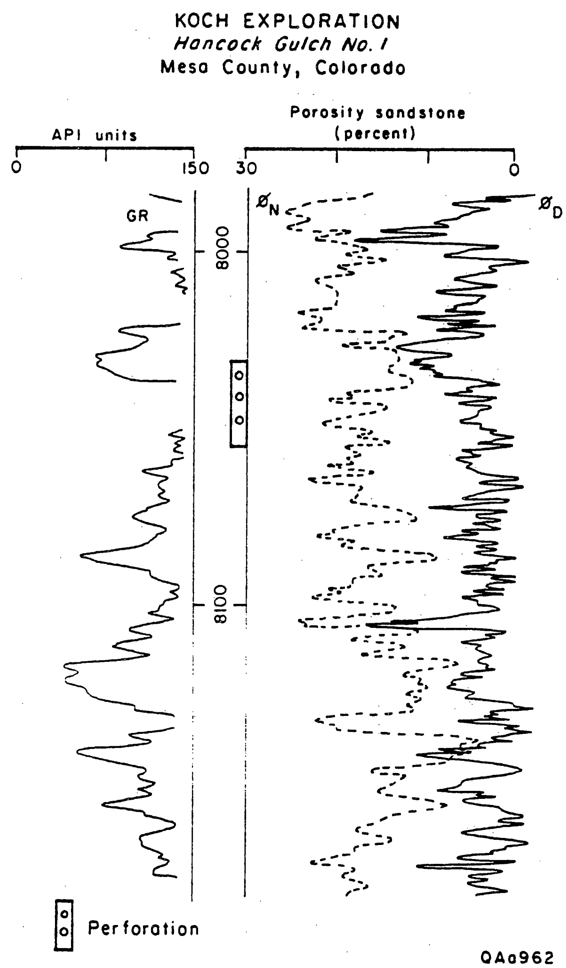


Figure 137. Neutron density log showing Dakota Sandstone, Piceance Basin.

reported in Pitman and Sprunt, 1986, p. 223). DuChene (1989) interpreted Dakota production in the San Juan Basin to be augmented by natural fractures, and Lacy and others (1992) report a horizontal Dakota well in the Denver Basin; presumably this well was aimed at natural fracture targets.

Engineering Assessment

The Dakota sandstone typically contains two porosity and permeability profiles. The higher porosity sandstones (12 to 14 percent, 0.45 md) are normally limited reservoirs (Colorado Oil and Gas Conservation Commission, 1981a). These are interpreted to be the channel sandstones described earlier. The overbank deposits have lower porosities and permeabilities (7 to 11 percent and 0.02 to 0.05 md). Wells drilled in the sweeter spots (channel sands) normally have higher initial producing rates, but the reservoirs are so limited that soon a well will produce as though it is completed in a low permeability reservoir (Colorado Oil and Gas Conservation Commission, 1981a). Some of these wells are completed without stimulation. Most of the wells produced naturally are offset by dry holes or by wells with poor recovery.

Overall, porosities in the Dakota range from an average of 7.2 percent in the southern part of the tight gas designated area (Colorado Oil and Gas Conservation Commission, 1981a) to as high as 10.6 percent average in the Douglas Arch area (Colorado Oil and Gas Conservation Commission, 1980j) (table 28). Grain densities of 2.65 g/cc are common in Dakota sandstones. Permeabilities are low throughout, with average permeabilities of 0.02 to 0.05 md reported in tight gas classification hearings.

Average water saturations are 40 percent in the productive sandstones of the region (Colorado Oil and Gas Conservation Commission, 1980j, 1981a), and net pay footages of 25 to 40 ft are observed. Reservoir temperature is 215°F, and reservoir pressures up to 2,400 psi are reported.

Table 28. Dakota Formation, Piceance Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 231

Cumulative production from tight completions 1970–1988 (Bcf): 66.3

Estimated ultimate recovery from tight areas (Bcf): 146

Net pay thickness (ft): 25–40

Porosity (%): 7.2–10.6

Permeability (md): 0.02–0.05

Water saturation (%): 40

Reservoir temperature (°F): 215

Reservoir pressure (psi): up to 2,400

Typical stimulation/hydro-frac: 60,000 to 80,000 gal fluid or foam and 100,000 lb sand

Production rate:

prestimulation (Mcf/d): 30

poststimulation (Mcf/d): 1,000 mcfd initially, drops to 70

Average recovery per completion (MMcf): 650

Decline rate: No data

Almost all Dakota sandstones require fracture stimulation. In the Debeque area (Garfield and Mesa Counties), operators of three wells reported an average fracture stimulation treatment of 102,000 gal fluid and 170,000 lb sand. In the Douglas Arch area (northwestern Garfield and Rio Blanco Counties), an average fracture stimulation treatment of 57,000 gal fluid and 72,000 lb sand has been used (Colorado Oil and Gas Conservation Commission, 1980j). The most recent fracture stimulation treatments in the area, however, use 60,000 to 80,000 gal fluid (or foam) and 100,000 lb sand.

Production history

Ultimate recovery is expected to be 146 Bcf in the Dakota Sandstone (table 28) plus 6 Bcf in the Morrison Formation (Hugman and others, 1992), and average recovery per completion is 0.65 Bcf. Wells will produce at a pre-stimulation rate of 30 Mcf/d (Colorado Oil and Gas Conservation Commission, 1980j). After stimulation, rates will be high, averaging 1,002 Mcf/d in the Douglas Creek Arch area; however, they will drop back to lower rates. In Rio Blanco and Garfield Counties, reports show a stabilized flow rate averaging 70 Mcf/d (Colorado Oil and Gas Conservation Commission, 1980j).

Mancos "B" Shale

The Mancos "B" interval in the Piceance Basin area is characterized by interbedded and interlaminated claystone, siltstone, and fine sandstone formed in a marine environment as part of the Mancos Shale during the Late Cretaceous (fig. 135) (Kellogg, 1977). Mancos "B" designated tight gas areas are located on the Douglas Creek Arch and its eastern flank in parts of Garfield and Rio Blanco Counties in Colorado (fig. 138). Thickness in these designated tight gas areas ranges from 400 to 700 ft, and depth to the top of the Mancos "B" ranges from 3,475 to

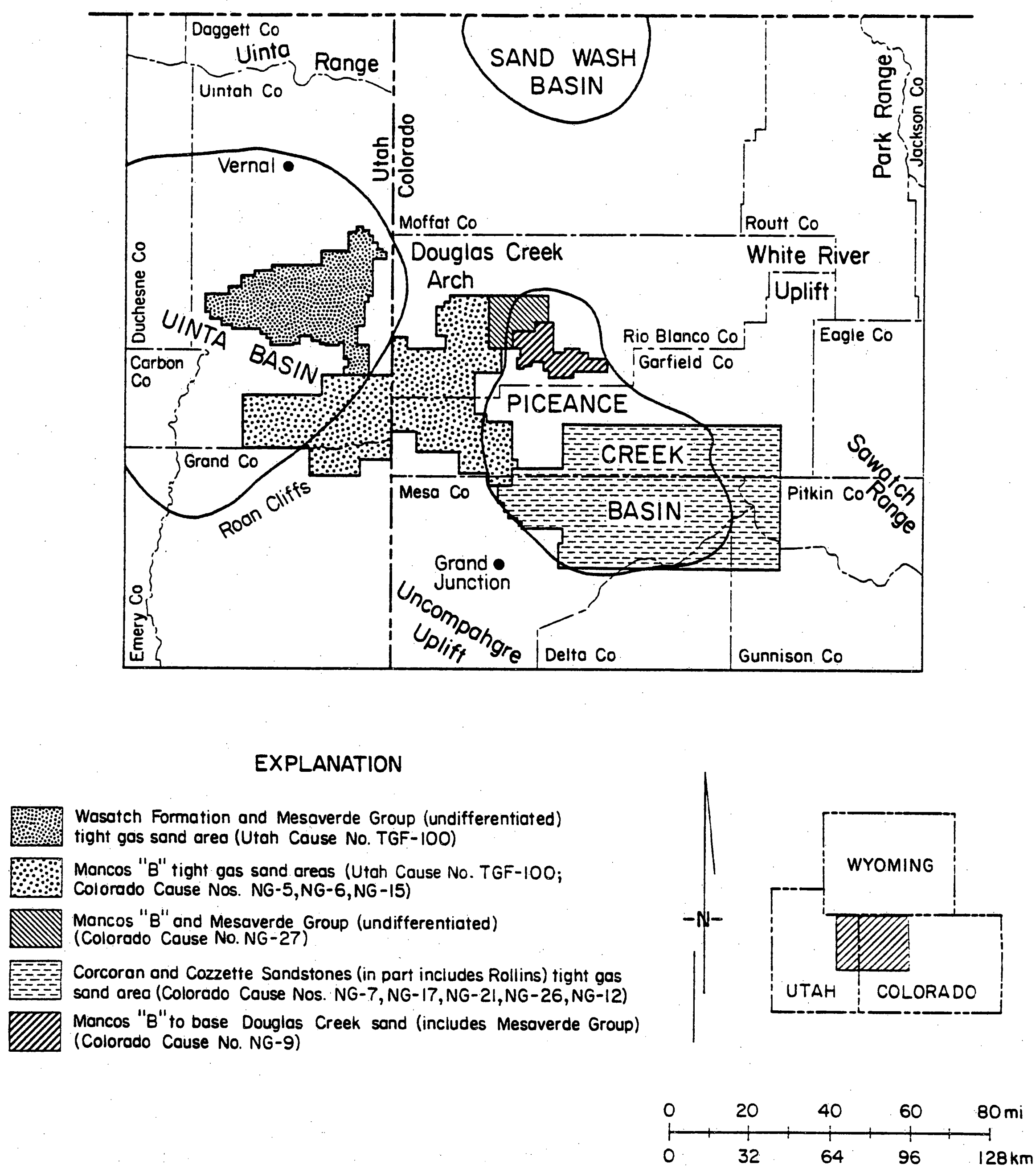


Figure 138. Areas covered by tight gas sand application, Piceance and Uinta Basins (from Finley, 1984).

3,603 ft (table 29) (Finley, 1984). Typical reservoir dimensions in the Douglas Creek Arch area range from 30 to 250 ft thick in a gross interval of 400 ft (Finley, 1984).

Depositional Systems and Reservoir Facies

The Mancos "B" interval was deposited in an offshore marine environment on a nearly horizontal marine shelf east of the Emery Sandstone (a time-equivalent shoreline deposit of the Mancos "B" located in the Uinta Basin) during a regressive phase of the Late Cretaceous (Kellogg, 1977). The Mancos "B" is encased in Mancos marine shales (fig. 135) (Finley, 1984). Finely laminated claystones, siltstones, and sandstones of the Mancos "B" are not traceable from well log to well log (fig. 139) (Kellogg, 1977). Units with greater quantities of either sandstone or sandstone and siltstone are considered potential gas reservoirs. The individual sandstone beds are not readily defined in the Mancos "B," but Kellogg (1977) has isolated generalized shaly, silty, and sandy facies (fig. 140). Sand content decreases off the Douglas Creek Arch to the southeast, and sands also pinch out northward on the arch (Finley, 1984).

Kellogg (1977) studied the Mancos "B" on the Douglas Creek Arch (fig. 134) and divided the Mancos "B" into five units; unit A is at the base of the Mancos "B" and unit E is at the top (fig. 140). The base of unit A is composed of siltstone and shale coarsening upward into 50 to 100 ft of increasingly sand-rich rocks. Unit A thins to the northern part of the arch, where it becomes mostly sand rich. The base of unit B coarsens upward and is composed of siltstone and shale. The sand content increases toward the top of the unit. Unit C is made up mostly of siltstone and shale, and sand amounts increase over the north end of the Douglas Creek Arch. Units A, B, and C generally indicate easterly, then northerly transport from the source area. Unit D coarsens upward from siltstone into sandstone, apparently filling erosional topography that developed on top of unit C. Transport of sediments from the source area was easterly and then southerly. Unit E is the most uniform in thickness and the thinnest of all units. Sands are thickest toward the southern Douglas Creek Arch area (fig. 140) (Kellogg, 1977).

Table 29. Mancos "B" Shale, Piceance Basin: production data and engineering parameters.

Estimated resource base (Tcf): No data

No. tight completions: 409

Cumulative production from tight completions 1970–1988 (Bcf): 185.6

Estimated ultimate recovery from tight areas (Bcf): 354

Net pay thickness (ft): 30–250

Porosity average (%): 9.5

Permeability (md): 0.01–0.08

Water saturation (%): No data

Reservoir temperature (°F): 90 in shallower fields

Reservoir pressure (psi): 450 in shallower fields

Typical stimulation/hydro-frac: 84,000 gal fluid and 215,000 lb sand

Production rate:

prestimulation (Mcf/d): Negligible

poststimulation (Mcf/d): 1,500 to 10,000, then 125 to 333 after 90 days

Average recovery per completion (MMcf): 1,500 on crest of Douglas Creek Arch, 250 along flank

Decline rate: 6%

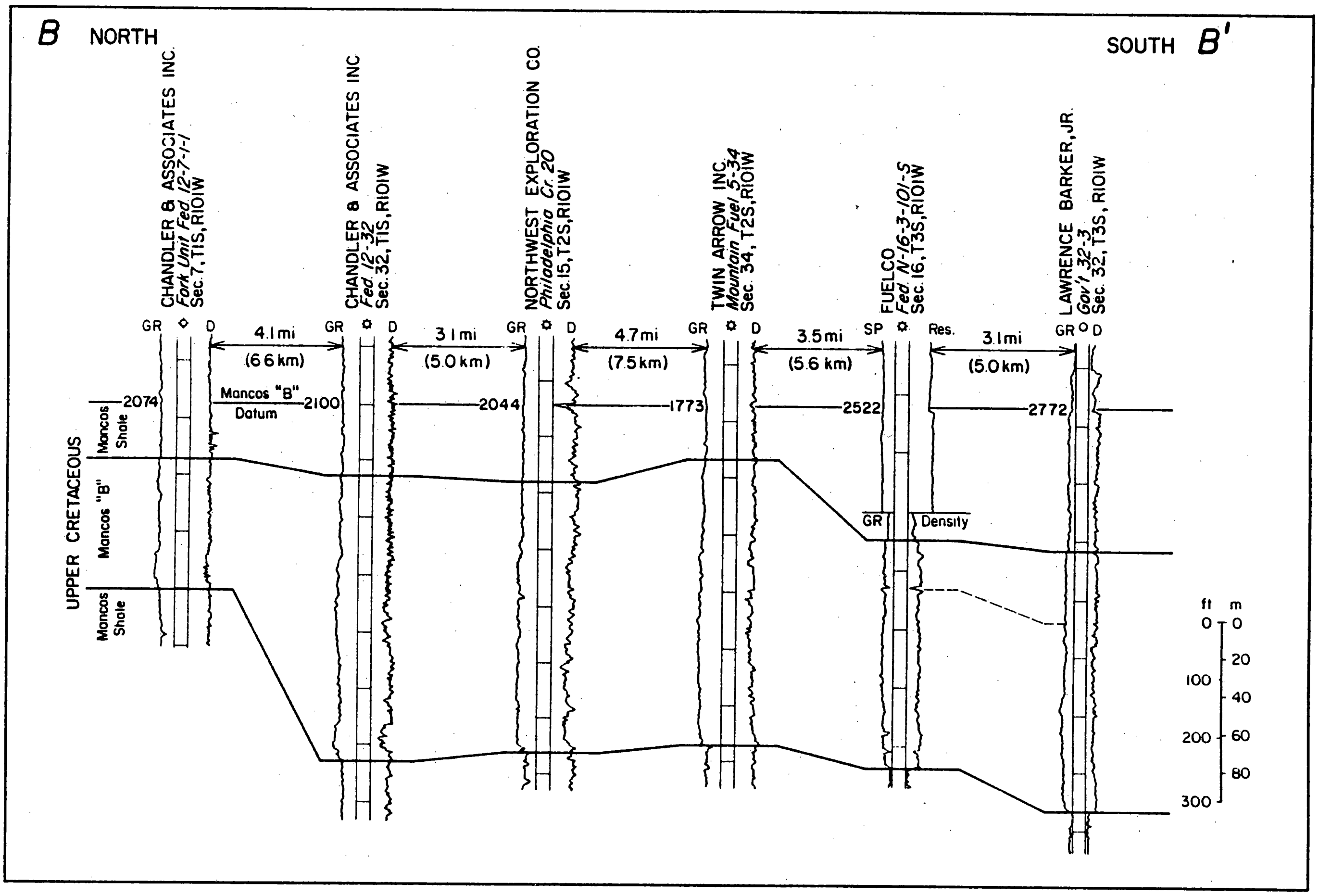


Figure 139. North–south stratigraphic cross section through Mancos "B" Shale, Piceance Basin (from Colorado Oil and Gas Conservation Commission, 1980b; Finley, 1984). Approximate line of section B–B' shown in figure 134.

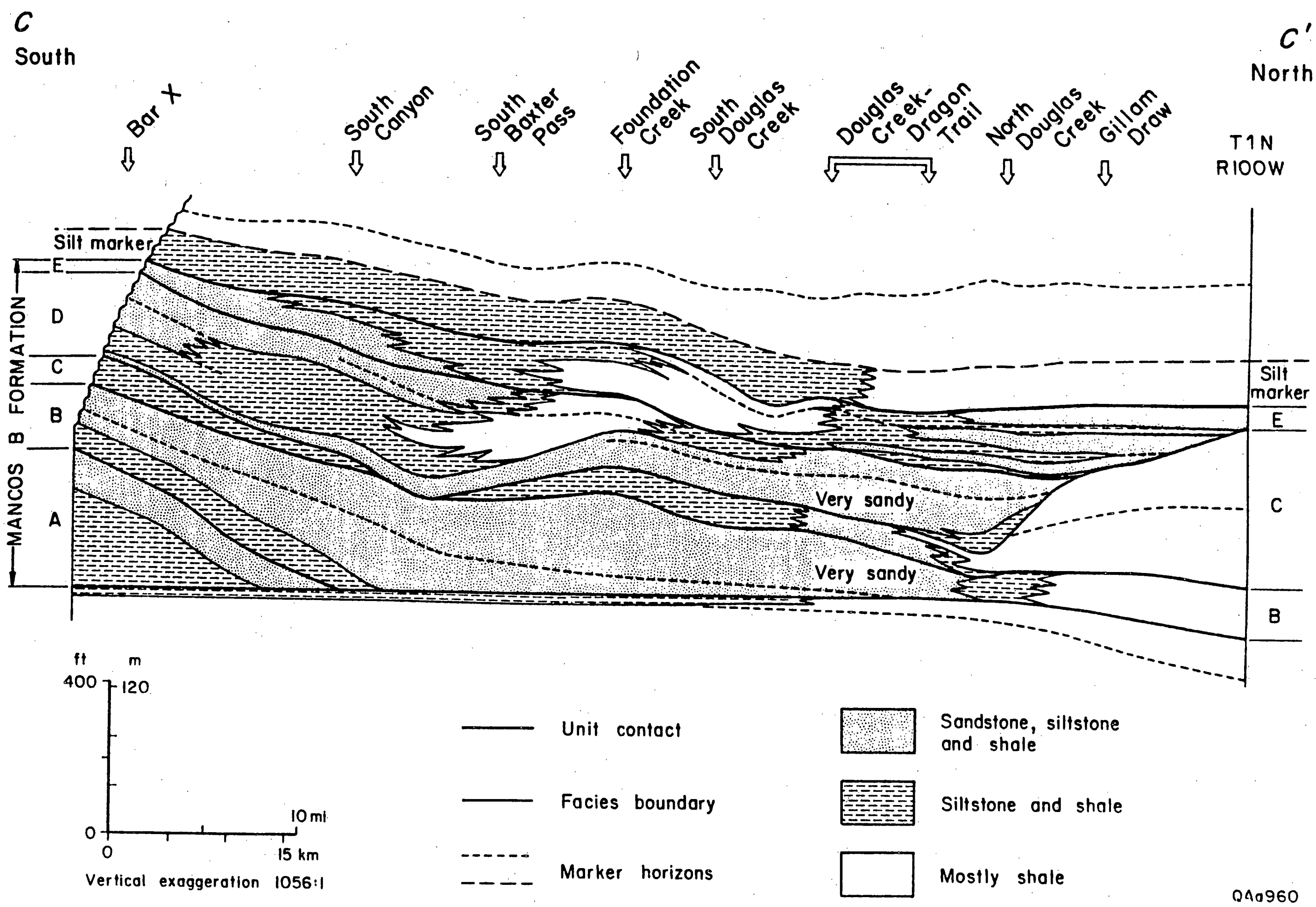


Figure 140. Restored south–north cross section through Mancos "B" Shale, Douglas Creek Arch. Approximate line of section C–C′ shown in figure 134 (from Kellogg, 1977).

Kellogg (1977) suggested that deposition of the Mancos "B" took place on a submarine terrace or slope and that slope angle tended to decrease as units B through E were being deposited (Finley, 1984). Increased sand content over the Douglas Creek Arch may have been the result of a winnowing effect or the stacking of units having progressively greater sand amounts. The sandy sequences in the Mancos "B" on the Douglas Creek Arch area may have been deposits from a distal delta-front to prodelta environment or may have been deposited on a shallow cratonic shelf within the storm-wave base, with sediments being dispersed by shelf processes (Finley, 1984).

Composition of Reservoir Facies

The Mancos "B" consists of thinly bedded and interlaminated very fine grained sandstone, siltstone, and shale (fig. 141) (Finley, 1984). The sandstone is composed predominantly of quartz (up to 80 percent in volume), is poorly sorted, and may have carbonaceous microlaminae. Shales are bentonitic. Diagenetic calcite and clay have reduced the porosity and effective permeability (Finley, 1984).

Natural Fractures

Finley (1984) reported that silty and shaly facies locally have contributed to production through fractures. Operators also report that, infrequently, faulted zones produce without stimulation.

In 1991, a GRI horizontal well was drilled to test the concept that fractures in the Mancos "B" can be exploited with slant drilling technology (R. E. Peterson, CER Corporation, written communication, 1992). Chandler & Associates air-drilled a 1,500 ft lateral across the 100-ft-thick "main porosity" interval of the Mancos "B" in an area of northwest Colorado where direct offsets of the well showed exceptional production thought to be due to the

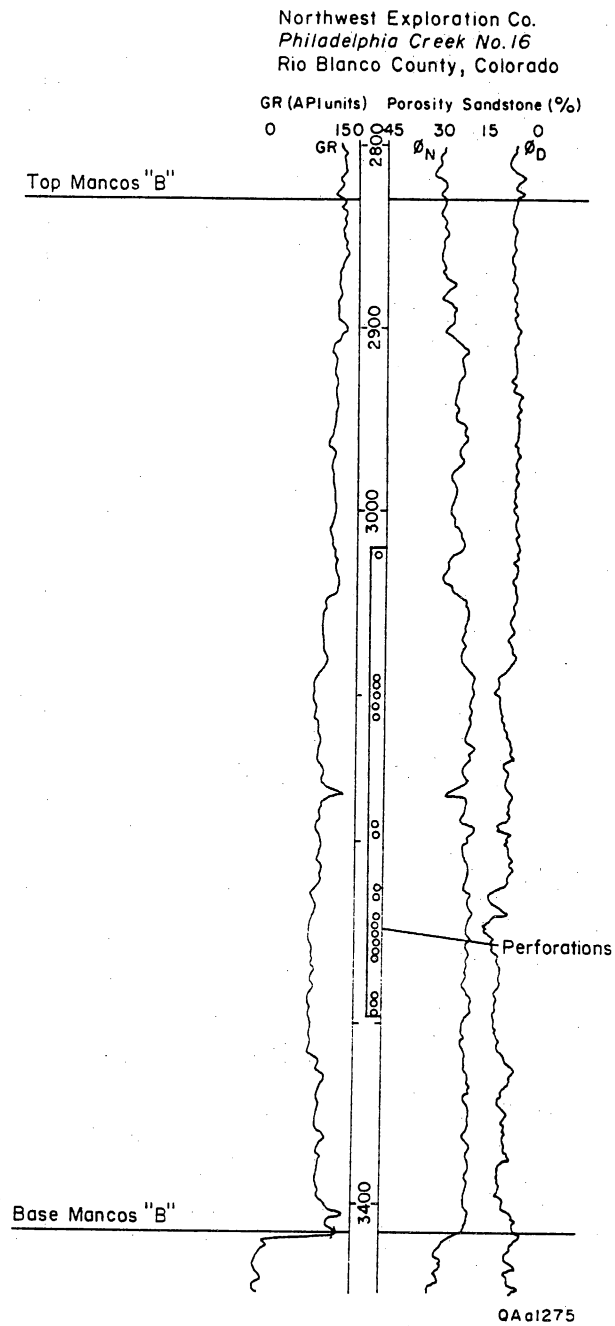


Figure 141. Type log from Mancos "B" Shale, Piceance Basin (Colorado Oil and Gas Commission, 1980b).

presence of natural fractures. The lateral was oriented N30°W, normal to the northeast–southwest regional trend of faults and approximately normal to the hydraulic fracture azimuth. Borehole image data from the horizontal well, however, did not detect any fractures in the Mancos "B" interval. Two hydraulic fracture treatments have been attempted, but high stresses and near-wellbore fracture tortuosity have caused screen outs and premature termination of treatments. Additional work is in progress on these experiments (R. E. Peterson, CER Corporation, personal communication, 1992). Lacy and others (1992) report a horizontal well in the Mancos of the San Juan Basin (at a depth of 3,800 ft) but give no other details.

Engineering Assessment

Porosity in the Mancos "B" interval averages 10 to 11 percent in the Douglas Creek Arch area (table 29), decreasing to 2 percent or less on the flanks or to the south. Porosities may be as high as 14 percent locally (Finley, 1984). The average porosity of the eight largest producing fields in the Mancos "B" is 9.5 percent, and permeabilities are less than 0.1 md. For one group of wells, using pressure build-up analysis, permeability is calculated to be 0.08 md (Colorado Oil and Gas Conservation Commission, 1980b). Core analysis on a second group of wells indicate permeabilities of 0.01 md (Colorado Oil and Gas Conservation Commission, 1980e). Conventional core analysis, uncorrected for overburden or relative permeability effects, averages 0.7 md over the Douglas Arch (Kopper, 1962; Mathias, 1971).

Because of the depth variability of the Mancos "B" sandstones, both reservoir temperature and pressure are difficult to generalize. In one of the shallower fields (2600 ft), reservoir temperature was 90°F and reservoir pressure was 450 psi (Colorado Oil and Gas Conservation Commission, 1980b), but in the Uinta Basin average reservoir pressure is 1160 psi (Finley, 1984). Kellogg (1977) estimates reservoir pressure gradient to be 0.17 to 0.22 psi/ft.

A typical fracture-stimulation treatment will consist of 84,000 gal of fluid and 215,000 lb of sand (table 29). The Mancos "B" is susceptible to formation damage from fresh water

(Kellogg, 1977). The extent of damage is dependent on the time that fresh water is in communication with Mancos "B" sandstones and is apparently irreversible.

Production history

Tight Mancos "B" sandstones have produced 185.6 Bcf and ultimate recovery is expected to be 354 Bcf (Hugman and others, 1992) (table 29). Estimated recovery is 1.5 Bcf in the wells on the crest of the Douglas Arch but declines to 0.25 Bcf along the flank (Coalson and others, 1982). Total tight completions by 1988 were 409 wells.

In almost all cases, prestimulation producing rates are too small to measure (Colorado Oil and Gas Conservation Commission, 1980e), although initial post-fracture stimulation rates are large. Rates of 1,500 to 10,000 Mcf/d have been reported (Kellogg, 1977). Typically, the rate drops to 125 to 333 Mcf/d (Colorado Oil and Gas Conservation Commission, 1980e; Kellogg, 1977) after 90 days and decline rate, after production has stabilized, is 6 percent per year.

Mesaverde Group

Tight gas reservoirs are present at several stratigraphic levels within the Upper Cretaceous Mesaverde Group of the Piceance Basin. In ascending stratigraphic order, these include the Corcoran, Cozzette, and Rollins Sandstones of the Iles Formation, and overlying undifferentiated sandstones of the Williams Fork Formation (fig. 135). The Iles and Williams Fork Formations are continuous throughout the subsurface of the Piceance Basin and cover an area of approximately 6,700 mi^2 (Tyler and others, 1991). The area designated as tight-gas-producing is concentrated in the southern half of the basin (Colorado Oil and Gas Conservation Commission, 1980b, e, h, 1981b, 1982a), although undifferentiated Mesaverde Group is also designated tight-gas-producing in the northernmost part of the basin (Colorado Oil and Gas Conservation Commission, 1980d, 1982b). The Iles and Williams Fork Formations contain up to 5,000 ft of intertonguing marine and nonmarine sediments, and the depth to the reservoir intervals vary from outcrop along the basin margins to more than 12,000 ft along the structural axis of the basin (Tyler and others, 1991; fig. 134). Most completions however, are from depths of 2,000 to 4,000 ft (Finley, 1984).

The Piceance Basin was selected for the Multi-Well Experiment Site (MWX) which was sponsored by the U.S. Department of Energy. This experimental site (fig. 134) has provided a detailed data set for characterizing the natural resources contained in the low permeability Corcoran, Cozzette, Rollins, and undifferentiated Williams Fork reservoir sandstones (Lorenz, 1983a, b; Spencer and Keighin, 1984; Lorenz, 1987; Law and Spencer, 1989). Further studies by Finley (1985), Brown and others (1986), and Tyler and others (1991) complement the MWX results and enable a definitive synthesis of the low-permeability Mesaverde Group reservoirs.

Depositional Systems and Reservoir Facies

Mesaverde Group deposition was characterized by episodes of southeasterly shoreline progradation that were interrupted by intermittent shoreline retreat (Young, 1955; Weimer, 1960). The framework sandstones were deposited in linear shoreline systems, backed by deltaic and coastal-plain distributaries and updip fluvial channel belts. Associated fine-grained clastics and coals were deposited in laterally adjacent back-barrier lagoons, coastal-plain swamps and on alluvial floodplains. The initial progradational episodes did not extend terrestrial sedimentation as far basinward as later episodes, such that the Corcoran, Cozzette and Rollins sandstones were deposited primarily in shoreline settings, and overlying undifferentiated Williams Fork Formation sandstones have coastal-plain distributary and fluvial-channel affinities (fig. 142). Figure 143 is a type log of the Mesaverde tight gas sandstones.

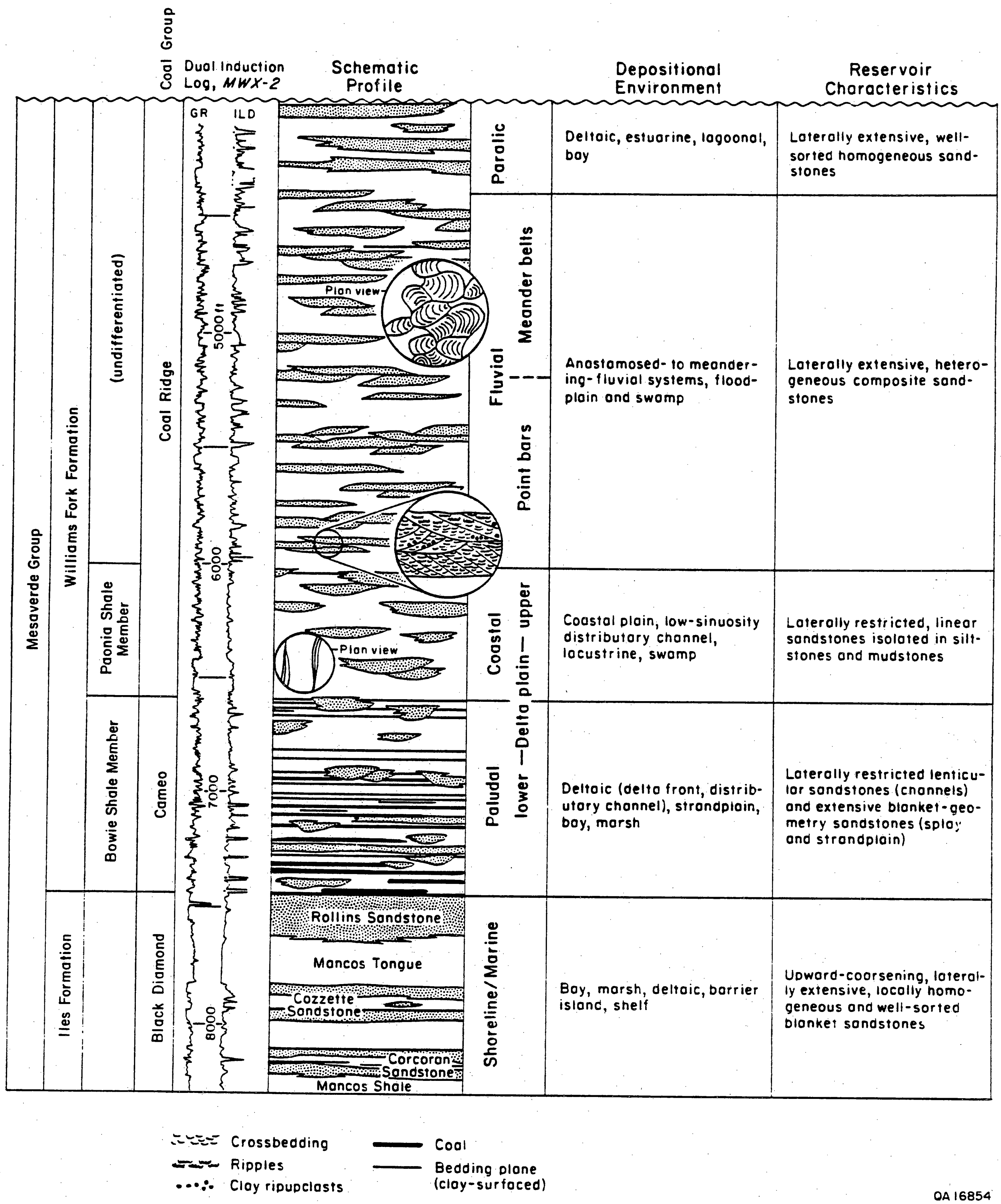


Figure 142. Schematic profile illustrating the depositional setting and reservoir characteristics of the Mesaverde tight gas sandstones (modified from Lorenz, 1983b).

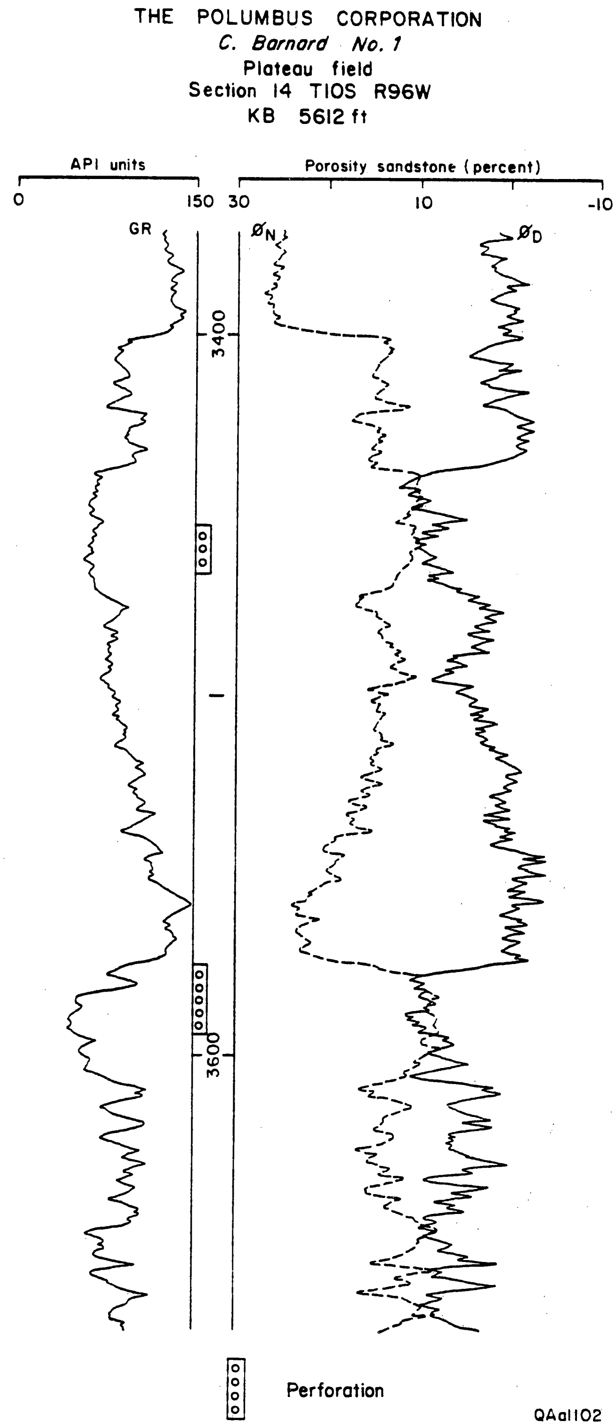


Figure 143. Type log of the Mesaverde Group tight gas sandstones, Piceance Basin.

Corcoran and Cozzette Sandstones

The Corcoran and Cozzette sandstones were deposited in a wave-dominated coastline (Lorenz, 1983a). The sandstones are each up to 220 ft thick and display good lateral continuity along a northeast-southwest trend. Although the sandstones have been described as having blanket morphology, Lorenz (1983a) considers that lateral variability, in the form of thickness changes of both the sandstones and the interbedded lithologies, occurs where wave reworking of feeder distributary-channel and mouth-bar facies was incomplete. Each of the sandstones consist of a lower, generally upward-coarsening sequence, with the cleanest and thickest sandstone development at the top, overlain by a more variable upper sequence with upward-coarsening to blocky gamma-ray log patterns (Finley, 1985). Sedimentary structures in these sandstones observed at outcrop and in core include hummocky, planar, and trough cross-stratification, as well as *Ophiomorpha* burrows, and indicate deposition in the lower and upper shoreface environment (Finley, 1985).

Rollins Sandstone

The Rollins sandstone caps the uppermost regressive sequence of the Iles Formation and is very similar in depositional setting to the Corcoran and Cozzette sandstones (fig. 142). Tyler and others (1991) described the unit as an upward-coarsening, laterally extensive blanket sandstone from 100 to 150 ft thick. Lorenz (1983a) attributed Rollins deposition to a sandy shoreline, seaward of the lower delta-plain facies of the Cameo Coal Member.

Undifferentiated Williams Fork Sandstones

The Williams Fork Formation records a large-scale regression, and coastal/delta-plain facies in the lower half of the unit grade into overlying fluvial facies (Tyler and others, 1991, fig. 142). Lorenz (1989) described the reservoir characteristics of the different depositional facies. The lowermost Williams Fork sandstones are distributary mouth bar deposits that occur in strike-elongate sheets and average 20 ft thick. These are overlain by coastal/delta-plain distributary channel facies of lenticular crossbedded sandstones typically from 300 to 500 ft wide and 20 to 35 ft thick. The fluvial reservoir sandstones were deposited as arcuate point bars that were approximately 700 ft wide and 2 to 13 ft thick. Stacking of successive point bars gave rise to composite meanderbelt sandstone sequences 20 to 60 ft thick and 1,000 to 2,000 ft wide (Lorenz and others, 1985). Internal bedding architecture is characterized by repetitive upward-fining cycles of fine to medium-grained crossbedded sandstone and overlying fine to very fine-grained rippled sandstone.

Composition of Reservoir Facies

Corcoran and Cozzette Sandstones

The Corcoran sandstone reservoirs are classified as sublitharenites (Folk, 1974) and consist primarily of quartz (55 to 65 percent) with lesser amounts of microcrystalline chert (14 to 16 percent), quartz-muscovite schist (5 to 15 percent), plagioclase (8 to 10 percent), detrital dolomite (5 to 10 percent), mica (2 to 5 percent), and volcanic rock fragments (trace to 2 percent) (Brown and others, 1986). Composition of the Cozzette sandstones is very similar to the Corcoran reservoirs, and most samples also classify as sublitharenites. Locally, however, mica and detrital dolomite content can be relatively high and the Cozzette sandstones are litharenites. Diagenetic alteration is comparable in both reservoir units. Quartz overgrowths are the major cementing agents along with lesser amounts of calcite and siderite. Pore types are dominantly micropores, but macropores can comprise as much as 30 percent of the porosity, particularly toward the northwest where the Corcoran and Cozzette sandstones are coarser grained (Brown and others, 1986). Detrital clays are predominantly mixed-layer illite-smectite and illite. Chlorite is present in minor to moderate amounts.

Rollins Sandstone

Composition of the framework fraction of Rollins sandstones is dominated by quartz (65 to 72 percent), with minor to moderate amounts of chert (2 to 13 percent), minor quartz-muscovite schist (5 to 10 percent), plagioclase (7 to 10 percent), and micas (2 to 5 percent) (Brown and others, 1986). These sandstones are classified as sublitharenites. Quartz overgrowths and fine to coarse crystalline calcite (derived from fossil fragments) are the major cements. Only very small amounts of other cements (siderite and marcasite) are observed (Brown and others, 1986). Pore types are predominantly intergranular micropores between illitic and kaolinitic clays. Total detrital and authigenic clay content ranges from a relatively low 2 percent in the coarsest Rollins sandstones to 7 percent in the finer-grained samples, and the clay assemblage is dominated by mixed layer illite-smectite (48 to 71 percent) and kaolinite (29 to 37 percent).

Undifferentiated Williams Fork Sandstones

Petrographic data on the Williams Fork sandstones are limited to a brief description in an application to the Colorado Oil and Gas Conservation Commission (1981c) and a preliminary description of the uppermost Williams Fork sandstone unit, the Ohio Creek Member (Hansley and Johnson, 1980). The Williams Fork sandstone is coarse to very fine-grained, usually poorly sorted, argillaceous, and calcareous (Colorado Oil and Gas Conservation Commission, 1981c). Typical framework composition is quartz from 35 to 67 percent, feldspar from 2 to 20 percent, and lithic fragments from 30 to 52 percent. Authigenic minerals include calcite (2 to 70 percent), dolomite (5 to 20 percent), and the clays, kaolinite, illite, and chlorite (5 to 40 percent). Ohio Creek sandstones are classified as feldspathic litharenites and lithic arkoses. Detrital components include quartz (45 to 85 percent), feldspar (5 to 25 percent), and lithic fragments (5 to 20 percent). Hansley and Johnson (1980) proposed a general diagenetic sequence for the Ohio Creek Member of early(?) calcite, chlorite, quartz overgrowths, calcite, secondary porosity, illite and kaolinite, and dolomite, ankerite(?) and calcite.

Natural Fractures

Observations of open fractures in core and the contrast between high formation permeabilities measured with well tests and low matrix permeabilities measured in core show that fractures are locally an important component of reservoir permeability in Mesaverde rocks in the Piceance Basin (Pitman and Sprunt, 1986). Fractures have been recognized in core and outcrop in various parts of the basin, and in particular in the vicinity of the Piceance Creek anticline, but the distribution of these fractures at depth is unknown (Millison, 1962; Ritzma, 1962; Mallory, 1977). Production in the Piceance Basin has been most successful in structurally closed areas where the reservoir rocks are naturally fractured (Pitman and Sprunt, 1986). The role of natural fractures in Cozzette Sandstone gas production has been studied at the U.S. Department of Energy's Multiwell (MWX) site and Slant Hole Completion Test well (SHCT) (Myal and Frohne, 1991, 1992) in Rulison field.

The most productive field in the Piceance Basin, Piceance Creek field, is on the Piceance Creek anticline, a structural closure with extensive natural fractures documented in the subsurface. Other fields reported to have natural fractures contributing to production include White River, Baldy Creek, Divide Creek, Wolf Creek, Mamm Creek, and Rulison (Sprunt and Pitman, 1986).

Core analysis indicates intense fracture development on the eastern side of the Piceance Basin adjacent to the White River Uplift. Fractures in the central and western parts of the basin are apparently less common. Pitman and Sprunt (1986) concluded that good gas production in Cretaceous and Tertiary rocks is controlled by open, vertical, interconnected natural fractures. The best producing wells are in fault zones or in nearby areas where fracture porosity and permeability are significant. Some of the best producing wells in Piceance Creek field are within a high-angle fault zone (Pitman and Sprunt, 1986). According to Brown and others (1986), high-production-rate Rollins, Cozzette, and Corcoran wells are coincident with structural closures, where faulting and fracturing provide additional flow capacity to wells, and early trapping of gas locally preserved primary porosity and open fractures by inhibiting precipitation of authigenic cements (Brown and others, 1986).

Pitman and Sprunt (1986) recognized fractures from core and well records. They found that cores from Piceance Creek field and from near Rulison field in the eastern part of the basin show extensive fractures through 8,500 ft of Cretaceous and Tertiary section. Fractures are locally partly open in core. Typical infilling minerals, in order of decreasing abundance, are calcite, clay minerals (dickite), quartz, and barite (Pitman and Sprunt, 1986). The fractures encountered in near-horizontal core from Rulison field are lined with acicular quartz crystals, arranged in such a way that it is clear that the part of the fracture captured in the core must have been open at depth (Lorenz and Hill, 1991). Pitman and Sprunt (1986) and Lorenz and Finley (1991) summarize fracture orientation, mineralogy and isotopic composition of fracture-filling minerals, and hypotheses for origins of fractures in the Piceance Basin.

Morrow and others (1989) describe experiments in which flow through partly mineralized fractures from MWX wells was investigated. Filled or healed fractures are more permeable than surrounding matrix, but differences in permeability values are within an order of magnitude. Because these fractures are largely filled with calcite, acid treatments of fractures in the laboratory resulted in several-thousandfold increases in permeability.

West-northwest-striking subvertical fractures occur in vertical core from the Cozzette Sandstone at the MWX site and in subhorizontal core from the SHCT well. In near-horizontal core from the SHCT well, open fractures with spacing averaging 3 ft were encountered (Lorenz and Hill, 1991) (figs. 144 and 145). Branagan (1992) estimates the flow potential of the

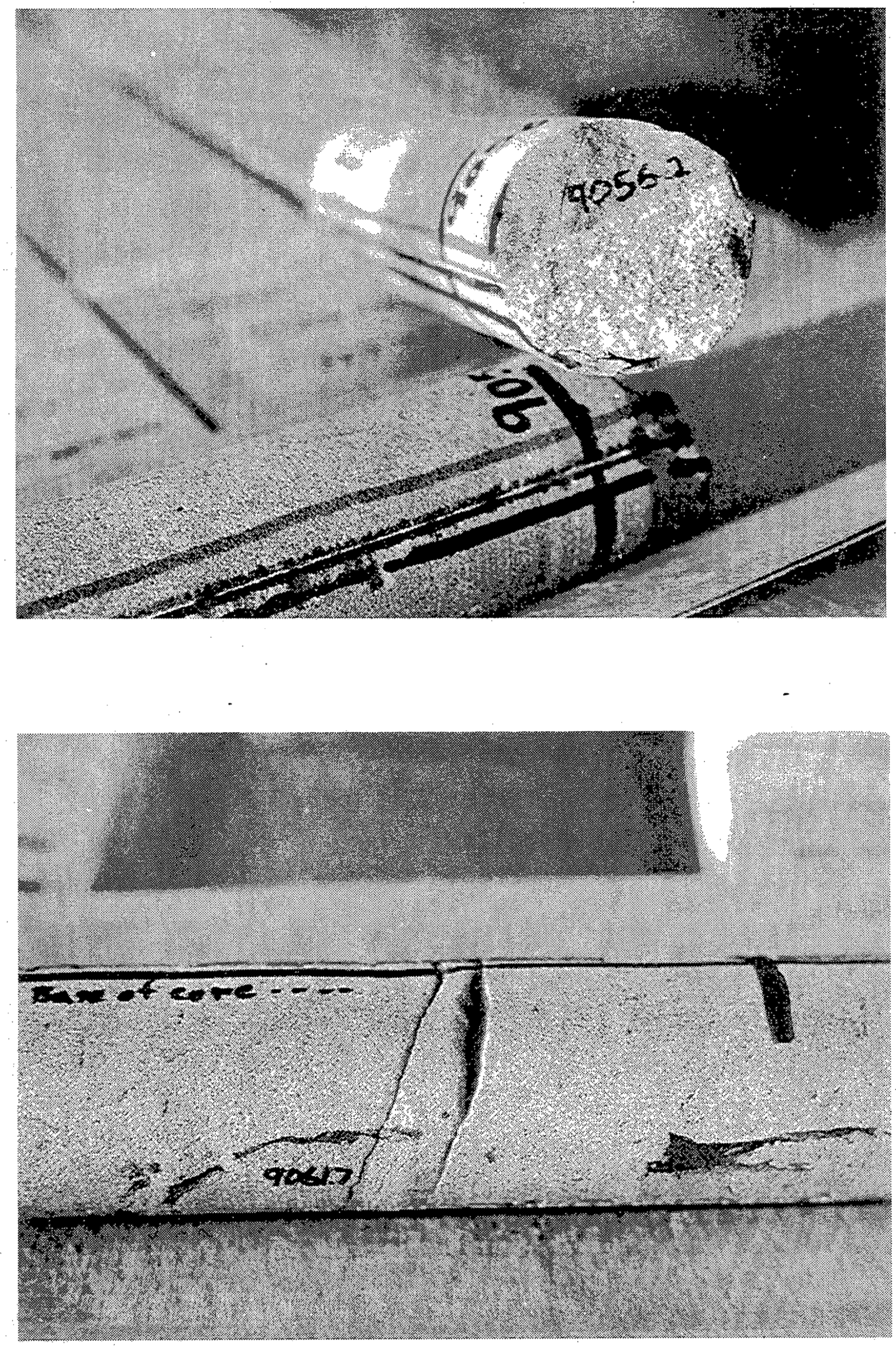


Figure 144. Natural fractures in horizontal core, from the Slant Hole Completion Test site well, Cozzette Sandstone, Piceance Basin.

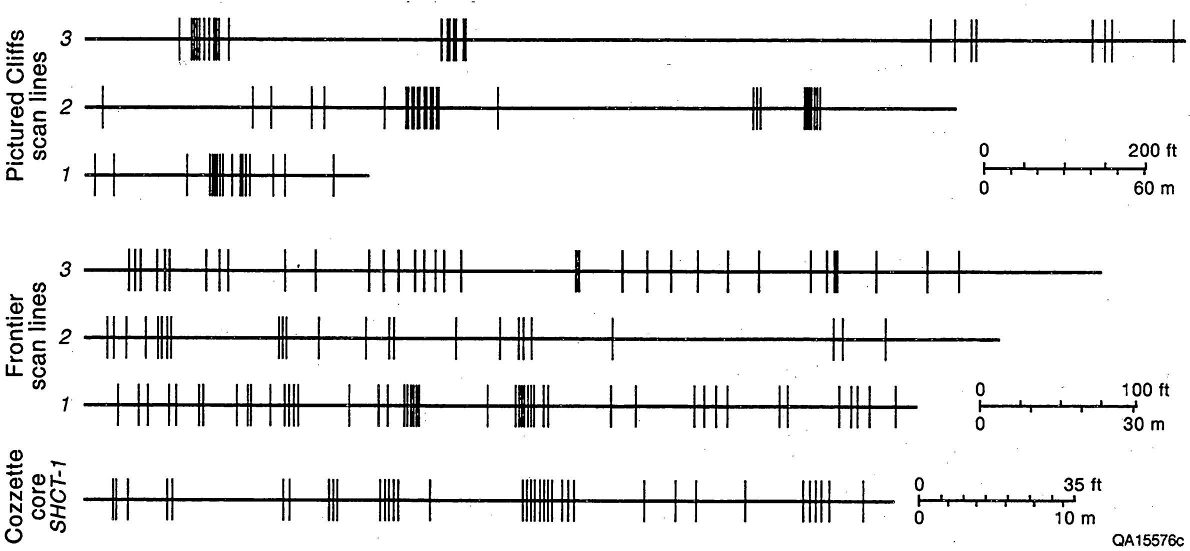


Figure 145. Fractures in outcrop traverses (scan lines) in Frontier Formation (Wyoming) and in Pictured Cliffs Sandstone (San Juan Basin, Colorado) and horizontal core from Cozzette Sandstone (Piceance Basin, Colorado). Scan lines show fractures that would be encountered in a horizontal borehole across the outcrop. From Laubach (1991).

horizontal SHCT well to be nearly an order of magnitude greater than the potential of nearby vertical wells.

Well test and core data from the MWX site and observations of fractures in nearby outcrops suggest that naturally occurring fractures in this area of the Piceance Basin have unidirectional west–northwest strike. Fractures in this area have been described by Pitman and Sprunt (1984, 1986) and Lorenz and Finley (1991) (Lorenz and others, 1991; Lorenz and Hill, 1991) and their effects on the reservoirs by Branagan (1987) and Lorenz (1987). Northrop and Frohne (1990) summarized results of the Multiwell Experiment and related geologic and engineering publications.

Although outcrop observations and well tests show that fracture systems at the MWX site are not well-interconnected vertically or laterally, they have a significant effect on well tests, reservoir stimulation, and gas production (Branagan, 1987; Lorenz and Finley, 1991). Data from the MWX wells indicate anisotropic fracture permeability throughout the Mesaverde, commonly with ratios 100:1 of Khmax to Khmin (Branagan, 1987).

Verbeek and Grout (1984) and Lorenz and Finley (1991) measured the orientation of fractures in surface exposures of the Mesaverde Group near Rulison field. Regional outcrop studies show that west–northwest fracture orientations are dominant in the northern part of the Piceance Basin (Verbeek and Grout, 1983). A younger north–northeast set that is common in outcrop may be confined to shallow depths and play little or no role in the subsurface (Pitman and Sprunt, 1986). Results of these studies and comparison of outcrop observations with horizontal core from the SHCT well show that outcrop observations of fractures provide useful insights into subsurface fracture patterns in this unit.

Engineering Assessment

Porosities in the Iles Formation, the most productive of Mesaverde sandstones, average 7 percent (Finley, 1984) (table 30). Porosity ranges from 4 to 17 percent for Corcoran sandstones

Table 30. Mesaverde Group, Piceance Basin: production data and engineering parameters.

Estimated resource base (Tcf): 65

No. tight completions: 253

Cumulative production from tight completions 1970–1988 (Bcf): 57

Estimated ultimate recovery from tight areas (Bcf): 141

Net pay thickness (ft): 16 to 70; typically <30

Porosity range and average (%): 2.6–22/7

Permeability (md): 0.0002–0.08

Water saturation (%): 30–60

Reservoir temperature (°F): Geothermal gradient is 2.6°–2.9°/100 ft

Reservoir pressure (psi): Pressure gradient is 0.42 psi/ft

Typical stimulation/hydro-frac: 70,000–130,000 lb sand

Production rate:

  prestimulation (Mcf/d): 55

  poststimulation (Mcf/d): 964

Average recovery per completion (Bcf): 0.563

Decline rate: 50% in 6–9 mo

and 2.6 to 18 percent for Cozzette sandstones. Porosity in Rollins sandstones ranges from 10.9 to 22 percent (Brown and others, 1986). Although higher than that of the Corcoran-Cozzette, most of the porosity in the Rollins sandstones is microporosity associated with mixed layer illite/smectite and kaolinite.

Short-term pressure transient analysis and production history match indicate permeabilities in the Corcoran range from 0.002 to 0.08 md and Cozzette reservoirs from 0.003 to 0.05 md (Brown and others, 1986) (table 30). Core permeabilities rarely are above 0.03 md (Finley, 1985). Rollins sandstones have low permeabilities as well, ranging from 0.0002 to 0.04 md (Baumgardner and others, 1988).

Core water saturations are as low as 30 percent in the clean productive sandstones (Finley, 1985). In shalier sandstones, water saturations increase and porosities decrease. Log calculated water saturations are in the 40 to 60 percent range (Finley, 1984). Net pay footages in the Corcoran sandstone range between 16 and 70 ft (NPC, 1980), but typically are less than 30 ft. Similarly, net pay footage in Cozzette sandstones is less than 30 ft. The reservoir temperature gradient is 2.6° to 2.9°F/100 ft. Reservoir pressure gradient was reported in selected wells to be 0.42 psi/ft (Finley, 1984).

As in many tight sandstones, the presence of numerous clay minerals (Baumgardner and others, 1988) make formation damage drilling and completion fluids a concern. Iles Formation sandstones require fracture stimulation. Finley (1985) reports that no direct correlation exists between the amount of proppant used and initial flow rates although thicker perforated intervals deliver higher flow rates. Overall, a typical fracture stimulation treatment will be between 70,000 and 130,000 lb sand, yielding initial production values ranging from 200 to 1,200 Mcf/d. Most of the wells drilled since 1983 have been in the southern Piceance Basin. Here a typical fracture stimulation treatment averages 141,000 gal fluid and 288,000 lb sand (Baumgardner and others, 1988). Postfracture stimulation rates will range from 3 to 6,475 Mcf/d with an average of 964 Mcf/d. Most Iles sandstones respond favorably to fracture treatments because of the high stress contrast between sandstones and shales.

Production History

Estimated resource base for the Mesaverde Group is 65 Tcf (Haas and others, 1988) (table 30). Resource base for the Corcoran-Cozzette is 21.4 Tcf. Total estimated recovery from existing wells is 141 Bcf. Average recovery per completion is 0.563 Bcf (Hugman and others, 1992). A typical well (Baumgardner and others, 1988) drilled in 1977 flowed 55 Mcf/d prior to fracture treatment. Initial production following treatment with 775,000 lb of sand was 800 Mcf/d. The well then declined and leveled off at 130 Mcf/d. After fracture stimulation, average initial production of 121 Rollins, Cozzette, and Corcoran wells was 964 Mcf/d (Finley, 1984). Many wells show a drop of one-half of initial production in 6 to 9 months.

GREEN RIVER BASIN

The Green River Basin is part of the Rocky Mountain foreland region, an extensive foreland basin that has been segmented by Laramide uplifts. Foreland basins are elongate asymmetric troughs that commonly occur on the cratonic side of thrust belts. The greater Green River Basin encompasses four intrabasin uplifts (the north-trending Moxa Arch and Rock Springs Uplift and the east-trending Wamsutter and Cherokee Arches) and four subbasins (Green River, Great Divide, Washakie, and Sand Wash) (fig. 146). The Cambrian- to Tertiary-aged sedimentary fill of the Green River Basin reaches a maximum thickness of 32,000 ft (Tyler and others, 1991). From Middle Cambrian through Middle Jurassic time, southwest Wyoming was part of the Rocky Mountain shelf that bordered a marine basin to the west (Peterson, 1977). Intermittent carbonate sedimentation dominated this ancestral Green River Basin until the Triassic, when clastic influx from the east interrupted shelf sedimentation (Ryder, 1988). The foreland-basin stage of sedimentation began in the Late Jurassic with initiation of thrusting along the west margin of the basin. Upper Jurassic through Upper Cretaceous intertonguing marine and nonmarine clastic sediments were derived from uplifts in the Thrust Belt. Beginning

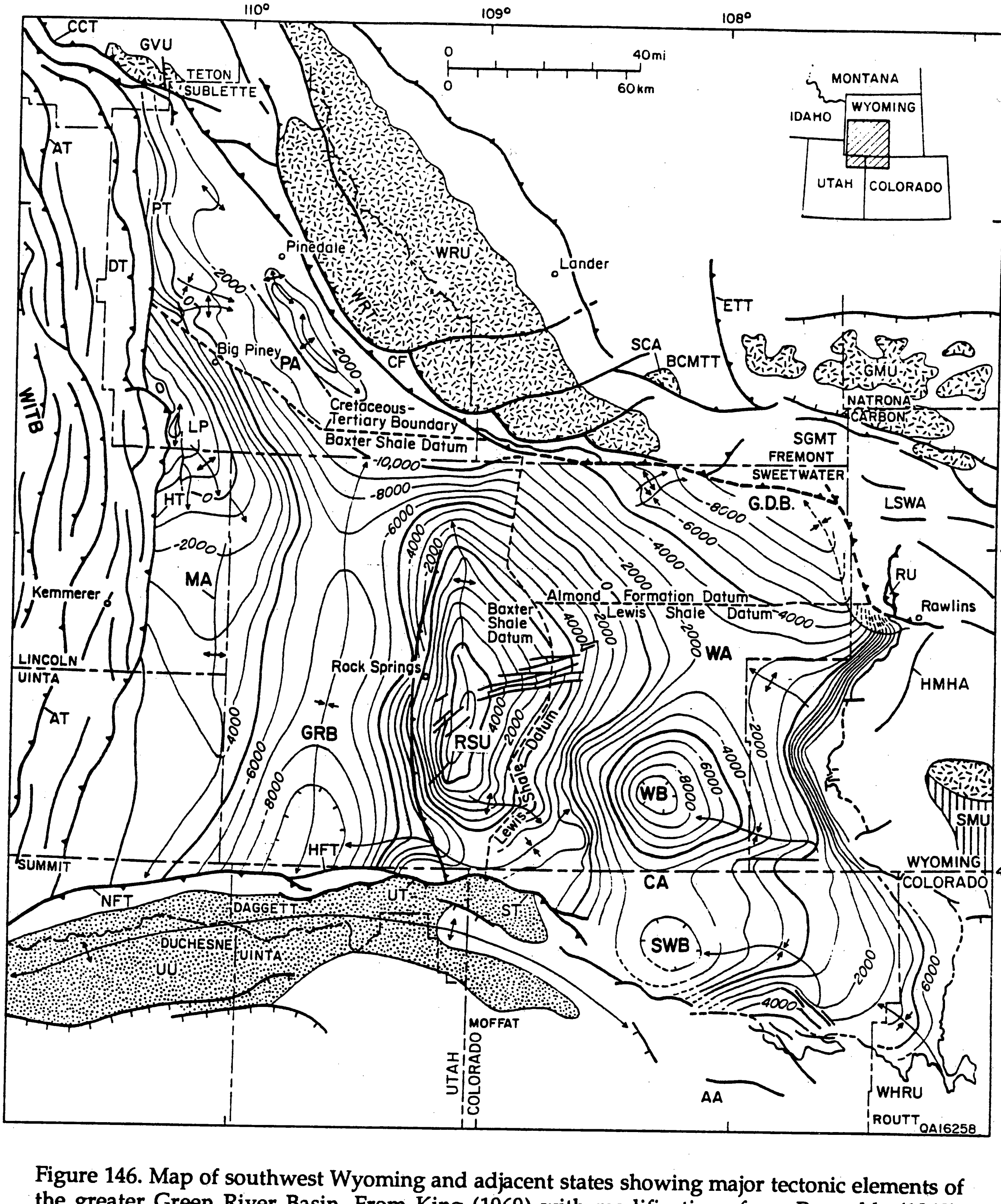


Figure 146. Map of southwest Wyoming and adjacent states showing major tectonic elements of the greater Green River Basin. From King (1969) with modifications from Reynolds (1968), Blackstone (1979), Love and Christiansen (1985), and Lickus and Law (1988). Structure contours on various surfaces in feet relative to mean sea level. Selected tectonic features are identified as follows: CA, Cherokee Arch; GDB, Great Divide Basin; GMU, Granite Mountain Uplift; GRB, Green River Basin (western subbasin); GVU, Gros Ventre Uplift; HT, Hogsback thrust fault; MA, Moxa Arch; LP, La Barge Platform; RSU, Rock Springs Uplift; SMU, Sierra Madre Uplift; SWB, Sand Wash Basin; UU, Uinta Uplift; WA, Wamsutter Arch; WB, Washakie Basin; WITB, Wyoming–Idaho Thrust Belt; and WRU, Wind River Uplift.

in the Late Cretaceous, Laramide uplift of peripheral and intrabasinal structures provided varied sources and volumes of sediment to subsiding areas in the basin.

The Green River Basin is currently in the Cordilleran extensional stress province. It is also southeast of an area of recent tectonic and volcanic activity centered on the Yellowstone area (fig. 147). The Yellowstone hot spot may be responsible for some of the anomalous stress measurements recorded in tight gas reservoirs in this basin.

Most of the low-permeability gas-bearing sandstones in the Green River Basin occur within Cretaceous and Paleocene formations (fig. 148), where they are parts of eastward-prograding regressive/transgressive cycles composed of interbedded fluvial, shoreline, and marine-shelf facies (Miller and VerPloeg, 1980; Law and others, 1989). Marine shoreline sandstones in the Bear River Formation (including the Muddy Sandstone) are formally designated tight locally at the north end of the Moxa Arch (fig. 146). The overlying Frontier Formation records the first major Upper Cretaceous regressive event and is designated tight along the Moxa Arch and the Rock Springs Uplift and locally in the Washakie Basin (fig. 146). A second major regressive event is represented by the Mesaverde Formation (fig. 148), which includes tight-gas sandstones throughout most of the greater Green River Basin east of the Rock Springs Uplift (Finley, 1984). Most tight-gas production in the Green River Basin (1,486 Bcf basin total) has come from the Frontier (810 Bcf) and the Mesaverde (528 Bcf) (Hugman and others, 1992) (table 2). The Lewis Shale, Fox Hills Sandstone, and Fort Union Formation have yielded only small amounts of gas from areas in which the formations are designated tight, although gas-in-place estimates are large for deep overpressured reservoirs in these intervals (Law and others, 1989).

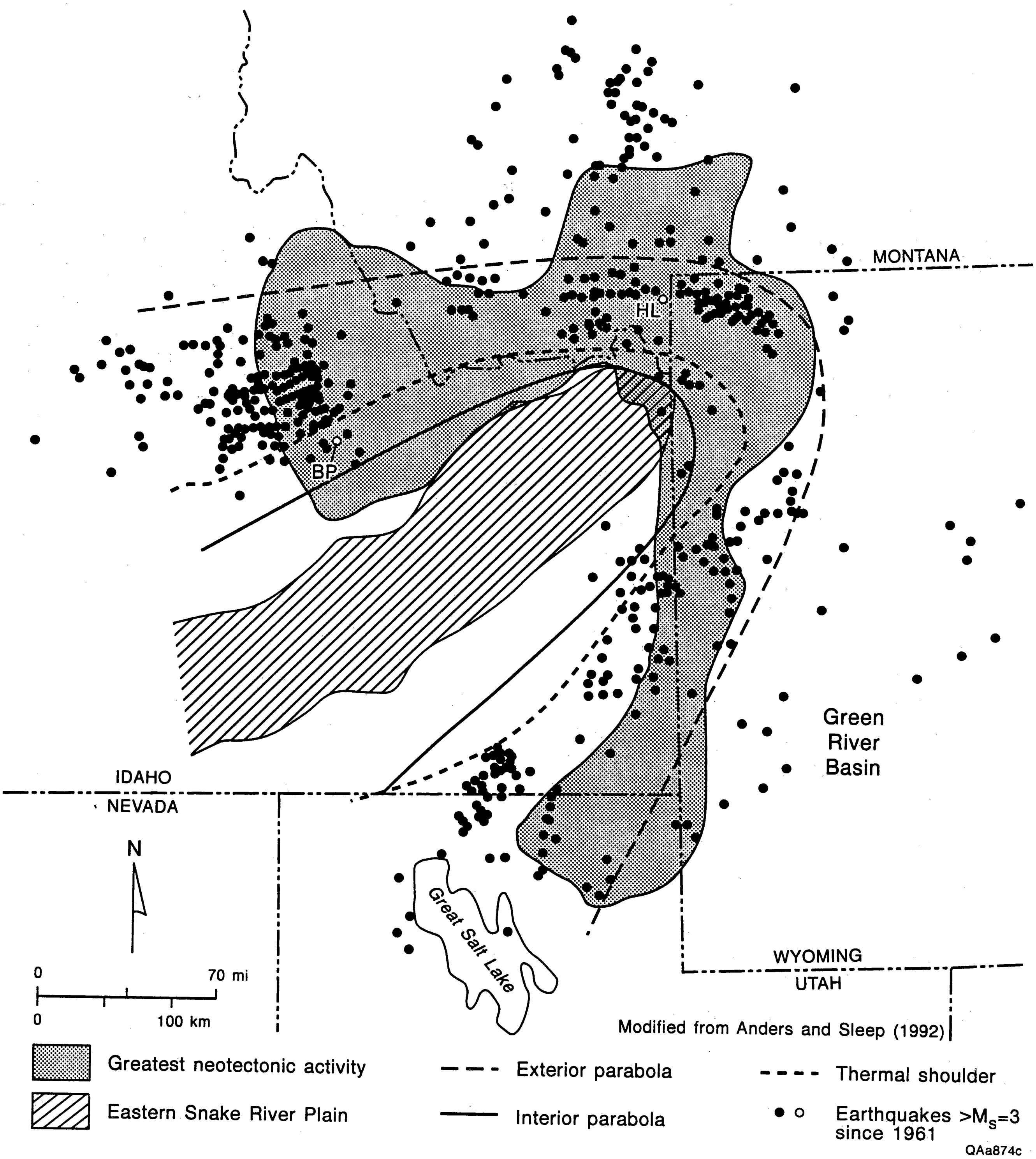


Figure 147. Neotectonic activity in the vicinity of the Greater Green River and Wind River basins due to magmatism associated with the Yellowstone hotspot (modified from Anders and Sleep, 1992). Map shows the distribution of earthquakes greater than $M_S = 3$ (small dots) since 1961. HL = 1959 Hebgen Lake $M_S = 7.5$ earthquake; BP = 1983 Borah Peak $M_S = 7.3$ earthquake. Tectonic activity has been postulated as a cause of anomalous reservoir stresses in the Frontier Formation in the Green River Basin (CER Corporation, 1992b).

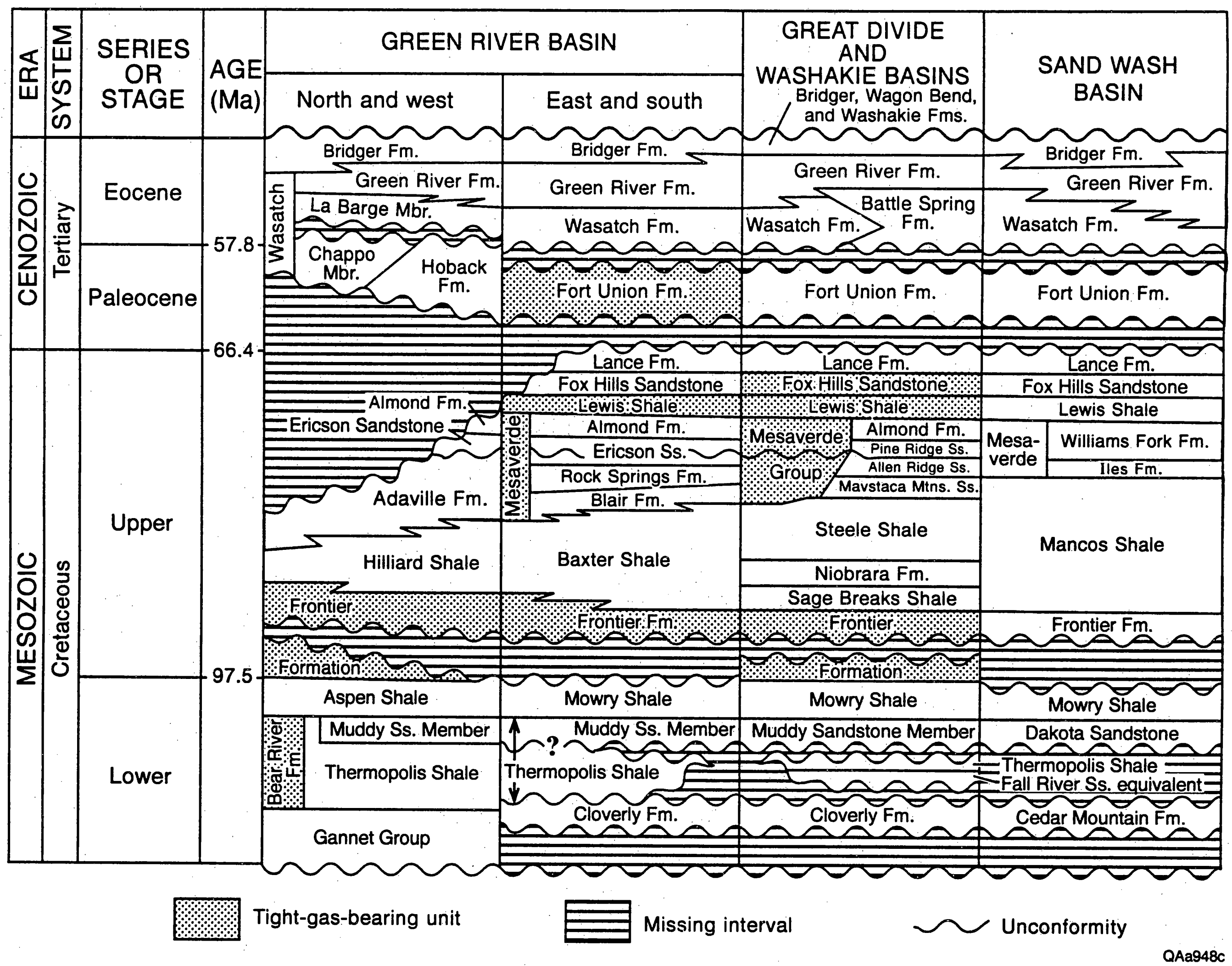


Figure 148. Cretaceous and lower Tertiary stratigraphy of the greater Green River Basin. Modified from Ryder (1988).

Frontier Formation

Introduction

Tight-gas sandstones in the Upper Cretaceous (Cenomanian–Turonian) Frontier Formation (fig. 148) are found mainly on the Moxa Arch and the Rock Springs Uplift. Almost all Frontier gas fields along the Moxa Arch are designated tight except for those on the west side of the La Barge Platform (fig. 149), where high initial potentials (>5 MMcf/d) in many wells apparently reflect anomalously high (for Frontier sandstone) permeabilities (Dutton and others, 1992). Depth to the Frontier increases from north to south along the Moxa Arch, ranging from about 6,000 to 15,000 ft. The Frontier is designated tight in a large area at the north end of the Rock Springs Uplift, but this area lies mainly north and east of existing Frontier production. Depth to the Frontier increases from about 4,000 to more than 20,000 ft in the Rock Springs Uplift tight-gas area because of steep northward and eastward dips (fig. 146). The Frontier is also designated tight in several small areas in the Washakie Basin southeast of the Rock Springs Uplift; depth to the Frontier in these areas ranges from about 5,000 to 9,000 ft.

From the La Barge Platform in the northwest part of the Green River Basin, the Frontier thins southward and eastward, owing to a combination of erosional truncation and stratigraphic pinchout (Dutton and others, 1992). On the La Barge Platform, the gross sandstone-bearing Frontier interval is about 1,000 to 1,200 ft thick (fig. 150). The First Frontier sandstone and sandstones in the Third Frontier and Fourth Frontier are present only in the La Barge area at the north end of the Moxa Arch (fig. 151). Although terminology varies, the Second Frontier interval contains all Frontier sandstones throughout the rest of the basin. The Second Frontier gross sandstone-bearing interval thins southward along the Moxa Arch from about 600 to 100 ft but thins only slightly eastward to the Rock Springs Uplift. The Second Frontier, as defined on the Moxa Arch, is divided into "First Frontier, Second Frontier, and

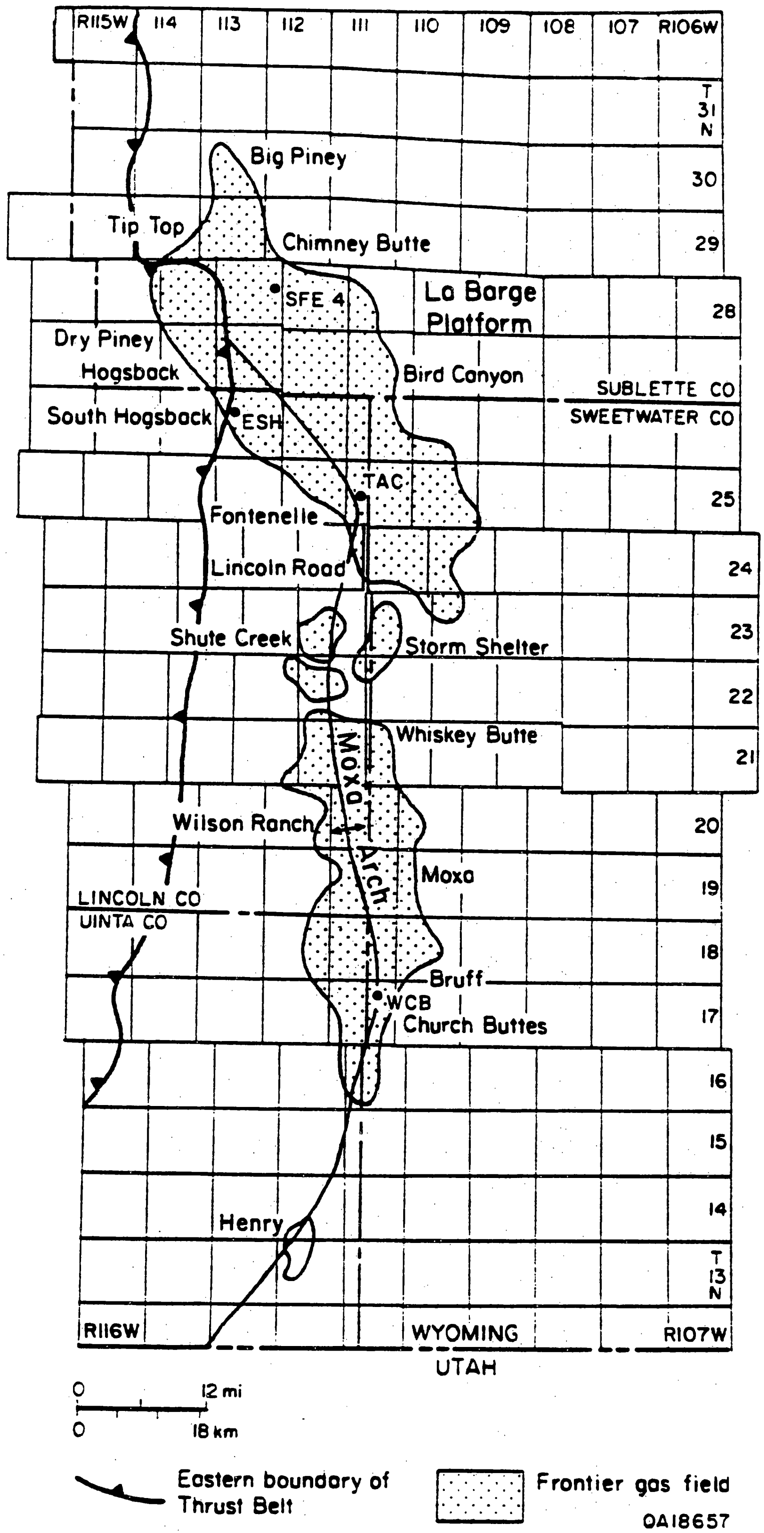


Figure 149. Map of major Frontier fields associated with the Moxa Arch, western Green River Basin. Modified from Gregory and De Bruin (1991). Names of selected Frontier gas fields are shown. Locations of GRI cooperative wells and staged field experiment well (SFE 4) are also shown (Dutton and others, 1992).

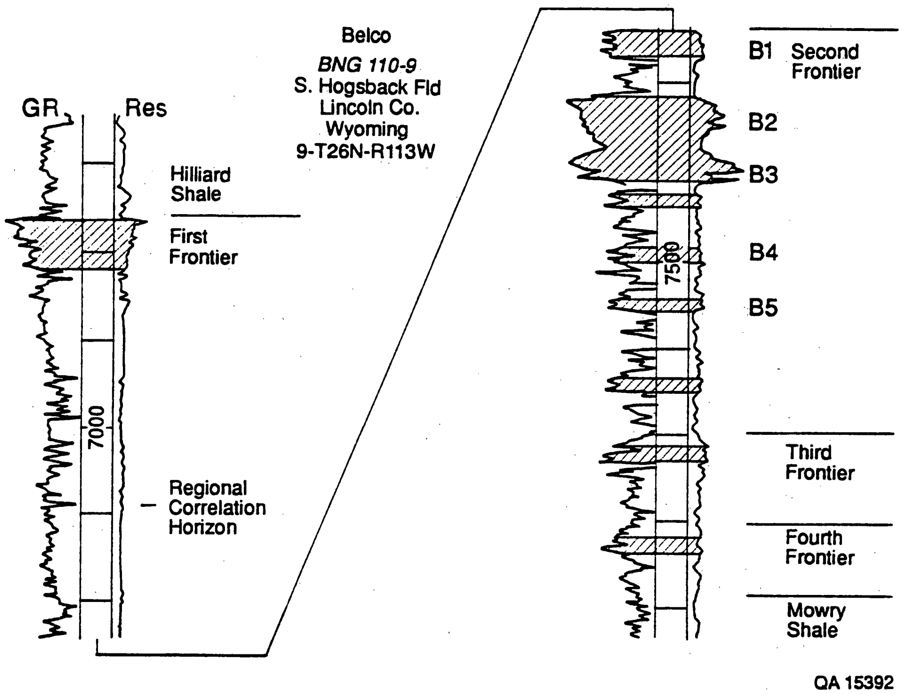


Figure 150. Typical gamma-ray/resistivity log, Frontier Formation, north Moxa Arch. From Dutton and Hamlin (1991). Frontier sandstones are shaded. In this area (La Barge Platform) the Second Frontier is divided into "benches" (B1 through B5).

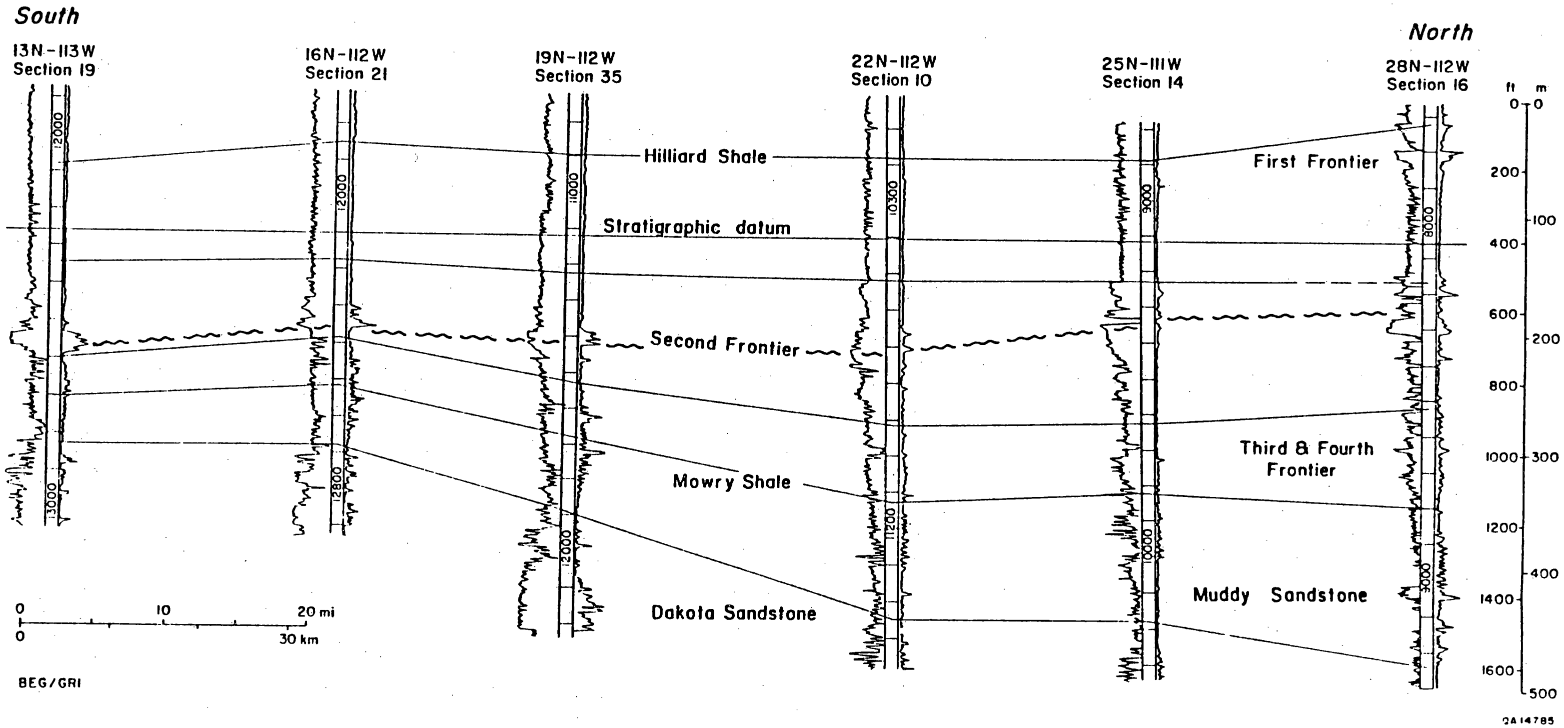


Figure 151. Regional north-south, gamma-ray/resistivity cross section along the Moxa Arch. Modified from Dutton and Hamlin (1991). Straight lines shown are continuous correlation horizons; formation boundaries, which are laterally gradational, are not shown. The First Frontier pinches out southward into Hilliard Shale, and the Third and Fourth Frontier grade southward into Mowry Shale. An erosional unconformity (dashed wavy line) within the Second Frontier separates fluvial channel-fill sandstone from underlying marine shoreface sandstone.

Third Frontier" intervals on the Rock Springs Uplift (Wyoming Oil and Gas Conservation Commission, 1981c).

The Frontier Formation along the Moxa Arch was studied as part of the GRI Tight Gas Sands project. As a part of this program, three Frontier cooperative wells and the GRI Staged Field Experiment No. 4-24 well (SFE No. 4) were drilled (fig. 149). In these wells cores from Frontier sandstones and bounding shales were recovered, extensive open-hole data acquisition programs were conducted, and well tests and fracture treatments were performed. Data from these investigations are publicly available through the GRI Tight Gas Sands program (specific references are listed in CER Corporation, 1992). GRI-supported geologic studies of the Frontier Formation along the Moxa Arch included (1) stratigraphy and depositional systems and facies analysis, (2) diagenetic history of the formation and mineralogic composition of the reservoirs, and (3) structural history and current structural setting of the basin and its contained reservoirs (Dutton and others, 1992). Specific references to the many other published studies of the Frontier in the Green River Basin can be found in this report or in Dutton and others (1992).

Depositional Systems and Reservoir Facies

In the Green River Basin, the Frontier Formation comprises marine and nonmarine sandstone and shale facies, which record early Late Cretaceous foreland-basin sedimentation. Frontier shorelines, composed of wave-dominated deltaic headlands and delta-flank strandplains, prograded eastward into the western interior Cretaceous seaway (Myers, 1977; Merewether and others, 1984; Winn and others, 1984; Moslow and Tillman, 1986; Hamlin, 1991; Dutton and others, 1992). The formation thickens and becomes increasingly more dominated by nonmarine facies westward into the Thrust Belt, whereas it thins and becomes increasingly more marine to the east. On the Moxa Arch and the Rock Springs Uplift, both nonmarine (fluvial or distributary) channel-fill sandstone and marine shoreline sandstone form important low-permeability reservoirs. Within the Frontier Formation, reservoir sandstones are interbedded with coastal-plain and nearshore-marine shales and sandy shales. The Frontier interval is enclosed in thick, regionally extensive marine shales: the Mowry (Aspen) Shale below and the Hilliard (Baxter) Shale above (figs. 148 and 151).

The Second Frontier (fig. 150) contains the most prolific tight-gas reservoirs in the Green River Basin. Second Frontier reservoirs lie in fluvial channel-fill and marine shoreface sandstones. The fluvial channel-fill sandstones form southeast-trending belts, which are a few miles wide and several tens of feet thick. Channel-fill sandstones are enclosed in interchannel facies consisting largely of shale but also including thin sandstones, bentonites, and coals. The marine shoreface sandstones have laterally continuous, blanket geometries and are 30 to 120 ft thick. Marine shoreface facies, which contain the most important reservoirs at the north end of the Moxa Arch and the Rock Springs Uplift, typically form upwardly coarsening and cleaning, progradational parasequences in a sea-level highstand systems tract. Fluvial channel-fill sandstones are important reservoirs along the central and south parts of the Moxa Arch, where they overlie truncated shoreface facies below a lowstand erosional unconformity (fig. 151) (Hamlin, 1992a, b).

The most porous and permeable Frontier pay zones typically have low detrital clay contents (clean sandstone). Within the fluvial channel belts, clean sandstone occurs as discontinuous lenses, generally less than 20 ft thick, which are interlayered and laterally gradational with mud-clast-rich sandstone. Ductile mud rip-up clasts deform into pores and pore throats during sandstone compaction. Within the shoreface parasequences, clean sandstone is typically best developed in upper shoreface and foreshore facies; the lower shoreface facies is composed of bioturbated shaly sandstone (fig. 152). Upper shoreface clean sandstone consistently occurs near the tops of progradational shoreface parasequences and therefore forms a predictable target (figs. 152 and 153). On the La Barge Platform, upper shoreface clean sandstone in the Second Frontier not only thins to the southeast, away from source areas to the west, but it also displays a distinct northeast-trending grain (fig. 154), which probably

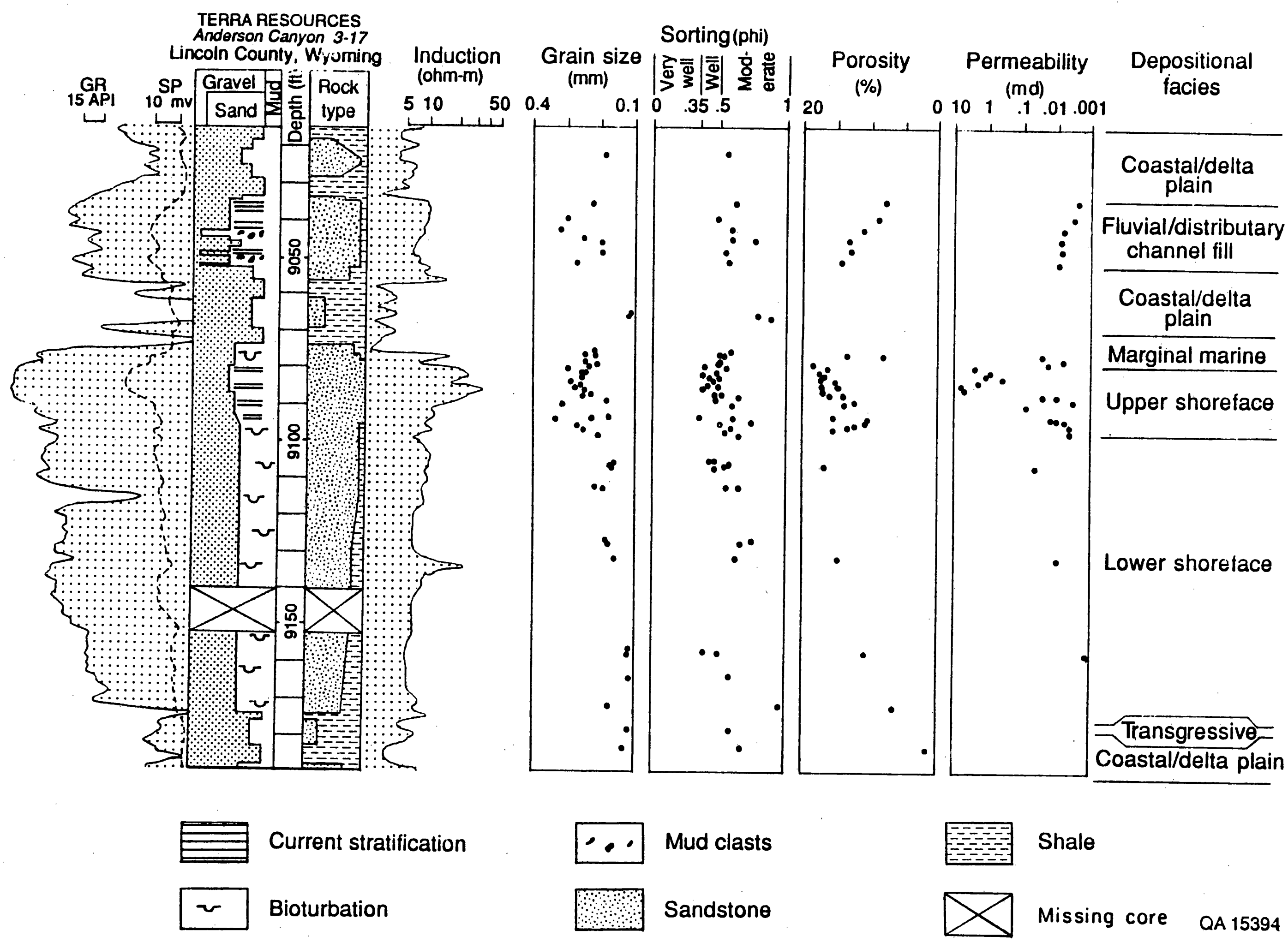


Figure 152. Log responses and rock properties in Second Frontier core. From Dutton and Hamlin (1991). Porosity and stressed permeability data from core are shown. Although the Frontier on average is tight, thin permeable zones are commonly found within the upper shoreface facies (as seen here) or, more locally, within the fluvial channel-fill facies.

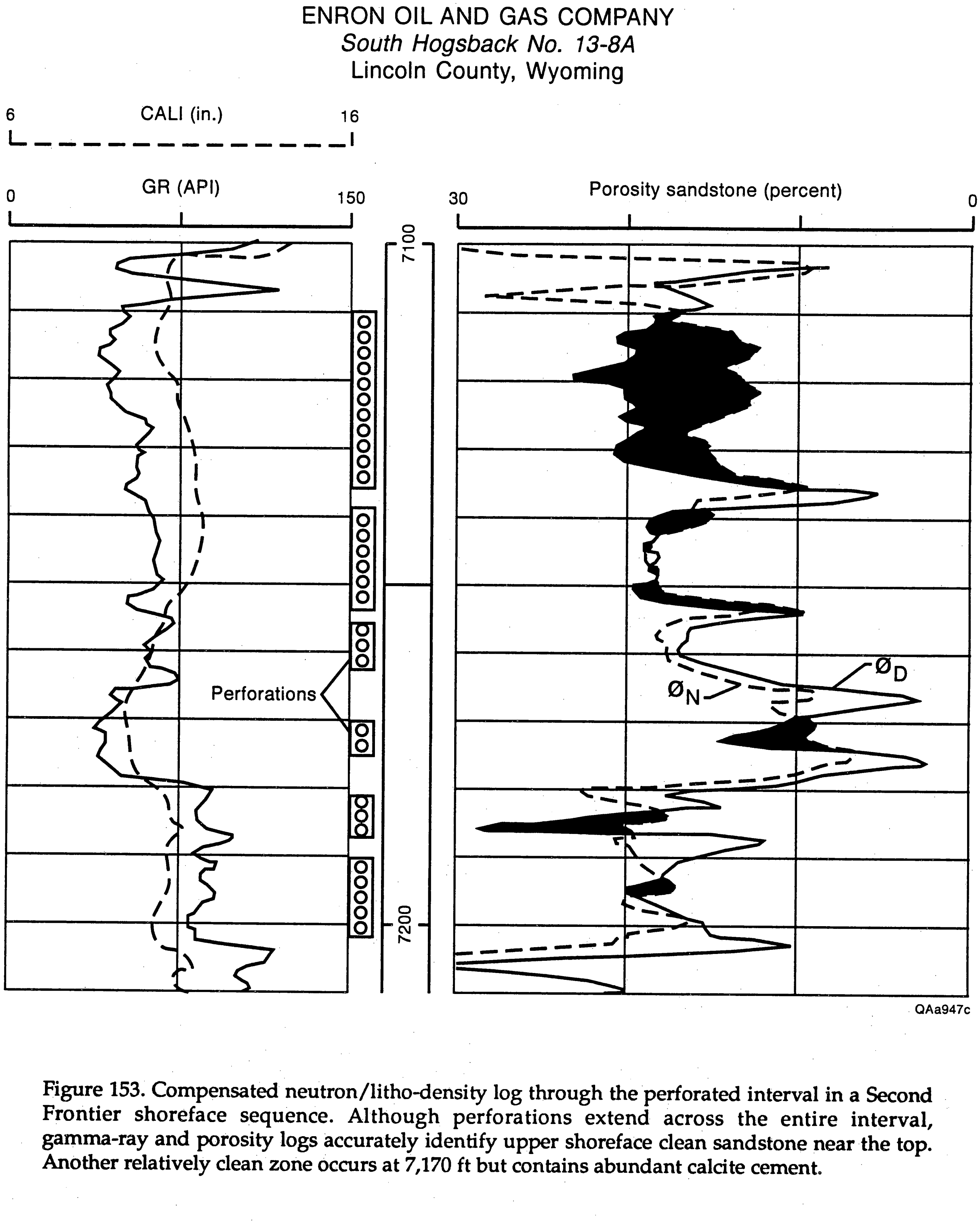


Figure 153. Compensated neutron/litho-density log through the perforated interval in a Second Frontier shoreface sequence. Although perforations extend across the entire interval, gamma-ray and porosity logs accurately identify upper shoreface clean sandstone near the top. Another relatively clean zone occurs at 7,170 ft but contains abundant calcite cement.

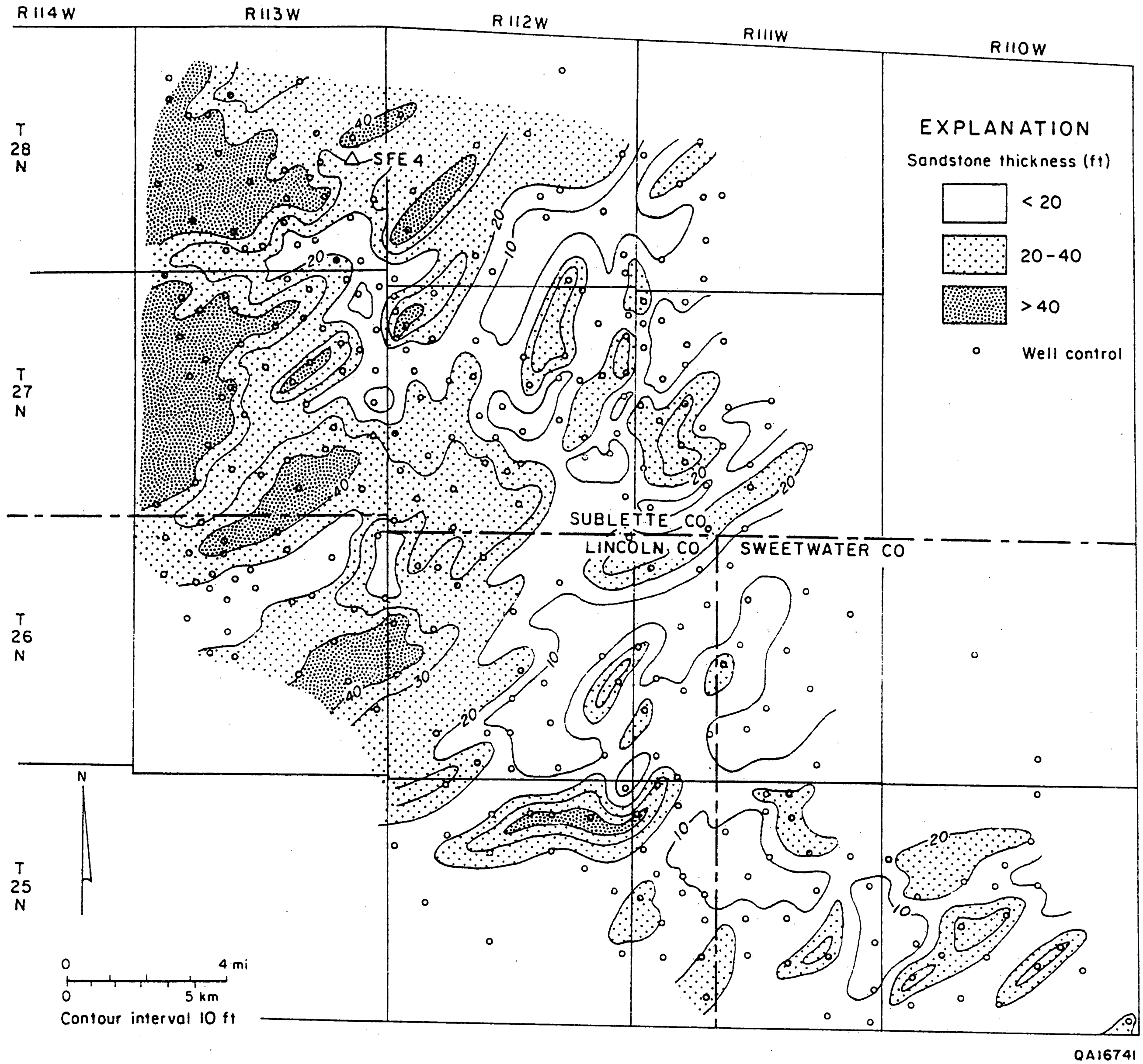


Figure 154. Net clean sandstone map of the Second Bench of the Second Frontier (B2 on fig. 150). From Dutton and others (1992). This map essentially displays variable development of high-energy, upper shoreface facies within a marine shoreline blanket-type sandstone.

delineates successive positions of the shoreline as it prograded seaward (Hamlin, 1991; Dutton and others, 1992).

Composition of Reservoir Facies

Frontier reservoirs are typically composed of very fine to medium grained sandstone, although coarse-grained, conglomeratic sandstone is present locally in the fluvial channel-fill facies. Detrital clay matrix is abundant in many Frontier sandstones, but most pay zones lie in clean sandstones containing <2 percent detrital clay matrix. On the Moxa Arch and the Rock Springs Uplift, clean Frontier sandstones are mostly well sorted to moderately well sorted, litharenites and sublitharenites (Winn and Smithwick, 1980; Wyoming Oil and Gas Conservation Commission, 1981c; Stonecipher and others, 1984; Winn and others, 1984; Dutton, 1991; Dutton and Hamlin, 1991). Average framework grain composition for 239 Frontier sandstone core samples from the Moxa Arch is 64 percent quartz, 6 percent feldspar, and 30 percent rock fragments (Dutton and others, 1992). Sedimentary rock fragments, particularly chert, are the most common lithic grains, and most of the feldspar is plagioclase.

Framework grain composition of Frontier sandstones varies with depositional environment, stratigraphic position, and geographic location (Winn and Smithwick, 1980; Stonecipher and others, 1984; Winn and others, 1984; Dutton and others, 1992). Fluvial channel-fill sandstones generally have less quartz and more rock fragments than do marine shoreface sandstones. In fluvial channel-fill sandstones in the lower part of the Second Frontier, volcanic rock fragments, plagioclase, biotite, and bentonite clasts are locally abundant. Frontier sandstones at the south end of the Moxa Arch are typically more quartz rich than are those at the north end. These compositional differences lead to variable diagenetic modification and reservoir quality.

Quartz, calcite, and mixed-layer illite-smectite (MLIS) and illite are the most abundant authigenic minerals, which constitute between 0 and 38 percent of rock volume (Dutton and others, 1992). Major diagenetic events in Frontier sandstones on the Moxa Arch were (1) mechanical compaction, (2) formation of illite and MLIS rims, (3) precipitation of quartz overgrowths, (4) precipitation of calcite cement, (5) generation of secondary porosity by dissolution of calcite cement and detrital feldspar, chert, and mudstone, (6) precipitation of kaolinite in secondary pores, and (7) chemical compaction by intergranular pressure solution and stylolitization and additional precipitation of quartz cement (Dutton, 1990; Dutton and others, 1992). The major causes of porosity loss during burial diagenesis were mechanical and chemical compaction and cementation by calcite, quartz, and clays. Most secondary porosity apparently formed by silicate dissolution (Dutton, 1992).

Authigenic clays reduce permeability in most clean Frontier sandstones (Winn and Smithwick, 1980; Stonecipher and others, 1984; Schultz and Lafollette, 1989), although the illite and illite-dominated MLIS cements in Frontier sandstones have relatively low expansibilities (Luffel and others, 1991). The fibrous morphology of these clay cements appears to have a more important effect on permeability than does sensitivity to fresh water. Fibers and sheets of illite and MLIS bridge pores and pore throats significantly lowering permeability (Luffel and others, 1991).

Quartz and calcite are the most common cements in Frontier sandstones. A strong correlation exists between volume of quartz cement and depth and thermal maturity of sandstone along the Moxa Arch (Dutton and Hamlin, 1992), but quartz cement alone does not control reservoir quality. Calcite cement is locally abundant, especially in marine shoreface sandstone, but its distribution is unpredictable prior to drilling.

Despite extensive diagenetic modification, reservoir quality is best in clean Frontier sandstones that were deposited in high-energy, upper shoreface and fluvial channel environments. In selected clean fluvial channel-fill sandstones from the Moxa Arch, thin section porosity averages 3.2 percent (2.4 percent secondary porosity), and mean stressed permeability equals 0.01 md. Selected clean upper shoreface sandstones average 7.8 percent thin section porosity (5.6 percent secondary porosity) and 0.05 md stressed permeability (Dutton and others, 1992). However, because of depositional and diagenetic variability, zones of higher porosity and permeability can be found within the fluvial and upper shoreface facies (fig. 152).

Natural Fractures

Based on observations of fractures in core collected from GRI research and cooperative wells and local occurrences of anomalously high production, fractures are suspected to play a role in gas production from some Frontier Formation wells (Laubach, 1991). Despite the low probability of vertical fractures intersecting with vertical core, 92 fractures were encountered in 10 Frontier wells having more than 1,580 ft of core (Laubach, 1991). Because of the undersampling bias inherent in using vertical wellbores to intersect vertical fractures, quantitative estimates of fracture abundance in the Frontier are not available. The depth and height of fractures in five Frontier cores is shown in figure 155. The deepest fractures are from 16,130 ft in the Energy Reserves Group Blue Rim Federal No. 1-30 well in Sweetwater County, Wyoming. Closely spaced fractures in this well are illustrated by Dutton and others (1992, their figure 53). Fractures have also been described in Frontier core from east of the Rock Springs Uplift, in the Table Rock field, Sweetwater County, Wyoming (Dickenson, 1992).

Fractures in Frontier core are mainly subvertical extension fractures. They are filled with variable amounts of calcite and quartz, and fracture porosity is locally preserved. Most mineralized extension fractures are <0.25 mm wide. Fractures generally end within sandstones and they are commonly composed of vertically discontinuous strands, suggesting that some fractures may not form continuous networks of interconnected fractures from the top to the base of a sandstone.

Fractures in oriented cores and visible on fracture-imaging logs strike east-northeast and northeast, north, and north–northwest, but the number of fractures sampled is so small and the wells are so widely distributed in the basin that generalizations on typical fracture orientations are not warranted (Dutton and others, 1992). Tensile strength anisotropy of

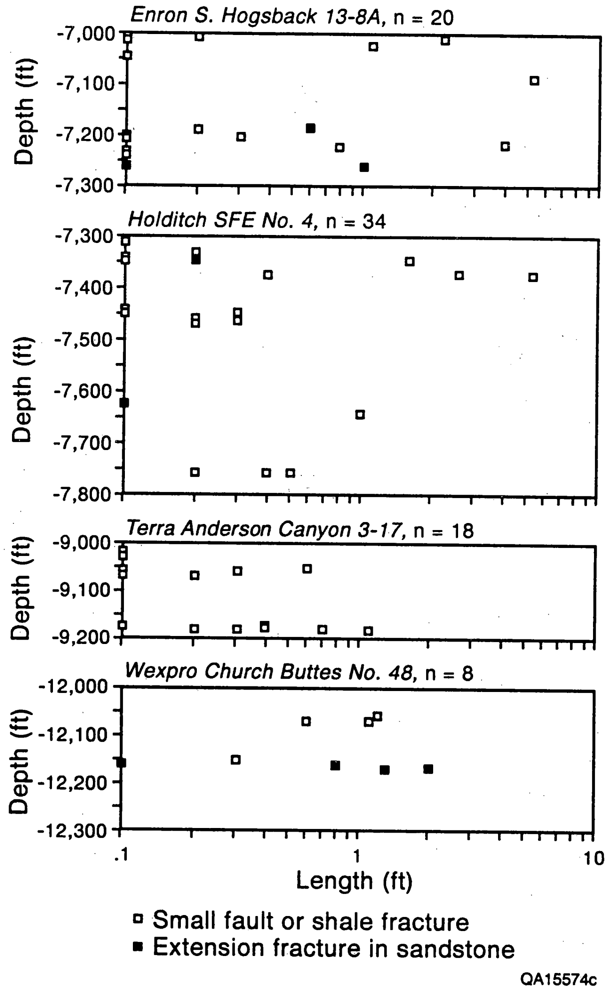


Figure 155. Fractures in core from five Frontier Formation wells in the Green River Basin (Laubach, 1992b).

sandstone cores from the northeastern La Barge Platform area that trend north and east have been interpreted to represent natural microfracture orientations (Laubach and others, 1992a; Clift and others, 1992). In the Holditch SFE No. 4 well, the trend of tensile strength anisotropy shifts from northward to eastward in adjacent sandstone beds (fig. 156). These tests may indicate the orientations of large fractures. In outcrops of Frontier Formation sandstones a similar pattern of shifting dominant fracture strike occurs (Laubach and Lorenz, 1992).

Frontier Formation fractures are exposed along the southern, western, and eastern margins of the Green River Basin (Laubach, 1992b). Fractures in outcrops of the Frontier Formation have been described from above the South Casper Creek field, Wyoming, where contrasting dominant fracture directions occur on the flanks and in the hinge of the fold (Hickman, 1989). Dominant fractures strike N20°W but a mineralized set of fractures strikes N65°E in the southwest flank of the fold; elsewhere, N65°E fractures are dominant (Hickman, 1989; Montgomery, 1991).

Along the western margin of the basin, Frontier Formation fractures in outcrop have been interpreted to be representative of those that exist at depth in the Green River Basin (Laubach, 1992b). Most fractures in these exposures are joints or veins oriented normal to bedding. Two prominent fracture sets are evident: north-striking fractures, which formed first, and east-striking fractures, which abutting and crossing relations between fractures show formed later. In many beds, only north-striking fractures are present (fig. 157), whereas in other beds, only east-striking fractures occur (figs. 145 and 158). Consequently adjacent beds may contain only one or the other fracture set.

Stretching during basin subsidence accounts for north-striking fractures, which parallel the depositional axis of the Cretaceous foredeep. As the basin subsided, strata were stretched east-west due to lengthening parallel to bedding as the original nearly flat depositional surface adjusted to conform to the asymmetric basin profile. Frontier Formation outcrops are along the leading eastern edge of the thrust belt. East-striking fractures formed after north-striking fractures when compression related to mountain building was dominant in the foreland,

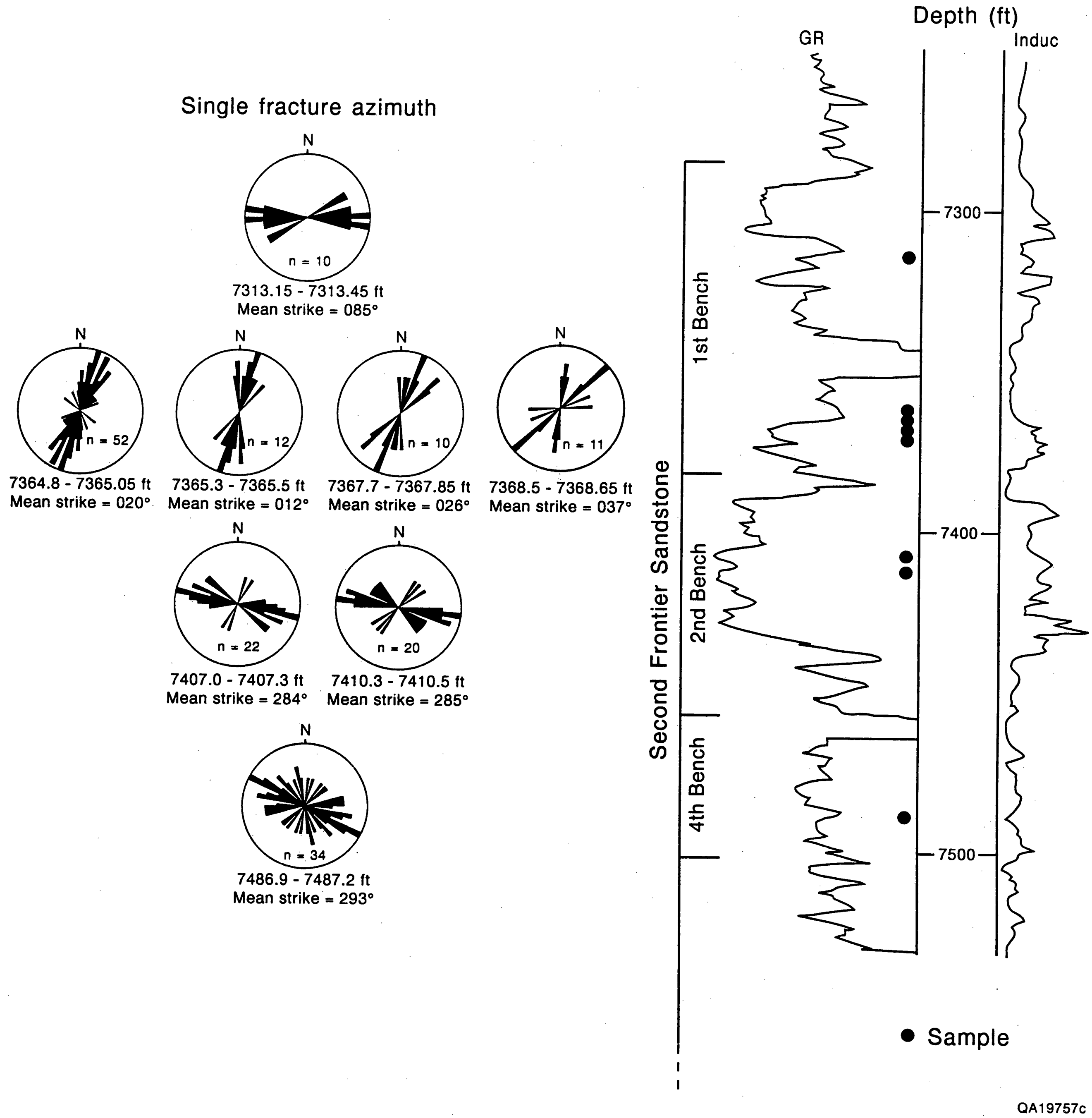


Figure 156. Rose diagrams showing strength anisotropy in Frontier Formation sandstones of Holditch SFE No. 4 well. Location of samples is indicated with dot on well profile. Tensile strength anisotropy in these rocks corresponds to natural microfracture orientations. From Laubach (1992b).

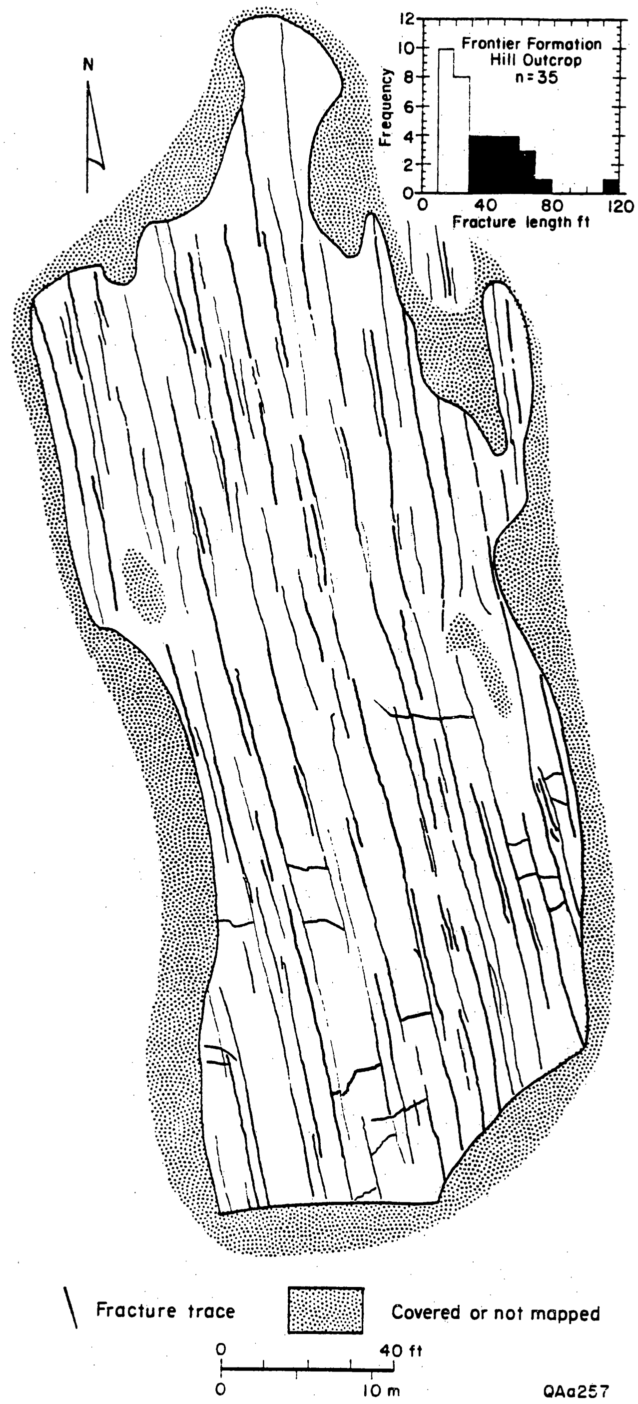


Figure 157. Outcrop example of Frontier Formation fractures formed during basin subsidence, illustrating evenly distributed, poorly interconnected fractures with uniform strike (from Laubach, 1992a). Inset shows histogram of length distribution (from Laubach, 1992).

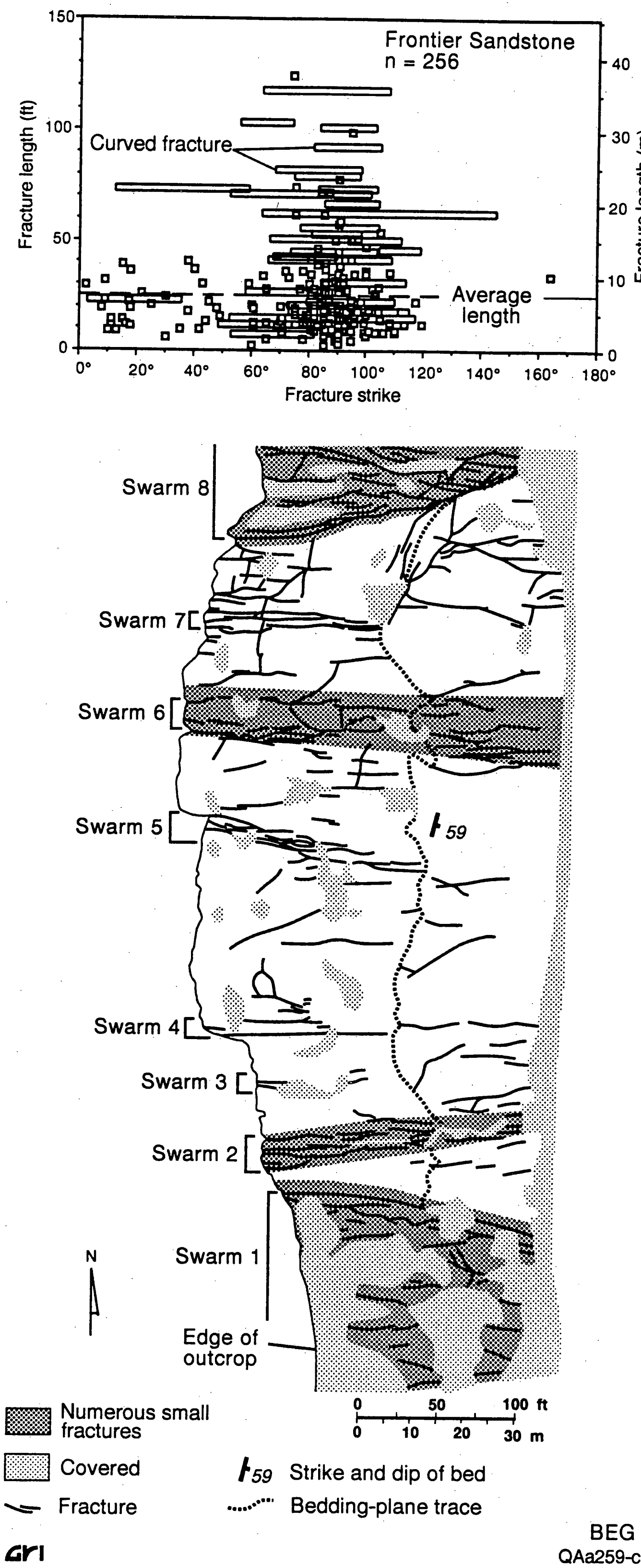


Figure 158. Outcrop example of Frontier Formation fractures formed during thrusting, illustrating fracture swarms. Inset shows range of fracture strikes and lengths (from Laubach, 1992a; fig. 1).

but before local folding and faulting. The convex salient in the foreland basin at this latitude may have accentuated the tendency to form fractures with generally eastward strikes.

Fracture traces on bedding planes end laterally by intersecting other fractures or by gradually diminishing in width. Fractures end vertically within sandstone beds or at bed boundaries. Because they rarely cross shales between sandstone beds, fracture heights are similar to or less than bed thicknesses, ranging from less than an inch to several feet. Fracture lengths, however, can be much greater than fracture heights, with length-to-height ratios greater than 10:1. A spectrum of fracture sizes is present, including microfractures normally visible only under the microscope and fractures thousands of feet long.

Attributes of the two fracture sets differ. Fractures formed during slow burial are uniformly spaced and have a narrow range of trace lengths in beds of a given thickness and composition. Spacing is generally closer in thin beds and in beds having extensive early cement. In contrast, the fracture set that formed during regional thrusting has fractures that are clustered into swarms containing fractures ranging widely in length. Swarms of closely spaced fractures are lenticular zones having widths that range from inches to more than 300 ft. Across the margin of a swarm, fracture spacing may change abruptly. Some swarms are separated by rocks having no fractures and others by areas of less closely spaced or less interconnected fractures; swarms are not obviously periodic (fig. 158).

Natural fracture permeability is one of the factors that can account for local high gas and/or water production and abrupt differences in Frontier Formation well performance, as well as other phenomena observed during hydraulic fracture treatments. For example, in one Frontier Formation well, the Enron S. Hogsback No. 13-8A, an approximately twentyfold increase in gas production after fracture treatment was interpreted to imply that stimulation fractures intersected an area of greater permeability away from the wellbore, possibly a natural fracture system (W. Whitehead, personal communication, 1990). Higher-than-expected leakoff coefficients needed in hydraulic fracture models of the Frontier Formation to fit pressure data also might reflect dilation of natural fractures (C. Wright, personal communication, 1992).

High treatment pressures and apparent near-wellbore constrictions to fluid flow during hydraulic fracture treatments could result from multiple fracture strands growing in naturally fractured intervals (S. A. Holditch, personal communication, 1992). Anomalous fracture growth directions detected with in-well geophones have also been ascribed to the interaction of growing hydraulic fractures and natural fracture systems (Laubach and others, 1992a).

Stress Information

Conflicting evidence exists for stress directions in the Green River Basin (Laubach and others, 1992a). We interpret SHmax to have a northerly trend, consistent with regional patterns mapped by Zoback and Zoback (1989). A typical stress profile from the Green River Basin is shown in figure 159.

Maximum horizontal stress (SHmax) in five Frontier Formation wells in the western Green River Basin (Moxa Arch) was inferred from wellbore breakouts, coring-induced fractures, circumferential acoustic velocity analysis (CVA), anelastic strain recovery (ASR), differential strain curve analysis (DSCA), and axial point-load tests (APT) (Laubach and others, 1992a). The actual direction of hydraulic fracture growth was measured with circumferential monitoring of induced microseismicity (CMS) caused by hydraulic fractures.

Defining SHmax in these wells is challenging because the results are highly scattered. Some tests indicate north-trending SHmax, but others yield easterly, northeasterly, or bimodal northerly and easterly azimuths for SHmax direction. According to microseismic monitoring analysis, the growth direction of hydraulic fractures in three wells was east-west or northeast. Laubach and others (1992a) inferred that scattered measured stress azimuths reflect (1) inherently large sources of error in using core-based techniques and interference of natural fractures with measurements of north-trending SHmax and/or direction of hydraulic fracture growth and (2) spatially variable stress directions and low deviatoric horizontal stresses.

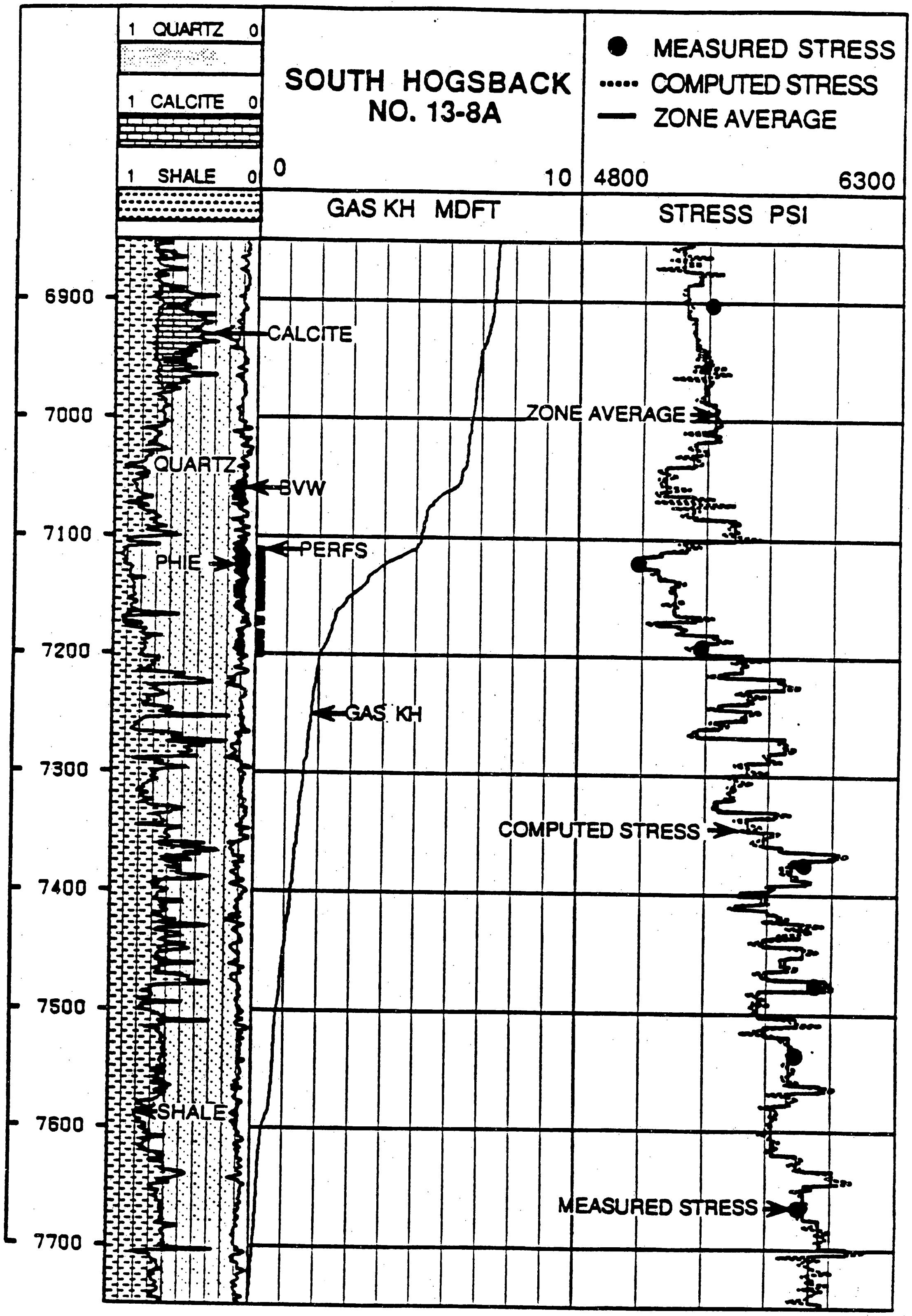


Figure 159. Frontier Formation stress-profile example, Enron S. Hogsback No. 13-8, Sweetwater County, Wyoming.

Reservoir characteristics are similar in the Frontier sandstones on the Moxa Arch and Rock Springs Uplift tight-gas areas. Overall, Frontier sandstone porosities range from 2 to 20 percent. In the Moxa Arch, area Finley (1984) describes two well groups, with average porosities of 13.4 and 12 percent (table 31). The Second Frontier on the Moxa Arch is described by Finley (1984) as having an average porosity of 13.8 percent. In the GRI research well, the SFE No. 4, average porosity in the Second Frontier is 10.3 percent, slightly lower than area-wide averages. Frontier porosity in the Rock Springs Uplift is described by Finley (1984) as 10.1 percent. Recent data (Wyoming Oil and Gas Conservation Commission, 1991b), suggests an average porosity of 11.9 percent for this same area.

Frontier permeabilities in both areas are low, although isolated core measurements approach 10 md (fig. 160). Moxa Arch Second Frontier sandstone permeabilities average between 0.016 and 0.0308 md with a range of 0.0001 to 0.306 md (Finley, 1984) (table 31). On the Rock Springs Uplift, average field permeabilities calculated from flow tests range from 0.006 to 0.07 md. One core showed average permeabilities of 0.154 md (Finley, 1984). However, this is uncorrected for overburden and water saturation.

Water saturations in Frontier sandstones range from 33 to 66 percent (CER Corporation, 1992b), depending on the shaliness of the reservoir. Average water saturation in 22 wells on the Rock Springs Uplift (Wyoming Oil and Gas Conservation Commission, 1991b) is 46 percent. Average water saturation in the SFE No. 4 well in the Second Frontier is also 46 percent. The capillary pressure curve shown in figure 161 indicates irreducible water saturation in the Second Frontier to be 47 percent, agreeing with reported water saturations, even though this sample was selected from a below average quality reservoir. Capillary pressure measurements in the cleaner part of the Second Frontier will probably show lower irreducible water saturations. Cementation and saturation exponents observed in the SFE No. 4 well were 2.24 and 1.71, respectively (CER Corporation, 1992b). Formation water salinity in the SFE No. 4 well is

Table 31. Frontier Formation, Green River Basin: production data and engineering parameters.

Estimated resource base (Tcf): 4.92

No. tight completions: 855

Cumulative production from tight completions 1970–1988 (Bcf): 809.7

Estimated ultimate recovery from tight areas (Bcf): 1,844

Net pay thickness (ft): 9–90

Porosity (%): 10–14

Permeability (md): 0.006–0.07

Water saturation range and average (%): 33–66/46

Reservoir temperature (°F): Geothermal gradient of 1.7°–2.0°/100 ft

Reservoir pressure range and average (psi): 224–6,789/3,211

Typical stimulation/hydro-frac: 90,000–200,000 gal fluid and 100,000–350,000 lb sand

Production rate:

prestimulation (Mcfd): 9–314

poststimulation (Mcfd): 48–8,240

Average recovery per completion (Bcf): 2.37

Decline rate: ≤50% in first and second years, then slower in subsequent years

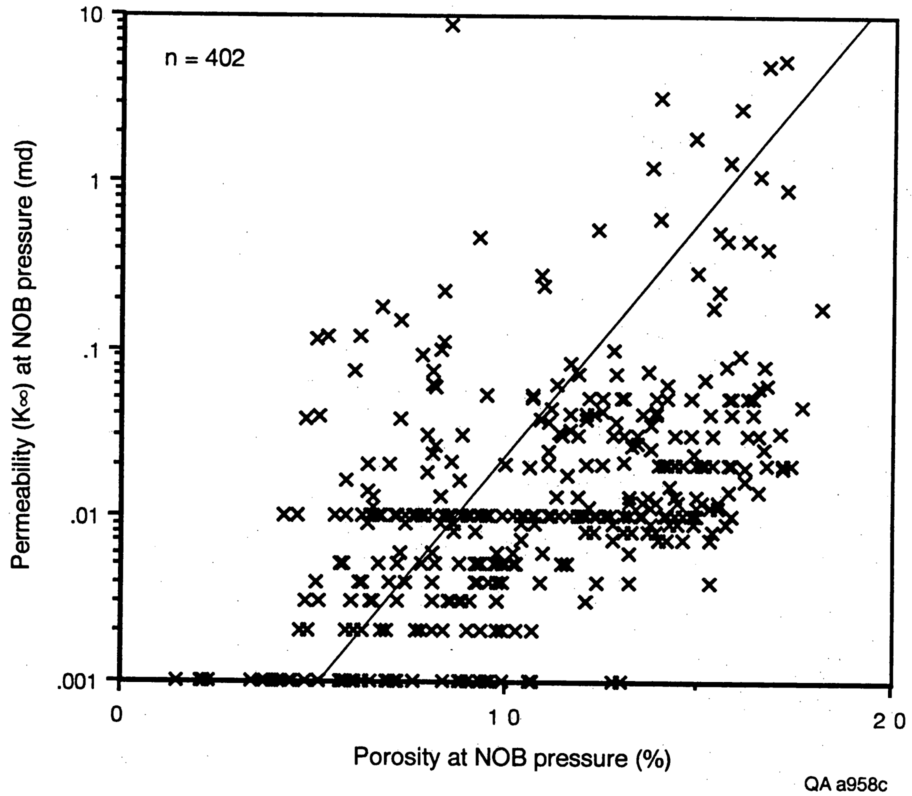


Figure 160. Semi-log plot of porosity measured at net overburden pressure vs. Klinkenberg-corrected gas permeability measured at net overburden pressure for 402 Frontier sandstone samples from the Moxa Arch area. Line is approximate trend line for porosity-permeability relationship, ignoring data interpreted to be of poor quality.

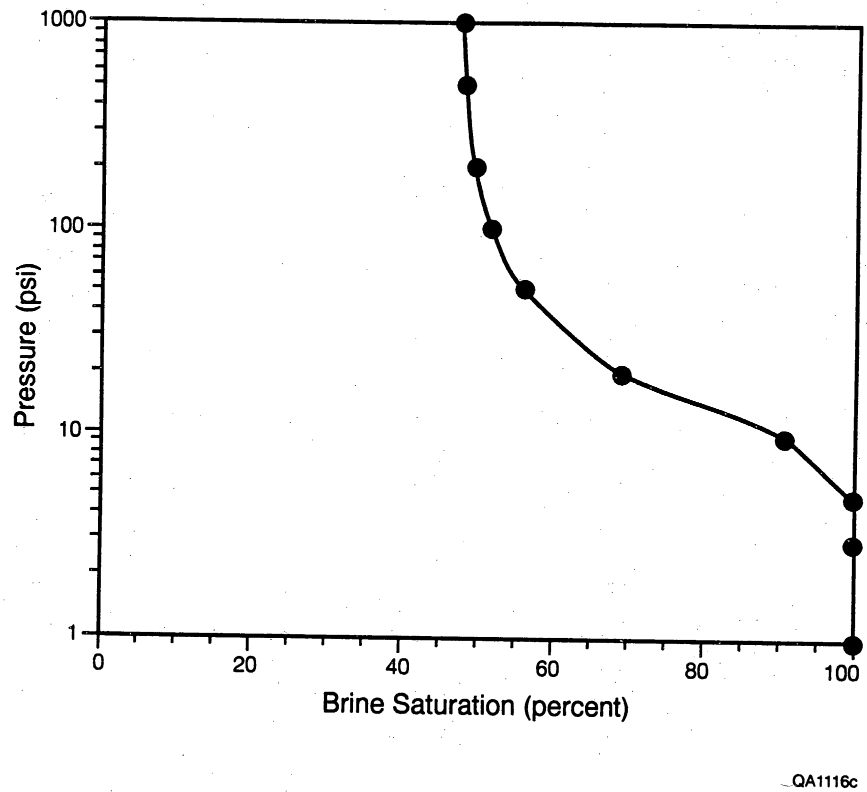


Figure 161. Typical capillary pressure curve from Second Frontier sandstone sample, SFE No. 4-24 well, La Barge Platform. From CER Corporation (1992).

approximately 20,000 ppm total dissolved solids, which corresponds to formation water resistivity of 0.12 at 160°F (CER Corporation, 1992b).

Frontier net pay footages range from 9 to 90 ft. In two groups of wells in the Moxa Arch area, Finley (1984) reports averages of 36 and 21 ft for two different fields. In the Rock Springs Uplift area averages for two fields are 20 and 39 ft. Porosity and water saturation cutoffs for net pay determination are 8 and 60 percent, respectively (CER Corporation, 1992a). The net pay footage for the SFE No. 4 well was 9.5 ft.

Basinwide average initial shut-in pressure is 3,211 psi with a range of 224 to 6,789 psi (Finley, 1984) (table 31). The range of reservoir pressures is wide because of the large depth variation of the Frontier across the basin. Second Frontier is slightly overpressured in some areas (Law and others, 1989). Temperature gradient is 1.7° to 2.0°F/100 ft (Dutton and Hamlin, 1992).

Frontier sandstones require fracture stimulation. In 35 completions, the average fracture stimulation treatment was 273,840 gal of fluid and 605,320 lb of sand. The range of fluid volumes was 87,300 to 510,000 gal. The range of proppant was 80,000 to 1,161,890 lb. For purposes of selection of a GRI research test site, completion data were collected on 82 wells on the Moxa Arch (Baumgardner and others, 1988). These data show a typical well was fracture stimulated using 90,000 to 200,000 gal of fluid and 100,000 to 350,000 lb of sand proppant (table 31).

Production History

The estimated resource base for the Frontier is 4.92 Tcf (National Petroleum Council, 1980). Ultimate recovery from current wells is 2.9 Tcf (Hugman and others, 1992). Average recovery per completion is 2.37 Bcf. Frontier sandstones on the Rock Springs Uplift produce gas at a prestimulation rate of 57 Mcf/d (Finley, 1984), whereas on the Moxa Arch, two groups of Frontier wells average 314 and 224 Mcf/d. The average post-stimulation production rate for 104 wells was 1,496 Mcf/d and ranged from 48 to 8,240 Mcf/d (Baumgardner and others, 1988) (table 31). Baumgardner and others (1988) report first year production of selected wells in Whiskey Buttes field to range from 50 to 375 MMcf. Wells decline at a rate approaching 50 percent between the first and second year, before leveling off at a slower decline in subsequent years.

Upper Almond and Blair Formations

Introduction

The upper Almond and Blair Formations are part of the Mesaverde Group, a 2,000- to 5,000-ft-thick Upper Cretaceous sequence of the Greater Green River Basin (fig. 148). The Mesaverde Group consists of several siliciclastic sediment wedges that were deposited during the late Santonian through Maestrichtian Stages along the western margin of the interior Cretaceous seaway (Weimer, 1961; Roehler, 1990; Surdam, 1992). Deposition was initiated by episodes of tectonic uplift and loading of the Overthrust Belt, but sedimentation patterns were also influenced by eustatic sea-level fluctuations (Kauffmann, 1977). The Mesaverde Group is thickest along the east flank of the Rock Springs Uplift (fig. 146). It thins to the west because of post-Mesaverde erosion and to the east by facies change, ultimately pinching out into shale (Martinsen and Christensen, 1992).

The Blair Formation is the lowermost unit of the Mesaverde Group in southwestern Wyoming (fig. 148). It is well developed in outcrop exposures around the flanks of the Rock Springs Uplift and in the immediately adjacent subsurface to the east (Shannon, 1983) but thins rapidly farther east, where it is difficult to distinguish from the underlying Baxter and overlying Rock Springs Formations (Newman, 1981).

The Almond Formation is the uppermost Mesaverde unit. It too is well developed at the Rock Springs Uplift but is more extensive to the east than is the Blair Formation. West of the Rock Springs Uplift, a change to nonmarine facies, as well as depositional and erosional thinning of Almond rocks, makes them indistinguishable from overlying and underlying units. Thus, the term Almond Formation is not generally used west of the Rock Springs Uplift (Martinsen and Christensen, 1992). The Almond Formation is informally divided into upper and lower parts, and historically, production is greatest from the upper Almond. The lower Almond is a fluvial sequence with minor marine incursions whereas the upper Almond consists of a series of landward-stepping strandline sandstones. The upper Almond is time transgressive and becomes younger from east to west (Martinsen and Christensen, 1992).

The Mesaverde Group contains a variety of reservoir types including conventional oil, conventional gas, and tight gas in the Greater Green River Basin but has been approved by FERC as a tight-gas-producing unit over an area that covers most of the Red Desert and Washakie Basins and Wamsutter Arch (fig. 162). A type log (fig. 163) illustrates the pay zone of the Blair and Upper Almond tight sandstones.

The Blair Formation averages 1,100 ft thick in outcrop and attains a maximum thickness of 1,400 ft along the southeastern flank of the Rock Springs Uplift (Shannon, 1983). The unit thins to the east and southeast where it is ultimately replaced by marine shales. Sandstone distribution appears highly variable but net sandstone thickness in the subsurface is up to 500 ft. Structural dip from the eastern edge of the Rock Springs Uplift into the basin is gentle and approximates 300 to 400 ft/mi. The top of the Blair Formation is at a depth of 4,000 to 5,000 ft, 20 mi east of Rock Springs. Steeper structural dips occur however, and the Blair Formation is at a depth of 15,000 ft due north of Rock Springs at the Sweetwater-Sublette County boundary. Depth to production in the Table Rock field is 8,200 ft.

The Almond Formation normally ranges in thickness from 300 to 800 ft (Roehler, 1990) and is thickest in the area of the Rock Springs Uplift. The lower Almond extends in the subsurface to the eastern margin of the Greater Green River Basin, but the upper Almond thins depositionally by facies change to the marine Lewis Shale in a southeasterly direction and is absent in the eastern half of the Sand Wash portion of the Green River Basin. Depth to the top of the Almond Formation varies from outcrop to 16,000 ft and is governed by the major structural

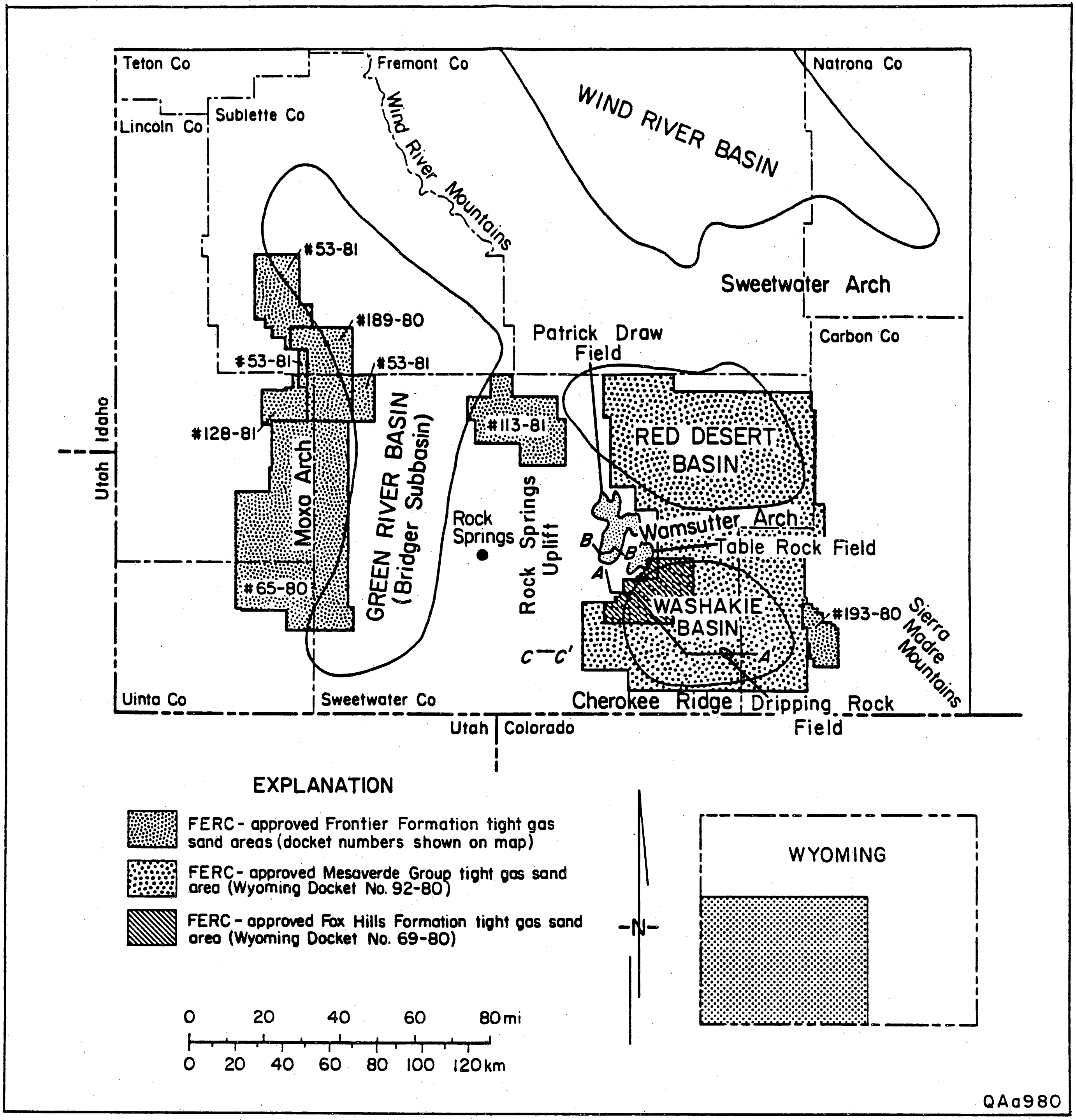


Figure 162. Areas covered by tight gas sand applications, Greater Green River Basin (Wyoming Oil and Gas Conservation Commission, 1980a, b, 1981a, b, c, d, e, f, 1991a).

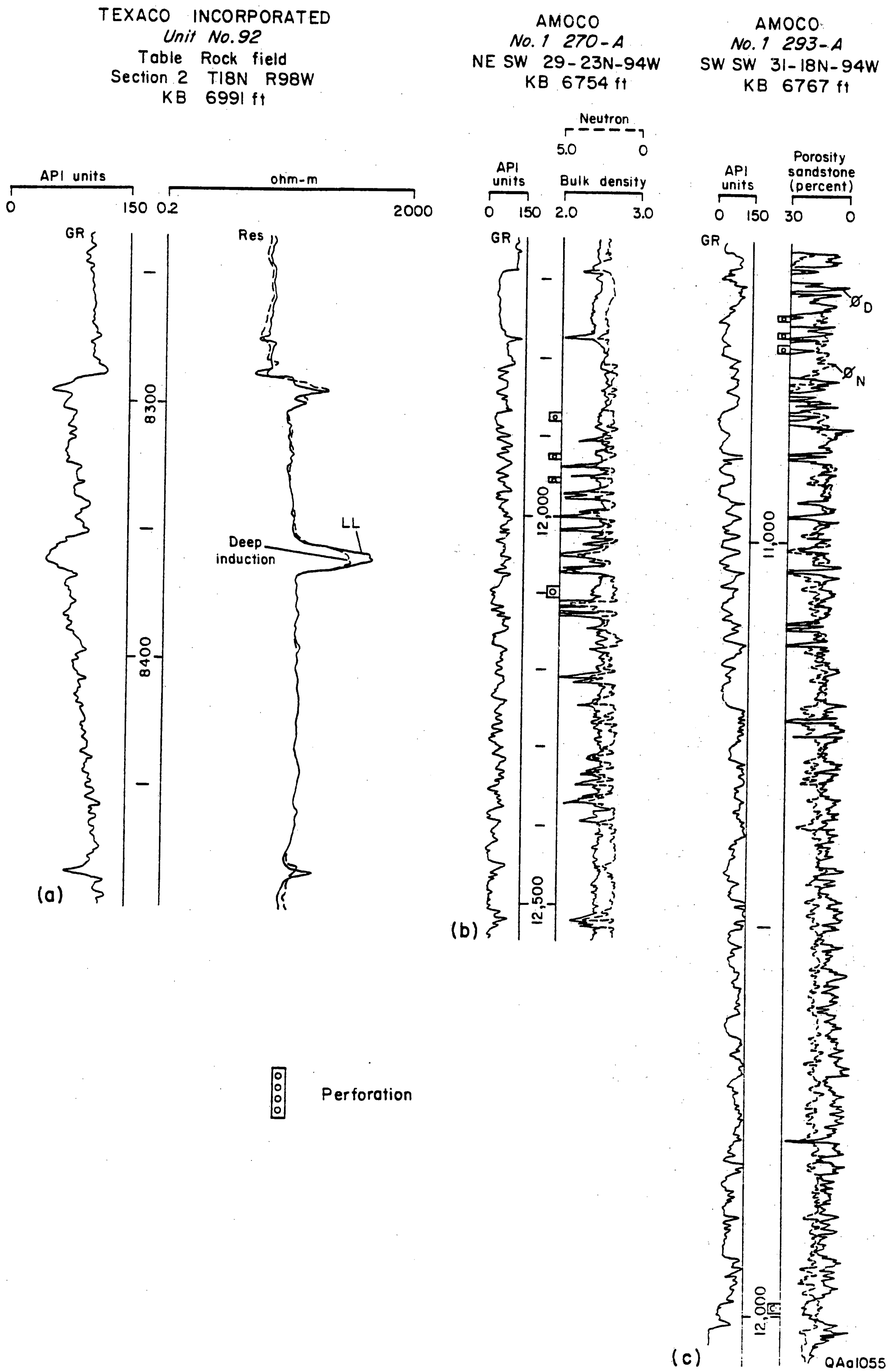


Figure 163. Representative log of the Mesaverde Group, Green River Basin.

elements of the Green River Basin. Depth to producing Almond sandstones also covers a wide range from 1,300 to 15,500 ft. Most production, however, is from 5,000 to 10,000 ft.

Data availability for the Blair Formation is poor and is summarized in Finley (1984). Geological investigations by Shannon (1983) provide a detailed sedimentological description of the unit in outcrop. More data are available for the Almond Formation because of high operator interest. This part of the Mesaverde Group is also the focus of a GRI-sponsored tight gas sands project (Surdam, 1992; Martinsen and Christensen, 1992; Yin and others, 1992).

Depositional Systems and Reservoir Facies

Blair Formation

The Blair Formation is commonly considered to be shallow marine (Hale, 1950, 1955; Keith, 1965), in part because of a shallow marine fauna (Finley, 1984). Miller (1977) suggested the unit was deposited adjacent to or offshore of the mouth a major distributary that entered the basin from the northwest. Shannon (1983) however, interpreted the Blair Formation as slope and basinal deposits distal to, and laterally equivalent of, the shelf and delta complex of the Rock Springs Formation. He cited stratification types and a paleotransport direction that was normal to the southwest-trending Rock Springs shoreline as evidence in support of this interpretation. The Blair Formation has a sharp conformable to locally erosional basal contact and contains intraformational channeling, syndepositional slumping, and high energy sedimentary structures. The unit in outcrop is divided into a lower Sandy Member and an upper Shaley Member (fig. 164), and within the lower Sandy Member, a basal sandstone, a middle shale, and an upper sandstone interval can be recognized (Shannon, 1983).

Continuity and character of potential Blair sandstone reservoirs are not well documented. In outcrop, fine to medium-grained trough cross-stratified sandstone units from 20 to 60 ft thick occur in the upper part of the basal sandstone interval, in the upper part of the upper sandstone

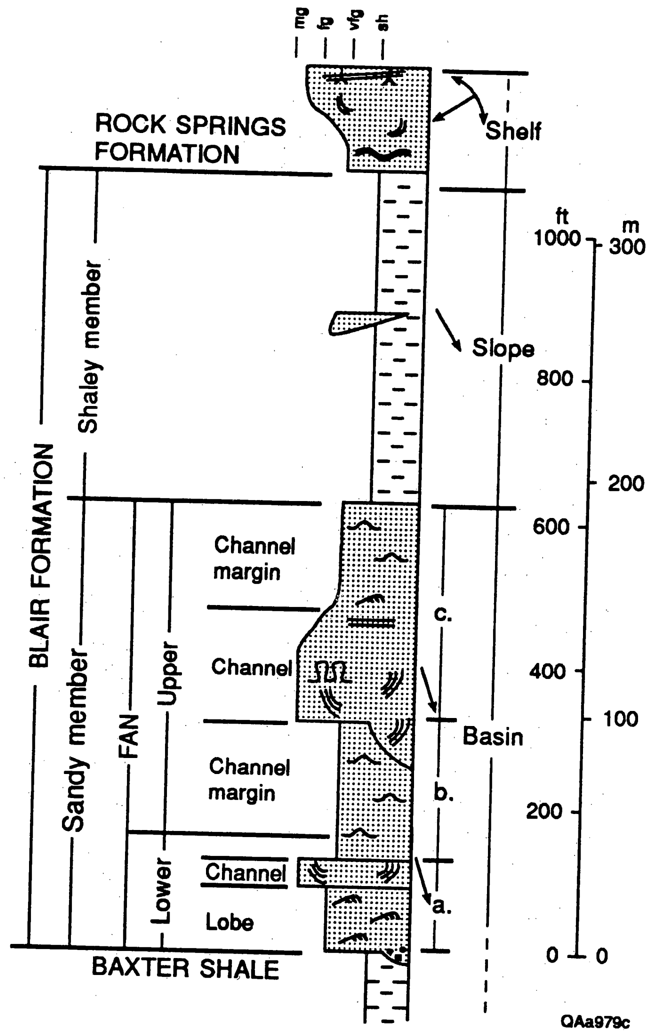


Figure 164. Generalized vertical sequence of lithologies and interpreted environments of the Blair–lower Rock Springs system (from Shannon, 1983). Abbreviations: a = basal sandstone, b = middle shaley sandstone, and c = upper sandstone.

interval, and at the top of the upper Shaley Member. Very fine to fine-grained sandstones are also present in thick sequences (up to 200 ft) throughout the Blair Formation and are arranged as thinly bedded, horizontal to ripple-laminated units, as trough cross-stratified units, and rhythmically interbedded with siltstone. In the subsurface, sandstone units displaying blocky and upward-coarsening SP log patterns are up to 200 ft thick and appear continuous for at least several miles. Shannon (1983) mapped one sandstone unit at the top of the Shaley Member and interpreted it as a narrow incised channel. This unit is approximately 150 ft wide and can be traced in outcrop along a northwest–southeasterly trend for at least 4,000 ft.

Almond Formation

The Almond Formation is divided into upper and lower units on the basis of depositional character. The lower unit is generally considered to be deposited in a nonmarine to brackish environment (Hale, 1950; Lewis, 1961; Jacka, 1965; Van Horn, 1979), whereas the upper unit was deposited in a shoreline setting during transgression (Martinsen and Christensen, 1992; fig. 165). Van Horn (1979) separated the nonmarine and brackish parts of the lower unit. In the nonmarine section, he recognized distributary channel, overbank, floodbasin and coastal fresh water marsh facies, and in the brackish section he listed saltmarsh, tidal creek-tidal flat, and lagoonal deposits as the principal facies associations. Potential reservoir facies are limited to the distributary-channel and tidal-flat facies. The distributary channel facies are fine and medium-grained sandstones from 20 to 30 ft thick, but they are lenticular, usually extending no more than a few hundred feet in outcrop. Wave-rippled sandstones of the tidal flat facies are far more continuous, extending laterally for over a mile in outcrop, but are thin (several feet thick).

The upper Almond Formation contains thick, laterally extensive shoreline sandstones and was deposited during the early stages of the T4 transgression of Weimer (1960). According to Roehler (1988, 1990), the Rock Springs embayment, which formed during this transgression,

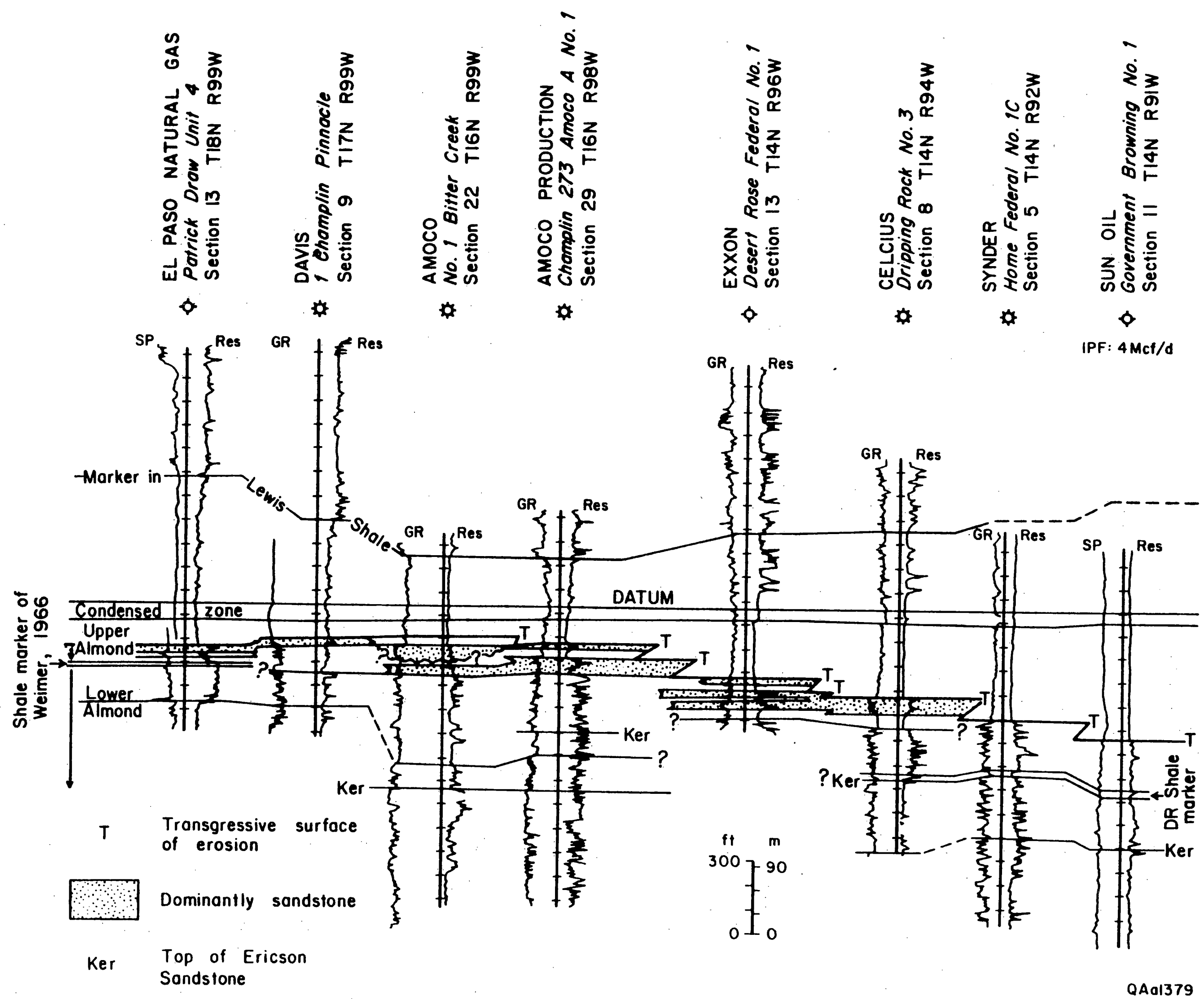


Figure 165. Regional stratigraphic cross section A–A′ of Almond Formation and associated units across the western and southern Washakie Basin (from Martinsen and Christensen, 1992). Section location is illustrated in figure 162.

had a focusing effect on tidal range in the Western Interior Seaway causing a mesotidal regime (tidal ranges of 4–8 ft). The upper Almond sandstones were deposited along this mesotidal coastline and were characterized by chains of barrier islands with closely spaced and highly active migrating tidal inlets (Martinsen and Christensen, 1992). Potential Almond reservoir sandstones are therefore laterally extensive. The uppermost Almond sandstone has excellent lateral continuity across the Wamsutter Arch and Patrick Draw field (Tyler, 1978; fig. 166) and fair to good lateral continuity across the southern end of the Rock Springs Uplift (Tyler, 1980) (fig. 167). Roehler (1988) described the barrier islands as "drumstick shaped" and 5 to 7 mi long, with associated flood tidal deltas up to 5 mi wide. Individual sandstone units are 10 to 80 ft thick but average 20 to 35 ft, and vertical stacking can create sandstone-rich sequences in excess of 200 ft thick (Van Horn, 1979). Martinsen and Christensen (1992) suggested that not all upper Almond reservoirs are tidally influenced barriers and that those in Dripping Rock field were deposited in a more storm-dominated environment.

Composition of Reservoir Facies

Composition of the Blair Formation sandstones has not been documented but is probably similar to other Mesaverde Group formations. Quartz is most likely the dominant framework grain with substantial rock fragments and minor feldspars and detrital clay.

The Almond sandstone reservoirs are very fine to fine grained, well sorted, and classified as sublitharenite, litharenite, and lithic arkose (Yin and others, 1992). Composition of the framework grains is depth dependent, except for detrital quartz, which remains constant at an average of 60 to 85 percent (range is 43 to 95 percent) from outcrop down to 12,000 ft. Lithic fragments range from 4 to 57 percent and consist predominantly of metamorphic rock fragments, with lesser sedimentary rock fragments and a minor contribution from volcanic rock fragments (Yin and others, 1992). Feldspar content decreases rapidly with depth and ranges from 3 to 21 percent above 8,000 ft to less than 5 percent below this depth. The percentage of lithic

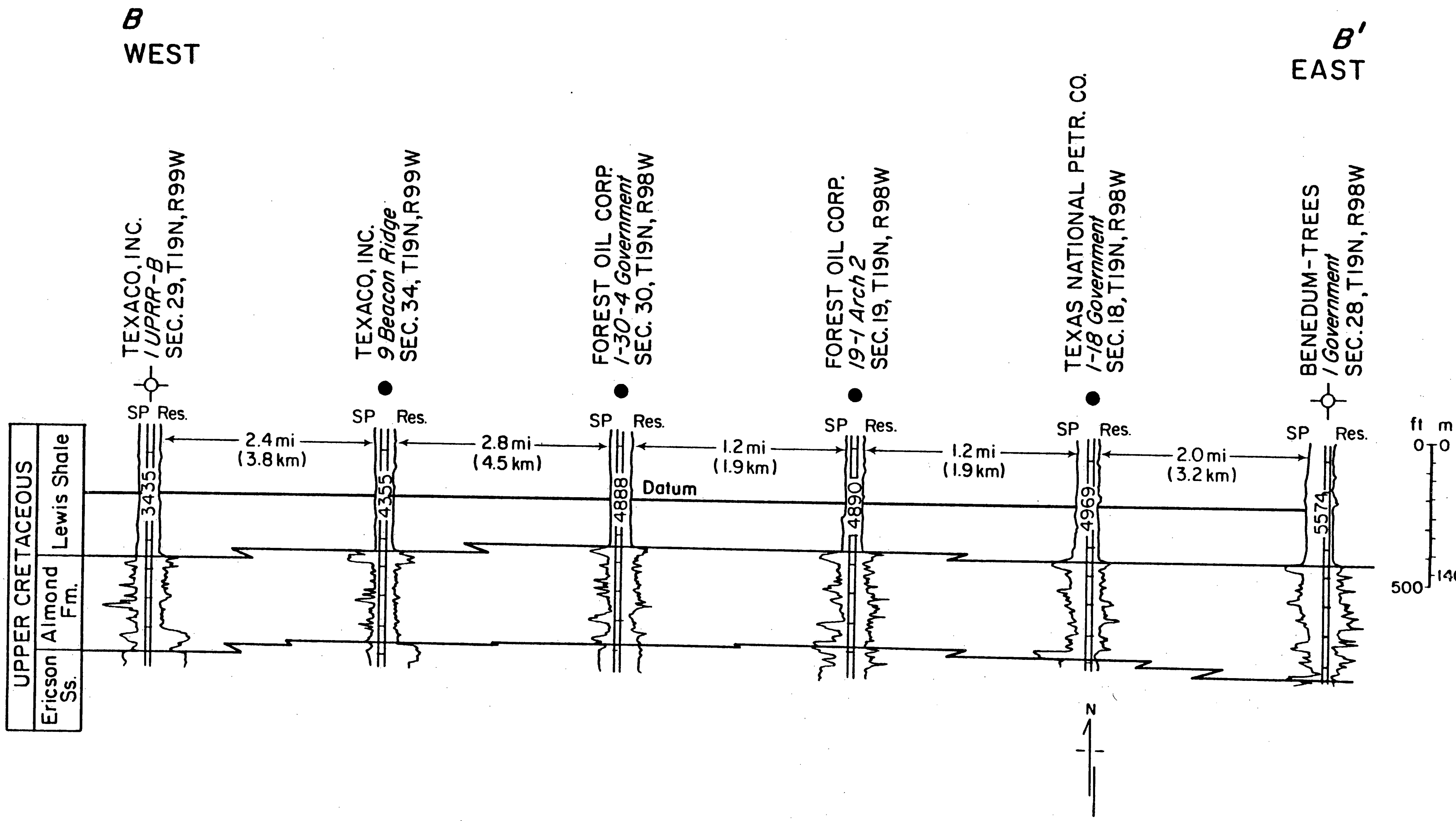


Figure 166. East–west stratigraphic cross section B–B′ through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1978). Section location is illustrated in figure 162.

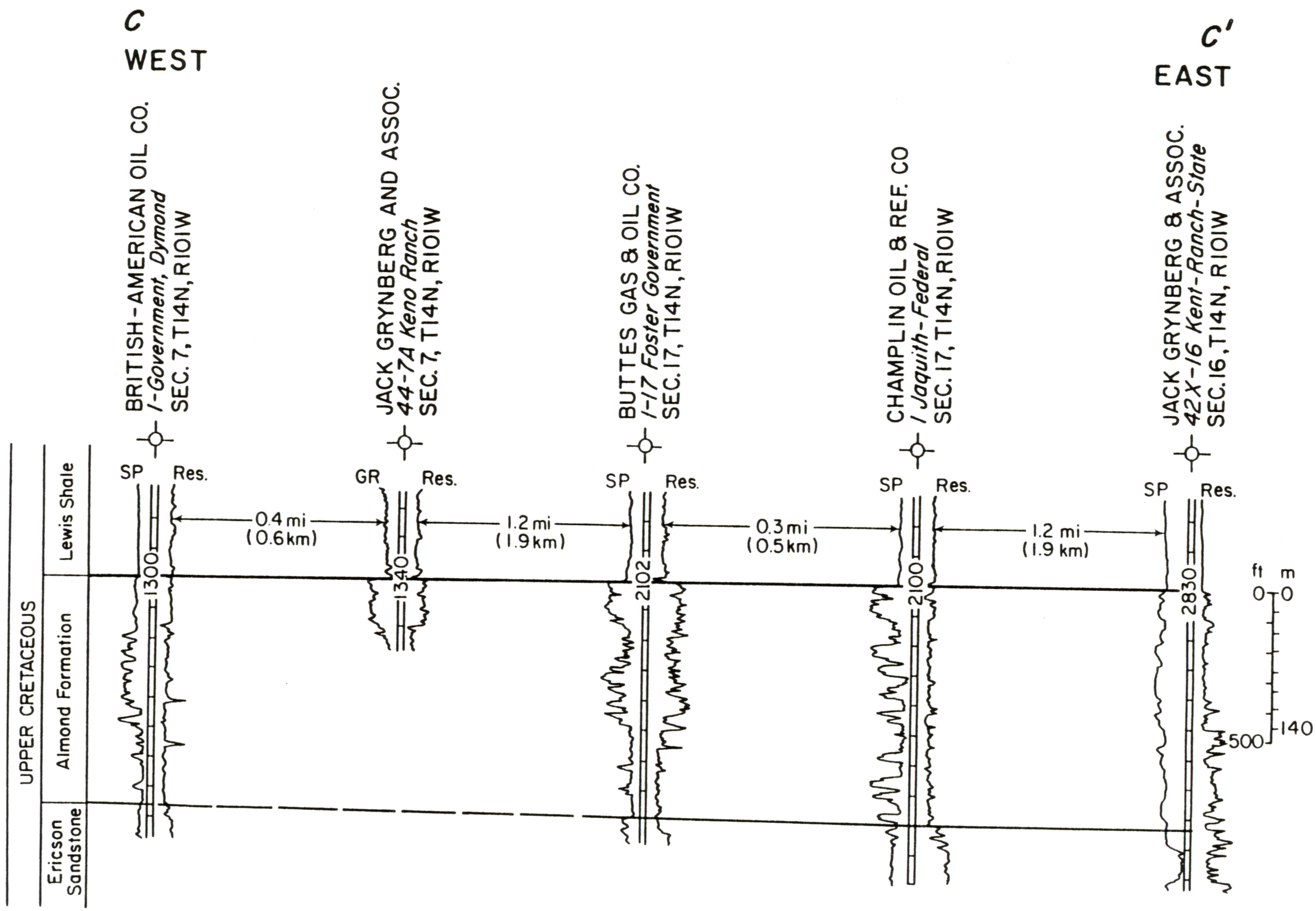


Figure 167. East–west stratigraphic cross section C–C′ through the Almond Formation (undivided), Greater Green River Basin (after Tyler, 1980). Section location is illustrated in figure 162.

fragments increases with depth from 10 to 30 percent above 8,000 ft to as much as 57 percent below 9,000 ft. Yin and others (1992) attributed the change in grain composition to diagenetic alteration but did not discount the possibility that the detrital sources varied through time because the Almond sandstones are retrogradationally stacked (Van Wagoner and others, 1991) and are thus time transgressive.

Distribution of authigenic minerals also varies with depth. At shallow depth (above 9,000 ft) kaolinite is predominant, and less than 5 percent quartz overgrowth cement is observed (Yin and others, 1992). Below 9,000 ft, kaolinite is rare, and quartz overgrowth cement and clay rims constitute 20 and 6 percent of the rock volume, respectively. Calcite and dolomite cements are common in Almond sandstones and range from 0 to 36 percent. Other commonly observed diagenetic minerals are illite and siderite (Law and others, 1984).

Keighin and others (1989) observed the depth control on reservoir character in the Almond sandstones and divided the reservoirs into conventional (4,000 to 5,000 ft depth) and unconventional (10,000 to 13,000 ft depth) types. The conventional reservoirs have porosities from 15 to 34 percent and permeabilities from 20 to 80 md, whereas the unconventional reservoirs have porosities from 3 to 12 percent and permeabilities less than 0.1 md. Mechanical compaction, carbonate and quartz cementation, and clay diagenesis cause a regular and predictable decrease in intergranular porosity from 30 percent at outcrop to 5 percent at 8,000 ft depth (Surdam, 1992). Below 8,000 ft very few intergranular pores are observed, and quartz cementation and clay diagenesis are the factors most damaging to porosity.

Natural Fractures

Finley (1984) reported no information on fractures from the Blair, but he mentioned three upper Almond wells that were thought to produce from natural fractures, having pre-stimulation flow of more than 3,000 Mcf/d. Fractures, including fractures filled with bitumen, have been observed in Almond Sandstone core from depths ranging from 4,699 to 13,647 ft in the

Washakie Basin (Yin and others, 1992). Fractures are reported to be common, and Yin and others (1992) conclude that fractures have played an important role in hydrocarbon migration and accumulation. Fractures are also reported from the northern Greater Green River Basin (Pitman and Dickenson, 1989).

Engineering Assessment

The Almond Formation is overpressured throughout much of the Greater Green River Basin and porosity averages 18 percent (Finley, 1984). In poorer quality Blair sandstones, recent FERC tight gas application hearings report porosities ranging from 1 to 10 percent and averaging 6.7 percent (Wyoming Oil and Gas Conservation Commission, 1991a) (table 32). In the designated tight gas area, average Almond sandstone permeability is 0.041 md. Core analyses of permeability in Blair sandstones range from 0.002 to 0.037 md and average 0.01 md (Wyoming Oil and Gas Conservation Commission, 1992).

Water saturations measured in one core average 59 percent and range from 45 to 88 percent (Finley, 1984) (table 32). Net pay is 14 to 18 ft/well. The thermal gradient is 1.4° to 1.6°F/100 ft. Reservoir pressure gradients range from 0.5 to 0.64 psi/ft. Average pressure for 43 Amoco wells from undifferentiated Mesaverde sandstones was 5,854 psi.

Almond and Blair sandstones are sensitive to drilling and completion fluids. A KCl mud system is recommended to minimize formation damage (Wyoming Oil and Gas Conservation Commission, 1991a). A recommended fracture stimulation treatment for Blair sandstones is 125,000 gal CO_2 foam and 250,000 lb 20/40 Ottowa sand (Wyoming Oil and Gas Conservation Commission, 1991a). In the undifferentiated Mesaverde sandstone completions, Amoco reported average fracture stimulation treatments of 162,000 gal fluid and 321,000 lb sand (Finley, 1984). A fourfold to fivefold production increase should be expected.

Table 32. Mesaverde Group, Green River Basin: production data and engineering parameters.

Estimated resource base (Tcf): Upper Almond = 1.77; Blair = 1.2

No. tight completions: Upper Almond = 517; Blair = 352

Cumulative production from tight completions 1970–1988 (Bcf): 517

Estimated ultimate recovery from tight areas (Bcf): 1,350

Net pay thickness (ft): 14–18

Porosity range and average (%): 0–10/6.7

Permeability range and average (md): 0.02–0.037/0.01

Water saturation range and average (%): 45–88/59

Reservoir temperature (°F): Geothermal gradient is 1.4° to 1.6°F/100 ft

Reservoir pressure (psi): 5,854

Typical stimulation/hydro-frac: 125,000 gal CO_2 and 250,000 lb sand

Production rate:

- prestimulation (Mcf/d): 214
- poststimulation (Mcf/d): 1,500–1,700

Average recovery per completion (Bcf): 2.85

Decline rate: No data

Production History

Estimated resource base is 1.77 Tcf for Almond and 1.2 Tcf for Blair sandstones (National Petroleum Council, 1980) (table 32). Tight gas ultimate recovery is 1350 Bcf (Hugman and others, 1992). Average recovery per completion is 2.85 Bcf. In the undifferentiated Mesaverde sandstones, pre-fracture stimulation rate was 214 Mcf/d. In the Upper Almond, some wells average 1,500 to 1,700 Mcf/d for the first year (Finley, 1984).

WIND RIVER BASIN

The Wind River Basin occupies most of Fremont and west Natrona Counties in central Wyoming. The basin is surrounded by basement uplifts and broad anticlines and is asymmetric: the structural axis trends west–northwest and is near the north basin margin (fig. 168). The deepest part of the basin contains 33,000 ft of sedimentary rocks, of which almost two-thirds is Upper Cretaceous and Tertiary (Paape, 1968). The present form of the Wind River Basin is chiefly the result of folding and thrust-faulting during the Laramide orogeny (latest Cretaceous to middle Eocene) (Love, 1988). Oil and gas fields are located in traps on intrabasinal Laramide structures (Keefer, 1969). Paleozoic and lower Mesozoic sedimentary rocks were deposited on a west-dipping stable marine shelf. Nonmarine clastic rocks dominate Triassic through lowermost Cretaceous strata. Marine conditions returned with the formation of the Cretaceous interior seaway; most of the Cretaceous is represented by a series of eastward-prograding regressive/transgressive cycles, depositing thick sequences of intertonguing sandstones and shales. During the latest Cretaceous and early Tertiary, basin-margin uplifts began rising and providing clastic debris to the Wind River Basin. The basin was blanketed by volcaniclastic sediments during the later Tertiary (Love, 1988).

Low-permeability gas reservoirs are common in Cretaceous and lower Tertiary formations in the Wind River Basin (fig. 169), although the overall tight-gas resource is relatively small.

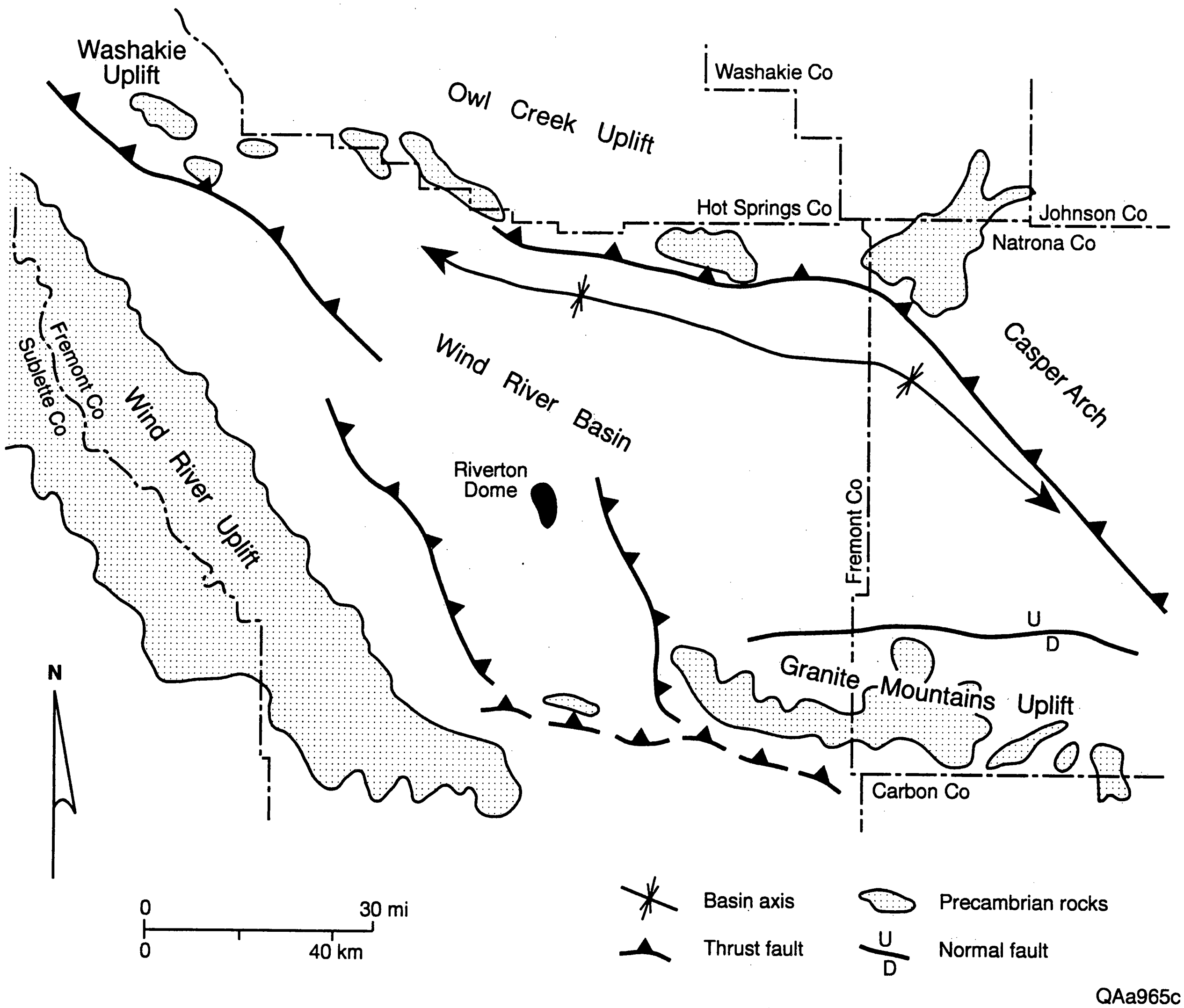


Figure 168. Map showing major structural features of the Wind River Basin. Modified from Paape (1968) and Love (1988). The Riverton Dome Frontier Formation tight-gas area is also shown.

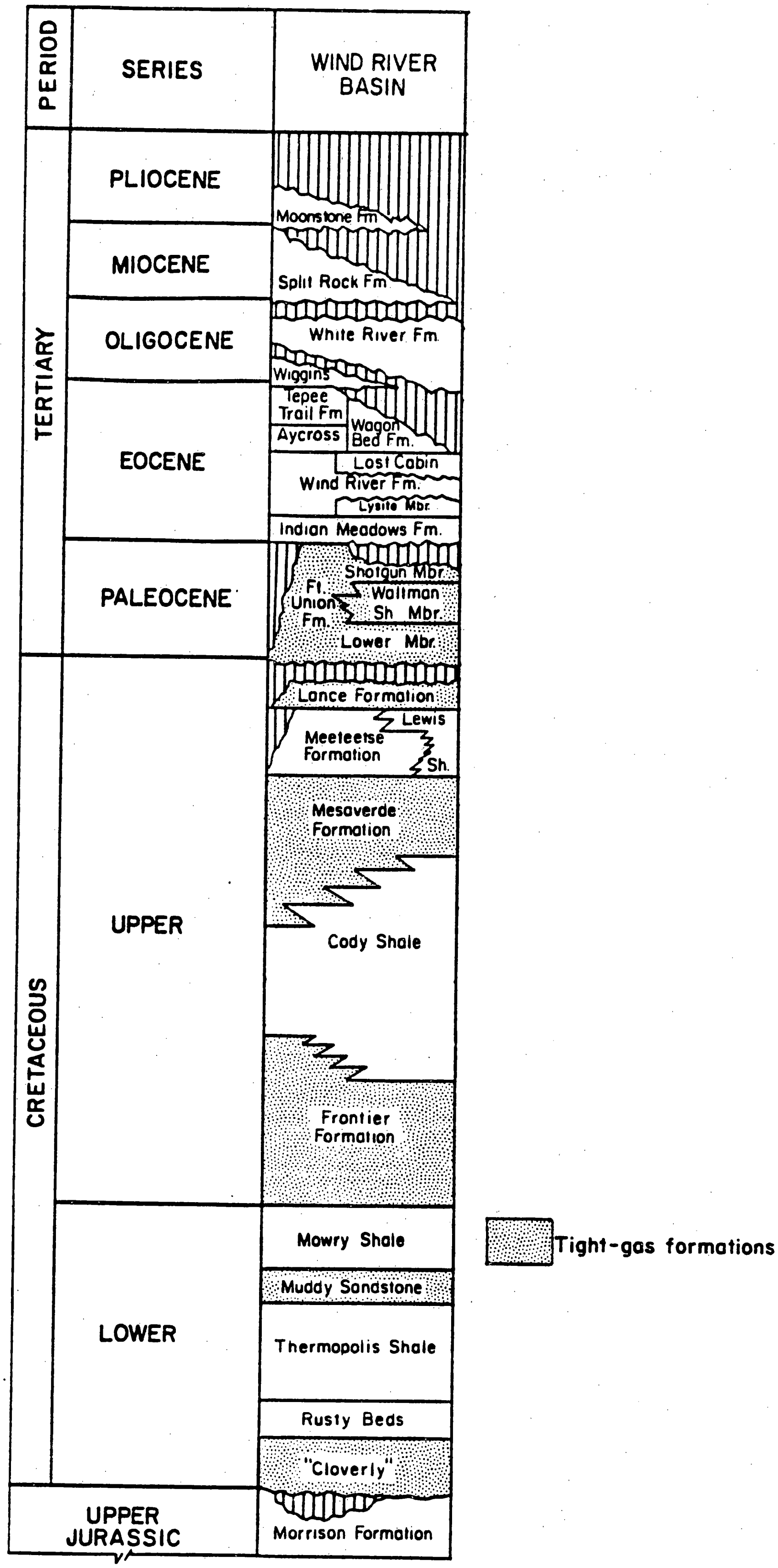


Figure 169. Cretaceous and Tertiary stratigraphy in the Wind River Basin. Modified from Wyoming Geological Association (1969).

The Lower Cretaceous Dakota Sandstone (Cloverly Formation) and Muddy Sandstone are designated tight in several areas, but only three tight-gas wells had been completed in these formations by 1988 (Hugman and others, 1992). The Frontier Formation is the major tight-gas interval in the Wind River Basin, producing almost 190 Bcf by 1988 (table 2). The Mesaverde, Lance, and Fort Union Formations (fig. 169) together have yielded less than 50 Bcf of tight gas (Hugman and others, 1992).

Frontier Formation

Introduction

In the Wind River Basin, the Frontier Formation comprises a stratigraphically variable interval of marine and nonmarine sandstone and shale of lowermost Upper Cretaceous age (fig. 169). The Frontier is approximately 600 to 1,000 ft thick and ranges in depth from outcrop to 25,000 ft (Finley, 1984). Although Frontier production is widespread in the basin, the formation has officially been designated tight in only one area, Riverton Dome field in Fremont County (fig. 168). Riverton Dome field is a north-trending anticline, in which the Frontier has a gross thickness of 950 ft and an average depth of 8,188 ft (range 7,652–9,722 ft) (Wyoming Oil and Gas Conservation Commission, 1982). At Riverton Dome the Frontier includes seven productive sandstone members (fig. 170).

The Wind River Basin is an important Rocky Mountain petroleum producing province, and much published literature on this subject is available (for example, Paape, 1968; Keefer, 1969; Wyoming Geological Association, 1989). The regional geology of the basin is also well described (Wyoming Geological Association, 1948, 1978; Keefer, 1965a, b, 1970a, b; Keefer and Van Lieu, 1966; Love, 1988). With the exception of studies by the National Petroleum Council (1980) and Finley (1984), however, little published information exists on Frontier tight gas reservoirs in the Wind River Basin. Most specific data on the Frontier in this report are derived

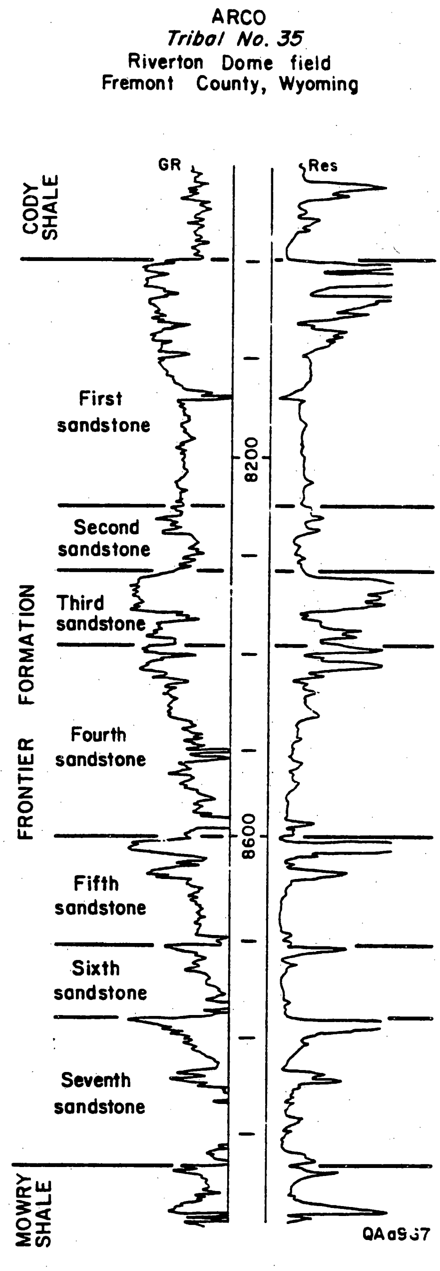


Figure 170. Typical gamma-ray/resistivity log through the Frontier Formation in Riverton Dome field, Wind River Basin. Modified from Wyoming Oil and Gas Conservation Commission (1982). Each Frontier sandstone member lies in an upward-coarsening shoreface parasequence.

from the Riverton Dome tight-gas application (Wyoming Oil and Gas Conservation Commission, 1982) and a recent field description (Borgerding, 1989).

Depositional Systems and Reservoir Facies

In the Wind River Basin, the Frontier Formation was deposited in coastal-plain, deltaic shoreline, and marine shelf systems similar to those in the Green River Basin. Frontier sandstones are thickest and nonmarine facies are most abundant in the west part of the basin close to source areas in the Wyoming–Idaho Thrust Belt. At Riverton Dome field, however, the Frontier includes only marine shelf and shoreline facies. Thick, regionally extensive marine shales, the Mowry Shale and the Cody Shale (fig. 169), underlie and overlie the Frontier, which at Riverton Dome is composed of seven upward-coarsening parasequences (fig. 170). Each parasequence is 50 to 200 ft thick and displays a vertical gradation from marine shale at the base, lower shoreface bioturbated sandy shale and shaly sandstone in the middle, and variably developed upper shoreface clean sandstone at the top. Shaly lower shoreface facies make up the bulk of each reservoir; upper shoreface and foreshore clean sandstones are typically only 1 to 3 ft thick (Wyoming Oil and Gas Conservation Commission, 1982). Frontier reservoir sandstones, although highly variable in thickness and quality, are continuous across the Riverton Dome tight-gas area (about 30 mi^2).

Composition of Reservoir Facies

Frontier reservoirs at Riverton Dome are fine to medium grained feldspathic sandstones (Wyoming Oil and Gas Conservation Commission, 1982; Borgerding, 1989). Glauconite and detrital clay are common to abundant accessory components. The main authigenic cements are quartz, carbonates, and clay minerals. Feldspar grains are commonly altered to clay.

Mechanical and chemical compaction are well developed, resulting in sutured pressure-solution boundaries between quartz grains. Porosity observed in thin section is scattered and unconnected.

Natural Fractures

No published information on naturally occurring fractures in Wind River Basin Frontier Formation reservoirs was found in the course of our inquiry. The Frontier Formation in the Wind River Basin is in a tectonic setting similar to that of other Cretaceous sandstones of the Rocky Mountain region (including the Frontier Formation in the Greater Green River Basin) where positive indications of naturally occurring fractures have been found. Natural fractures are therefore likely to be a reservoir element in Wind River Basin Frontier Formation reservoirs, but their potential role in gas production, if any, cannot be assessed at this time.

Engineering Assessment

Porosity in Frontier sandstones averages 11.1 percent (Borgerding, 1989) (table 33). Log derived porosities in the ARCO Tribal No. 34 well (Riverton Dome field) range from 8 to 17 percent (fig. 171). Permeabilities have been estimated using both core and flow tests. Average core permeability for Frontier sandstones at Riverton Dome field is 0.004 md. Average flow test permeability is 0.054 md. The average permeability presented before the Wyoming Oil and Gas Conservation Commission (1982) is 0.034 md.

Water saturations average 50 percent in Frontier sandstones in Riverton Dome field (table 33), comparable to the Frontier in the Green River Basin (table 31). Formation water resistivity is 4.29 $\Omega \cdot m$ at 68°F. This is extremely fresh and corresponds to salinities of 1,300 ppm total dissolved solids. Low-salinity formation waters make log interpretation to calculate water saturation difficult. Clay conductivities significantly higher than formation water conductivities may result in pessimistic water saturation determinations.

Table 33. Frontier Formation, Wind River Basin: production data and engineering parameters.

Estimated resource base (Tcf): 2.035 or 0.091

No. tight completions: 40

Cumulative production from tight completions 1970–1988 (Bcf): 189.9

Estimated ultimate recovery from tight areas (Bcf): 404

Net pay thickness (ft): 60

Porosity range and average (%): 8–17/11.1

Permeability average (md): 0.034

Water saturation average (%): 50

Reservoir temperature (°F): 180

Reservoir pressure (psi): 3,610

Typical stimulation/hydro-frac (hundred thousand): 5,500 gal fluid and 5,500 lb sand

Production rate:

prestimulation (Mcf/d): 185

poststimulation (Mcf/d): 350

Average recovery per completion (Bcf): No data

Decline rate: 20%/yr

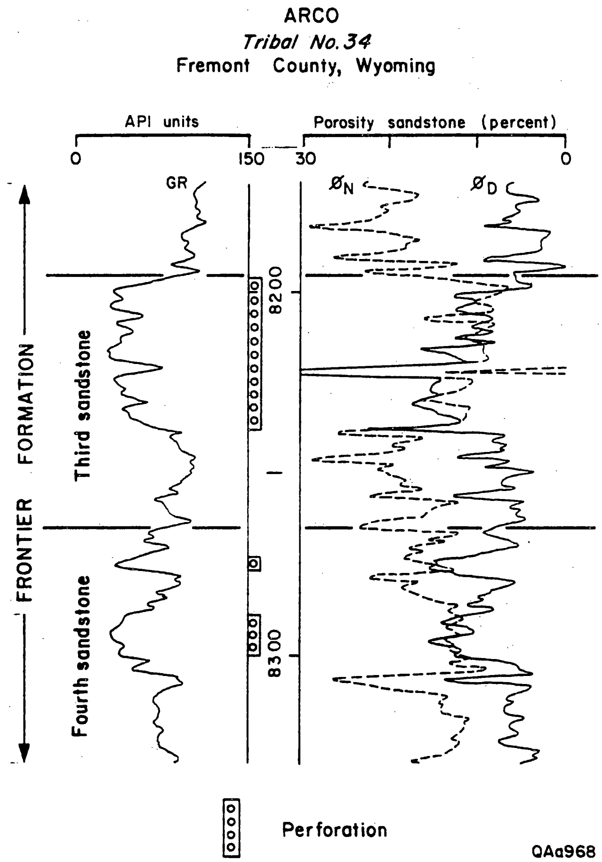


Figure 171. Porosity logs through perforated intervals in Frontier sandstones, Riverton Dome field, Wind River Basin.

Original reservoir pressure in Riverton Dome field was 3,610 psi (Borgerding, 1989). Current pressure data were unavailable. Because the drive mechanism is gas expansion, lower pressures should be expected. Reservoir temperature at Riverton Dome is 180°F. Most wells have to be stimulated by acidizing and/or hydraulic fracturing (Wyoming Oil and Gas Conservation Commission, 1982). Most fracture treatments are small, however, and consist of 5,500 gal fluid and 5,500 lb sand (Borgerding, 1989).

Production History

Estimated resource base is 2.035 Tcf (National Petroleum Council, 1980) (table 33). Ultimate recovery at Riverton Dome field will be 91.4 Bcf (Borgerding, 1989) of which 81.0 Bcf has been produced. However, Hugman and others (1992) estimated that ultimate recovery from Frontier formation tight reservoirs in the Wind River Basin will be 404 Bcf (table 2). The discrepancy between the two estimates may be due to the potential of the methodology of Hugman and others to overestimate the reserves in tight reservoirs. An ultimate recovery of 91.4 Bcf, which is based on a more detailed study of the Frontier reservoirs, is probably the better estimate.

Wells produce pre-fracture stimulation at rates averaging 185 Mcf/d (Wyoming Oil and Gas Conservation Commission, 1982). Postfracture stimulation results are available on only three wells. Improvement up to 350 Mcf/d was seen on one well (Wyoming Oil and Gas Conservation Commission, 1982). High initial production is followed by a rapid dropoff (almost 50 percent) and then a leveling off at a low flow rate within a year. Wells decline at a rate of approximately 20 percent per year (Borgerding, 1989).

ACKNOWLEDGMENTS

Funding for this study was provided by the Gas Research Institute under contract number 5082-211-0708, John Hansen, Project Manager. Laura L. Brock, Douglas C. Dawson, and Barbara A. Marin assisted in various phases of the project. We have benefited from guidance and advice by Robert J. Finley, Bureau of Economic Geology. Individuals who contributed ideas and information to this study include Ken Barrow, Bureau of Economic Geology; Dennis Bicknell, Colorado Oil and Gas Conservation Commission; Alan Coogan, Kent State University; Joseph H. Frantz, Jr., S. A. Holditch & Associates; Mark Haas, ICF Resources; Stephen A. Holditch, S. A. Holditch & Associates; West Kubik, K & A Energy; Richard D. Marvel, Wyoming Oil and Gas Conservation Commission; Douglas C. Patchen, West Virginia Geological and Economic Survey; Richard E. Peterson, CER Corporation; Arlene Salazar, Bureau of Land Management, New Mexico; Michael Stogner, New Mexico Oil Conservation Division; John Thomas, Beldon and Blake Corporation; Carol Tremain, Colorado Geological Survey; Neil Whitehead, New Mexico Bureau of Mines and Mineral Resources; and William S. Whitehead, S. A. Holditch & Associates.

Figures in this report were prepared under the direction of Richard L. Dillon, chief cartographer. Word processing was done by Susan Lloyd. Amanda R. Masterson edited the report, Kitty Challstrom and Jeannette Miether coordinated its production, and Jamie H. Coggin was the designer.

REFERENCES

Aguilera, R., 1980, Naturally fractured reservoirs: Tulsa, Oklahoma, PennWell Books, 619 p.

Alexander, S. C., Tieh, T. T., Berg, R. R., 1985, The effects of diagenesis on reservoir properties in the Lobo sandstones, Webb County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 35, p. 301–308.

Almon, W. R., and Davies, D. K., 1978, Clay technology and well stimulation: Gulf Coast Association of Geological Societies Transactions, v. 28, p. 1–6.

Anders, M. H., and Sleep, N. H., 1992, Magmatism and extension: the thermal and mechanical effects of the Yellowstone Hotspot: Journal of Geophysical Research, v. 97, no. B11, p. 15379–15393.

Arastoopour, H., Chen, S. T., and Hariri, M. H., 1987, Analysis of flow of gas and water in a fractured and non-fractured low-permeability reservoir under production: Proceedings, 1987 Society of Petroleum Engineers Annual Technical Conference, Dallas, Texas, SPE Paper No. 16948, p. 157–163.

Ayers, W. B., Jr., and Ambrose, W. A., 1990, Geologic controls on the occurrence of coalbed methane, Fruitland Formation, San Juan Basin, *in* Ayers, W. B., and others, Geologic evaluation of critical production parameters for coalbed methane resources, Part 1: San Juan Basin: Gas Research Institute, contract no. 5087-214-1544 (GRI-90/0014.1), p. 9–72.

Ayers, W. B., Jr., Ambrose, W. A., and Yeh, Joseph, 1991, Depositional and structural controls on coalbed methane occurrence and resources in the Fruitland Formation, San Juan Basin, *in* Ayers, W. B., and others, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: Gas Research Institute contract no. 5087-214-1544 (GRI-91/0072), p. 9–46.

Ayers, W. B., Jr., Kaiser, W. R., Laubach, S. E., and others, 1991, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for Gas Research Institute under contract no. 5087-214-1544, 314 p.

Ayers, W. B., Jr., and Zellers, S. D., 1988, Sedimentologic and structural controls on the occurrence and producibility of coalbed methane, Fruitland Formation, northern San Juan and Rio Arriba Counties, New Mexico, *in* Ayers, W. B., Jr., and others, Geologic evaluation of critical production parameters for coalbed methane resources, Part 1: San Juan Basin: Gas Research Institute, contract report no. 5087-214-1544 (GRI-88/0332.1), p. 3–59.

Baars, D. L., and others, 1988, Basins of the Rocky Mountain region, *in* Sloss, L. L., ed., Sedimentary cover—North American Craton: U.S.: Geological Society of America, The Geology of North America, v. D-2, p. 109–220.

Bailey, J. W., 1983, Stratigraphy, environments of deposition, and petrography of the Cotton Valley Terryville Formation in eastern Texas: The University of Texas at Austin, Master's thesis, 229 p.

Baker, R. K., 1979, The depositional environment of the Pennsylvanian upper Marchand sandstones, northern Caddo County, Oklahoma, *in* Hyne, N. J., ed., Pennsylvanian sandstones of the Mid-Continent: Tulsa Geological Society Special Publication No. 1, p. 195–219.

Barrow, K. T., and Asquith, G. B., 1992, Geologic controls on tight-gas production from a storm-dominated shelf: Upper Cretaceous Olmos Formation, Texas (abs.): American Association of Petroleum Geologists 1992 Annual Convention Official Program, Calgary, Alberta, Canada, p. 7.

Barrow, K. T., Asquith, G. B., and Causey, G. L., 1992, Shaly sand analysis as an indicator of hydrocarbon potential in the Olmos Formation, Las Tiendas Trend, South Texas: Gulf Coast Association of Geological Societies Transactions, v. 42, p. 13–26.

Baumgardner, R. W., Jr., 1991, Comparative lineament analysis of the San Juan Basin: relationships between lineament attributes and coalbed methane production, *in* Ayers, W. B., Jr., Kaiser, W. R., Laubach, S. E., and others, 1991, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for Gas Research Institute under contract no. 5087-214-1544, p. 153–179.

Baumgardner, R. W., Jr., Tye, R. S., Laubach, S. E., Diggs, T. N., Herrington, K. L., and Dutton, S. P., 1988, Site selection for GRI cooperative tight gas field research, volume II: geologic characteristics of selected low-permeability gas sandstones: topical report no. GRI-88/0180 prepared for the Gas Research Institute under contract no. 5082-211-0708, 194 p., plus appendix.

Beaumont, E. C., Dane, C. H., and Sears, J. D., 1956, Revised nomenclature of Mesaverde Group in San Juan Basin, New Mexico: American Association of Petroleum Geologists Bulletin, v. 40, p. 2149–2162.

Bebout, D. G., and Garrett, C. M., Jr., 1989, Upper Pennsylvanian and Lower Permian slope and basinal sandstone, *in* Kosters, E. C., and others, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology, p. 116–118.

Bebout, D. G., Weise, B. R., Gregory, A. R., and Edwards, M. B., 1982, Wilcox sandstone reservoirs in the deep subsurface along the Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 117, 125 p.

Bebout, D. G., White, W. A., Garrett, C. M., Jr., and Hentz, T. F., eds., in press, Atlas of major central and eastern Gulf Coast gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology, 83 p.

Bebout, D. G., White, W. A., and Hentz, T. F., in press, Atlas of major Midcontinent reservoirs: The University of Texas at Austin, Bureau of Economic Geology.

Bentz, L. M., 1992, Pecos Slope field, U.S.A.: Permian Basin, New Mexico, *in* Foster, N. H., and Beaumont, E. A., compilers, Stratigraphic traps III: American Association of Petroleum Geologists, Treatise of petroleum geology, p. 129–153.

Berg, R. R., 1986, Reservoir sandstones: Englewood Cliffs, New Jersey, Prentice-Hall, 481 p.

Berg, R. R., Marshall, W. D., and Shoemaker, P. W., 1979, Structural and depositional history, McAllen Ranch Field, Hidalgo County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 29, p. 247–253.

Blackstone, D. L., Jr., 1979, Geometry of the Prospect-Darby and La Barge faults at their junction with the La Barge Platform, Lincoln and Sublette Counties, Wyoming: The Geological Survey of Wyoming Report of Investigations No. 18, 34 p.

Bles, J. L., and Feuga, B., 1986, The fracture of rock: New York, Elsevier Scientific Publishing Company, 131 p.

Borgerding, J. H., 1989, Riverton Dome, *in* Wyoming Geological Association, Wyoming oil and gas fields symposium, Bighorn and Wind River Basins: Wyoming Geological Association, p. 404–409.

Branagan, P. T., 1992, Current status and flow test procedures for SHCT-1: CER Corporation memorandum to distribution, Jan. 16, 1992. (Addendum of Jan. 24, 1992.)

Branagan, P. T., 1987, Well testing, analysis, and reservoir evaluation: *in* Multiwell Experiment Final Report: 1. The marine interval of the Mesaverde Formation, Sandia National Laboratories Report, SAND 87-0327, p. 7-1–7-44.

Brashear, W. W., 1961, Lips field, *in* Wagner, C. R., and others, eds., Oil and gas fields of the Texas and Oklahoma Panhandles: Panhandle Geological Society, p. 181–183.

Broadhead, R. F., 1983, Correlation of the Abo outcrop with the subsurface gas-producing Abo red beds of east-central New Mexico, *in* Zideck, Jiri, ed., Guidebook for field trip to the Abo red beds (Permian), central and south-central New Mexico: Roswell Geological Society and New Mexico Bureau of Mines and Mineral Resources, p. 45–52.

Broadhead, R. F., 1984a, Geology of gas production from "tight" Abo red beds, east central New Mexico: Oil and Gas Journal, v. 82, no. 24, p. 147–158.

Broadhead, R. F., 1984b, Stratigraphically controlled gas production from Abo red beds (Permian), east-central New Mexico: New Mexico Bureau of Mines and Mineral Resources, Circular 183, 36 p.

Brown, C. A., Smagala, T. M., and Haefele, G. R., 1986, Southern Piceance Basin model—Cozzette, Corcoran, and Rollins sandstones, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology Series No. 24, p. 207–219.

Brown, R. O., Forgotson, J. M., and Forgotson, J. M., Jr., 1980, Predicting the orientation of hydraulically created fractures in the Cotton Valley Formation of East Texas: SPE Paper No. 9269, 55th Annual Fall Conference, p. 1–12.

Buffler, R. T., and Sawyer, D. S., 1985, Distribution of crust and early history, Gulf of Mexico Basin: Gulf Coast Association of Geological Societies Transactions, v. 35, p. 333–344.

Buffler, R. T., Watkins, J. S., Shaub, F. J., and Worzel, J. L., 1980, Structure and early geologic history of the deep central Gulf of Mexico, *in* Proceedings, Symposium on the origin of the Gulf of Mexico and the early opening of the central North Atlantic Ocean: Baton Rouge, Louisiana State University, School of Geoscience, p. 3–16.

Bureau of Land Management, 1991, Information Packet for tight formation area designation applications and tight formation well determination applications, 12 p.

Burford, A. E., and Frech, K. R., 1988, Nature of porosity-permeability of "Clinton" (Lower Silurian) sandstones of Ohio: Geological Society of America Abstracts with Programs, v. 20, no. 5, p. 337–338.

Bushaw, D. J., 1968, Environmental synthesis of the East Texas Lower Cretaceous: Gulf Coast Association of Geological Societies Transactions, v. 18, p. 416–438.

Cast, R. F., 1977, Hemphill Granite Wash field, *in* Selected fields of the Texas Panhandle: Panhandle Geological Society, p. 31–33.

CER Corporation, 1991a, Summary of open-hole data acquisition and field operations, Enron Sawyer A-144 No. 5: unnumbered topical report prepared for the Gas Research Institute under Contract No. 5091-221-2130, variously paginated.

_________ 1991b, Summary of open-hole data acquisition and field operations, Maxus H. T. Glasgow No. 2: unnumbered topical report prepared for the Gas Research Institute under Contract No. 5091-221-2130, variously paginated.

_________ 1991c, Summary of open-hole data acquisition and field operations, Phillips Ward C-11: unnumbered topical report prepared for the Gas Research Institute under Contract No. 5091-221-2130, variously paginated.

_________ 1992a, Investigation of the Davis Sandstone (Ft. Worth Basin, Texas) as a suitable formation for the GRI hydraulic fracture test site: topical report submitted to the Gas Research Institute under contract number 5091-221-2130, 51 p.

_________ 1992b, Staged Field Experiment No. 4: application of advanced technologies in tight gas sandstone—Frontier Formation, Chimney Buttes field, Sublette County, Wyoming: CER Corporation, report no. GRI-92/0394, prepared for the Gas Research Institute, 269 p.

_________ 1992c, Summary of open-hole data acquisition and field operations, Maxus Carl Ellis "E" No. 3: unnumbered topical report prepared for the Gas Research Institute under Contract No. 5091-221-2130, variously paginated.

CER Corporation and S. A. Holditch & Associates, eds., 1988, Advances in Travis Peak formation evaluation and hydraulic fracture technology, Staged Field Experiment No. 1: Gas Research Institute Report 88/0077, 223 p.

_________ 1989, Staged Field Experiment No. 2: application of advanced geologic, petrophysical, and engineering technology to evaluate and improve gas recovery from low permeability reservoir sandstones, v. 1: Gas Research Institute report 89/0140, 178 p.

_________ 1990, Staged Field Experiment No. 2: application of advanced geologic, petrophysical, and engineering technology to evaluate and improve gas recovery from low permeability reservoir sandstones, v. 2: Gas Research Institute report 90/0093, 237 p.

_________ 1991, Staged Field Experiment No. 3: application of advanced technologies in tight gas sandstones—Travis Peak and Cotton Valley Formations, Waskom Field, Harrison County, Texas: Gas Research Institute report 91/0048, 253 p.

Channas, John, 1971, Petroleum potential of Ohio, *in* Cram, I. H., ed., Future petroleum provinces of the United States—their geology and potential: American Association of Petroleum Geologists, Memoir 15, v. 2, p. 1254–1257.

Choate, Raoul, Lent, J., and Rightmire, C. T., 1984, Upper Cretaceous geology, coal, and the potential for methane recovery from coalbeds in San Juan Basin—Colorado and New Mexico, *in* Rightmire, C. T., Eddy, G. E., and Kirr, J. N., eds., Coalbed methane resources in the United States: American Association of Petroleum Geologists Studies in Geology Series No. 17, p. 185–222.

Clavier, C., Coates, G., Dumanoir, J., 1984, The theoretical and experimental basis for the dual water-model for interpretation of shaly sand: Society of Petroleum Engineers Journal, v. 24, p. 153–167.

Clement, W. A., 1991, East Clinton field, U.S.A.: Anadarko Basin, Oklahoma, *in* Foster, N. H., and Beaumont, E. A., compilers, Stratigraphic traps II: American Association of Petroleum Geologists, Treatise of petroleum geology, p. 207–267.

Cliffs Minerals, Inc., 1982, Analysis of the Devonian shales in the Appalachian Basin: U.S. DOE contract DE-AS21-80MC14693, Final Report, Springfield Clearing House, Washington, D.C., variously paginated.

Clift, S. J., Laubach, S. E., and Holder, Jon, 1992, Strength anisotropy in low-permeability sandstone gas reservoirs: application of the axial point-load test: Transactions, Gulf Coast Association of Geological Societies, v. 42, p. 237–248.

Coalson, Edward, Duey, H., and Kellogg, H. E., 1982, Greater Douglas Arch area, oil and gas fields of Colorado–Nebraska and adjacent areas: Rocky Mountain Association of Geologists, p. 184–213.

Coleman, J. L., Jr., 1985, Diagenesis of Cotton Valley sandstone (Upper Jurassic), east Texas: implications for tight gas formation pay recognition: discussion: American Association of Petroleum Geologists Bulletin, v. 69, no. 5, p. 813–815.

Coleman, J. L., Jr., and Coleman, C. J., 1981, Stratigraphic, sedimentologic and diagenetic framework for the Jurassic Cotton Valley Terryville massive sandstone complex, Northern Louisiana: Gulf Coast Association of Geological Societies Transactions, v. 31, p. 71–79.

Coleman, J. M. C., 1990, Depositional systems and tectonic/eustatic history of the Oligocene Vicksburg episode of the Northern Gulf Coast: The University of Texas at Austin, Ph.D. dissertation, 538 p.

Coleman, Janet, and Galloway, W. E., 1990a, Petroleum geology of the Vicksburg Formation, Texas: Gulf Coast Association of Geological Societies Transactions, v. 40, p. 119–130.

_________ 1990b, Sequence stratigraphic analyses of the lower Vicksburg Formation of Texas: Society of Economic Paleontologists and Mineralogists Foundation, Gulf Coast Section, Eleventh Annual Research Conference, Program and Abstracts, p. 99–112.

Collins, E. W., Laubach, S. E., Dutton, S. P., and Hill, R. E., 1992, Depositional environments, petrology, and fractures of the Atoka Davis Sandstone: a low-permeability, gas-bearing sandstone of the Fort Worth Basin, North-Central Texas, *in* Cromwell, D. W., Moussa, M. T., and Mazzullo, L. J., eds., Southwest Section of the American Association of Petroleum Geologists, Transactions, Publication SWS 92-90, p. 221–230.

Collins, S. E., 1980, Jurassic Cotton Valley and Smackover reservoir trends, east Texas, north Louisiana, and south Arkansas: American Association of Petroleum Geologists Bulletin, v. 64, no. 7, p. 1004–1013.

Colorado Oil and Gas Conservation Commission, 1980a, Cause No. NG-3, application by Amoco Production Company for designation of the "J" Sand in parts of Weld, Adams, and Boulder Counties, Colorado, as a tight gas sand.

_________ 1980b, Cause no. NG-6, application by Chandler and Associates, Inc., for designation of the Mancos "B" Sandstone in parts of Rio Blanco County, Colorado, as a tight gas sand.

_________ 1980c, Cause no. NG-7, application by Chandler and Associates, Inc., for designation of the lower Mesaverde (Group) in part of Mesa County, Colorado, as a tight gas sand.

_________ 1980d, Cause no. NG-8, application by Coseka Resources (U.S.A.), Ltd., for designation of the Dakota Formation in parts of Rio Blanco County, Colorado, as a tight gas sand.

_________ 1980e, Cause no. NG-9, application by Rio Blanco Natural Gas Co. for designation of the Fort Union Formation, the Mesaverde (Group), and the Mancos Shale (to base of Mancos "B" Shale) in part of Rio Blanco County, Colorado, as tight gas sands.

_________ 1980f, Cause no. NG-10, application by Natomas North America, Inc., for designation of the Dakota and Morrison Formations in parts of La Plata County, Colorado, as tight gas sands.

_________ 1980g, Cause no. NG-11, application by Natomas North America, Inc., for designation of the Sanostee Member of the Mancos Shale and the Dakota Sandstone in parts of La Plata and Archuleta Counties, Colorado, as tight gas sands.

_________ 1980h, Cause no. NG-12, application by Koch Industries, Inc., for designation of the Rollins, Cozzette, and Corcoran Formations in parts of Mesa and Garfield Counties, Colorado, as tight gas sands.

_________ 1980i, Cause no. NG-14, application by Northwest Exploration Co. for designation of the Mancos "B" Formation in part of Rio Blanco County, Colorado, as a tight gas sand.

_________ 1980j, Cause no. NG-15, application by American Resources Management Corporation for designation of the Dakota and Mancos "B" Formations in parts of Rio Blanco and Garfield Counties, Colorado, as tight gas sands.

_________ 1980k, Cause no. NG-17, application by Dome Petroleum Corp. for designation of the Rollins, Cozzette, and Corcoran Formations in part of Garfield County, Colorado, as tight gas sands.

_________ 1981a, Cause no. NG-19, application by Koch Industries, Inc., for designation of the Dakota Formation in parts of Garfield and Mesa Counties, Colorado, as a tight gas sand.

_________ 1981b, Cause no. NG-21, application by Northwest Exploration Co. for designation of the Mesaverde Formation in part of Garfield County, Colorado, as a tight gas sand.

_________ 1981c, Cause no. NG-23, application by Atlantic Richfield Company for designation of the Dakota Formation in parts of La Plata and Archuleta Counties, Colorado, as a tight gas sand.

_________ 1981d, Cause no. NG-24, application by ARCO Oil and Gas Company for designation of the Mesaverde Formation in parts of La Plata and Archuleta Counties, Colorado, as a tight gas sand.

_________ 1982a, Cause no. NG-26, application by Snyder Oil Co. for designation of the upper Mancos (Shale) and lower Mesaverde (Group) in part of Mesa County, Colorado, as tight gas sands.

_________ 1982b, Cause no. NG-27, application by Sun Oil Co. for designation of the Mesaverde Group in part of Rio Blanco County, Colorado, as a tight gas sand.

_________ 1982c, Cause no. NG-28, application by Mitchell Energy Corporation for designation of the Dakota and Morrison Formations in parts of Garfield and Mesa Counties, Colorado, as tight gas sands.

Condon, S. M., 1988, Joint patterns on the northwest side of the San Juan Basin (Southern Ute Indian Reservation), southwest Colorado: in Geology and coalbed methane resources of the San Juan Basin, Colorado and New Mexico: Rocky Mountain Association of Geologists, p. 61–68.

Connolly, E. T., 1974, Digital log analysis recognition and treatment of field recording errors: 1974 Society of Professional Well Log Analysts Logging Symposium, McAllen, Texas, Paper S, unpaginated.

Coogan, A. H., 1991, A fault-related model for the facies of the Lower Silurian Clinton sandstone interval in the subsurface of eastern Ohio: Northeastern Geology, v. 13, no. 2, p. 110–129.

Cook, F. A., and Oliver, J. E., 1981, The Late Precambrian–Early Paleozoic continental edge in the Appalachian orogen: American Journal of Science, v. 281, p. 991–1008.

Copely, D. L., 1980, Upgrading Medina gas well production in western New York: World Oil, v. 190, no. 5, p. 97–106.

Cornell, F. L., 1989, Engineering improvements for Red Fork fracturing: Society of Petroleum Engineers, Proceedings, 1989 SPE Joint Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition, SPE 18963, p. 341–353.

Cornell, F. L., 1991, Engineering improvements for Red Fork fracturing: Journal of Petroleum Technology, February, p. 132–137.

Cumella, S. P., 1981, Sedimentary history and diagenesis of the Pictured Cliffs Sandstone, San Juan Basin, New Mexico and Colorado: The University of Texas at Austin, Texas Petroleum Research Committee, Report no. UT81-1, 219 p.

Dart, R. L., 1989, Horizontal stresses from well-bore breakouts and lithologies associated with their formation, Oklahoma and Texas Panhandle, *in* Johnson, K. S., ed., Anadarko Basin Symposium, 1988: Oklahoma Geological Survey Circular, v. 90, p. 97–120.

Davies, D. K., Williams, B. P. J., and Vessell, R. K., 1991, Reservoir models for meandering and straight fluvial channels; examples from the Travis Peak Formation, East Texas: Gulf Coast Association of Geological Societies Transactions, v. 41, p. 152–174.

De Witt, Wallace, Jr., 1986, Devonian gas-bearing shales in the Appalachian Basin, *in* Spencer, C. W., and Mast, R. F., Geology of tight gas reservoirs, American Association of Petroleum Geologists Studies in Geology Series No. 24, p. 1–8.

De Witt, Wallace, Jr., Cohee, G. V., and McGrew, L. W., 1979, Oil and gas in Mississippian rocks in part of eastern United States, *in* Craig, L. C., and Connor, C. W., eds., Paleotectonic investigations of the Mississippian System in the United States, Part II: Interpretive summary and special features of the Mississippian System: U.S. Geological Survey Professional Paper 1010, p. 441–455.

De Witt, Wallace, Jr., and McGrew, L. W., 1979, Appalachian Basin region, *in* Craig, L. C., and Connor, C. W., eds., Paleotectonic investigations of the Mississippian System in the United States, Part I: Introduction and regional analyses of the Mississippian System: U.S. Geological Survey Professional Paper 1010, p. 13–48.

Devine, P. E., 1991, Transgressive origin of channeled estuarine deposits in the Point Lookout Sandstone, northwestern New Mexico: a model for Upper Cretaceous, cyclic regressive parasequences of the U.S. Western Interior, American Association of Petroleum Geologists, v. 75, no. 6, p. 1039–1063.

Dickenson, R. G., 1992, Table Rock field—Frontier Formation, an overpressured reservoir, *in* Mullen, C. E., ed., Wyoming Geological Association Guidebook, p. 139–144.

Diecchio, R. J., 1985, Regional controls of gas accumulation in Oriskany Sandstone, Central Appalachian Basin: American Association of Petroleum Geologists Bulletin, v. 69, no. 5, p. 722–732.

Dillinger, J. K., 1989, Stratigraphic and sedimentologic studies of the Twowells Tongue of the Dakota Sandstone, southern San Juan Basin, New Mexico: USGS Open File Report 89-498, 32 p.

Dolson, John, Muller, Dave, Evetts, M. J., and Stein, J. A., 1991, Regional paleotopographic trends and production, Muddy Sandstone (Lower Cretaceous), central and northern Rocky Mountains: American Association of Petroleum Geologists Bulletin, v. 75, no. 3, p. 409–435.

Donaldson, A. C., and Shumaker, R. C., 1981, Late Paleozoic molasse of Central Appalachians, in Miall, A. D., ed., Sedimentation and tectonics in alluvial basins: Geological Association of Canada Special Paper 23, p. 99–124.

Donselaar, M. E., 1989, The Cliff House Sandstone, San Juan Basin, New Mexico: Model for the stacking of "transgressive" barrier complexes, Journal of Sedimentary Petrology, v. 59, no. 1, p. 13–27.

Dramis, L. A., 1981, Structural control of lower Vicksburg (Oligocene) turbidite channel sandstones, McAllen Ranch field, Texas: Gulf Coast Association of Geological Societies Transactions, v. 31, p. 81–88.

DuChene, H. R., 1989, Fracture reservoirs in the San Juan Basin, Colorado and New Mexico, *in* Lorenz, J. C., and Lucas, S. G., eds., Energy Frontiers in the Rockies, Albuquerque Geological Society, p. 101–109.

Dutton, S. P., 1982, Pennsylvanian fan-delta and carbonate deposition, Mobeetie field, Texas Panhandle: American Association of Petroleum Geologists Bulletin, v. 66, no. 4, p. 389–407.

__________ 1987, Diagenesis and burial history of the Lower Cretaceous Travis Peak Formation, East Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 164, 58 p.

__________ 1990a, Mobeetie field, *in* Beaumont, E. A., and Foster, N. H., compilers, Structural traps II: traps associated with tectonic faulting: Treatise of petroleum geology, atlas of oil and gas fields: American Association of Petroleum Geologists, p. 127–159.

__________ 1990b, Variations in diagenesis and reservoir quality in the Frontier Formation along the Moxa Arch, Green River Basin, Wyoming (abs.): American Association of Petroleum Geologists Bulletin, v. 74, p. 1321–1322.

__________ 1991, Diagenetic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming: The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-91/0057 prepared for the Gas Research Institute under contract no. 5082-211-0708, 48 p.

__________ 1992, Late-stage diagenesis and development of secondary porosity in Frontier Formation low-permeability sandstones, Green River Basin, Wyoming, U.S.A. (abs.): American Association of Petroleum Geologists Annual Convention, Official Program, p. 34.

Dutton, S. P., Clift, S. J., Folk, R. L., Hamlin, H. S., and Marin, B. A., in press, Porosity preservation by early siderite cementation in Sonora Canyon sandstones, Val Verde Basin, southwest Texas: American Association of Petroleum Geologists.

Dutton, S. P., and Diggs, T. N., 1990, History of quartz cementation in the Lower Cretaceous Travis Peak Formation, East Texas: Journal of Sedimentary Petrology, v. 60, no. 2, p. 191–202.

__________ 1992, Evolution of porosity and permeability in the Lower Cretaceous Travis Peak Formation, East Texas: American Association of Petroleum Geologists Bulletin, v. 76, no. 2, p. 252–269.

Dutton, S. P., Finley, R. J., and Herrington, K. L., 1987, Organic geochemistry of the Lower Cretaceous Travis Peak Formation in East Texas: Gulf Coast Association of Geological Societies Transactions, v. 37, p. 65–74.

Dutton, S. P., and Hamlin, H. S., 1991, Geologic controls on reservoir properties of Frontier Formation low-permeability gas reservoirs, Moxa Arch, Wyoming: Society of Petroleum

Engineers Joint Rocky Mountain Regional/Low Permeability Reservoirs Symposium Proceedings, SPE Paper 21851, p. 479–488.

__________ 1992, Interaction of burial history and diagenesis of the Upper Cretaceous Frontier Formation, Moxa Arch, Green River Basin, Wyoming: Wyoming Geological Association Guidebook, p. 37–50.

Dutton, S. P., Hamlin, H. S., and Laubach, S. E., 1992, Geologic controls on reservoir properties of low-permeability sandstone, Frontier Formation, Moxa Arch, southwest Wyoming: The University of Texas at Austin, Bureau of Economic Geology, report no. GRI-92/0127, prepared for the Gas Research Institute, 199 p.

Dutton, S. P., and Land, L. S., 1985, Meteoric burial diagenesis of Pennsylvanian arkosic sandstones, southwestern Anadarko Basin, Texas: American Association of Petroleum Geologists Bulletin, v. 69, no. 1, p. 22–38.

Dutton, S. P., Laubach, S. E., Tye, R. S., 1991a, Depositional, diagenetic, and structural controls on reservoir properties of low-permeability sandstone, Travis Peak Formation, East Texas: Gulf Coast Association of Geological Societies Transactions, v. 41, p. 209–220.

Dutton, S. P., Laubach, S. E., Tye, R. S., Baumgardner, R. W., Jr., and Herrington, K. L., 1991b, Geologic characterization of low-permeability gas reservoirs, Travis Peak Formation, East Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 204, 89 p.

Dutton, S. P., Laubach, S. E., Tye, R. S., Herrington, K. L., and Diggs, T. N., 1991c, Geological analysis of the Travis Peak Formation and Cotton Valley Sandstone, *in* Peterson, R. E., ed., Staged Field Experiment No. 3: application of advanced technologies in tight gas sandstones—Travis Peak and Cotton Valley Formations, Waskom Field, Harrison County, Texas: CER Corporation and S. A. Holditch & Associates, Inc., report no. GRI-91/0048, prepared for the Gas Research Institute, 253 p.

Dyke, Chris, 1992, How sensitive is natural fracture permeability at depth to variation in effective stress?: Conference preprints, Fractured and jointed rock masses symposium, p. 88–95.

Edwards, M. B., 1981, The upper Wilcox Rosita delta system of south Texas: record of growth-faulted shelf-edge deltas: American Association of Petroleum Geologists Bulletin, v. 65, p. 54–73.

Engelder, Terry, 1985, Loading paths to joint propagation during a tectonic cycle: an example from the Appalachian Plateau, U.S.A.: Journal of Structural Geology, v. 7, no. 3/4, p. 459–476.

Engelder, Terry, 1987, Joints and shear fractures in rock, *in* Atkinson, B. K., ed., Fracture mechanics of rock: New York, Academic Press, p. 27–65.

Ethridge, F. G., and Dolson, J. C., 1989, Unconformities and valley-fill sequences—key to understanding "J" Sandstone (Lower Cretaceous) reservoirs at Lonetree and Poncho fields, D-J Basin, Colorado, *in* Coalson, E. B., ed., Petrogenesis and petrophysics of selected sandstone reservoirs of the Rocky Mountain region: Rocky Mountain Association of Geologists, p. 221–233.

Ewing, T. E., 1986, Structural styles of the Wilcox and Frio growth-fault trends in Texas: constraints on geopressured reservoirs: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 154, 86 p.

Fassett, J. E., 1977, Geology of the Point Lookout, Cliff House and Pictured Cliffs sandstones of the San Juan Basin, New Mexico and Colorado, New Mexico Geological Society Guidebook, 28th Field Conference, San Juan Basin III, p. 193–197.

Fasset, J. E., Arnold, E. C., Hill, J. M., Hatton, K. S., Martinez, L. B., and Donaldson, D. A., 1978, Stratigraphy and oil and gas production of northwest New Mexico, in Fassett, J. E., ed., Oil and gas fields of the Four Corners Area, v. 1: Four Corners Geological Society, p. 46–61.

Fassett, J. E., and Hinds, J. S., 1971, Geology and fuel resources of the Fruitland Formation and Kirtland Shale of the San Juan Basin, New Mexico and Colorado: U.S. Geological Survey Paper 676, 76 p.

Finley, R. J., 1984, Geology and engineering characteristics of selected low-permeability gas sandstones: a national survey: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 138, 220 p.

__________ 1985, Reservoir properties and gas productivity of the Corcoran and Cozette tight sandstones, Colorado: Society of Petroleum Engineers, SPE/DOE paper 13852, p. 33–39.

__________ 1986, An overview of selected blanket-geometry, low-permeability gas sandstones in Texas, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology No. 24, p. 69–85.

Finley, R. J., Dutton, S. P., Lin, Z. S., and Saucier, A. E., 1985, The Travis Peak (Hosston) Formation: geologic framework, core studies, and engineering field analysis: The University of Texas at Austin, Bureau of Economic Geology, contract report no. GRI-85/0044, prepared for the Gas Research Institute, 233 p.

Finley, R. J., Guevara, E. H., Jirik, L. A., Kerr, D. R., Langford, R. P., Wermund, E. G., Zinke, S. G., Collins, R. E., Hower, T., Lord, M., Howard, W. E., and Ballard, J. R., 1990, Secondary natural gas recovery: targeted technology applications for infield reserve growth: The University of Texas at Austin, Bureau of Economic Geology, annual report prepared for the Gas Research Institute under contract no. 5088-212-1718, 194 p.

Finley, R. J., Laubach, S. E., Tyler, Noel, and Holtz, M. H., 1990, Opportunities for horizontal drilling in Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 90-2, 32 p.

Fisher, W. L., and Brown, L. F., Jr., 1992, Clastic depositional systems—a genetic approach to facies analysis: The University of Texas at Austin, Bureau of Economic Geology, 211 p.

Fisher, W. L., and McGowen, J. H., 1967, Depositional systems in the Wilcox Group of Texas and their relationship to occurrence of oil and gas: Gulf Coast Association of Geological Societies Transactions, v. 17, p. 105–125.

Folk, R. L., 1974, Petrology of sedimentary rocks: Austin, Texas, Hemphill, 182 p.

Forgotson, J. M., 1954, Regional stratigraphic analysis of Cotton Valley Group of Upper Gulf Coastal Plain: American Association of Petroleum Geologists Bulletin, v. 38, no. 12, p. 2476–2499.

Forgotson, J. M., Jr., and Forgotson, J. M., 1975, "Porosity pod": concept for successful stratigraphic exploration of fine-grained sandstones: American Association of Petroleum Geologists Bulletin, v. 59, no. 7, p. 1113–1125.

Fouch, T. D., Wandrey, C. J., Pitman, J. K., Nuccio, V. F., Schmoker, J. W., Rice, D. D., Johnson, R. C., and Dolton, G. L., 1992, Natural gas accumulations in low-permeability Tertiary, and Cretaceous (Campanian and Maastrichtian) rock, Uinta Basin, Utah: Final report DOE/MC/20422-3051 (DE92001132) prepared by the U.S. Geological Survey for the U.S. Department of Energy, 81 p.

Franklin, S. P. and Tieh, T. T., 1989, Petrography, diagenesis, and reservoir properties of the Dakota Sandstone of West Lindrith Field, Rio Arriba County, New Mexico; Petrogenesis and petrophysics of selected sandstone reservoirs of the Rock Mountain Region, the Rocky Mountain Association of Geologists, Denver, Colorado, p. 117–133.

Frantz, J. H., Jr., Hopkins, C. W., and Lancaster, D. E., in press, Reservoir and stimulation evaluation of the Berea Sandstone Formation in Pike County, Kentucky: Society of Petroleum Engineers 1993 Joint Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium.

Frech, K. R., 1983, Aspects of diagenesis of the "Clinton" Formation: Akron, Ohio, The University of Akron, Master's thesis, 243 p.

Frenzel, H. N., Bloomer, R. R., Cline, R. B., and others, 1988, The Permian Basin region, *in* Sloss, L. L., ed., Sedimentary cover—North American craton, U.S.: Geological Society of America, The geology of North America, v. D-2, p. 261–306.

Friedman, M., 1975, Fracture in rock: Reviews of Geophysics and Space Physics, v. 13, p. 352–358.

Galloway, W. E., 1989, Genetic stratigraphic sequences in basin analysis II: application to northwest Gulf of Mexico Cenozoic basin: American Association of Petroleum Geologists Bulletin, v. 73, p. 143–154.

Galloway, W. E., Ewing, T. E., Garrett, C. M., Tyler, Noel, and Bebout, D. G., 1983, Atlas of major Texas oil reservoirs: The University of Texas at Austin, Bureau of Economic Geology Special Publication, 139 p.

Galloway, W. E., and Hobday, D. K., 1983, Terrigenous clastic depostional systems: applications to petroleum, coal, and uranium exploration: New York, Springer-Verlag, 423 p.

Garbis, S. J., Brown, B. J., and Mauritz, S. J., 1985, Review of completion practices in the Wilcox Formation in south and south central Texas: Society of Petroleum Engineers/U.S. Department of Energy Low Permeability Gas Reservoirs Symposium Proceedings, SPE Paper No. 13900, p. 497–508.

Gas Research Institute, 1992, Developing in-situ stress profiles: GRI Technical Summary, 8 p.

Gilbert, M. C., 1983, The Meers fault of southwestern Oklahoma—Evidence for possible strong Quaternary seismicity in the Midcontinent (abs.): Eos, Transactions of the American Geophysical Union, v. 64, no. 18, p. 313.

Gill, J. R., Merewether, E. A., and Cobban, W. A., 1970, Stratigraphy and nomenclature of some Upper Cretaceous and lower Tertiary rocks in south-central Wyoming: U.S. Geological Survey Professional Paper 667, 37 p.

Gorham, F. D., Jr., Woodward, L. A., Callender, J. F., and Greer, A. R., 1979, Fractures in Cretaceous rocks from selected areas of San Juan Basin, New Mexico: exploration implications: American Association of Petroleum Geologists Bulletin, v. 63, p. 598–607.

Gregory, R. W., and De Bruin, R. H., 1991, Oil and gas fields map of the Greater Green River Basin and Overthrust Belt: The Geological Survey of Wyoming, Map Series 36, scale 1:316,800.

Grout, M. A., and Verbeek, E. R., 1983, Field studies of joints, insufficiencies and solutions, with examples from the Piceance Creek Basin, Colorado: Proceedings, 16th Oil Shale Symposium (Gray, J. H., ed.), Colorado School of Mines, Golden Colorado, p. 65–80.

Gulf Coast Association of Geological Societies, compiler, 1972, Tectonic map of Gulf Coast region, U.S.A.: American Association of Petroleum Geologists, scale 1:1,000,000.

Haas, M. R., 1990, Impact of improved technology on potential reserves of tight gas in East Texas and North Louisiana: ICF-Lewin, Inc., topical report GRI-90/0174, prepared for the Gas Research Institute, 119 p.

Haas, M. R., McFall, K. S., and Coates, J.-M., 1988, Site selection for GRI cooperative tight gas field research, volume I: screening of candidate tight gas formations: topical report no. GRI-89/0018, ICF-Lewin Energy, prepared for the Gas Research Institute under contract no. 5083-211-817, 66 p., plus appendices.

Hagar, R., and Petzet, G. A., 1982, Hefty wellhead prices spark drilling in U.S. tight gas sands: Oil and Gas Journal, v. 80, no. 17, p. 69–74.

Haimson, B. C., 1977, Crustal stress in the continental United States as derived from hydrofracturing tests, *in* Heacock, J. C., ed., The Earth's crust: American Geophysical Union Geophysics Monograph Series, v. 20, p. 576–592.

Haldorsen, H. H., and MacDonald, C. J., 1987, Stochastic modeling of underground reservoir facies (SMURF) SPE Paper No. 16751, Proceedings, Society of Petroleum Engineers Annual Technical Conference and Exhibition, p. 99–114.

Hale, L. A., 1950, Stratigraphy of the Upper Cretaceous Montana Group in the Rock Springs Uplift, Sweetwater County, Wyoming: Wyoming Geological Association Guidebook, 5th Annual Field Conference, p. 49–58.

__________ 1955, Stratigraphy and facies relationships of the Montana Group in south-central Wyoming, northern Utah, and northwestern Colorado: Wyoming Geological Association Guidebook, 10th Annual Field Conference, p. 89–94.

Hall, C. D., Janks, J. S., and Ladle, G. H., 1984, Sedimentology and diagenesis of the Cotton Valley sandstone in the Amoco No. 1 Cullers well, Rusk County, Texas, *in* Presley, M. W., ed., The Jurassic of East Texas: East Texas Geological Society, Tyler, Texas, p. 127–140.

Ham, W. E., and Wilson, J. L., 1967, Paleozoic epeirogeny and orogeny in the central United States: American Journal of Science, v. 265, no. 5, p. 332–407.

Hamlin, H. S., 1991, Stratigraphy and depositional systems of the Frontier Formation and their controls on reservoir development, Moxa Arch, southwest Wyoming: The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-91/0128, prepared for the Gas Research Institute under contract no. 5082-211-0708, 45 p.

__________ 1992a, Frontier Formation stratigraphy and depositional systems architecture, Green River Basin, Wyoming: a record of sequence development in a proximal foreland basin (abs.): American Association of Petroleum Geologists Annual Convention, Official Program, p. 50–51.

__________ 1992b, Low-permeability gas reservoirs of the Frontier Formation, western Green River Basin, Wyoming (abs.): Society for Sedimentary Geology (SEPM) 1992 Theme Meeting, Program with Abstracts, p. 29.

Hamlin, H. S., Clift, S. J., and Dutton, S. P., 1992a, Stratigraphy and diagenesis of Sonora Canyon deep-water sandstones, Val Verde Basin, southwest Texas: American Association of Petroleum Geologists, Southwest Section Transactions, p. 209–220.

Hamlin, H. S., Miller, W. K., Peterson, R. E., and Wiltgen, Nick, 1992b, Results of applied research in the Canyon Sands, Val Verde Basin, southwest Texas: In Focus—Tight Gas Sands, v. 8, no. 1, p. 1–32.

Han, J. H., 1981, Genetic stratigraphy and associated growth structures of the Vicksburg Formation, South Texas: The University of Texas at Austin, Ph.D. dissertation, 162 p.

Han, J. H., and Scott, A. J., 1981, Relationship of syndepositional structures and deltation, Vicksburg Formation (Oligocene), South Texas: Society of Economic Paleontologists and Mineralogists, Gulf Coast Section, Second Annual Research Conference, Program and Abstracts, p. 33–40.

Hancock, P. L., 1985, Brittle microtectonics: principles and practice: Journal of Structural Geology, v. 7, no. 3/4, p. 437–458.

Hancock, P. L., Al-Kahdi, A., Barka, A. A., and Bevan, T. G., 1987, Aspects of analyzing brittle structures: Annales Tectonicae, v. 1, p. 5–19.

Hancock, P. L., and Bevan, T. G., 1987, Brittle modes of foreland deformation, *in* Coward, M. P., Dewey, J. F., and Hancock, P. L., eds., Continental Extensional Tectonics, Geological Society of London Special Publication No. 28, p. 127–137.

Handford, C. R., Dutton, S. P., and Fredericks, P. E., 1981, Regional cross sections of the Texas Panhandle: Precambrian to mid-Permian: The University of Texas at Austin, Bureau of Economic Geology, 8 p., 7 plates.

Hansley, P. L., and Johnson, R. C., 1980, Mineralogy and diagenesis of low-permeability sandstones of Late Cretaceous age, Piceance Creek basin, northwestern Colorado: The Mountain Geologist, v. 17, no. 4, p. 88–129.

Hanson, B. M., Powers, B. K., Garrett, C. M., Jr., and others, 1991, The Permian basin, *in* Gluskoter, H. J., Rice, D. D., and Taylor, R. B., eds., Economic Geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 339–355.

Hatchell, W. O., Blagbrough, J. W., and Hill, J. M., 1982, Stratigraphy and copper deposits of the Abo Formation, Abo Canyon area, central New Mexico: New Mexico Geological Society Guidebook, 33rd Field Conference, p. 249–260.

Hawthorne, H. W., 1985, The Red Fork Sandstone, Cherokee Group (Pennsylvanian) of the Southeast Thomas field, Custer County, Oklahoma: Shale Shaker, v. 35, no. 3, p. 50–58.

Henke, K. A., 1982, Origin of the late Paleocene-early Eocene Wilcox sandstones, Lobo trend, Webb and Zapata Counties, Texas: Master's thesis, Texas A&M University, 198 p.

__________ 1985, Reservoir characteristics of Lower Wilcox sandstones, Lobo trend, Webb and Zapata Counties, Texas (abs.): American Association of Petroleum Geologists Bulletin, v. 69, p. 265.

Hensel, W. M., Jr., 1987, A perspective look at fracture porosity: SPE Paper No. 16806, 62nd Annual Technical Conference, p. 571–575.

Hentz, T. F., 1992, Low-permeability, gas-bearing Cleveland Formation (Upper Pennsylvanian), western Anadarko Basin: structure, paleoenvironments, and paleotectonic control on depositional patterns, *in* Cromwell, D. W., Moussa, M. T., and Mazzullo, L. J., eds., Southwest Section of the American Association of Petroleum Geologists, Transactions, Publication SWS 92-90, p. 231–252.

__________ in press, Lithostratigraphic and sequence-stratigraphic framework of the gas-bearing, fluvial-deltaic Cleveland Formation (Upper Pennsylvanian), western Anadarko Basin, Texas Panhandle: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations.

Herkommer, M. A., and Denke, G. W., 1982, Stratigraphy and hydrocarbons, Parker County, Texas, *in* Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend Arch area: Dallas Geological Society, p. 97–127.

Hermann, R. B., 1979, Surface wave focal mechanisms for eastern North American earthquakes with tectonic implications: JGR, v. 84, no. B7, p. 3543–3552.

Hickman, R. G., 1989, Production implications of fractures and minor faults at South Casper Creek field: unpublished report, Union Oil of California, Project 624-62511, 8 p.

Higley, D. K., and Schmoker, J. W., 1989, Influence of depositional environment and diagenesis on regional porosity trends in the Lower Cretaceous "J" Sandstone, Denver Basin, Colorado, *in* Coalson, E. B., ed., Petrogenesis and petrophysics of selected sandstone reservoirs of the Rocky Mountain region: Rocky Mountain Association of Geologists, p. 183–196.

Hill, D. P., Lennon, R. B., and Wright, C. L., 1991, Making an old gem sparkle, the rejuvenation of McAllen Ranch field, Texas: Gulf Coast Association of Geological Societies Transactions, v. 41, p. 325–335.

Hill, R. E., 1992, Analysis of natural and induced fractures in the Barnett Shale, Mitchell Energy Corporation T. P. Sims No. 2, Wise County, Texas: CER Corporation, topical report prepared for Gas Research Institute under contract no. 5091-212-2242, 14 p., plus appendix.

Hillis, G. A., 1985, Petrophysics of the Morrow Formation, southeastern New Mexico: Transactions Southwest Section of the American Association of Petroleum Geologists, 1985 Convention, Fort Worth, Texas, p. 157–173.

Hills, J. M., 1968, Gas in Delaware and Val Verde Basins, West Texas and Southeastern New Mexico, *in* Beebe, B. W., ed., Natural gases of North America, v. 2: American Association of Petroleum Geologists Memoir 9, p. 1394–1432.

__________ 1984, Sedimentation, tectonism, and hydrocarbon generation in Delaware Basin, West Texas and southeastern New Mexico: American Association of Petroleum Geologists Bulletin, v. 68, p. 250–267.

Hills, J. M., and Galley, J. E., 1988, The Permian Basin region, general introduction, *in* Sloss, L. L., ed., Sedimentary cover–North American Craton, U.S.: Geological Society of North America, v. D-2, p. 261–267.

Hodgson, R. A., 1961, Regional study of jointing in Comb Ridge–Navajo Mountain area, Arizona and Utah: American Association of Petroleum Geologists Bulletin, v. 45, p. 1–38.

Hollberg J. E., Dahm, M. A., and Bath, J., 1985, Geology and production performance of the Niobrara low-permeability reservoir in the Denver-Julesburg Basin: Society of Petroleum Engineers, Proceedings, 1985 SPE/DOE Joint Symposium on Low Permeability Reservoirs, SPE/DOE 13886, p. 353–364.

Hollenshead, C. T., and Pritchard, R. L., 1961, Geometry of producing Mesaverde sandstones, San Juan Basin, *in* Peterson, J. A., and Osmond, J. C., eds., Geometry of sandstone bodies: American Association of Petroleum Geologists, 1960 Symposium, p. 98–118.

Holmquist, H. J., 1965, Deep pays in Delaware and Val Verde Basins: American Association of Petroleum Geologists Memoir 4, p. 247–279.

Hoppe, W. F., 1978, Basin Dakota, *in* Fassett, J. E., Oil and gas fields of the Four Corners area, v. 1: Four Corners Geological Society, p. 204–206.

Hoskins, B. W., 1982, Fracture analysis of Pennsylvanian carbonate bank systems—the Graford formation in North-Central Texas, *in* Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend Arch area: Dallas Geological Society, p. 179–192.

Howard, W. E., and Hunt, E. R., 1986, Travis Peak: an integrated approach to formation evaluation: Proceedings, 1986 Society of Petroleum Engineers/U.S. Department of Energy/Gas Research Institute Joint Symposium on Unconventional Gas Technology, Louisville, Kentucky, SPE Paper No. 15208, p. 7–18.

Hower, T. L., 1990, Using depletion ratios to select and evaluate drilling locations in naturally fractured gas reservoirs: Society of Petroleum Engineers 1990 65th Annual Technical Conference and Exhibition, p. 429–437.

Huang, Fu-Wen Frank, 1989, Depositional environments, diagenesis and porosity relationships of the Canyon sands, Edwards and Sutton Counties, Texas: Texas Tech University, Ph.D. dissertation, 244 p.

Huffman, A. C., and Taylor, D. J., 1991, Basement fault controls on the occurrence and development of San Juan Basin energy resources (abs.): Geological Society of America Abstracts with Programs, 34 p.

Hugman, R. H., Springer, P. S., and Vidas, E. H., 1992a, Tight gas field, reservoir, and completion analysis of the United States: volume 1—project summary, volume 2—output tables: topical report nos. GRI-92/0226.1 and 92/0226.2, prepared by Energy and Environmental Analysis, Inc., for the Gas Research Institute, v. 1, 41 p., plus appendices; v. 2, 516 p.

Hunter, B. E., 1979, Regional analysis of the Point Lookout Sandstone, Upper Cretaceous, San Juan Basin, New Mexico–Colorado, Ph.D. dissertation, Texas Tech University, 118 p.

Hyman, L. A., Malek, D. J., Admire, C. A., and Walls, J. D., 1991, The effects of microfractures on directional permeability in tight gas sands: SPE Paper 21878, SPE/DOE Low-Permeability Reservoir Symposium, Denver, unpaginated.

ICF-Lewin Energy Division, 1988, Resource analysis and technology evaluation for the tight gas sands project: Presentation to the Gas Research Institute Project Advisors Group, Shreveport, Louisiana, April 27, 1988, 21 p.

Jacka, A. D., 1965, Depositional dynamics of the Almond Formation, Rocks Springs Uplift, Wyoming: Wyoming Geological Association Guidebook, 19th Annual Field Conference, p. 81–100.

Jackson, M. L. W., and Laubach, S. E., 1991, Structural history and origin of the Sabine Arch, East Texas and Northwest Louisiana: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 91-3, 47 p.

James, A. D., 1984, Lower Pennsylvanian reservoirs of the Parkway-Empire South field area, Eddy County, New Mexico: Transactions Southwest Section of the American Association of Petroleum Geologists, 1984 Convention, Midland, Texas, p. 33–52.

__________ 1985, Producing characteristics and depositional environments of Lower Pennsylvanian reservoirs, Parkway-Empire South area, Eddy County, New Mexico: American Association of Petroleum Geologists Bulletin, v. 69/7, p. 1043–1063.

Johnson, K. S., Amsden, T. W., Denison, R. E., and others, 1988, Southern Midcontinent region, *in* Sloss, L. L., ed., Sedimentary cover–North American Craton: U.S.: Geological Society of America, The geology of North America, v. D-2, p. 307–359.

Johnson, R. C., and Finn, T. M., 1986, Cretaceous through Holocene history of the Douglas Creek Arch, Colorado and Utah, Rocky Mountain Association of Geologists 1986 Symposium, p. 77–95.

Johnson, R. C., and Nuccio, V. F., 1986, Structural and thermal history of the Piceance Creek Basin, western Colorado, in relation to hydrocarbon occurrence in the Mesaverde Group, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology 24, p. 165–205.

Jonas, E. C., and McBride, E. F., 1977, Diagenesis of sandstone and shale: application to exploration for hydrocarbons: The University of Texas at Austin, Department of Geological Sciences Continuing Education Publication No. 1, 120 p.

Jones, F. O., and Owens, W. W., 1980, A laboratory study of low-permeability gas sends: Journal of Petroleum Technology, v. 32, p. 1631–1640.

Jons, R., and Stanley, J., 1981, Rock Tank (Morrow sandstone) field, Eddy County, New Mexico, *in* Henry, G., ed., Basins of the Southwest—Phase 2: North Texas Geological Society, p. 110–130.

K & A Energy, 1992, Geophysical and geological reservoir characterization of the Devonian shales: Annual Technical Report, v. 1, 36 p.

Kauffmann, E. G., 1977, Geological and biological overview—Western Interior Cretaceous Basin, *in* Kauffmann, E. G., ed., Cretaceous facies, faunas, and paleoenvironments across the Western Interior Basin: The Mountain Geologist, v. 6, p. 227–245.

Keefer, W. R., 1965a, Geologic history of Wind River Basin, central Wyoming: American Association of Petroleum Geologists Bulletin, v. 49, p. 1878–1892.

__________ 1965b, Stratigraphy and geologic history of the uppermost Cretaceous, Paleocene, and lower Eocene rocks in the Wind River Basin, Wyoming: U.S. Geological Survey Professional Paper 495-A, 77 p.

__________ 1969, Geology of petroleum in Wind River Basin, central Wyoming: American Association of Petroleum Geologists Bulletin, v. 53, no. 9, p. 1839–1865.

__________ 1970a, Geology of petroleum in Wind River Basin, central Wyoming: American Association of Petroleum Geologists Bulletin, v. 53, p. 1839–1865.

__________ 1970b, Structural geology of the Wind River Basin, Wyoming: U.S. Geological Survey Professional Paper 495-D, 35 p.

Keefer, W. R., and Van Lieu, J. A., 1966, Paleozoic formations in the Wind River Basin, Wyoming: U.S. Geological Survey Professional Paper 495-B, 60 p.

Keighin, C. W., Law, B. E., and Pollastro, R. M., 1989, Petrology and reservoir characteristics of the Almond Formation, Greater Green River Basin, Wyoming: Rocky Mountain Association of Geologists, p. 281–298.

Keith, E. W., 1965, Rock Springs and Blair Formations on and adjacent to the Rock Springs Uplift, Sweetwater County, Wyoming: Wyoming Geological Association Guidebook, 19th Annual Field Conference, p. 43–53.

Kellogg, Harold E., 1977, Geology and petroleum of the Mancos "B" Formation Douglas Creek Arch area Colorado and Utah, Rocky Mountain Association of Geologists 1977 Symposium, p. 167–179.

Kelly, V. C., 1971, Geology of the Pecos country, southeastern New Mexico: New Mexico Bureau of Mines and Mineral Resources, Memoir 24, 75 p.

Keltch, Brian, 1985, Why use geology for Clinton exploration? (Examples and reasons from Guernsey County, Ohio): The New Clinton Collection, Ohio Geological Society, p. 21–42.

Keltch, Brian, Wilson, D. A., and Potter, P. E., 1987, Depositional environment controls Clinton production in Guernsey County, Ohio: Oil & Gas Journal, v. 85, no. 34, p. 68–71.

Kennedy, C. L., ed., 1983a, Codell Sandstone: D-J Basin's new objective, *in* Petroleum Frontiers: Petroleum Information Corporation, Denver, Colorado, v. 1, no. 1, p. 4–34.

King, P. B., compiler, 1969, Tectonic map of North America: U.S. Geological Survey, 2 sheets, scale 1:5,000,000.

Klass, M. J., Kersey, D. G., Berg, R. R., and Tieh, T. T., 1981, Diagenesis and secondary porosity in Vicksburg sandstones, McAllen Ranch field, Hidalgo County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 31, p. 115–123.

Knight, W. V., 1969, Historical and economic geology of Lower Silurian Clinton Sandstone of northeastern Ohio: American Association of Petroleum Geologists Bulletin, v. 53, no. 7, p. 1421–1452.

Knipe, R., 1992, Faulting processes and fault seal, *in* Larsen, R. M., Brekke, H., Larsen, B. T., and Talleraas, E., eds., Structural and tectonic modelling and its application to petroleum geology, NPF (Norwegian Petroleum Society) Special Publication 1, Elsevier, Amsterdam, p. 325–342.

Kopper, P. K., 1962, Douglas Creek anticline and adjoining area, *in* Exploration for Oil and Gas in Northwestern Colorado: Rocky Mountain Association of Geologists, p. 108–110.

Kosters, E. C., and Hamlin, H. S., 1989, Gulf Coast plays, *in* Kosters, E. C., and others, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology, p. 4–58.

Kosters, E. C., and others, 1989, Atlas of major Texas gas reservoirs: The University of Texas at Austin, Bureau of Economic Geology, 161 p.

Kraig, D. H., Wiltschko, D. V., and Spang, J. H., 1987, Interaction of basement uplift and thin-skinned thrusting, Moxa arch and Western Overthrust Belt, Wyoming: a hypothesis: Geological Society of America, v. 99, no. 5, p. 654–662.

Kranz, R. L., 1983, Microcracks in rock: a review: Tectonophysics, v. 100, p. 449–480.

Krupa, M. P., and Spencer, C. W., 1989, U.S. Geological Survey publications on western tight gas reservoirs: Final Report DOE/MC/20422-2677 (DE89000968), prepared by the U.S. Geological Survey for the U.S. Department of Energy, 133 p.

Kulander, B. R., Dean, S. L., and Ward, B. J., Jr., 1990, Fractured core analysis: American Association of Petroleum Geologists Methods in Exploration No. 8, 88 p.

Lachenbruch, A. H., 1979, Heat flow in the Basin and Range province and thermal effects of tectonic extension: Pure and Applied Geophysics, v. 117, p. 35–50.

Lacy, S. L., Ding, W. Z., and Joshi, S. D., 1992, Perspectives on horizontal wells in the Rocky Mountain region: Conference abstracts, Horizontal drilling symposium—domestic and international case studies: Rocky Mountain Association of Geologists, unpaginated.

Ladeira, F. L., and Price, N. J., 1981, Relationship between fracture spacing and bed thickness: Journal of Structural Geology, v. 3, p. 179–183.

Lahti, V. R., and Huber, W. F., 1982, The Atoka Group (Pennsylvanian) of the Boonesville field area, North-Central Texas, *in* Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend Arch area: Dallas Geological Society, p. 377–399.

Landes, K. K., 1970, Petroleum Geology of the United States: New York, Wiley, 571 p.

Lane, D. W., 1963, Sedimentary environments in Cretaceous Dakota Sandstone in northwestern Colorado, American Association of Petroleum Geologists Bulletin, v. 47, no. 2, p. 229–256.

Langford, R. P., Grigsby, J. D., Howard, W. E., Hall, J. D., and Maguregui, J., 1990, Sedimentary facies and petrophysical characteristics of cores from the lower Vicksburg gas reservoirs, McAllen Ranch field, Hidalgo County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 40, p. 439–450.

Langford, R. P., Wermund, E. G., Grigsby, J. D., Guevara, E. H., and Zinke, S. K., 1992, Secondary natural gas recovery: reservoir heterogeneity and potential for reserve growth through infield drilling: an example from McAllen Ranch field, Hidalgo County, Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-92/0112 prepared for the Gas Research Institute under contract no. 5088-212-1718 and the U.S. Department of Energy under contract no. DE-FG21-88MC25031, 289 p.

LaPointe, P. R., 1988, A method to characterize fracture density and connectivity through fractal geometry: International Journal of Rock Mechanics and Geomechanics Abstracts, v. 25, no. 6, p. 421–429.

Larese, R. E., 1974, Petrology and stratigraphy of the Berea Sandstone in the Cabin Creek and Gay-Fink trends, West Virginia: West Virginia University, Ph.D. dissertation, 387 p.

Laubach, S. E., 1988, Fractures generated during folding of the Palmerton Sandstone, eastern Pennsylvania: Journal of Geology, v. 96, no. 4, p. 495–503.

__________ 1989a, Fracture analysis of the western flank of the Sabine Arch, East Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 185, 55 p.

__________ 1989b, Paleostress directions from the preferred orientation of closed microfractures (fluid-inclusion planes): Journal of Structural Geology, v. 11, no. 5, p. 603–611.

__________ 1991, Fracture patterns in low-permeability-sandstone gas reservoir rocks in the Rocky Mountain region: SPE Paper 21853, SPE/DOE Rocky Mountain Regional Meeting/Low-Permeability Reservoir Reservoir Symposium, Denver, p. 501–510.

__________ 1992a, Attributes of fracture networks in selected Cretaceous sandstones of the Green River and San Juan basin, *in* Schmoker, J. W., Coalson, E. B., and Brown, C. A., eds., Geological studies relevant to horizontal drilling: examples from western North America: Rocky Mountain Association of Geologists, p. 61–74.

__________ 1992b, Identifying key reservoir elements in low-permeability sandstones: natural fractures in the Frontier Formation, southwestern Wyoming: In Focus–Tight Gas Sands, v. 8, no. 2, p. 3–11.

Laubach, S. E., Clift, S. J., Hill, R. E., Fix, J. E., 1992a, Stress directions in Cretaceous Frontier Formation, Green River Basin, Wyoming: Wyoming Geological Association Guidebook, v. 48, p. 75–86.

Laubach, S. E., Hamlin, H. S., Buehring, R. L., Baumgardner, R. W., Jr., and Monson, E. R., 1990, Application of borehole-imaging logs to geologic analysis, Cotton Valley Group and Travis Peak Formation, GRI staged field experiment wells, East Texas: The University of Texas at Austin, Bureau of Economic Geology, topical report no. GRI-90/0222 prepared for the Gas Research Institute, 115 p.

Laubach, S. E., and Jackson, M. L. W., 1990, Origin of arches in the northwestern Gulf of Mexico basin: Geology, v. 18, p. 595–598.

Laubach, S. E., and Lorenz, J. C., 1992, Preliminary assessment of natural fracture patterns in Frontier Formation sandstones, southwestern Wyoming: Wyoming Geological Association Guidebook, v. 48, p. 87–96.

Laubach, S. E., and Monson, E., 1988, Coring-induced fractures: indicators of hydraulic fracture propagation in a naturally fractured reservoir: SPE Paper No. 18164, Proceedings, SPE Annual Technical Conference and Exhibition, p. 587–596.

Laubach, S. E., and Tremain, C. M., 1991, Regional coal fracture patterns and coalbed methane development: 32nd U.S. Symposium on Rock Mechanics, The Netherlands, A. A. Balkema, p. 851–861.

Laubach, S. E., Tremain, C. M., and Baumgardner, R. W., Jr., 1991, Fracture swarms in Upper Cretaceous sandstone and coal, northern San Juan Basin, Colorado: Potential targets for methane exploration, *in* Ayers, W. B., Jr., and others, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: The University of Texas at Austin, Bureau of Economic Geology, topical report prepared for Gas Research Institute under contract no. 5087-214-1544, p. 119–140.

Laubach, S. E., Tye, R. S., Dutton, S. P., and Herrington, K. L., 1989, Staged Field Experiment No. 2, Geologic analysis of the Travis Peak Formation, *in* Peterson, R. E., ed., Application of advanced geologic, petrophysical, and engineering technology to evaluate and improve gas recovery from low permeability reservoir sandstones: CER Corporation and S. A. Holditch and Associates, Inc., report no. GRI-89/0140 prepared for Gas Research Institute, p. 42–90.

Laubach, S. E., Tyler, Roger, Ambrose, W. A., Tremain, C. M., and Grout, M. A., 1992b, Preliminary map of fracture patterns in coal in the western United States: Wyoming Geological Association Guidebook, v. 48, p. 253–267.

Laubach, S. E., Vendeville, B. C., and Reynolds, S. J., 1992c, Patterns in the development of extensional fault-block shapes from comparison of outcrop-scale faults and experimental physical models, *in* Larsen, R. M., Brekke, H., Larsen, B. T., and Talleraas, E., eds., Structural and tectonic modelling and its application to petroleum geology, NPF (Norwegian Petroleum Society) Special Publication 1, Elsevier, Amsterdam, p. 231–241.

Laughrey, C. D., 1984, Petrology and reservoir characteristics of the Lower Silurian Medina Group reservoir sandstones, Athens and Geneva fields, northwestern Pennsylvania: Pennsylvania Geological Survey, 4th series, Mineral Resource Report 85, 126 p.

Laughrey, C. D., and Harper, J. A., 1986, Comparisons of Upper Devonian and Lower Silurian tight formations in Pennsylvania—Geological and engineering characteristics, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology No. 24, p. 9–43.

Law, B. E., and Spencer, C.W., 1989, Introduction, *in* Law, B. E., and Spencer, C. W., eds., Geology of tight gas reservoirs in the Pinedale Anticline area, Wyoming, and at the multiwell experiment site, Colorado: U.S. Geological Survey Bulletin 1886, p. K1–K24.

Law, B. E., Spencer, C. W., Charpentier, R. R., Crovelli, R. A., Mast, R. F., Dolton, G. L., and Wandrey, C. J., 1989, Estimates of gas resources in overpressured low-permeability Cretaceous and Tertiary sandstone reservoirs, Greater Green River Basin, Wyoming, Colorado, and Utah: 40th annual field conference, Wyoming Geological Association Guidebook, p. 39–61.

Levine, S. D., 1984, Provenance and diagenesis of the Cherokee sandstones, deep Anadarko Basin, western Oklahoma: Shale Shaker, v. 34, no. 10, p. 120–144.

Lewis, J. L., 1961, The stratigraphy and depositional history of the Almond Formation in the Great Divide Basin, Sweetwater County, Wyoming: Wyoming Geological Association Guidebook, 16th Annual Field Conference, p. 87–95.

Lickus, M. R., and Law, B. E., 1988, Structure contour map of the greater Green River Basin, Wyoming, Colorado, and Utah: U.S. Geological Survey Miscellaneous Field Studies Map MF-2031.

Lindquist, S. J., 1977, Secondary porosity development and subsequent reduction, overpressured Frio Formation sandstone (Oligocene), South Texas: Gulf Coast Association of Geological Societies Transactions v. 27, p. 99–107.

Lomando, A. J., 1992, The influence of solid reservoir bitumen on reservoir quality: American Association of Petroleum Geologists Bulletin, v. 76, no. 8, p. 1137–1152.

Long, J. C. S., and Billaux, D. M., 1987, From field data to fracture network modeling: An example incorporating spatial structure: Water Resources Research, v. 23, no. 7, p. 1201–1216.

Long, J. C. S., and Witherspoon, P. A., 1985, The relationship of the degree of interconnection to permeability in fracture networks: Journal of Geophysical Research, v. 90, no. B4, p. 3087–3099.

Long, John, 1986, The Eocene Lobo gravity slide, Webb and Zapata Counties, Texas, *in* Stapp, W. L., ed., Contributions to the geology of South Texas: San Antonio, Texas, South Texas Geological Society, p. 270–293.

Long, Mike, 1978, Drilling near standstill in Laredo play: The Oil and Gas Journal, Oct. 2, p. 62–63.

Lorenz, J. C., 1983a, Lateral variability in the Corcoran and Cozzette blanket sandstones and associated Mesaverde rocks, Piceance Creek basin, northwestern Colorado: Society of Petroleum Engineers, SPE/DOE paper 11608, p. 81–86.

__________ 1983b, Reservoir sedimentology in Mesaverde rocks at the multi-well experiment site: Sandia National Laboratories report SAND83-1078, 38 p.

__________ 1987, Reservoir sedimentology in Mesaverde rocks at the multi-well experiment site and east central Piceance Creek basin: Sandia National Laboratories report SAND87-0040, 40 p.

_________ 1989, Reservoir sedimentology in Mesaverde rocks, multi-well experiment site and east-central Piceance basin, northwest Colorado, *in* Law, B. E., and Spencer, C. W., eds., Geology of tight gas reservoirs in the Pinedale Anticline area, Wyoming, and at the multiwell experiment site, Colorado: U.S. Geological Survey Bulletin 1886, p. K1–K24.

Lorenz, J. C., and Finley, S. J., 1991 Regional fractures II: Fracturing of Mesaverde Reservoirs in the Piceance Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 75, no. 11, p. 1738–1757.

Lorenz, J. C., Finley, S. J., and Warpinski, N. R., 1990, Significance of coring-induced fractures in Mesaverde core, northwest Colorado: American Association of Petroleum Geologists Bulletin, v. 74, p. 1017–1029.

Lorenz, J. C., Heinze, D. M., Clark, J. A., and Searls, C. A., 1985, Determination of widths of meander-belt sandstone reservoirs from vertical downhole data, Mesaverde Group, Piceance Creek Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 69, no. 5, p. 710–721.

Lorenz, J. C., and Hill, R. H., 1991, Subsurface fracture spacing: Comparison of inferences from slant/horizontal core and vertical core in Mesaverde reservoirs: Proceedings, Joint SPE Rocky Mountain Regional Meeting/Low-Permeability Reservoir Symposium, SPE Paper No. 21877, p. 705–716.

Lorenz, J. C., Teufel, L. W., and Warpinski, N. R., 1991, Regional fractures I: A mechanism for the formation of regional fractures in flat-lying reservoirs: American Association of Petroleum Geologists Bulletin, v. 75, p. 1714–1737.

Loucks, R. G., 1976, Pearsall Formation, Lower Cretaceous, South Texas: depositional facies and carbonate diagenesis and their relationship to porosity: The University of Texas at Austin, Ph.D. dissertation, 362 p.

_________ 1978, Sandstone distribution and potential for geopressured geothermal energy production in the Vicksburg Formation along the Texas Gulf Coast: Gulf Coast Association of Geological Societies Transactions, v. 28, p. 239–270.

Loucks, R. G., Dodge, M. M., and Galloway, W. E., 1986, Controls on porosity and permeability of hydrocarbon reservoirs in lower Tertiary sandstones along the Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 149, 78 p.

Loucks, R. G., Richman, D. L., and Milliken, K. L., 1981, Factors controlling reservoir quality in Tertiary sandstones and their significance to geopressured geothermal production: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 111, 41 p.

Louisiana Office of Conservation, 1981, Docket no. NGPA 81-TF-1, 2, application by Texas Oil and Gas Corp. for designation of the Cotton Valley in parts of 28 Louisiana parishes as a tight gas sand.

Love, J. D., 1988, Geology of the Wind River Basin, central Wyoming, *in* Sloss, L. L., ed., Sedimentary cover—North American craton, U.S.: Geological Society of America, The Geology of North America, v. D-2, p. 196–200.

Love, J. D., and Christiansen, A. C., 1985, Geologic map of Wyoming: U.S. Geological Survey Map, 3 sheets, scale 1:500,000.

Lovick, G. P., Mazzine, C. G., and Kotila, D. A., 1982, Atokan clastics—depositional environments in a foreland basin, *in* Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend Arch area: Dallas Geological Society, p. 193–211.

Lowry, P. H., Brown, R. W., Kubik, W. T., and Hobson, J. P., Jr., 1991, Application of single-fold seismic data, natural fracture and lithologic characterization, comprehensive study wells, and preliminary geologic study, GRI Experimental Development Well Site Selection Area: Annual technical report prepared for the Gas Research Institute under contract no. 5087-213-1617-A, 236 p.

Luffel, D. L., Herrington, K. L., and Harrison, C. W., 1991, Fibrous illite controls productivity in Frontier gas sands, Moxa Arch, Wyoming: Society of Petroleum Engineers Joint Rocky Mountain Regional/Low-Permeability Reservoirs Symposium Proceedings, SPE Paper No. 21876, p. 695–704.

Luffel, D. L., Herrington, K. L., Walls, J. D., 1990, Effect of extraction and drying on flow, capillary, and electrical properties of Travis Peak cores containing fibrous illite, *in* Proceedings, 1990 Society of Petroleum Engineers Annual Technical Conference, SPE Paper No. 20725, p. 131–138.

MacKenzie, D. B., 1965, Depositional environments of Muddy Sandstone, western Denver Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 49, no. 2, p. 186–206.

Madole, R. F., 1988, Stratigraphic evidence of Holocene faulting in the mid-continent: The Meers fault, southwestern Oklahoma: Geological Society of America Bulletin, v. 100, no. 3, p. 392–401.

Mallory, W. W., 1977, Fractured shale hydrocarbon reservoirs in southern Rocky Mountain basins, *in* Veal, H. K., ed., Exploration frontiers of the central and southern Rockies: Rocky Mountain Association of Geologists, p. 89–94.

Mann, C. J., and Thomas, W. A., 1964, Cotton Valley Group (Jurassic) nomenclature, Louisiana and Arkansas: Gulf Coast Association of Geological Societies Transactions, v. 14, p. 143–152.

Mannhard, G. W., 1976, Stratigraphy, sedimentology, and paleoenvironments of the La Ventana Tongue (Cliff House Sandstone) and adjacent formation of the Mesaverde Group (Upper Cretaceous), southeastern San Juan Basin, New Mexico: Ph.D. dissertation, The University of New Mexico, Albuquerque, 182 p.

Marin, B. A., Clift, S. J., Hamlin, H. S., and Laubach, S. E., in press, Natural fractures in Sonora Canyon sandstones, Sonora and Sawyer fields, Sutton County, Texas: Society of Petroleum Engineers 1993 Joint Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium.

Marshall, W. D., 1981, Turbidite origin of the Oligocene Vicksburg sandstone, McAllen Ranch field, Hidalgo County, Texas: Society of Economic Paleontologists and Mineralogists, Gulf Coast Section, Second Annual Research Conference, Program and Abstracts, p. 43–44.

Martini, I. P., 1971, Regional analysis of sedimentology of Medina Formation (Silurian), Ontario and New York: American Association of Petroleum Geologists Bulletin, v. 55, no. 8, p. 1249–1261.

Martinsen, R. S., and Christensen, G., 1992, A stratigraphic and environmental study of the Almond Formation, Mesaverde Group, Greater Green River Basin, Wyoming: Wyoming Geological Association Guidebook, 1992, p. 171–190.

Mathias, J. P., 1971, Successful stimulation of a thick, low pressure, water sensitive gas reservoir by pseudolimited entry; Journal of Petroleum Technology, vol. 23, no. 2, p. 185–190.

Matuszczak, R. A., 1973, Wattenberg field, Denver Basin, Colorado: Mountain Geologist, v. 10, no. 3, p. 99–105.

__________ 1976, Wattenberg field: a review, *in* Epis, R. C., and Weimer, R. J., eds., Studies in Colorado field geology: Colorado School of Mines Professional Contribution No. 8, p. 275–279.

Mazzullo, L. J., 1983a, Reservoir and clay mineral trends in the Morrow Formation, southeastern New Mexico: Bulletin of the West Texas Geological Society, v. 23, no. 1, p. 4–9.

__________ 1983b, Stratigraphy and sedimentation of the Lower and Middle Morrow of southeastern New Mexico (abs): Transactions Southwest Section of the American Association of Petroleum Geologists, 1983 Convention, Abilene, Texas, 203 p.

Mazzullo, L. J., and Mazzullo, J. M., 1984, Detrital and authigenic clay minerals of the Lower Morrow sandstones of eastern New Mexico: Transactions Southwest Section of the American Association of Petroleum Geologists, 1984 Convention, Midland, Texas, p. 53–60.

__________ 1985, Geology and clay mineralogy of the Morrow Formation, southeastern New Mexico: Society of Petroleum Engineers/U.S. Department of Energy Joint Symposium on Low Permeability Reservoirs, Denver, Colorado, SPE/DOE Paper No. 13849, p. 7–10.

McGarr, A., 1988, On the state of lithosphereic stress in the absence of applied tectonic forces: Journal of Geophysical Research, v. 93, no. B11, p. 13609–13617.

McGowen, M. K., and Harris, D. W., 1984, Cotton Valley (Upper Jurassic) and Hosston (Lower Cretaceous) depositional systems and their influence on salt tectonics in the East Texas Basin: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 84-5, 41 p.

Merewether, E. A., Blackmon, P. D., and Webb, J. C., 1984, The mid-Cretaceous Frontier Formation near the Moxa Arch, southwestern Wyoming: U.S. Geological Survey Professional Paper 1290, 29 p.

Middleman A. A., 1983, Albino Gallup field, San Juan County, New Mexico, *in* Four Corners Geological Society, Oil and Gas Fields of the Four Corners Area, Volume III, p. 924–926.

Milici, R. C., and De Witt, Wallace, Jr., 1988, The Appalachian Basin, *in* Sloss, L. L., ed., Sedimentary Cover—North American Craton, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. D-2, p. 427–469.

Miller, D. N., Jr., and VerPloeg, A. J., 1980, Tight gas sand inventory of Wyoming: The Geological Survey of Wyoming, open-file report no. WGS 81-1, 20 p., plus appendices, plates.

Miller, F. X., 1977, Biostratigraphic correlation of the Mesaverde Group in southwestern Wyoming and northwestern Colorado, *in* Veal, H. K., ed., Exploration frontiers of the central and southern Rockies: Rocky Mountain Association of Geologists, 1977 Symposium, p. 117–137.

Miller, W. K., Peterson, R. E., Stevens, J. E., Lackey, C. B., and Harrison, C. W., 1991, In-Situ stress profiling and prediction of hydraulic fracture azimuth for the Canyon Sands Formation, Sonora and Sawyer fields, Sutton County, Texas, SPE 21848, presented at the 1991 Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium, p. 445–456.

Millison, C., 1962, Accumulation of oil and gas in northwestern Colorado controlled principally by stratigraphic variations, *in* Amuedo, C. L., and Mott, M. R., eds., Exploration for oil and gas in northwestern Colorado: Rocky Mountain Association of Geologists, p. 41–48.

Mitchell, M. H., 1975, Depositional environment and facies relationships of the Canyon sandstone, Val Verde Basin, Texas: Texas A&M University, Master's thesis, 210 p.

Molenaar, C. M., 1977, Stratigraphy and depositional history of Upper Cretaceous rocks of the San Juan Basin area, New Mexico and Colorado, with a note on economic resources: New Mexico Geological Society 28th Field Conference Guidebook, p. 159–166.

__________ 1983, Major depositional cycles and regional correlations of Upper Cretaceous rocks, southern Colorado plateau and adjacent areas, *in* Reynolds, M. W., and Dolly, E. D., eds., Mesozoic paleogeography of west-central United States: SEPM (Society for Sedimentary Geology) Rocky Mountain Section, p. 201–224.

Momper, J. A., 1981, Denver Basin, Lower Cretaceous, J Sandstone, tight reservoir gas potential: American Association of Petroleum Geologists short course notes (Geochemistry for Geologists), p. 1–15.

Montgomery, Scott, 1991, Reservoir (re)characterization in old fields: Petroleum Frontiers, v. 8, no. 3, 61 p.

Morrow, N. R., Brower, K. R., Shoxiang, M., Buckley, J. S., 1990, Fluid flow in healed tectonic fractures: Journal of Petroleum Technology, v. 42, p. 1310–1318.

Moslow, T. F., and Tillman, R. W., 1986, Sedimentary facies and reservoir characteristics of Frontier Formation sandstones, southwestern Wyoming, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology No. 24, p. 271–295.

Multer, H. G., 1963, Geology of the Silurian producing zones in the Moreland Oil Pool, Wayne County, Northeast Ohio: Ohio Geological Survey Report of Investigations, v. 47, p. 1–42.

Murray, G. E., 1957, Geologic occurrence of hydrocarbons in Gulf Coastal Province of the United States: Gulf Coast Association of Geological Societies Transactions, v. 7, p. 253–299.

Myal, F. R., and Frohne, K. H., 1991, Slant-hole completion test in the Piceance Basin, Colorado: Society of Petroleum Engineers, paper 21866, Rocky Mountain Regional/Low Permeability Reservoir Symposium, p. 611–622.

__________ 1992, Drilling and early testing of a sidetrack from the Slant Hole Completion Test well—a case study of gas recovery research in Colorado's Piceance Basin: Society of Petroleum Engineers, paper 24382, Rocky Mountain Regional Meeting, p. 201–209.

Myer, H. J., and McGee, H. W., 1985, Oil and gas fields accompanied by geothermal anomalies in Rocky Mountain region: American Association of Petroleum Geologists Bulletin, v. 69, p. 933–945.

Myers, P. B., Miller, R. D., and Steeples, D. W., 1987, Shallow seismic reflection profile of the Meers fault, Comanche County, Oklahoma: Geophysical Research Letters, v. 14, no. 7, p. 749–752.

Myers, R. C., 1977, Stratigraphy of the Frontier Formation (Upper Cretaceous), Kemmerer area, Lincoln County, Wyoming: 29th annual field conference, Wyoming Geological Association Guidebook, p. 271–311.

National Petroleum Bibliography, 1965, Geological maps—Panhandle oil and gas: Amarillo, Texas, 220 p.

National Petroleum Council, 1980, Unconventional gas sources: Tight Gas reservoirs, v. 5, part I, p. 1–222; part II, p. 10-1–19-24; and Executive Summary, 32 p.

Nelson, R. A., 1985, Geologic analysis of naturally fractured reservoirs: Houston, Gulf Publishing Company, Contributions in Petroleum Geology and Engineering, v. 1, 320 p.

New Mexico Oil Conservation Division, 1981a, Case no. 7086, application by Blackwood and Nichols Co. for designation of the Pictured Cliffs Sandstone in parts of San Juan and Rio Arriba Counties, New Mexico, as a tight gas sand.

_________ 1981b, Case no. 7087, application by Blackwood and Nichols Co. for designation of the Fruitland Formation in parts of San Juan and Rio Arriba Counties, New Mexico, as a tight gas sand.

_________ 1981c, Case no. 7093, application of Mesa Petroleum Company and Yates Petroleum Corporation for designation of a tight formation, Torrance, Guadalupe, De Baca, Lincoln, and Chaves Counties, New Mexico, as a tight gas sand.

_________ 1981d, Case no. 7116, application by Consolidated Oil and Gas for designation of the Dakota Formation in parts of San Juan County, New Mexico, as a tight gas sand.

_________ 1981e, Case no. 7154, application by Mobil Producing Texas and New Mexico for designation of the Mesaverde Formation in parts of Rio Arriba County, New Mexico, as a tight gas sand. Application was withdrawn due to acreage dispute between USGS and State of New Mexico.

_________ 1981f, Case no. 7209, application by Koch Industries for designation of the Mesaverde Formation in parts of San Juan County, New Mexico, as a tight gas sand.

__________ 1981g, Case no. 7252, application by Four Corners Gas Producers Association for designation of the Basin Dakota Field in parts of San Juan and Rio Arriba Counties, New Mexico, as a tight gas sand.

__________ 1981h, Case no. 7300, application by Dome Petroleum for designation of the Chacra Formation in parts of Sandoval County, New Mexico, as a tight gas sand.

__________ 1981i, Case no. 7395, application by Curtis J. Little for designation of the Pictured Cliffs Formation in parts of Rio Arriba County, New Mexico, as a tight gas sand.

__________ 1982a, Case no. 7489, application by Amoco Production Company for designation of the Chacra Formation in parts of Rio Arriba County, New Mexico, as a tight gas sand.

__________ 1982b, Case no. 7492, application by Havey E. Yates Company for designation of the Atoka-Morrow Formation in parts of Chaves, Lea and Roosevelt Counties, New Mexico, as a tight gas sand.

__________ 1982c, Case no. 7515, application by Four Corners Gas Producers Association for designation of the Dakota Formation in parts of San Juan County, New Mexico, as a tight gas sand.

__________ 1982d, Case no. 7598, Application of ANR Production Company and Yates Petroleum Corporation for designation of a tight formation in San Miguel, Torrance, Guadalupe, De Baca, Lincoln, and Chaves Counties, New Mexico, as a tight gas sand.

__________ 1982e, Case no. 7697, Application of Oxoco Production Corp. for designation of the Mesaverde Formation in parts of San Juan County, New Mexico, as a tight gas sand.

__________ 1983a, Case no. 7735, application by Bass Interprises for designation of the Morrow Formation in parts of Lea and Eddy Counties, New Mexico, as a tight gas sand.

__________ 1983b, Case no. 7784, application by Jake L. Hamon for designation of the Morrow Formation in part of Eddy County, New Mexico, as a tight gas sand.

__________ 1984, Case no. 10428, application by Superior Oil for designation of the Morrow Formation in part of Lea County, New Mexico, as a tight gas sand.

__________ 1992a, Case no. 10420, application by UNOCAL for designation of the Dakota Formation in parts of Rio Arriba County, New Mexico, as a tight gas sand.

__________ 1992b, Case no. 10428, application by Enron Oil and Gas Company for designation of the Morrow Formation in part of Lea County, New Mexico, as a tight gas sand.

Newman, H. E., III, 1981, The Upper Cretaceous and lower Tertiary stratigraphy and natural gas potential of the Greater Green River Basin of Wyoming: U.S. Department of Energy, Bartlesville Energy Technology Center, DOE-BC-10003-20, 158 p.

Ng, D. T. W., 1979, Subsurface study of Atoka (Lower Pennsylvanian) clastic rocks in parts of Jack, Palo Pinto, Parker, and Wise Counties, North-Central Texas: American Association of Petroleum Geologists Bulletin, v. 63, no. 1, p. 50–66.

Nickelsen, R. P., and Hough, V. D., 1967, Jointing in the Appalachian Plateau of Pennsylvania: Geological Society of America Bulletin, v. 78, p. 609–630.

Noe, D. C., in press, Mancos marine sandstones on the Douglas Creek Arch, Atlas of Major Rocky Mountain Gas Reservoirs, Gas Research Institute.

Nolen-Hoeksema, R. C., and Howard, J. H., 1987, Estimating drilling direction for optimum production in a fractured reservoir: American Association of Petroleum Geologists Bulletin, v. 71, no. 8, p. 958–966.

Northrop, D. A., and Frohne, K. H., 1990, Insights and contributions from the Multiwell Experiment: a field laboratory in tight sandstone reservoirs: Journal of Petroleum Technology, v. 42, p. 722–779.

NSI Technologies, Inc., 1991a, Well completion and hydraulic fracture treatment design and analysis of the Canyon sands (lower interval): topical report no. GRI-91-0165 prepared for the Gas Research Institute under contract no. 5091-221-2130, 192 p.

__________ 1991b, Well completion and hydraulic fracture treatment design and analysis of the Canyon sands (lower and middle intervals): topical report no. GRI-91-0207 prepared for the Gas Research Institute under contract no. 5091-221-2130, 276 p.

__________ 1991c, Well completion and hydraulic fracture treatment design and analysis of the Canyon sands (middle interval): topical report no. GRI-91-0257 prepared for the Gas Research Institute under contract no. 5091-221-2130, 121 p.

__________ 1991, Well completion and hydraulic fracture treatment design and analysis of the Canyon sands (upper interval): topical report no. GRI-91-0323 prepared for the Gas Research Institute under contract no. 5091-221-2130, 89 p.

Nur, A., 1982, The origin of tensile fracture lineaments: Journal of Structural Geology, v. 4, p. 31–40.

O'Brien, B. E., and Freeman, R. E., 1979, Lobo trend of south Laredo area, Webb and Zapata Counties, Texas: Oil and Gas Journal, v. 77, p. 158–176.

Ohio Geological Society, 1985a, Clinton Sandstone papers presented at the Ohio Oil and Gas Association Winter Meetings 1961 to 1978—Abridged Reprint of 1980 Volume: Ohio Geological Society, Columbus, Ohio, 228 p.

_________ 1985b, The New Clinton Collection—1985: Ohio Geological Society, Columbus, Ohio, 243 p.

Overbey, W. K., and Henninger, B. R., 1985, History, development, and geology of oil fields in Hocking and Perry Counties, Ohio, *in* The New Clinton Collection—1985: Ohio Geological Society, Columbus, Ohio, p. 77–100.

Overbey, W. K., and Rough, R. L., 1971, Prediction of oil and gas bearing rock fractures from surface structural features: United States Bureau of Mines Report of Investigations, v. 7500, p. 1–14.

Owen, D. E., 1973, Depositional history of the Dakota Sandstone, San Juan Basin area, New Mexico, *in* Fassett, J. E., ed., Cretaceous and Tertiary rocks of the southern Colorado Plateau: Four Corners Geological Society Memoir, p. 37–51.

Owen, D. E. and Siemers, C. T., 1977, Lithologic correlation of the Dakota Sandstone and adjacent units along the eastern flank of the San Juan Basin, New Mexico: New Mexico Geological Society Guidebook, 28th Field Conference, San Juan Basin III, p. 179–183.

Paape, D. W., 1968, Geology of Wind River Basin of Wyoming and its relationship to natural gas accumulation: American Association of Petroleum Geologists Memoir No. 9, v. 1, p. 760–779.

Palmer, J. J., and Scott, A. J., 1984, Stacked shoreline and shelf sandstones of La Ventana Tongue (Campanian), northwestern New Mexico: American Association of Petroleum Geologists Bulletin, v. 68, no. 1, p. 74–91.

Parker, R. L., and Gibson, C. R., 1977, Saint Clair field, *in* Selected gas fields of the Texas Panhandle: Panhandle Geological Society, p. 71–73.

Pashin, J. C., and Ettensohn, F. R., 1987, An epeiric shelf-to-basin transition: Bedford-Berea sequence, northeastern Kentucky and south-central Ohio: American Journal of Science, v. 287, p. 893–926.

Pepper, J. F., de Witt, Wallace, Jr., and Demarest, D. F., 1954, Geology of the Bedford Shale and Berea Sandstone in the Appalachian Basin: U.S. Geological Survey Professional Paper 259, 111 p.

Peterson, J. A., 1977, Paleozoic shelf margins and marginal basins, western Rocky Mountains: Wyoming Geological Association Guidebook, 29th Annual Field Conference, p. 135–154.

Peterson, J. A., Loleit, A. J., Spencer, C. W., and Ullrich, R. A., 1965, Sedimentary history and economic geology of San Juan Basin: American Association of Petroleum Geologists Bulletin, v. 49, p. 2076–2119.

Petroleum Information Corporation, 1983, Pecos Slope Abo red beds: shallow target for New Mexico gas: Petroleum Frontiers, v. 1, no. 1, p. 35–59.

Picou, E. B., Jr., 1981, McAllen Ranch field: depositional environments of reservoir sandstones and associated shales—the Shell Oil viewpoint: Society of Economic Paleontologists and Mineralogists, Gulf Coast Section, Second Annual Research Conference, Program and Abstracts, p. 48–51.

Pitman, J. K., and Dickenson, W. W., 1989, Petrology and isotope geochemistry of mineralized fractures in Cretaceous rocks—evidence for cementation in a closed hydrologic system: U.S. Geological Society Bulletin 1886-J, p. J1–J15.

Pitman, J. K., and Sprunt, E., 1986, Origin and distribution of fractures in Lower Tertiary and Upper Cretaceous rocks, Piceance Basin, Colorado, and their relationship to the occurrence of hydrocarbons, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology No. 24, p. 221–234.

Plumb, R. A., 1989, Fracture patterns associated with incipient wellbore breakouts, *in* Maury, V., and Fourmaintraux, D., eds., Rock at Great Depth, Balkema, Rotterdam, p. 761–768.

Plumb, R. A., Herron, S. L., and Olsen, M. P., 1992, Influence of composition and texture on comprehensive strength variations in the Travis Peak Formation: *in* Proceedings, Society of Petroleum Engineers Annual Technical Conference and Exhibition, SPE Paper No. 24758, p. 985–998.

Plumb, R. A., and Hickman, S. H., 1985, Stress-induced borehole elongation: a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn geothermal well: Journal of Geophysical Research, v. 90, no. B7, p. 5513–5521.

Pollard, D. D., and Aydin, A., 1988, Progress in understanding jointing over the past century: Geological Society of America Bulletin, v. 100, no. 8, p. 1181–1204.

Pollard, D. D., and Segall, P., 1987, Theoretical displacements and stresses near fractures in rock, with applications to faults, joints, veins, dikes, and soliution surfaces, *in* Atkinson, B. K., ed., Fracture mechanics of rock: New York, Academic Press, p. 277–347.

Potter, P. E., deReamer, J. H., Jackson, D. S., and Maynard, J. B., 1983, Lithologic and paleoenvironmental atlas of Berea Sandstone (Mississippian) in the Appalachian Basin: Appalachian Geological Society Special Publication 1, 157 p.

Presley, M. W., ed., The Jurassic of East Texas: East Texas Geological Society, Tyler, Texas, 304 p.

Presley, M. W., and Reed, C. H., 1984, Jurassic exploration trends of east Texas, *in* Presley, M. W., ed., The Jurassic of East Texas: East Texas Geological Society, Tyler, Texas, p. 11–22.

Price, N. J., 1974, The development of stress systems and fracture patterns in undeformed sediments: Proceedings, Third International Congress of Society for Rock Mechanics, p. 487–495.

Railroad Commission of Texas, 1977, District 4, Laredo (Lobo) field, Docket No. 4-67, 530.

__________ 1980a, Recommendation of the Railroad Commission of Texas that the Cisco Sandstone Formation be designated as a tight formation in Texas: Docket No. 20-75, 144.

__________ 1980b, Recommendation of the Railroad Commission of Texas that the Cotton Valley Sandstone Formation, the Bossier Shale, and the Cotton Valley Lime Formation be designated as tight formations in Texas: Docket No. 20-75, 144.

__________ 1980c, Recommendation of the Railroad Commission of Texas that the deep Vicksburg Formation in Starr County, Texas, be designated as a tight formation: Docket No. 4-76, 658.

__________ 1980d, Recommendation of the Railroad Commission of Texas that the geopressured Wilcox Lobo Formation be designated as a tight formation in Texas: Docket No. 20-75, 144.

__________ 1981a, Application by Diamond Shamrock Corporation for designation of the Cleveland Formation in parts of Lipscomb, Ochiltree, Hansford, Hutchinson, Roberts, Hemphill, and Wheeler Counties, Texas, as a tight gas sand: Docket No. 10-77, 222.

__________ 1981b, Docket no. 4-77, 117, application by Petro-Lewis Corp. for designation of the Olmos Formation in parts of Webb and Dimmitt Counties, Texas, as a tight gas sand.

__________ 1981c, Recommendation of the Railroad Commission of Texas that the Wilcox Formation in the Bonus, S. (Wilcox 13,900′) field be designated as a tight formation in Texas: Docket No. 3-76, 565.

_________ 1982a, Application for designation of the Granite Wash Formation in parts of Ochiltree, Lipscomb, Roberts, Hemphill, and Wheeler Counties, Texas, as a tight gas sand: Docket No. 10-78, 976.

_________ 1982b, Recommendation of the Railroad Commission of Texas that the Upper Wilcox (Mackhank) (First Tom Lyne) Sand Formation be designated as a tight gas formation in the area near Clegg, Live Oak County, Texas: Docket No. 2-78, 232.

_________ 1983a, Recommendation of the Railroad Commission of Texas that the Canyon Sand Formation in Irion County, Texas, be designated as a tight formation: Docket No. 7C-79, 698.

_________ 1983b, Recommendation of the Railroad Commission of Texas that the lower Vicksburg "P" Sandstone in the McAllen Ranch field, Hidalgo County, Texas, be designated as a tight formation: Docket No. 4-78, 772.

_________ 1985, Application for designation of the Olmos Formation in McMullen County, Texas, as a tight gas sand: Docket No. 1-85, 978.

_________ 1986, Application for designation of the Olmos Formation in McMullen County, Texas, as a tight gas sand: Docket No. 1-86, 560.

_________ 1988, Application of Bright & Company for the Commission's recommendation to the Federal Energy Regulatory Commission that the Guerra reservoir underlying certain portions of the McAllen Ranch (Guerra, E.) field, Hidalgo County, Texas be recognized as a tight gas sand: Docket No. 4-92, 360.

_________ 1990, Application of Texaco Producing, Inc., for the Commission's recommendation to the Federal Energy Regulatory Commission that the Guerra reservoir underlying certain portions of the McAllen Ranch (Guerra) field, Hidalgo County, Texas, be recognized as a tight gas sand: Docket No. 4-93, 629.

_________ 1991a, Oil and gas annual report, v. 2, 389 p.

_________ 1991b, The application of Enron Oil and Gas Company for the recommendation before the Federal Energy Regulatory Commission that the lower Wilcox Sand interval underlying certain portions of Webb County, Texas, be recognized as a tight gas formation: Docket No. 4-96, 631.

_________ 1991c, The application of RK Petroleum Corporation for the recommendation before the Federal Energy Regulatory Commission that the Canyon Formation underlying certain portions of Tom Green County, Texas, be recognized as a tight gas formation: Docket No. 7C-96, 334.

Rall, R. W., and Rall, E. P., 1958, Pennsylvanian subsurface geology of Sutton and Schleicher Counties, Texas: American Association of Petroleum Geologists Bulletin, v. 42, no. 4, p. 839–870.

Ramelli, A. R., and Slemmons, D. B., 1986, Neotectonic activity of the Meers fault: Oklahoma Geological Survey Guidebook 24, p. 45–54.

Reiss, L. H., 1980, The reservoir engineering aspects of fractured formations: Houston, Gulf Publishing Company, 108 p.

ResTech, Inc., 1989, Development of petrophysical techniques for evaluating tight gas sands: final report no. GRI-89/0103 prepared for the Gas Research Institute under contract no. 5084-211-1062, 194 p., plus appendix.

__________ 1991, Petrophysical analysis, Canyon Sands, Sutton field: unpublished report, unpaginated.

Reynolds, M. W., 1968, Geologic map of the Muddy Gap quadrangle, Carbon County, Wyoming: U.S. Geological Survey Geologic Quadrangle Map GQ-771.

Richardson, R. M., 1992, Ridge forces, absolute plate motions, and the intraplate stress field: Journal of Geophysical Research, v. 97, no. B8, p. 11739–11748.

Richman, D. L., Milliken, K. L., Loucks, R. G., and Dodge, M. M., 1980, Mineralogy, diagenesis, and porosity in Vicksburg sandstones, McAllen Ranch field, Hidalgo County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 30, p. 473–481.

Ritzma, H. R., 1962, Piceance Creek gas field, *in* Amuedo, C. L., and Mott, M. R., eds., Exploration for oil and gas in northwest Colorado: Rocky Mountain Association of Geologists, p. 96–103.

Roberts, C. N., 1981, Fracture optimization in a tight gas play, Muddy "J" Formation, Wattenberg field, Colorado, *in* SPE/DOE Low Permeability Symposium, Proceedings, Paper No. 9851, p. 245–252.

Robinson, B. M., Holditch, S. A., and Lee, W. J., 1986, A case study of the Wilcox (Lobo) trend in Webb and Zapata Counties, Texas: Journal of Petroleum Technology, December, p. 1355–1364.

Rocky Mountain Association of Geologists, 1977, Subsurface cross sections of Colorado: Special Publication No. 2, 39 p.

Roehler, H. W., 1988, The Pintail Coal Bed and Barrier Bar G-A Model for Coal Barrier Bar-Lagoon Origin, Upper Cretaceous Almond Formation, Rock Springs Coal Field, Wyoming: U.S. Geological Survey Professional Paper 1398, 60 p.

Roehler, H. W., 1990, Stratigraphy of the Mesaverde Group in the Central and Eastern Greater Green River Basin, Wyoming, Colorado, and Utah: United States Geological Survey Professional Paper 1508, 52 p.

Rogers, R. E., 1968, Carthage field, Panola County, Texas, *in* Beebe, B. W., ed., Natural gases of North America: American Association of Petroleum Geologists Memoir 9, Part 1, p. 1020–1059.

Rose, P. R., Everett, J. R., and Merin, I. S., 1986, Potential basin-centered gas accumulation in Cretaceous Trinidad Sandstone, Raton Basin, Colorado, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight gas reservoirs: American Association of Petroleum Geologists Studies in Geology No. 24, p. 111–128.

Roth, E. E., 1968, Natural gases of the Appalachian Basin, *in* Beebe, B. W., ed., Natural Gases of North America: American Association of Petroleum Geologists, Memoir 9, v. 2, p. 1702–1715.

Ryder, R. T., 1988, Greater Green River Basin, *in* Sloss, L. L., ed., Sedimentary cover—North American Craton, U.S.: Geological Society of America, The Geology of North America, v. D-2, p. 154–165.

S. A. Holditch & Associates, Inc., 1991, A review of the Clinton Formation in Ohio as a potential location for the GRI hydraulic fracture test (HFTS) site: report prepared for the Gas Research Institute, 40 p.

__________ 1992, Cooperative well report: Maxus Exploration Company H. T. Glasgow well No. 2, Ochiltree County, Texas: topical report no. GRI-92/0087 prepared for the Gas Research Institute under contract number 5091-221-2129, 43 p., plus appendices.

Sanders, L. L., 1991, Geochemistry of formation waters from the Lower Silurian Clinton Formation (Albion Sandstone), Eastern Ohio: American Association of Petroleum Geologists Bulletin, v. 75, no. 10, p. 1593–1608.

Saucier, A. E., Finley, R. J., and Dutton, S. P., 1985, The Travis Peak (Hosston) Formation of East Texas and North Louisiana, *in* Proceedings, 1985 Society of Petroleum Engineers/Department of Energy Joint Symposium on Low Permeability Reservoirs, SPE/DOE Paper No. 13850, p. 15–22.

Schmoker, J. W., and Gautier, D. L., 1989, Compaction of basin sediments: modeling based on time-temperature history: Journal of Geophysical Research, v. 94, no. B6, p. 7379–7386.

Schmoker, J. W., and Higley, D. K., 1991, Porosity trends of the Lower Cretaceous J Sandstone, Denver Basin, Colorado: Journal of Sedimentary Petrology, v. 61, no. 6, p. 909–920.

Schrider, L. A., Watts, R. J., and Wasson, J. A., 1970, An evaluation of the East Canton oil field waterflood: Journal of Petroleum Geology, v. 22, p. 1371–1378.

Schultz, M. S., and Lafollette, R. F., 1989, Effect of drilling and completion methods on Frontier gas production, northern Moxa Arch, southwest Wyoming: 40th Annual Field Conference, Wyoming Geological Association Guidebook, p. 247–254.

Scott, G. L., Brannigan, J. P., and Mitchell, S. T., 1983, Pecos Slope Abo Gas field, Chaves County, New Mexico, *in* Zidek, Jiri, ed., Guidebook for field trip to the Abo red beds (Permian), central and south-central New Mexico: Roswell Geological Society and New Mexico Bureau of Mines and Mineral Resources, 1 plate.

Self, G. A., Breard, S. Q., Rael, H. P., Stein, J. A., Thayer, P. A., Easom, W. D., 1986a, Lockhart Crossing field: New Wilcox trend in southeastern Louisiana: Oil & Gas Journal, v. 84, p. 81–87.

Self, G. A., Breard, S. Q., Rael, H. P., Stein, J. A., Thayer, P. A., Traugott, M. O., and Easom, W. D., 1986b, Lockhart Crossing field: New Wilcox trend in southeastern Louisiana: American Association of Petroleum Geologists Bulletin, v. 70, no. 5, p. 501–515.

Selley, R. C., 1978, Concepts and methods of subsurface facies analysis: American Association of Petroleum Geologists, Continuing Education Course Note Series No. 9, 82 p.

Seni, S. J., and Jackson, M. P. A., 1983, Evolution of salt structures, East Texas diapir province, part 1: sedimentary record of halokinesis: American Association of Petroleum Geologists Bulletin, v. 67, no. 8, p. 1219–1244.

Shanmugam, G., and Moiola, R. J., 1988, Submarine fans: characteristics, models, classification, and reservoir potential: Earth-Science Reviews, v. 24, p. 383–428.

Shannon, L. T., 1983, Stratigraphy of the Blair Formation: An upper Cretaceous slope and basin deposit, Rocks Springs Uplift, Sweetwater County, Wyoming: Colorado School of Mines, Master's thesis, 150 p.

Sitler, G. F., 1985, East Canton-Magnolia oilfield, *in* Ohio Geological Society, Clinton Sandstone papers presented at the Ohio Oil and Gas Association Winter Meetings 1961 to 1978—Abridged Reprint of 1980 Volume: Ohio Geological Society, Columbus, Ohio, p. 41–51.

Smiraldo, M. S., 1985, Lithology, porosity development, and silica cement source of the "Clinton" Formation in eastern Ohio: The University of Akron, Akron, Ohio, Master's thesis, 132 p.

Smith, J. H., 1961, A summary of stratigraphy and paleontolgy, upper Colorado and Montanan Groups, south-central Wyoming, northwestern Utah, and northwestern Colorado: Wyoming Geological Association Guidebook, 16th Annual Field Conference, p. 101–112.

_________ 1965, A summary of stratigraphy and paleontolgy, upper Colorado and Montanan Groups, south-central Wyoming, northeastern Utah, and northwestern Colorado: Wyoming Geological Association Guidebook, 19th Annual Field Conference, p. 13–26.

Smith, M. B., Holman, G. B., Fast, C. R., and Colvin, R. J., The azimuth of deep, penetrating fractures in the Wattenberg field: Society of Petroleum Engineers paper 6092, p. 24–35.

Snedden, J. W., and Jumper, R. S., 1990, Shelf and shoreface reservoirs, Tom Walsh-Owen field, Texas, *in* Barwis, J. H., McPherson, J. G., and Studlick, J. R. J., eds., Sandstone petroleum reservoirs: Casebooks in Earth Sciences, Springer-Verlag, New York, p. 415–436.

Snedden, J. W., and Kersey, D. G., 1982, Depositional environments and gas production trends, Olmos Sandstone, Upper Cretaceous, Webb County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 32, p. 497–518.

Sneider, R. M., 1987, Practical petrophysics for exploration and development: American Association of Petroleum Geologists Education Department Short Course Notes, variously paginated.

Soeder, D. J., 1986, Laboratory drying procedures and the permeability of tight sandstone core: Society of Petroleum Engineers Formation Evaluation, v. 1, no. 1, p. 16–22.

Soeder, D. J., and Chowdiah, Prasan, 1990, Pore geometry in high- and low-permeability sandstones, Travis Peak Formation, East Texas: Society of Petroleum Engineers Formation Evaluation, v. 5, no. 4, p. 421–430.

Sohl, N. F., Martinez R., Eduardo, Salmeron-Urena, Pedro, and Soto-Jaramillo, Fidel, 1991, Upper Cretaceous, *in* Salvador, Amos, ed., The Gulf of Mexico Basin: Boulder, Colorado, Geological Society of America, The Geology of North America, v. J, p. 205–244.

Speer, S. W., 1983, Abo Formation, north-central Sacramento Mountains: an onlapping fluvial clastic wedge, *in* Zidek, Jiri, ed., Guidebook for field trip to the Abo red beds (Permian), central and south-central New Mexico: Roswell Geological Society and New Mexico Bureau of Mines and Mineral Resources, p. 54–72.

Spencer, A. B., 1965, Upper Cretaceous asphalt deposits of the Rio Grande Embayment: Corpus Christi Geological Society Guidebook, 67 p.

Spencer, C. W., 1989, Review of characteristics of low-permeability gas reservoirs in western United States: American Association of Petroleum Geologists Bulletin, v. 73, no. 5, p. 613–629.

Spencer, C. W., and Keighin, C. W., eds., 1984, Geological studies in support of the U.S. Department of Energy multiwell experiment, Garfield County, Colorado: U.S. Geological Survey Open-File Report 84-757, 134 p.

Stevens, C., and Stevens, D., compilers, 1960, Hugoton Embayment—Anadarko Basin handbook: Amarillo, Texas, National Petroleum Bibliography, 412 p.

Stonecipher, S. A., Winn, R. D., Jr., and Bishop, M. G., 1984, Diagenesis of the Frontier Formation, Moxa Arch: a function of sandstone geometry, texture and composition, and fluid flux: American Association of Petroleum Geologists Memoir 37, p. 289–316.

Surdam, R. C., 1992, Sandstone geometries, petrophysical characteristics, and pressure regimes, Mesaverde Group, Green River Basin, Wyoming: Wyoming Geological Association Guidebook, 1992, p. 167–169.

Surlyk, Finn, and Ineson, J. R., 1992, Carbonate gravity flow deposition along a platform margin scarp (Silurian, north Greenland): Journal of Sedimentary Petrology, v. 62, no. 3, p. 400–410.

Thomas, G. R., and Lauffer, J. B., 1964, Completion techniques and results of recent Berea sand development in Pike County, Kentucky: Kentucky Geological Survey, Special Publication No. 8, p. 83–89, 5 plates.

Thomas, W. A., and Mack, G. H., 1982, Paleogeographic relationship of a Mississippian barrier-island and shelf-bar system (Hartselle Sandstone) in Alabama to the Appalachian-Ouachita orogenic belt: Geological Society of America Bulletin, v. 93, no. 1, p. 6–19.

Thomas, W. A., and Mann, C. J., 1966, Late Jurassic depositional environments, Louisiana and Arkansas: American Association of Petroleum Geologists Bulletin, v. 50, no. 1, p. 178–182.

Thompson, D. M., 1982, Atoka Group (Lower to Middle Pennsylvanian), northern Fort Worth Basin, Texas: terrigenous depositional systems, diagenesis, and reservoir distribution and quality: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 125, 62 p.

Tye, R. S., 1989, Stratigraphy and depositional systems of the Lower Cretaceous Travis Peak Formation, East Texas Basin: The University of Texas at Austin, Bureau of Economic Geology, report no. GRI/91/0128, prepared for the Gas Research Institute, 45 p.

———— 1991, Fluvial sandstone reservoirs of the Travis Peak Formation, East Texas Basin, in Miall, A. D., and Tyler, Noel, eds., The three-dimensional facies architecture of terrigenous clastic sediments, and its implications for hydrocarbon discovery and recovery: SEPM (Society for Sedimentary Geology), Concepts in Sedimentology and Paleontology, v. 3, p. 172–188.

Tye, R. S., Laubach, S. E., Dutton, S. P., and Herrington, K. L., 1989, The role of geology in characterizing low-permeability sandstones, North Appleby field, East Texas Basin, *in* Proceedings, 1989 Society of Petroleum Engineers Joint Rocky Mountain Regional Meeting and Low-Permeability Reservoir Symposium, SPE Paper No. 18964, p. 355–365.

Tyler, Noel, and Ambrose, W. A., 1986, Depositional systems and oil and gas plays in the Cretaceous Olmos Formation, South Texas: The University of Texas at Austin, Burea of Economic Geology Report of Investigations No. 152, 42 p.

Tyler, Noel, Galloway, W. E., Garrett, C. M., Jr., and Ewing, T. E., 1984, Oil accumulation, production characteristics, and targets for additional recovery in major oil reservoirs of Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 84-2, 31 p.

Tyler, Roger, Ambrose, W. A., Scott, A. R., and Kaiser, W. R., 1991, Coalbed methane potential of the Greater Green River, Piceance, Powder River, and Raton Basins: Gas Research Institute Topical Report, GRI-91/0315, 244 p.

Tyler, T. F., 1978, Preliminary chart showing electric log correlation section A–A′ of some Upper Cretaceous and Tertiary rocks, Washakie Basin, Wyoming: U.S. Geological Survey Open-File Report 78-703, 4 sheets.

———— 1980, Preliminary chart showing electric log correlation section H–H′ of some Upper Cretaceous and Tertiary rocks, south end Rock Springs Uplift, Washakie Basin, Wyoming: U.S. Geological Survey Open-File Report 80-1248, 3 sheets.

Van Golf-Racht, T. D., 1982, Fundamentals of fractured reservoir engineering: Amsterdam, Elsevier Scientific Publishing Company, Developments in Petroleum Science, 712 p.

Van Horn, M. D., 1979, Stratigraphy of the Almond Formation, east-central flank of the Rocks Springs Uplift, Sweetwater County, Wyoming: a mesotidal-shoreline model for the Late Cretaceous: Colorado School of Mines, Master's thesis, 150 p.

Van Wagoner, J. C., Mitchum, R. M., Campion, K. M., and Rahmanian, V. D., 1991, Siliciclastic sequence stratigraphy in well logs, cores, and outcrops: concepts for high-resolution correlation of time and facies: American Association of Petroleum Geologists Methods in Exploration Series, no. 7, 55 p.

Vavra, C. L., Kaldi, J. G., and Sneider, R. M., 1992, Geological applications of capillary pressure: a review, American Association of Petroleum Geologists Bulletin, v. 76, no. 6, p. 840–850.

Veach, R. W., Jr., and Moschovidis, Z. A., 1986, An overview of recent advances in hydraulic fracturing technology: Proceedings of the 1986 SPE Meeting in Beijing, China, SPE Paper No. 14085, p. 76–86.

Ver Steeg, K., 1944, Some structural features of Ohio: Journal of Geology, v. 52, p. 131–138.

Verbeek, E. R., and Grout, M. A., 1983, Fracture history of the northern Piceance Creek Basin, northwestern Colorado, *in* Gary, J. H., ed., Proceedings of the 16th Oil Shale Symposium: Colorado School of Mines Press, Golden, Colorado, p. 29–44.

__________ 1984, Prediction of subsurface fracture patterns from surface studies of joints—an example from the Piceance Creek Basin, Colorado: U.S. Geological Survey, Open-File Report 84-757, 86 p.

Virginia Tight Sand Committee, 1981, Areas requested for tight sand designation in the Berea Sandstone in the Plateau region of Virginia, 18 p.

Voneiff, G. W., and Holditch, S. A., 1992, An economic assessment of applying recent advances in fracturing technology to six tight gas formations: SPE Paper No. 24888, Proceedings, 67th Society of Petroleum Engineers Annual Technical Conference and Exhibition, p. 281–296.

von Schoenfeld, H. A., Kehle, R. O., and Gray, K. E., 1973, Mapping of stress field in the upper earth's crust of the U.S.: Final technical report, grant 14-08-0001-1222, U.S. Geological Survey, Reston, Virginia, 78 p.

Wagner, C. R. (ed.), 1961, Oil and gas fields of the Texas and Oklahoma Panhandles: Panhandle Geological Society, 264 p.

Walls, J. D., 1982, Tight gas sands—permeability, pore structure, and clay: Journal of Petroleum Technology, v. 34, no. 11, p. 2708–2714.

Walper, J. L., 1977, Paleozoic tectonics of the southern margin of North America: Gulf Coast Association of Geological Societies Transactions, v. 27, p. 230–241.

__________ 1982, Plate tectonic evolution of the Fort Worth Basin, *in* Martin, C. A., ed., Petroleum geology of the Fort Worth Basin and Bend Arch area: Dallas Geological Society, p. 237–251.

Warpinski, N. R., Schmidt, R. A., and Northrop, D. A., 1982, In situ stresses: the predominant influence on hydraulic fracture containment, Journal of Petroleum Technology, p. 653–664.

Watts, R. J., Schrider, L. A., and Craig, J. G., 1972, Reservoir and production characteristics of the Clinton sand, East Canton Oilfield, *in* Ohio Geological Society, Clinton Sandstone papers presented at the Ohio Oil and Gas Association Winter Meetings 1961 to 1978—Abridged Reprint of 1980 Volume: Ohio Geological Society, Columbus, Ohio, p. 58–60.

Waxman, M. H., and Smits, L. J. M., 1968, Electrical conductivities in oil-bearing Shaly Sands: Society of Petroleum Journal, v. 8, p. 107–122.

Weaver, O. D., and Smitherman, J., III, 1978, Hosston sand porosity critical in Mississippi, Louisiana: Oil and Gas Journal, v. 76, no. 10, p. 108–110.

Weimer, R. J., 1960, Upper Cretaceous stratigraphy, Rocky Mountain area: American Association of Petroleum Geologists Bulletin, v. 44, no. 1, p. 1–20.

__________ 1961, Uppermost Cretaceous rocks in central and southern Wyoming, and northwest Colorado: Wyoming Geological Association Guidebook, 16th Annual Field Conference, p. 17–28.

Weimer, R. J., and Sonnenberg, S. A., 1983, Codell Sandstone—new exploration play, Denver Basin: Oil and Gas Journal, v. 81, no. 22, p. 119–125.

__________ 1989, Sequence stratigraphic analysis of Muddy (J) Sandstone reservoir, Wattenberg field, Denver Basin, Colorado, *in* Coalson, E. B., ed., Petrogenesis and petrophysics of selected sandstone reservoirs of the Rocky Mountain region: Rocky Mountain Association of Geologists, p. 197–220.

Weimer, R. J., Sonnenberg, S. A., and Young, G. B. C., 1986, Wattenberg field, Denver Basin, Colorado, *in* Spencer, C. W., and Mast, R. F., eds., Geology of tight reservoirs: American Association of Petroleum Geologists, Studies in Geology No. 24, p. 143–164.

Weise, B. R., 1980, Wave-dominated delta systems of the Upper Cretaceous San Miguel Formation, Maverick Basin, South Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 107, 39 p.

Wescott, W. A., 1983, Diagenesis of Cotton Valley sandstone (Upper Jurassic), east Texas: implications for tight gas formation pay recognition: American Association of Petroleum Geologists Bulletin, v. 67, no. 6, p. 1002–1013.

_________ 1985, Diagenesis of Cotton Valley sandstone (Upper Jurassic), east Texas: implications for tight gas formation pay recognition: reply: American Association of Petroleum Geologists Bulletin, v. 69, no. 5, p. 816–818.

West Virginia Tight Formation Committee, 1981, Areas recommended for tight formations in Mercer, McDowell, and Wyoming Counties, West Virginia, 8 p.

_________ 1982, Areas recommended for tight formations in Boone Cabell, Konawha, Lincoln, Logan, Mingo, Putman, and Wayne Counties, West Virginia, 47 p.

Whitehead, W. S., Gatens, J. M., III, Holditch, S. A., 1989, Determination of in situ stress profiles through hydraulic fracturing measurements in two distinct geologic areas: International Journal of Rock Mechanics Mining Science & Geomechanics Abstracts, v. 26, no. 6, p. 637–645.

Whitehead, W. S., Holditch, S. A., and Hunt, E. R., 1986, In-situ stresses: a comparison between log-derived values and actual field measured values in the Travis Peak Formation of East Texas: Proceedings, 1986 Society of Petroleum Engineers/U.S. Department of Energy/Gas Research Institute Joint Symposium on Unconventional Gas Technology, Louisville, Kentucky, SPE Paper No. 15209, p. 19–34.

Whiting, P. H., 1984, Depositional environment of Red Fork sandstones, deep Anadarako Basin, western Oklahoma: Shale Shaker, v. 34, no. 9, p. 104–119.

Wilson, D. A., and Hensel, W. M., Jr., 1984, The Cotton Valley Sandstone of East Texas: A log-core study, *in* Presley, M. W., ed., The Jurassic of East Texas: East Texas Geological Society, Tyler, Texas, p. 141–152.

Wilson, M. D., 1981, Origins of clays controlling permeability in tight gas sands *in* Proceedings, 1981 Society of Petroleum Engineers/Department of Energy Low-Permeability Reservoir Symposium, SPE Paper No. 9843, p. 157–164.

Wiltschko, D. V., and Dorr, J. A., 1983, Timing of deformation in overthrust belt and foreland of Idaho, Wyoming, and Utah: American Association of Petroleum Geologists Bulletin, v. 67, no. 8, p. 1304–1322.

Winker, C. D., and Edwards, M. B., 1983, Unstable progradational clastic shelf margins: Society of Economic Paleontologists and Mineralogists Special Publication No. 33, p. 139–157.

Winn, R. D., Jr., and Smithwick, M. E., 1980, Lower Frontier Formation, southwestern Wyoming: depositional controls on sandstone compositions and on diagenesis: 31st Annual Field Conference, Wyoming Geological Association Guidebook, p. 247–254.

Winn, R. D., Jr., Stonecipher, S. A., and Bishop, M. G., 1984, Sorting and wave abrasion: controls on composition and diagenesis in lower Frontier sandstones, southwestern Wyoming: American Association of Petroleum Geologists Bulletin, v. 68, p. 268–284.

Woodward, L. A., and Callender, J. F., 1977, Tectonic framework of the San Juan Basin, *in* Fassett, J. E., ed., San Juan Basin III, northwestern New Mexico: New Mexico Geological Society Guidebook, 28 Annual Field Conference, p. 209–212.

Wyoming Geological Association, 1948, Wind River Basin, Wyoming: Third Annual Field Conference, Wyoming Geological Association Guidebook, 202 p.

__________ 1969, Wyoming stratigraphic nomenclature chart.

__________ 1978, Wind River Basin: 29th annual field conference, Wyoming Geological Association Guidebook, 318 p.

__________ 1989, Wyoming oil and gas fields symposium, Bighorn and Wind River Basins: Wyoming Geological Association, 558 p., plus appendix.

Wyoming Oil and Gas Conservation Commission, 1980a, Docket no. 65-80, Cause no. 1, application by Amoco Production Company for designation of the Frontier Formation in parts of Lincoln, Sweetwater, and Uinta Counties, Wyoming, as a tight gas sand.

__________ 1980b, Docket no. 92-80, Cause no. 1, application by Amoco Production Company for designation of the Mesaverde Group in parts of Sweetwater and Carbon Counties, Wyoming, as a tight gas sand.

__________ 1981a, Docket no. 53-81(A), Cause no. 1, application by Belco Petroleum Corporation for designation of the Frontier Formation in parts of Lincoln, Sublette, and Sweetwater Counties, Wyoming, as a tight gas sand.

__________ 1981b, Docket no. 69-80, Cause no. 1, application by Texas Oil and Gas Corporation for designation of the Fox Hills Formation in part of Sweetwater County, Wyoming, as a tight gas sand.

__________ 1981c, Docket no. 113-81, Cause no. 1, application by Houston oil and Minerals Corporation for designation of the Frontier Formation in part of Sweetwater County, Wyoming, as a tight gas sand.

__________ 1981d, Docket no. 128-81, Cause no. 1, application by Pacific Transmission Supply Company for designation of the Frontier Formation in parts of Sweetwater and Lincoln Counties, Wyoming, as a tight gas sand.

__________ 1981e, Docket no. 189-80(A), Cause no. 1, application by Energetics, Inc., for designation of the Frontier Formation in parts of Lincoln, Sweetwater, and Sublette Counties, Wyoming, as a tight gas sand.

__________ 1981f, Docket no. 193-80, Cause no. 1, application by Benson-Montin-Greer for designation of the Frontier Formation in part of Carbon County, Wyoming, as a tight gas sand.

__________ 1982, Application for tight formation designation, Frontier Formation sandstone members, Riverton Dome field, Fremont County, Wyoming: Docket No. W353-2.

__________ 1991a, Docket no. 139-91, Cause no. 5, application by Texaco Inc., for designation of the Blair Formation in part of Sweetwater County, Wyoming, as a tight gas sand.

__________ 1991b, Docket no. 257-91, application by The Daube Company for designation of the Second Frontier Formation in part of Sweetwater County, Wyoming, as a tight gas sand.

Yin Peigui, Liu Jie, and Surdam, R. C., 1992, Petrographic and petrophysical properties of the Almond Sandstone in the Washakie Basin: Wyoming Geological Association Guidebook, 1992, p. 191–205.

Young, R. G., 1955, Sedimentary facies and intertonguing in the Upper Cretaceous of the Book Cliffs, Utah-Colorado: Geological Society of America Bulletin, v. 66, no. 2, p. 177–202.

Zemanek, J., Glenn, E., Norton, L. J., and Caldwell, R. L., 1970, Formation evaluation by inspection with the borehole televiewer: Geophysics, v. 35, p. 254–269.

Zoback, M. D., and Zoback, M. L., 1991, Tectonic stress field of North America and relative plate motions, *in* Slemmons, D. B., Engdahl, E. R., Zoback, M. D., and Blackwell, D. D., eds., Neoteconics of North America: Boulder, Colorado, Geological Society of America, Decade Map Volume 1, p. 339–366.

Zoback, M. L., 1992, First- and second-order patterns of stress in the lithosphere: the world stress map project: Journal of Geophysical Research, v. 97, no. B8, p. 12971–12980.

Zoback, M. L., and Zoback, M. D., 1980, State of stress in the conterminous United States: Journal of Geophysical Research, v. 85, no. B11, p. 6113–6156.

__________ 1989, Tectonic stress field of the continental United States, *in* Pakiser, L. C., and Mooney, W. D., eds., Geophysical framework of the continental United States: Boulder, Colorado, Geological Society of America Memoir 172, p. 523–539.