OKLAHOMA GEOLOGICAL SURVEY
Charles J. Mankin, *Director*

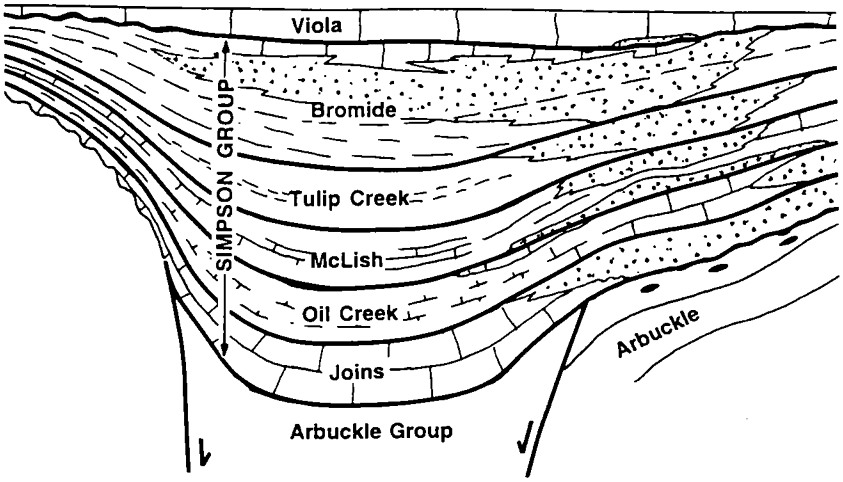
CIRCULAR 99

ISSN 0078-4397

Simpson and Viola Groups in the Southern Midcontinent, 1994 Symposium

KENNETH S. JOHNSON
Editor

Anadarko and Ardmore Basins



Proceedings of a symposium held March 29–30, 1994, in Norman, Oklahoma.

Co-sponsored by:
Oklahoma Geological Survey
and
Bartlesville Project Office,
U.S. Department of Energy

The University of Oklahoma
Norman
1997

OKLAHOMA GEOLOGICAL SURVEY

Charles J. Mankin, *Director*
Kenneth S. Johnson, *Associate Director*

SURVEY STAFF

James H. Anderson, *Cartographic Drafting Tech III*
Richard D. Andrews, *Geologist III*
Larry T. Austin, *Core and Sample Library Assistant*
Betty D. Bellis, *Word-Processing Operator II / Technical Typist*
Tom L. Bingham, *Geologist II*
Mitzi G. Blackmon, *Clerk-Typist I*
Raymon L. Brown, *Geophysicist III*
Jock A. Campbell, *Geologist IV*
Brian J. Cardott, *Geologist IV*
James R. Chaplin, *Geologist IV*
Janise L. Coleman, *Office Assistant IV*
Christie L. Cooper, *Editor*
Tammie K. Creel, *Secretary II*
Charles R. Dyer III, *Drilling Technician*
Walter C. Esry, *Manager, Core and Sample Library*
Robert O. Fay, *Geologist IV*
T. Wayne Furr, *Manager of Cartography*
Patronalia M. Hanley, *Chemist*
LeRoy A. Hemish, *Geologist IV*
John Humphrey, *Operations Assistant I*
Shirley A. Jackson, *Research Specialist I*
Priscilla A. Johnson, *Office Assistant IV*
James E. Lawson, Jr., *Chief Geophysicist*
Charlotte C. Lloyd, *Cartographic Drafting Tech II*
Kenneth V. Luza, *Geologist IV*
Todd S. McCormick, *Electronic Technician*
Michael J. Mercer, *Manager, Log Library*
Richard G. Murray, *Copy Center Operator*
Sue M. Palmer, *Office Assistant II*
Tracy P. Peeters, *Associate Editor*
David O. Pennington, *Operations Assistant II*
Judy A. Schmidt, *Office Manager*
Connie G. Smith, *Promotion and Information Specialist*
Paul E. Smith, *Supervisor, Offset Press Copy Center*
Lloyd N. Start, *Assistant Drilling Technician*
Joyce A. Stiehler, *Chief Clerk*
Michelle J. Summers, *Technical Project Coordinator*
Neil H. Suneson, *Geologist IV*
Jane L. Weber, *Coordinator, Departmental Computer Systems*
Stephen J. Weber, *Chief Chemist*

Title-Page Illustration

Generalized stratigraphic profile of Simpson and Viola Groups in southern Oklahoma (from p. 9 of this volume).

♻ *printed on recycled paper*

This publication, printed by the Oklahoma Geological Survey, is issued by the Oklahoma Geological Survey as authorized by Title 70, Oklahoma Statutes, 1981, Sections 231–238. 1,000 copies have been prepared for distribution at a cost of $9,434 to the taxpayers of the State of Oklahoma. Copies have been deposited with the Publications Clearinghouse of the Oklahoma Department of Libraries.

PREFACE

The transfer of technical information will aid in the search for, and production of, our oil and gas resources. To facilitate this technology transfer, the Oklahoma Geological Survey (OGS) and the Bartlesville Project Office of the U.S. Department of Energy (BPO–DOE) co-sponsored a symposium dealing with petroleum geology and reservoir characterization of the Simpson and Viola Groups in the southern Midcontinent. The symposium was held March 29–30, 1994, at the Oklahoma Center for Continuing Education, The University of Oklahoma, Norman. This volume contains the proceedings of that symposium.

Research reported upon at the symposium focused on geology, depositional settings, reservoir characterization, diagenetic history, enhanced oil recovery, and horizontal drilling. In describing the various petroleum reservoirs in the Simpson and Viola Groups in the southern Midcontinent, the researchers have increased our understanding of how the depositional and diagenetic history of these strata can affect reservoir heterogeneity and our ability to efficiently recover the hydrocarbons they contain. We hope that the symposium and these proceedings will bring such research to the attention of the geoscience and energy-research community, and will help foster exchange of information and increased research interest among industry, university, and government workers.

Twenty papers were presented orally at the symposium, and they are presented here as full papers or abstracts. An additional 10 reports were given as posters, and they are presented here as short reports or abstracts. About 280 persons attended the symposium. Stratigraphic nomenclature and age determinations used by the various authors in this volume do not necessarily agree with those of the OGS.

This is the seventh symposium in as many years dealing with topics of major interest to geologists and others involved in petroleum-resource development in Oklahoma and adjacent states. These symposia are intended to foster the exchange of information that will improve our ability to find and recover our nation's oil and gas resources. Earlier symposia subjects covered the Anadarko basin (published as OGS Circular 90); Late Cambrian–Ordovician geology of the southern Midcontinent (OGS Circular 92); source rocks in the southern Midcontinent (OGS Circular 93); petroleum-reservoir geology in the southern Midcontinent (OGS Circular 95); structural styles in the southern Midcontinent (OGS Circular 97); and deltaic reservoirs in the southern Midcontinent (OGS Circular 98).

Persons involved in the organization and planning of the Simpson–Viola symposium include Kenneth Johnson, Jock Campbell, Bob Northcutt, and Charles Mankin of the OGS; and Tom Wesson, Michael Ray, and Edith Allison of BPO–DOE. Other personnel who contributed include: Michelle Summers and Tammie Creel, registration co-chairs; LeRoy Hemish, poster-session chair; Connie Smith, publicity chair; and Gwen Williamson and Judy Schmidt, exhibits coordinators. Technical editing of this volume was done by William D. Rose, Rose Perspectives, Westford, Massachusetts; layout and production was done by Polly Cook, Nitick, Massachusetts. Appreciation is expressed to each of them, and to the many authors who worked toward a highly successful symposium.

KENNETH S. JOHNSON
General Chairman

CONTENTS

iii Preface

PART I — Papers Presented Orally at the Symposium

3 **Simpson Stratigraphy of the Southern Midcontinent**
Raymond W. Suhm

39 **Contrasting Sedimentation Inside and Outside the Southern Oklahoma Aulacogen During Middle and Late Ordovician**
Rodger E. Denison

48 **Major Simpson and Viola Oil and Gas Reservoirs in Oklahoma**
Robert A. Northcutt and Kenneth S. Johnson

58 **Stratigraphy and Petroleum Production of the Simpson and Viola (Ordovician) in Kansas and Nebraska**
Marvin P. Carlson and K. David Newell

65 **Tobosa Basin–Related Sedimentation of the Simpson–Viola in Trans-Pecos Texas**
David V. LeMone

66 **Karst Development in the Viola Limestone in Southern Oklahoma**
Michael Sykes, Jim Puckette, Azhari Abdalla, and Zuhair Al-Shaieb

76 **Viola Fractures—Friend or Foe?**
Carlos M. Gonzales

78 **The Viola Group as a Petroleum System: Implications for Horizontal-Drilling Prospects**
David A. Wavrek, Michael A. Garcia, and Clive D. Ferebee

87 **A Geochemical Study of Viola Source Rocks and Associated Crude Oils in the Anadarko Basin, Oklahoma**
Huai Da Wang and R. Paul Philp

102 **Source Potential of the Viola Springs Formation, Southern Limb of the Arbuckle Anticline, Arbuckle Mountains, Oklahoma**
Alton A. Brown and Joe T. Sentfle

103 **Ordovician Sea-Level Changes Recorded in Deep-Water, Continental-Margin Facies of North America**
Stanley C. Finney

111 **Structural and Stratigraphic Factors That Influence Simpson Group Production in Central Oklahoma**
Paul W. Smith

137 **Stratigraphy, Paleogeomorphology, and Structure of Simpson, Viola, and Mississippian Strata, and Their Integral Relationships to "Second Wilcox" Production in Lincoln and Logan Counties, Oklahoma**
Kurt Rottmann

155 **Facies and Depositional Environments of the Simpson Group (Middle Ordovician) in the Salina Basin of Kansas**
Jim Mazzullo and Martha McRae

164 **Middle Ordovician Ironstones in Kansas: Subsurface Markers of Paleoshorelines for the Midcontinent**
Pieter Berendsen and John H. Doveton

172 **Simpson–Arbuckle Contact Revisited in Northwest Oklahoma County, Oklahoma**
Michael D. Allison and Robert W. Allen

183 **Reservoir Analysis of a Horizontal-Well Completion in the Viola Limestone "Chocolate Brown Zone," Marietta Basin, Oklahoma**
Magell P. Candelaria and Brian P. Roux

194 **Influence of Vertical Permeability Barriers on the Ultimate Recovery from Oil Creek Reservoirs**
James M. Forgotson, J. Thomas Boyce, Roy M. Knapp, Huaibo Liu, and Paul W. Smith

203 **Characterization of High-Molecular-Weight Paraffin in Ordovician Simpson Group Reservoirs (Oklahoma and Texas)—Implications for Advanced Recovery Technologies**
N. F. Dahdah and D. A. Wavrek

209 **Diagenetic Banding as a Sealing Mechanism in Simpson Sandstone Reservoirs in Central Oklahoma**
Azhari Abdalla, Jim Puckette, and Zuhair Al-Shaieb

PART II — Abstracts and Short Reports Related to Poster Presentations

218 **Sequence Stratigraphic Model for the Simpson Group of the Southern Midcontinent: Key to a New Stratigraphic Play**
Magell P. Candelaria, C. Robertson Handford, and Christy L. Reed

224 **Stratigraphy of the Middle to Upper Ordovician Everton Formation, St. Peter Sandstone, Joachim Dolomite, and Plattin, Kimmswick, and Fernvale Limestones (Simpson–Viola Equivalents) of Northern Arkansas**
William W. Craig

227 **Seismic Evidence of the Development of Abrupt Sedimentary Buildups in the Simpson Group of the Marietta Embayment, Oklahoma**
Gary L. Garner

235 **Wettability Alterations in Reservoir Rocks from Polar Constituents in Crude Oil**
Anuj Gupta

238 **Hydrocarbon Microseepage Signature of the Clarita Prospect, Coal County, Oklahoma**
Daniel C. Hitzman and Brooks A. Rountree

241 **Tobosa Basin Karsting in Trans-Pecos Texas**
David V. LeMone

242 **Controls of Quartzarenite Diagenesis in the Simpson Group, Oklahoma: Implications for Reservoir-Quality Prediction**
Mark E. Mathisen

247 **Correlation and Distribution of Reservoir and Sealing Facies Within the Viola Formation, South-Central Kansas**
K. David Newell

260 **Progress Report on Simpson and Viola Correlations from the Arbuckles to the Ozarks**
James E. O'Brien and James R. Derby

267 **Shallowing-Upward Events and Their Implications for Internal Correlations and Depositional Environment of the St. Peter Sandstone in the Forest City Basin, Northeastern Kansas**
W. Lynn Watney, Bryan Stephens, and K. David Newell

PART I

PAPERS PRESENTED ORALLY AT THE SYMPOSIUM

Oklahoma Geological Survey Circular 99, 1997

Simpson Stratigraphy of the Southern Midcontinent

Raymond W. Suhm
Consulting Geologist/Geophysicist
Oklahoma City, Oklahoma

ABSTRACT.—Formations of the Simpson Group of Middle Ordovician age are correlated throughout Oklahoma and Arkansas from surface and subsurface data. Numerous intersecting cross sections and a variety of isopach maps allow generalizations to be made about the stratigraphy and the distribution of sandstone reservoirs and tectonics, and provide the basis for a new interpretation of the paleogeography of the southern Midcontinent during Whiterockian and early Mohawkian time.

The Simpson Group and equivalents in Arkansas form specific lithologic associations in distinct tectonic provinces: (1) thin, supratidal to shallow-subtidal carbonates and initial quartz sandstones of the Ozark dome and its southern extension, the South Ozark arch, and the South Ozark platform where the Simpson is shown to be in angular relationship with the underlying karsted Arbuckle and overlying Viola; (2) thick, restricted marine carbonates of the Reelfoot basin where deposition was uninterrupted; (3) thin, shallow-subtidal limestone, dolomite, shale, and younger sandstone of the Oklahoma shelf; (4) thick, shallow to moderately deep subtidal limestone, shale, and sandstone of the Anadarko and Ardmore basins that are separated by syndepositional faults from the Texas arch to the southwest and the South Ozark platform to the northeast; (5) thin, intertidal to shallow-subtidal carbonates of the Texas arch; and (6) thick, relatively deep-marine shales of the Ouachita trough derived from a southern landmass termed Llanoria, but which contain quartz sands originating from the north.

The early Whiterockian Calico Rock and Newton/Burgen/Basal Oil Creek Sandstones and their lateral carbonate equivalents (lower Everton and Joins) represent the basal deposits of the Tippecanoe Sequence and show a generally transgressive relationship. Lowered sea levels and a shift toward aridity are indicated in upper parts of the Everton and Oil Creek Formations, as well as the Basal McLish Sandstone, setting the stage for the extensive St. Peter transgression that began in northeastern Arkansas, paused in central Oklahoma, resulted in deposition of the Tulip Creek sand, and ended in the northern Midcontinent with deposition of the Starved Rock barrier complex that extended west of the slightly positive Ozark dome into Oklahoma, forming the widespread Bromide sand complex; coeval carbonates of the Joachim and "Plattin" were deposited in Arkansas. Following Simpson deposition, the Ozark dome and the South Ozark arch were uplifted high enough to exude Simpson detritus off their southwest flanks to form the Seminole Sandstone of the Viola Group of Late Ordovician age.

INTRODUCTION

Purpose

The purpose of this study is to correlate strata of the Simpson Group throughout Oklahoma and Arkansas, utilizing all available wireline logs and outcrop data. Formations of the Simpson Group are characterized by readily identifiable well-log signatures that can be traced with accuracy and relative ease. Simpson lithofacies are mapped from well logs and well samples; "St. Peter–like" quartz sandstones are emphasized, as are their reservoir qualities.

All formations of the Simpson Group are productive in Oklahoma; the most prolific fields are developed in sandstone reservoirs on anticlinal structures, but carbonates also yield oil and gas. Production is concentrated on the Cherokee platform, but accentuated and complex structures in the eastern Anadarko basin and the Ardmore basin have yielded exceptionally large reserves from multiple reservoirs within the Simpson (Figs. 1,2). The Simpson in the Arkoma basin is not as prolific, with the exception of a few high-reserve fields in Coal County, Oklahoma. In the Arkansas portion of the Arkoma basin, the Everton Formation and the St. Peter Sandstone are locally productive. Shows in the Reelfoot basin are encouraging. The Ouachita Mountain province, largely undrilled, has not yielded significant hydrocarbons from the Simpson or its facies equivalent. However, no bit has even penetrated the autochthonous Ouachita facies of the Simpson; the Crystal Mountain and Blakely Sandstones have exceptional potential.

Promising Simpson structural and stratigraphic hydrocarbon traps are present in several areas of the southern Midcontinent, many of which have received minimal attention to date. Structural plays include anticlines, fault blocks, and fractured carbonate rocks;

Suhm, R. W., 1997, Simpson stratigraphy of the southern Midcontinent, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 3–38.

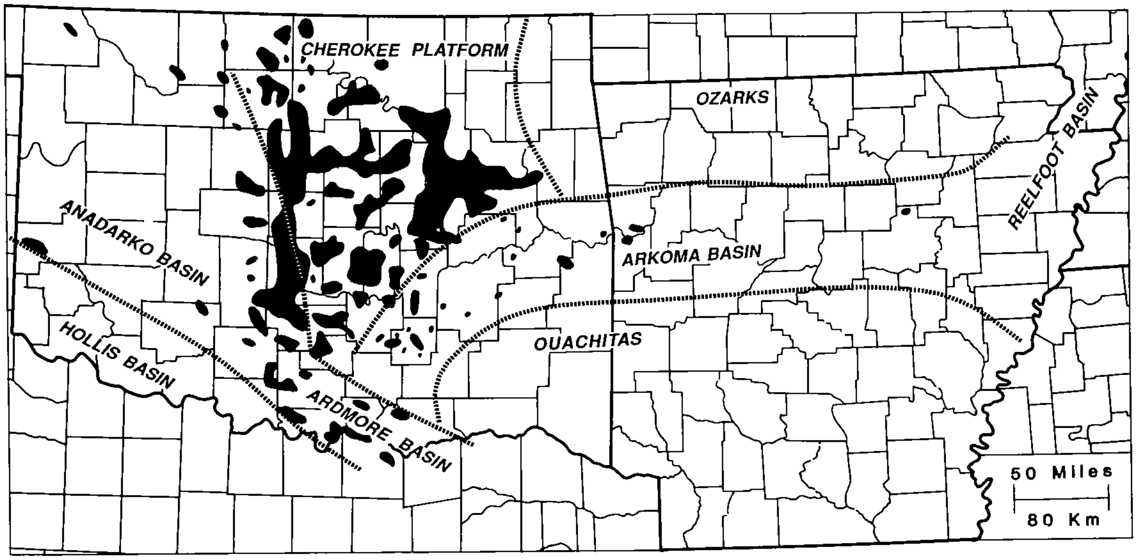


Figure 1. Oil and gas fields (black) producing from Simpson Group rocks, and their relation to present-day petroleum provinces. Names of fields in Oklahoma can be found in Burchfield (1985).

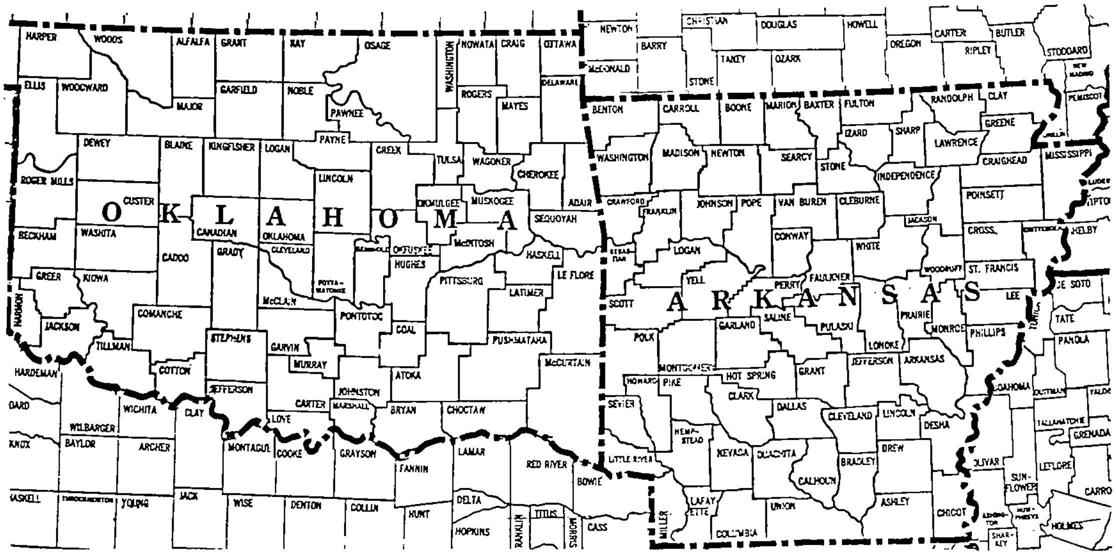


Figure 2. County location map.

stratigraphic potential includes pinchouts of porous quartz sandstones and carbonates, and karsted reservoirs within the lower Simpson.

Information is readily available for the Simpson Group exposed in the Arbuckle Mountains and Ozarks of Oklahoma and Arkansas. However, relatively few recent studies have been published on the subsurface stratigraphy of the Simpson Group in Oklahoma and its relationship to contemporaneous strata in Arkansas. Thirty years ago, Schramm (1964) and Statler (1965) published reports containing various isopach and lithofacies maps for the subsurface Simpson in Oklahoma, and Holden (1965) extended his subsurface studies into Arkansas. These maps and their interpretations remain useful today, even though numerous wells have been drilled since then. Subsurface studies such as these show that geophysical wireline logs are valuable tools, which, through correlation, can lead to an understanding of facies relationships and allow various reservoirs of the Simpson Group to be mapped.

This subsurface study provides the basis for a new interpretation of the paleogeography of the Midcontinent region during Ordovician time. Numerous isopach and lithofacies maps illustrate the relationship of tectonic and eustatic controls on deposition, sand-dispersal patterns, and source areas, and allow the tectonic and paleogeographic frameworks to be reconstructed. New names for tectonic regimes are proposed. These data can be used to evaluate areas of potential economic interest and to reconstruct geologic history.

Nomenclature

Traditional nomenclatural history of the Simpson Group in Oklahoma is discussed by Harris (1957), Schramm (1964, 1965), Statler (1965), and more recently by Longman (1981). The Simpson, as defined from outcrops in the Arbuckle Mountain area, consists of five formations, in ascending order—the Joins, Oil Creek, McLish, Tulip Creek, and Bromide, each with a basal sandstone, or in the case of the lowest formation, the Joins, a basal carbonate conglomerate. Although this study has attempted to conform to traditional terminology, it was found that only the Oil Creek and McLish Formations have basal sandstones that can be traced an appreciable distance from their type sections. Additionally, for purposes of correlation to the Arkansas section and discussion, the Basal Oil Creek Sandstone and the Basal McLish Sandstone are separated from the Oil Creek Formation and the McLish Formation, respectively. Also, the Joins Formation, long considered to be stacked and discrete, is found to interfinger with the Basal Oil Creek Sandstone. The upper and lower boundaries of the Joins, therefore, are placed at stratigraphic positions different from those generally accepted by the Oklahoma Geological Survey. The "Birdseye limestone," long established as a readily recognizable subsurface unit, is named the Pruitt Ranch Member of the Oil Creek Formation (Harris and Harris, 1965). Additionally, the upper boundary of the Tulip Creek Formation is placed at the top of the Tulip Creek sandstone rather than within a shale sequence beneath the Bromide.

Bromide and Viola subdivisions, such as the Pooleville and Mountain Lake Members of the Bromide (Cooper, 1956), the Corbin Ranch Member (Harris, 1957; Amsden and Sweet, 1983), the Viola Springs Formation (Amsden and Sweet, 1983), and the Welling Formation (Amsden, 1979), are not used because they are facies of larger existing units and lack distinguishing subsurface characteristics. The generally inclusive name *Viola* is used here, which includes the Corbin Ranch, Fite, Upper Tyner, Viola Springs, and Welling. The Seminole Sandstone is considered to be the basal sandstone of the Viola Group and should be advanced to member or formation status. The nomenclature of Simpson equivalents exposed in the McSpaddin Falls area of northeastern Oklahoma is entrenched and referred to for biostratigraphic purposes.

Simpson equivalents in Arkansas and Missouri are assigned to the Everton Formation, the St. Peter Sandstone, the Joachim Formation, and the Plattin Limestone. The nomenclature of this interval has been discussed by Giles (1930), McKnight (1935), Miser (1922), Suhm (1970, 1974), and Thompson (1991). In Arkansas, informal stratigraphic subdivisions of the Everton defined by Suhm (1970), such as members A, B, and C, are used here but may not be recognized by the Arkansas Geological Commission. The Kings River Sandstone (Purdue and Miser, 1916) is a local facies of the Newton Sandstone Member and member B of the Everton Formation and is not discussed in this study.

Detailed lithologic descriptions of the formations and members are not included in this report. For this information, the reader may wish to refer to several articles in *Symposium on the Simpson,* published in 1965 by the Tulsa Geological Society (Herndon, 1965) and those cited at the end of this report.

PROCEDURE AND CORRELATION

Over 3,500 wireline logs, many of which are supported by well-sample descriptions, were copied and interpreted (Fig. 3). Locations of studied logs were plotted on a base map with a scale of 1 in. = 22,000 ft.

Simpson correlations began in the Ozarks along the Buffalo and White Rivers (Suhm, 1974) and extended southward into the subsurface (Fig. 4). The Simpson, including the Everton, St. Peter, Joachim, and Plattin, was then correlated south and west across the Arkoma basin to Cleveland County in central Oklahoma, in an area that has been extensively drilled. Here, all the Simpson sands are well developed, relatively flat lying, and known and named by petroleum geologists (Fig. 5). From central Oklahoma, the Simpson was subsequently traced southward to exposures in the Arbuckle Mountains (Harris, 1957; Fay, 1969), where it was tied to the Northern Natural Gas No. 1–6 Little "A" (sec. 6, T. 3 S., R. 2 E.), Carter County, Oklahoma (Fig. 6). Owing to its proximity to the Arbuckle Mountains, this well served as a subsurface reference section for the Simpson Group in southern Oklahoma. Unfortunately, however, this well was drilled in the region of the Arbuckle Mountains that has experienced structural deformation, the complexity of which might affect the validity of lithostratigraphic or biostratigraphic conclusions drawn in the area.

After outcrop data were integrated with subsurface wireline logs and well cuttings, regional cross sections were generated. Twenty-eight intersecting dip-and-strike cross sections were constructed from well logs at a vertical scale of 1 in. to 150 ft (Fig. 4). The cross sections served not only to confirm correlations but were helpful in evaluating regional changes in thickness and lithology.

A diagrammatic regional cross section extending from southwestern Oklahoma to northeastern Arkansas shows that formations of the Simpson Group, and their equivalents in Arkansas, form an intertonguing complex of sandstone, limestone, dolomite, and shale that displays changes in thickness across various tectonic provinces (Fig. 7). In spite of facies complexity, stratigraphic position was maintained through careful correlation. Anomalous, yet persistent, log irregularities within or between formations, called markers, facilitated correlation. The Simpson was divided into several operational map units. Each Simpson unit, generally a formation or member, represents a specific depositional event that occurred during a discrete interval of time. It would be unlikely, as this study indicates, that time lines cross from one formational unit into another. Strike cross sections are especially meaningful; strata parallel to the strike form stratigraphic sets that are about equal in thickness and about the same age and so may represent isochronous units. Certain "shale breaks" or "hot streaks" maintained stratigraphic persistence on a regional scale, sometimes over a hundred miles. For this reason, they resemble ash falls or biokill zones. From their study of Ordovician bentonites in the eastern and central Midcontinent regions, Huff and Kolata (1990) found that isochronous bentonites support existing lithostratigraphic correlations.

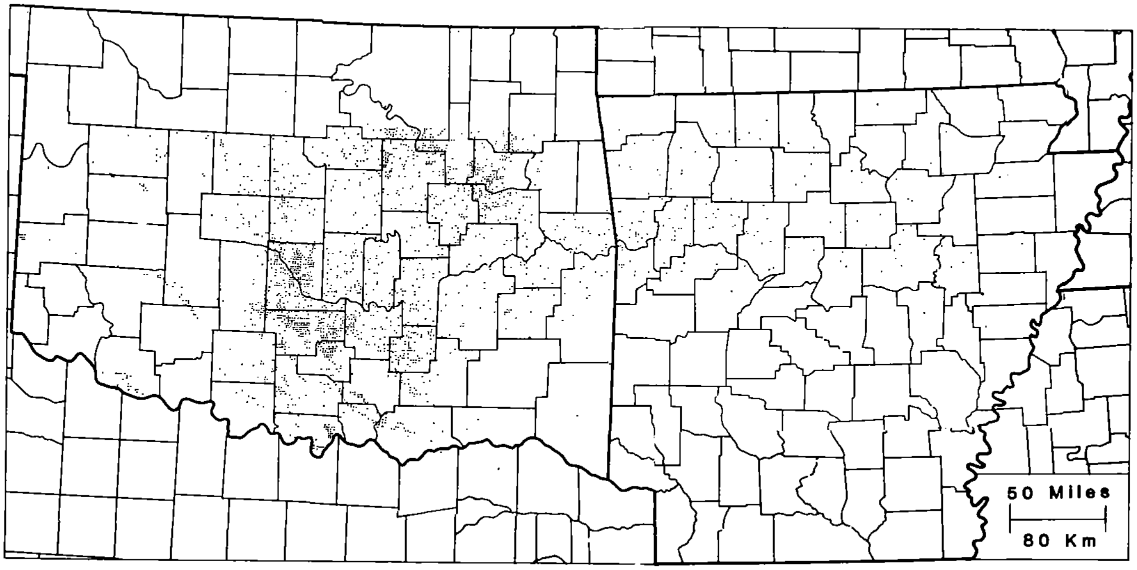


Figure 3. Map showing location of 1,100 wells that penetrated most, if not all, of the Simpson Group. Also used in this study are 2,500 well logs (not shown) that penetrated the upper to middle Simpson.

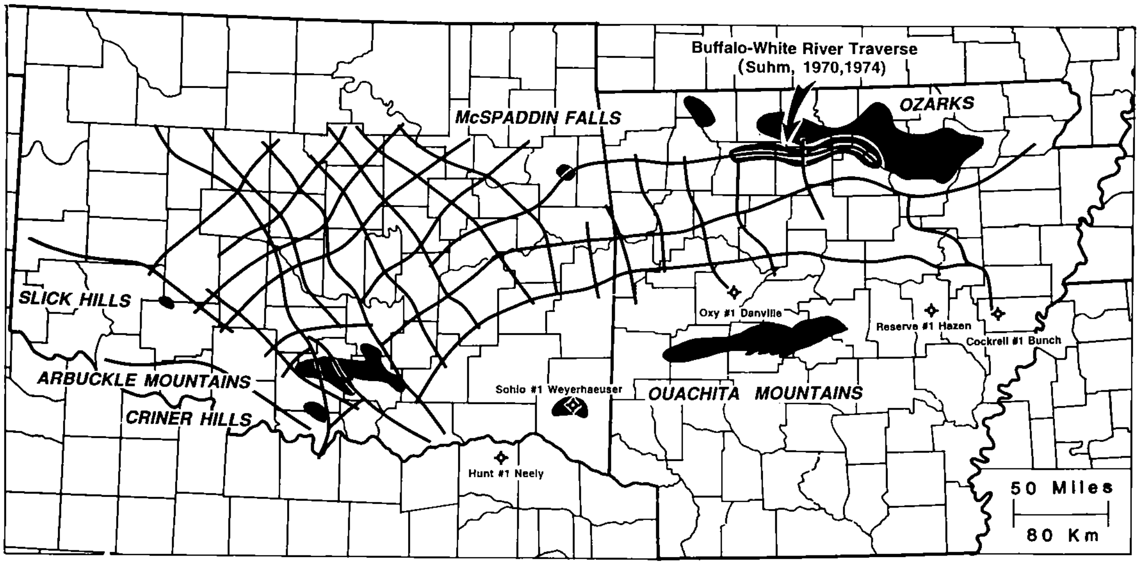


Figure 4. Surface exposures of Simpson Group (black) and lines of subsurface cross sections based on a study of 3,500 well logs. Also shown are key wells in the Ouachita frontier.

Although a faunal study was not undertaken, the results of this lithostratigraphic study generally agree with the biostratigraphic conclusions of Derby (1969, 1973a) and Derby and others (1991) for the Arbuckle Mountain area; Bauer (1989) for northeastern Oklahoma; and Cooper (1956), Craig and others (1986), Derby (1973b), and Golden (1969) for Arkansas (Fig. 8). The results of this study support a conclusion reached by Templeton and Willman (1963); i.e., lithostratigraphic correlations utilizing lithogy (and well-log signature) may be as chronostratigraphically accurate as biostratigraphic correlations. Since the Simpson was correlated in a "time-stratigraphic" sense by stratigraphic position, each of the Simpson formations can be related to specific tectonic, depositional, and paleogeographic events taking place at the time of its deposition.

Twelve isopach and isolith maps (not all included herein) that show the distribution of various Simpson facies and reservoirs were prepared at a scale of 1 in. to 22,000 ft. Porosity trends have been established for all major sandstones of the Simpson Group. The Simpson on these maps has been restored in areas where the strata have been removed by post-Ordovician erosion, such as in the Wichita and Arbuckle Mountains. Application of sequence stratigraphic concepts was attempted, but their meaningfulness is negated by variations in subsidence, depositional rates, and the supply of quartz sand across different tectonic regimes.

TECTONIC SETTING
General

Tectonics exert a major control on sedimentation. They control the rate of supply of terrigenous material, the gradient across which sediment is transported, and the rate of subsidence in the basin of deposition. Lithologic associations result from the relationship between tectonics and sedimentary response. Gross-interval isopach maps, together with lithologic associations, are extremely useful in evaluating the tectonic fabric, since they reflect variations in the tectonic stability of the surface on which sediments were deposited. Several tectonic and sedimentologic provinces, some new, are recognized from the middle to upper Simpson isopach map (Fig. 9).

Anadarko and Ardmore Basins

Simpson thicknesses are greatest in the Anadarko and Ardmore basins, thickening to over 2,000 ft in the deepest part of the Ardmore basin (Fig. 9). The Simpson consists of open-marine basinal limestone and shale with variable amounts of shallow-water sandstone in its upper part.

The Ardmore and Anadarko basins were connected by a contiguous seaway but have different structural histories and styles. The Simpson thickens gradually into the Anadarko basin (Fig. 10A), but in the Ardmore basin in Stephens and Carter Counties, Oklahoma, the Simpson exhibits extreme variation in thickness (Fig. 10A). Some excessive thicknesses observed from well logs in the Ardmore basin may be due to steep dips related to post-Simpson structural deformation, but study of detailed isopach maps shows that many of the extremes in thickness are due to differences in depositional rates generated by movements of syndepositional fault blocks (horsts and grabens), which generated an irregular sea floor. Some of the horsts may have been at or slightly above sea level in pre-Whiterockian time, allowing the underlying Arbuckle to be karstified, such as at Healdton field, Carter County, Oklahoma (Waddell and others, 1993; Latham, 1968). South and west of the Ardmore basin, in Love and Jefferson Counties, Oklahoma, the Simpson gradually thins toward the Texas arch and changes facies from shale to dominantly carbonate. Studies of Simpson relationships in Texas are ongoing and will be published at a later date.

The junction of the Ardmore basin with the South Ozark platform, along a northwest–southeast line extending through Murray, Johnston, and part of Garvin Counties, Oklahoma, is believed to be a syndepositional fault, perhaps the result of reactivation of a buried rift (Figs. 9, 10B). The Simpson thickens from about 800 ft on the South Ozark platform to over 2,000 ft in the Ardmore basin in a horizontal distance of a few miles, apparently the result of a growth fault. The trace of this fault also coincides with a depositional hinge line separating shallow-water platform deposits on the northeast from thicker, deep-water basinal facies (Longman, 1981). Sandstone isopach maps, to be discussed later,

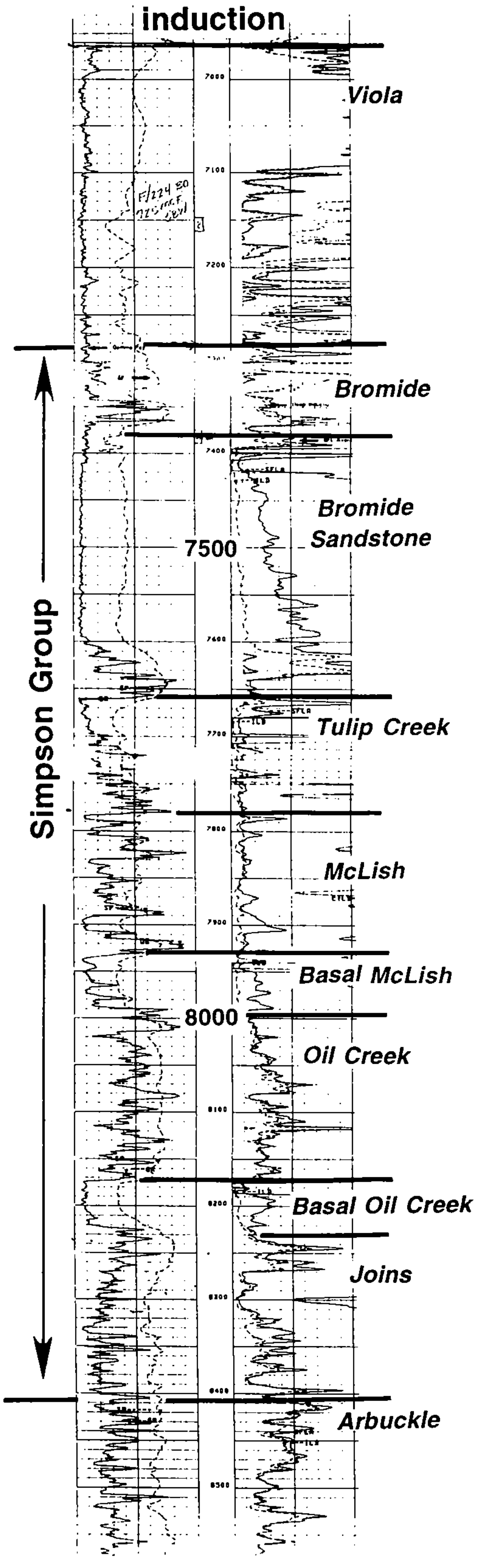


Figure 5 (left). Subsurface reference well log (Anson No. 1–21 Northcutt) for Simpson Group in central Oklahoma, Oklahoma Shelf province, sec. 21, T. 7 N., R. 1 W., Cleveland County.

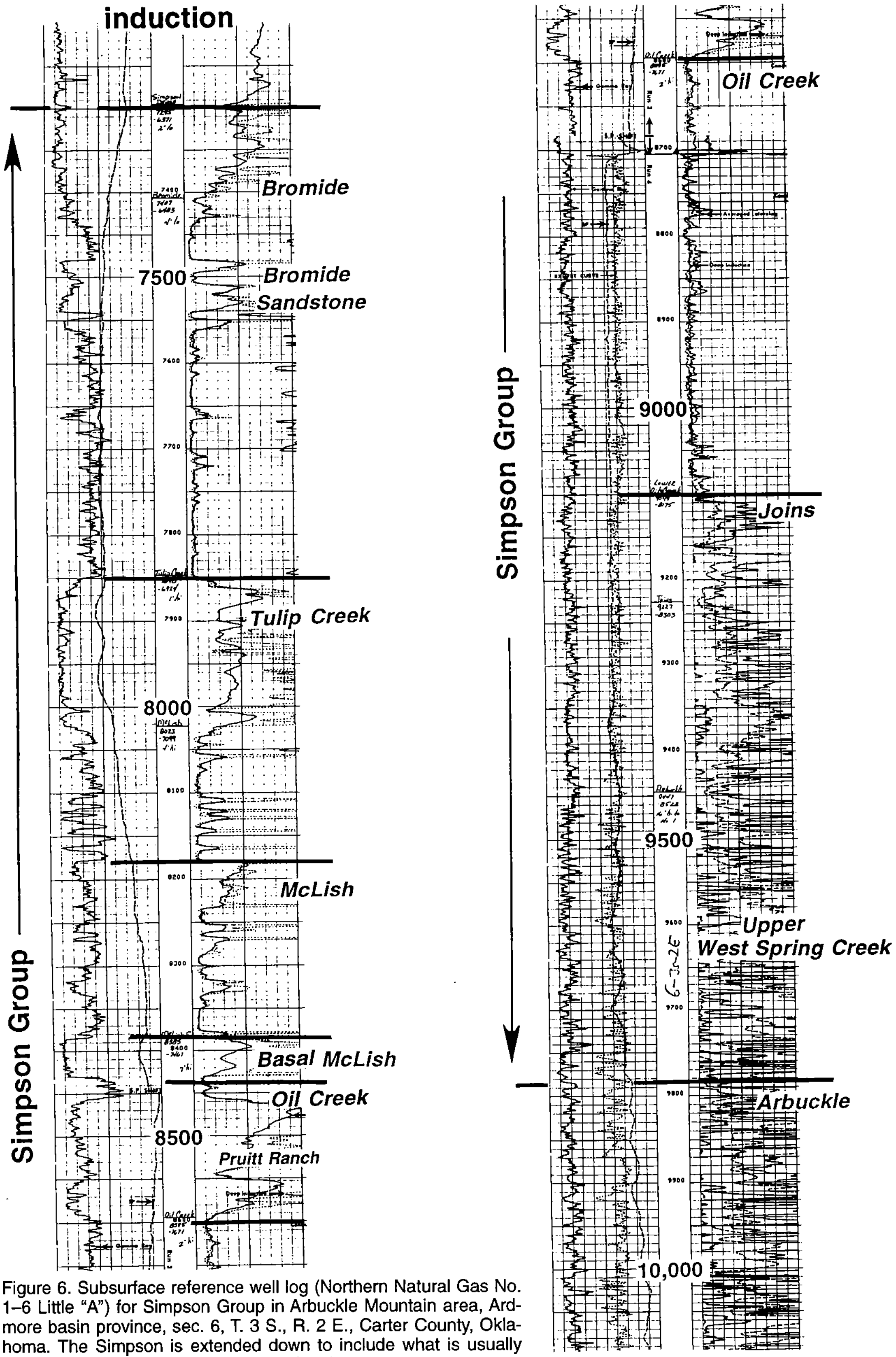


Figure 6. Subsurface reference well log (Northern Natural Gas No. 1–6 Little "A") for Simpson Group in Arbuckle Mountain area, Ardmore basin province, sec. 6, T. 3 S., R. 2 E., Carter County, Oklahoma. The Simpson is extended down to include what is usually referred to as the upper West Spring Creek.

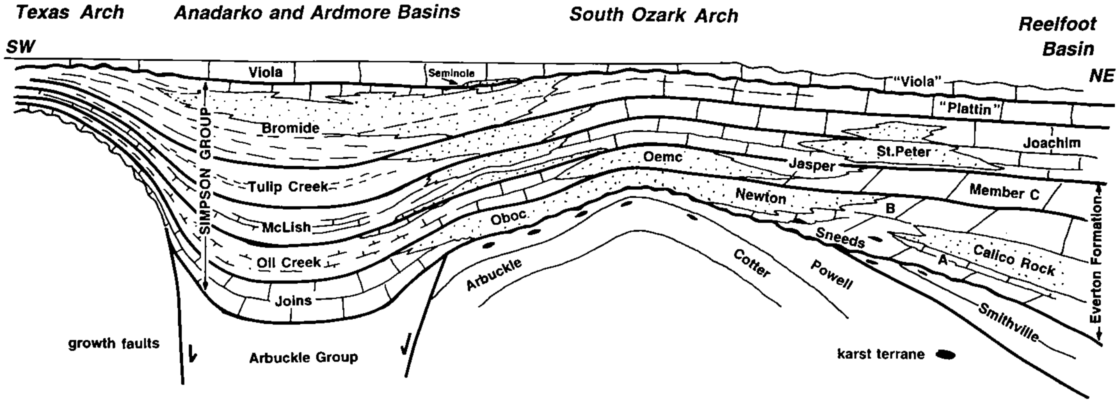


Figure 7. Generalized stratigraphic profile from southwestern Oklahoma to northeastern Arkansas, showing Simpson rock units and their equivalents in Arkansas. Relative thicknesses of each formation have been altered for diagrammatic purposes. Thick lines are best-fit inferred time lines. *Oemc* is member C (Everton); *Oboc* is Basal Oil Creek Sandstone. Geologic provinces are shown in Figure 9.

show that southwestward-moving quartz sands of the lower Simpson piled up in shallow water at this hinge line. Some sand spilled over a short distance into the basin, but most of the sand was redirected by shallow-water currents flowing toward the Oklahoma shelf. The somewhat anomalous distribution of lower Simpson sands, therefore, appears to be the result of depositional variations and not to post-Simpson strike-slip fault movements as suggested by Tanner (1967). Upper Simpson sands, on the contrary, tend to be thickest in the Anadarko and Ardmore basins, suggesting a "filling in" of the basins, perhaps coincident with diminishing movement along syndepositional faults. The southeastern limit of the Ardmore basin is unknown but is believed to be transitional with the Ouachita trough.

The Anadarko basin is flanked by the broad area of the Oklahoma shelf to the northeast and the Texas arch to the southwest. The junction with the Oklahoma shelf appears to be gradual and transitional. However, a syndepositional fault, perhaps related to a buried rift, is inferred to be present on the southwest flank of the Anadarko basin at its junction with the Texas arch. The Simpson is 200–300 ft thick in Tillman County, Oklahoma, and over 1,700 ft thick 45 mi to the north in northern Comanche and southern Caddo Counties, Oklahoma. The exact position of this fault, however, cannot be ascertained, because the Simpson has been truncated in a broad band parallel with the present-day Wichita Mountains. The fault appears to be near a northwest–southeast line trending through Beckham, Kiowa, Comanche, and Stephens Counties, Oklahoma (Fig. 9).

Texas Arch

The Texas arch, also termed the Texas peninsula, is a stable craton that extends from central Texas northwest to the Pedernal massif of New Mexico (Adams, 1954). The Simpson is present in the subsurface of southwestern Oklahoma in a narrow band south of the Anadarko and Ardmore basins, trending from Tillman County, Oklahoma (Fig. 9), into parts of the Fort Worth basin in Clay, Montague, Wise, Denton, and Tarrant Counties, Texas (Whiteside and McCommons, 1991). The Simpson is generally less than 500 ft thick in this area, the result of slow depositional rates and the removal of the upper Simpson by pre-Viola truncation. Southward on the Texas arch, it thins to extinction. The Simpson reappears in the Tobosa basin of west Texas, where it exhibits lithologic and electric-log similarities with the Oklahoma section (Galley, 1958; Suhm and Ethington, 1975). Interestingly, a well-log cross section for the Tobosa basin prepared by Wright (1965, fig. 3) is a mirror image of a cross section of the Simpson across Tillman County, Oklahoma (not included in this report). Simpson equivalents in the Tobosa basin are petroleum reservoirs and include the Connell, McKee, and Waddell Sandstones.

Discrete sandstone beds, however, are virtually absent in the Simpson on the Texas arch in Oklahoma. The Simpson is dominantly shallow-marine sandy carbonate with some shale. The base of the Simpson is placed under sandy oolitic carbonates (termed *Ellenburger "A"* by Whiteside and McCommons, 1991) that are inferred to be unconformable on relatively nonsandy carbonates of the Arbuckle or Ellenburger. It is likely that solution breccias in the underlying Arbuckle are indicative of karst related to the regression that took place at the end of deposition of the Sauk Sequence. Karsted Ellenburger limestones are common on the south side of the Texas arch bordering the Tobosa basin (Galley, 1958).

South Ozark Platform, South Ozark Arch, and Ozark Dome

In a widespread area extending from the Ardmore basin toward the Reelfoot basin, the Simpson exhibits thicknesses and lithofacies of a tectonically stable marine platform (Fig. 9). Dominating this region are shallow-water, restricted marine to supratidal carbonates and barrier to peritidal sand complexes of the lower Simpson, Everton, and St. Peter (Suhm, 1974) and sabkha-like tidal flats to shallow subtidal carbonates of the upper Simpson, Joachim, and Plattin (Craig and others, 1988). Shale is generally absent or limited to a few thin beds. The Simpson is bounded by regional angular unconformities with the underlying Arbuckle (Powell and Cotter of Arkansas) and the overlying Viola.

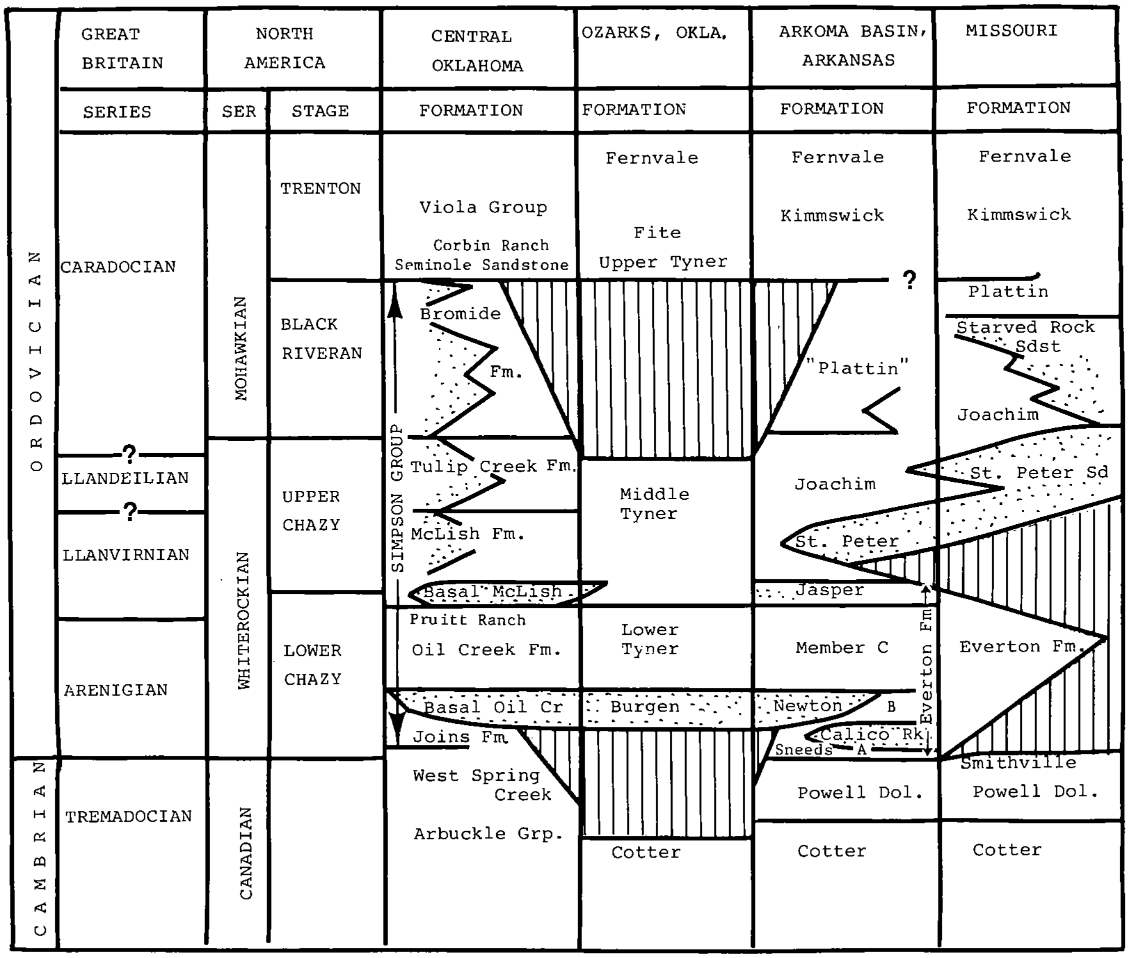


Figure 8. Correlation chart showing generalized relationships of the Simpson Group and equivalents in Arkansas and Missouri. Compiled through consideration of work of Derby and others (1991), Ross and others (1982), Ross and Ross (1992), Thompson (1991), Suhm (1974), and Witzke (1980). Lacunas in Arkansas and Oklahoma reflect uplift of the Ozark dome and South Ozark arch. The term *Trenton* was eliminated in the preparation of the American Association of Petroleum Geologists' COSUNA project (Salvador, 1985), but it is retained here because of its current subsurface use. The Cambrian–Ordovician boundary in North America is placed at the top of the Tremadocian (Lapworth, 1879; Jackson, 1964; Patterson, 1961; Whittington, 1968; Suhm and others, 1975).

The Simpson is relatively uniform in thickness, ranging between 200 and 800 ft, but it thins depositionally in the direction of the Ozark dome owing to diminished subsidence and/or uplift, which is reflected by numerous intraformational unconformities and diastems in outcrops of the Ozarks of Arkansas. Solution breccias and cave-fill deposits were observed in the Everton Formation in the Sneeds Dolomite, members A and B, and unnamed dolomites (Suhm, 1970; McKnight, 1935; Purdue and Miser, 1916; Minke, 1969), suggesting short-term exposure before burial by younger Everton beds.

North of the 400-ft isopach line, the Simpson also becomes thinner by truncation through a post-Simpson–pre-Viola erosional event, reflecting uplift of an arch related to, but south of, the Ozark dome—here termed the *South Ozark arch* (Fig. 9). The Viola truncates progressively older Simpson beds toward the axis of the arch, where it is unconformable on strata as old as the Oil Creek Formation and member C of the Everton. The Viola also thins over the arch and is totally absent on the Ozark dome through pre-Sylamore (Devonian) erosion. The Simpson is absent farther north on the Ozark dome in Missouri and eastern Kansas, with the exception of remnants of Simpson sand that filled sinkholes developed in Arbuckle carbonates (Lee and others, 1948; Thompson, 1991).

The South Ozark arch and the Ozark dome may also have experienced an earlier uplift—at the end of Whiterockian time, before or during deposition of the Bromide ("Plattin"). From outcrops in Arkansas, Craig and others (1988), Glick and Frezon (1953), and Jee (1984) report an angular unconformity between the Joachim Formation (Tulip Creek equivalent) and the "Plattin" Limestone. In western outcrops in Newton County, Arkansas, the Joachim is absent, and the "Plattin" rests directly on the St. Peter (McLish). Without biostratigraphic control, however, the "Plattin" in this instance may represent a

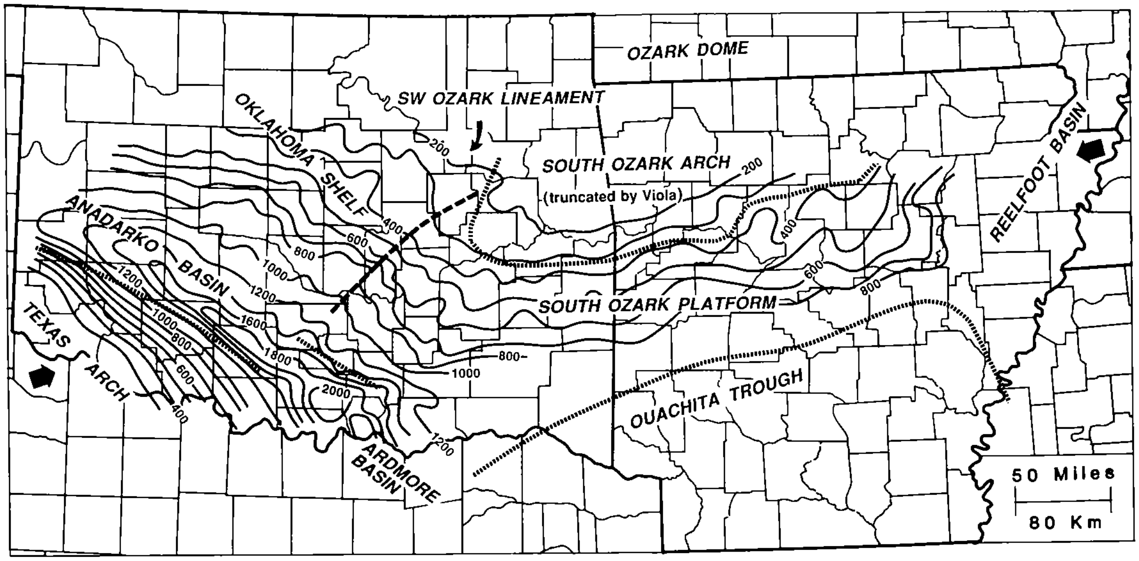


Figure 9. Middle to upper Simpson isopach map, with tectonic provinces based on lithologic associations (contours in feet). Hachure separating the South Ozark arch from the South Ozark platform is based on truncation of Simpson by Viola. Line hachures flanking the Anadarko and Ardmore basins represent syndepositional faults. Thick arrows indicate general location of cross section illustrated in Figure 7.

dense facies of the lower Viola, equivalent to the upper Tyner and the Fite Limestone in northeastern Oklahoma.

The Simpson also thins by northward progressive onlap over the Arbuckle and older beds of the Simpson. The loss of lower Simpson strata is observed both from well logs and outcrops. In northwestern Arkansas, the Newton Sandstone (Everton) has overstepped the Sneeds and member B (Suhm, 1974; Purdue and Miser, 1916, who call the Newton the St. Peter) to eventually rest on what Hedden (1976) describes as the lower Powell. In northeastern Oklahoma, the Burgen (Newton) Sandstone oversteps the Joins Formation and rests unconformably on Arbuckle carbonates (Huffman, 1965).

The unconformity at the base of the Simpson Group furnishes evidence that the Ozark dome and its related structural counterpart, the South Ozark arch, were uplifted and eroded at the end of Canadian time coincident with a fall in sea level at the Sauk–Tippecanoe interface. The unconformity increases in magnitude toward the Ozark dome, where progressively older Arbuckle strata were eroded. Arbuckle limestones were selectively karstified over much of the South Ozark platform to at least the 500-ft isopach line (Fig. 9), from the Arbuckle Wilburton field, Latimer County, Oklahoma (Carpenter and Evans, 1991; Mescher and others, 1993), to possibly the Arbuckle Albion field, White County, Arkansas.

Paleotopographic expression of the Ozark dome affected dispersal routes of quartz sand originating from the Canadian shield. Isopach maps show that, with the exception of the Bromide sand, all sands of the Simpson Group were transported on the east side of the Ozark dome. Bromide sands were transported on the west side of the Ozark dome, perhaps in response to a post-Whiterockian uplift. Early Simpson sands were carried southwestward across the South Ozark arch and South Ozark platform in a series of coalescing barriers, strandlines, and sand banks. Southwest transport of these sands, however, essentially ceased in the deeper water of the South Ozark platform where it adjoins the Ardmore basin; some sand spilled over into the Ardmore basin, but most of it was redirected by northwest currents toward the Oklahoma shelf. Bromide sands covered much of the Oklahoma shelf. The South Ozark platform is separated from the adjoining Oklahoma shelf by the Southwest Ozark lineament.

Oklahoma Shelf and Southwest Ozark Lineament

The Oklahoma shelf is a distinct tectonic and sedimentologic province that slopes gently in a southwest direction from the Ozark dome toward deeper water of the subsiding Anadarko basin. Unlike the sharp boundary between the South Ozark platform and the Ardmore basin, the junction of the Oklahoma shelf with the Anadarko basin is arbitrarily placed at about the 1,000- to 1200-ft contour line (Fig. 9). The Oklahoma shelf is separated from the South Ozark platform by a southwest–northeast tectonic flexure called the *Southwest Ozark lineament* (Fig. 9). Presumably, this structural lineament, based on contour deflection, allowed the Oklahoma shelf to subside somewhat independently from the adjoining South Ozark platform. This resulted in thickness and lithologic differences readily seen in the Simpson. For example, in comparison with the South Ozark platform, the Oklahoma shelf was less stable and was characterized by slightly deeper water, lower energy environments with more clay, and less quartz sand (except sand of the Bromide). The differences were even more apparent in Bromide time, when regional crustal equilibrium shifted; the Oklahoma shelf subsided more rapidly than the South Ozark platform to accommodate vast quantities of Bromide sand. The sands reached their

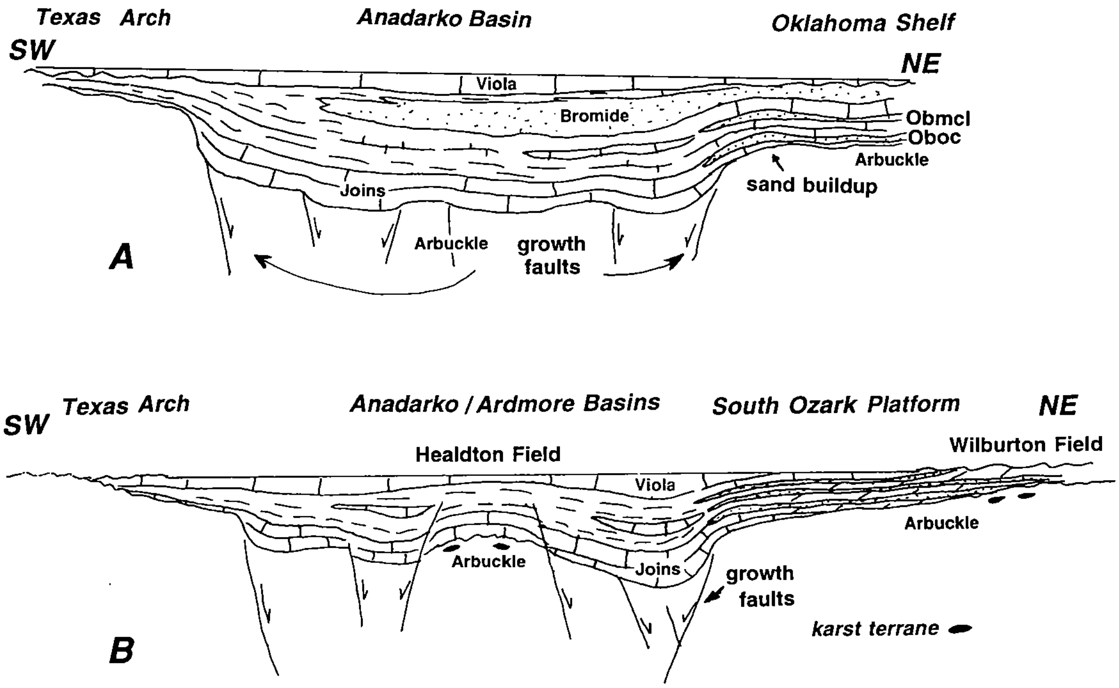


Figure 10. (A) Schematic northeast–southwest cross section illustrates the effect of syndepositional faults on Simpson thickening into the Anadarko basin. Basal Oil Creek (*Oboc*) and Basal McLish (*Obmcl*) sands piled up on the upthrown side of the growth fault. (B) Schematic cross section across the junction of the Anadarko basin with the Ardmore basin. Thickness variations in the Simpson suggest, in part, intrabasinal horsts and grabens bound by syndepositional faults. At Wilburton field, and possibly Healdton field, karstification of the Arbuckle may have taken place before Simpson deposition.

maximum thickness in a sediment-loaded tectonic basin centered on the Oklahoma shelf in Canadian County, Oklahoma. This small basin continued to subside during the remainder of Simpson time, resulting in thick deposits of the upper Bromide limestone. Its effect on Viola sedimentation is less noticeable.

Surprisingly, the Southwest Ozark lineament is generally coincident with the present-day province boundary separating the Cherokee platform from the Arkoma basin (compare Figs. 1 and 9). Perhaps the tectonic foundation and history of these two distinct hydrocarbon provinces began as far back as Ordovician time—creating differences in the timing of sourcing and migration of hydrocarbons and their structural entrapment. This appears to be the case, since most of the petroleum of the Cherokee platform (Oklahoma shelf) is trapped in sands of the Bromide, whereas hydrocarbons in the Arkoma basin (South Ozark platform) are in older sands of the Simpson.

Reelfoot Basin

The Reelfoot basin in the Mississippi embayment of northeastern Arkansas was created by tensional rifting in Cambrian time (Buschbach, 1971; Schwalb, 1982). Pre-Simpson rift deposits exceed 30,000 ft in thickness (Howe and Thompson, 1984); the Simpson, however, is only about 2,000 ft thick. Apparently, in Ordovician time, the Reelfoot area changed from a rapidly subsiding rift system to a broad, mildly subsiding cratonic embayment or basin. On the basis of isopach maps, the Simpson thickens east and southeast of the South Ozark platform toward the Reelfoot basin (Fig. 9). Thickening can also be seen from published seismic lines for east-central Arkansas (VanArsdale and Schweig, 1990) and from maps of Frezon and Glick (1959) and Suhm (1979). The lower Simpson exhibits the greatest thickening. Simpson strata younger than the Newton show minor thickening, which indicates that the Reelfoot basin stabilized from Whiterockian through Mohawkian time.

The well-documented unconformity at the base of the Simpson on the South Ozark platform loses identity in the Reelfoot basin, where deposition was continuous across the Sauk–Tippecanoe interface. Unfortunately, lithologic contrasts are also lacking, making it difficult to distinguish the Smithville/Powell from the overlying Simpson or Everton (Suhm, 1972).

Unlike the wide variety of lithologies on the South Ozark platform, the Simpson in the Reelfoot basin consists of thick sections of limestone and late secondary dolomite that were deposited under more constant environmental conditions. Sandstones of the Calico Rock and St. Peter are poorly developed, owing to a facies change to thickening carbonates. Shale is essentially absent. The entire Simpson section becomes principally an interfingering complex of lime mudstone, pelletal and intraclastic limestone, finely to coarsely crystalline secondary dolomite, and a few discontinuous thins beds of dolomitic sandstone such as were recovered from the Cockrell No. 1 Bunch well (Fig. 4), Lee County, and the Cockrell No. 1 Carter well, St. Francis County, Arkansas. Dolomite in some well cuttings displays finely disseminated hydrocarbons and asphaltic stains. Terrigenous admixtures, insoluble residues, and microfossils are commonly used to differentiate rock units.

Although facies changes between dolomite and limestone play havoc with correlation and inhibit an understanding of depositional history, they enhance the petroleum potential of a reservoir by setting up conditions for the stratigraphic entrapment of hydrocarbons. Dolomite porosity is intergranular, intercrystalline, or vuggy and generally increases with increasing crystallinity. The distribution of dolomite porosity is less readily predictable than sandstone porosity, but nevertheless it is just as important. Stratigraphic traps, such as permeability barriers, may be created where crystalline dolomite grades to tight limestone or aphanitic dolomite.

East from the Cockrell No. 1 Bunch, Lee County, Arkansas, Simpson equivalents grade into the "Knox" and Stones River Groups in the Black Warrior basin of Mississippi and Alabama, described by Thomas (1988). Mellen (1974) reported a porosity of over 14% from Ordovician dolomite correlative with the Everton.

Data are scarce from the Reelfoot basin, not only because of limited drilling but also because the Simpson is partly to completely missing by post-Simpson erosion over the Pascola arch in far northeastern Arkansas. The absence or near absence of the Simpson results in stratigraphic disorientation when correlating widely scattered wireline and sample logs. Without awareness of stratigraphic and structural position and without an understanding of regional facies changes, errors in "calling tops" result—such as many of those listed in Dart (1992). Well-log markers and intervals of terrigenous admixtures help, but correlation remains difficult. From regional cross sections, not included here, Simpson equivalents reappear in southeastern Missouri.

The southern limit of the Reelfoot basin is in the vicinity of the Reserve No. 1 Hazen well, Prairie County, Arkansas (compare Figs. 4 and 9). The upper Simpson consists of dark basinal argillaceous limestone indicative of proximity to the Ouachita trough. Dip logs for this well, however, show several faults and complex structural anomalies that negate its usefulness in stratigraphic correlation and interpretation.

Ouachita Trough

The Ouachita trough was a rapidly subsiding linear basin—the failed rift system of Lowe (1989)—that received large quantities of terrigenous clay, quartz sand, and lesser amounts of lime mudstone (Fig. 9). It was bounded on the south by a large block of continental crust termed *Llanoria,* the southern edge of which formed the continental margin in Ordovician and later times (Lowe, 1989). Llanoria was the landmass from which most of the clay was derived (Lowe, 1989; Dix and others, 1994). Simpson equivalents in the Ouachita facies include, in ascending order, the Mazarn Shale, the Blakely Sandstone, the Womble Shale, and perhaps the Crystal Mountain Sandstone below the Mazarn. The Womble Shale and the Blakely Sandstone were encountered in only a few wells in the Ouachita allochthon. No wells have penetrated the autochthonous Ouachita facies of the Simpson in Oklahoma and Arkansas.

Because of the lack of deep wells, the location of the junction between the South Ozark platform and the Ouachita trough is unknown. The Ouachita trough, however, does appear to extend farther south than the Reserve No. 1 Hazen, Prairie County, Arkansas; the Oxy No. 1 Danville, Yell County, Arkansas; the Sohio No. 1 Weyerhaeuser, McCurtain County, Oklahoma; and the Hunt No. 1 Neely, Lamar County, Texas (Fig. 4). Although the Simpson in the Hunt No. 1 Neely and the Sohio No. 1 Weyerhaeuser consists of low-rank metamorphic carbonates, the lithology and remnant textures indicate similarity to strata on the platform to the north and so may have been deposited in similar shallow-water environments. Wireline-log signatures of those wells are also similar to those of wells drilled on the platform (Milliken, 1988; Leander and Legg, 1988). The Sohio No. 1 Weyerhaeuser was drilled within the Broken Bow uplift, a feature not unlike the Benton uplift of Arkansas and the Waco and Devils River uplifts in Texas as reported by Nicholas and Rozendal (1975) and Nicholas and Waddell (1989). In their study of a regional north–south COCORP seismic line through the Ouachita Mountains of Arkansas, Lillie and others (1983) speculated that cratonic, not geosynclinal, successions exist beneath the Benton uplift of Arkansas. The Benton uplift is on strike with the Broken Bow uplift of Oklahoma; therefore, the platform–trough margin probably extends farther south in the subsurface than these uplifts. In light of these conclusions, as well as from the study of isopach maps prepared for this study, the present-day Ouachita thrust front in Oklahoma and Arkansas must have been transported over the cratonic facies a distance greater than 50–60 mi, which is similar to what earlier investigators reported (Hendricks, 1959; Miser, 1929).

In the southern part of the Reelfoot basin, the Reserve No. 1 Hazen, Prairie County, Arkansas, penetrated thick, dark, argillaceous basinal limestone tentatively identified as Simpson (Suhm, 1978). The section is interpreted as a deep-water limestone with a clay content that suggests close proximity to the Ouachita trough. Eastward, the Ouachita trough extends into southern Mississippi and Alabama south of the Black Warrior basin and the Alabama promontory (Thomas, 1988; Lowe, 1989).

The location of the platform–trough break has important considerations for the petroleum potential of the Simpson; thick reservoir-quality sands could have piled up at the shelf edge or perhaps spilled over into the trough, such as at the margin of the Ardmore basin with the South Ozark platform. If the shelf break were generated by episodic syndepositional faulting, then fractured Simpson carbonates could also represent viable reservoir objectives. Additionally, excessively thick organic-rich basinal shale of the Ouachita trough appears to have had the potential for acting as a hydrocarbon source.

STRATIGRAPHY

Joins Formation (Oklahoma); Sneeds Dolomite and Members A and B of Everton Formation (Arkansas)

The Joins Formation, long considered to be discrete and sequentially stacked below the Basal Oil Creek Sandstone in many parts of the subsurface, is a facies of this sandstone (Figs. 7,11,12). Lateral facies changes from carbonate to sandstone can take place across distances as short as a few miles. Joins equivalents in Arkansas, especially limestone–sandstone members A and B of the Everton, show a similar facies relationship to the Calico Rock and Newton Sandstones, respectively (Suhm, 1974).

The Joins consists of sandy ostracodal, pelletal, and oolitic limestone, lime mudstone, and dolomite. Gastropods and ostracodes are locally abundant, but species diversity is low; this suggests deposition in restricted shallow-marine environments. Over a large area of Oklahoma, the Joins was embayed by the Basal Oil Creek sand complex (Fig. 12). Quartz sandstone exists as thin beds and tends to be very dolomitic or very calcareous. Shale is rare except in basinal and deeper shelf positions, where it is associated with argillaceous limestone. Chert is usually not present in the Joins, unlike its characteristic presence in the underlying Arbuckle. Several limestone conglomerates are present in the lower Joins and the subjacent upper part of the West Spring Creek, one of which is commonly used to mark the base of the Joins in the Arbuckle Mountains.

There is much confusion about the contact of the Joins with the Arbuckle on wireline logs (Statler, 1965;

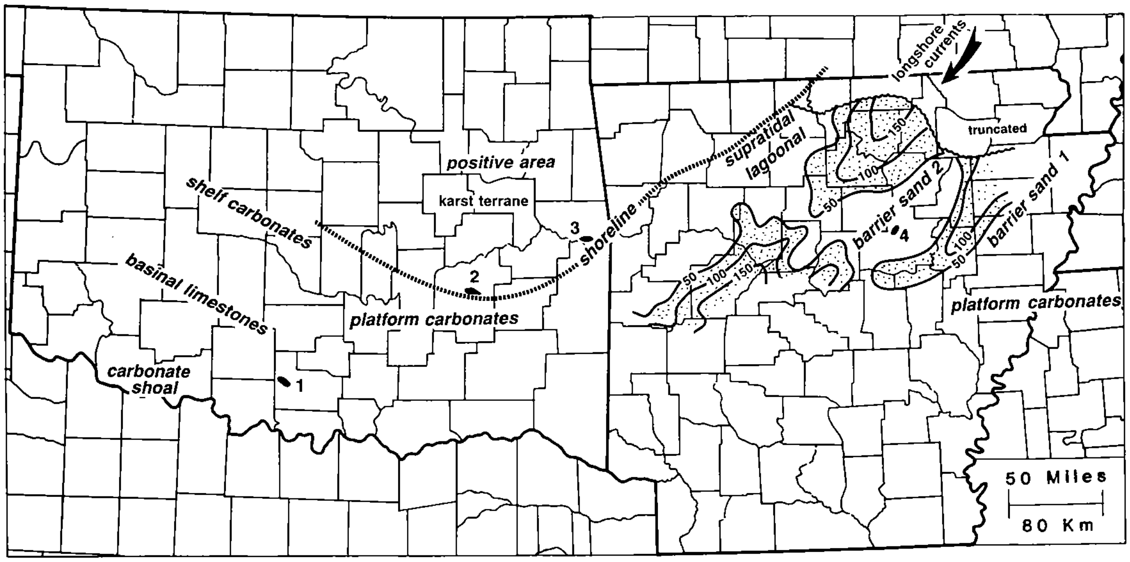


Figure 11. Calico Rock Sandstone isolith map and earliest Whiterockian facies, including the Sneeds and member A of the Everton (Arkansas) and the upper West Spring Creek to Joins (Oklahoma). Arbuckle karst is indicated at (1) Healdton field, Carter County; (2) Wilburton field, Latimer County; (3) Paw Paw NE field, Sequoyah County; and (4) Albion field, White County, Arkansas.

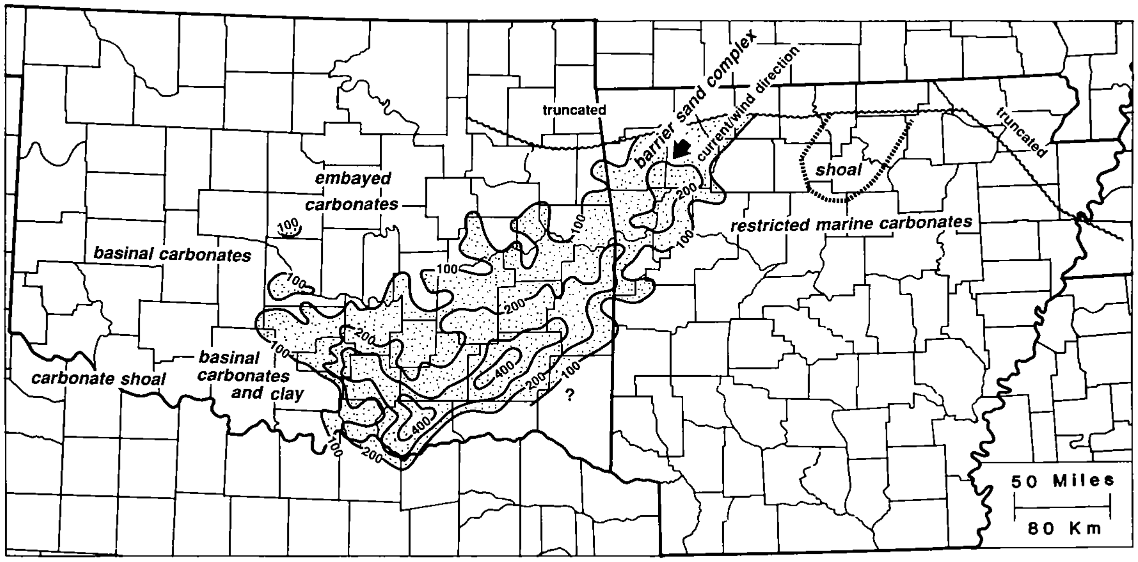


Figure 12. Basal Oil Creek Sandstone and Newton Sandstone isolith map with adjacent Joins facies in Oklahoma and middle Everton facies in Arkansas. Values for Pushmataha County, Oklahoma, are interpreted.

Cronenwett, 1956; Allison and Allen, 1997). In this study, however, the base of the Simpson (Joins) and equivalents in Arkansas is placed at the base of the lowest quartz sandstone, above the thick monotonous carbonate section of the Arbuckle. In the absence of sandstone, the base of the Joins is arbitrarily placed at a change on the density log from a silica-rich (sandy) density to a carbonate-dominated density value. Interestingly, when the Joins contact is defined in this manner, its base invariably extends downward to include the upper part of the West Spring Creek Formation of the Arbuckle Group, perhaps as low as the *Diparelasma* and *Pomatotrema* zone marker beds of Ham (1955) and Fay (1969) in the Arbuckle Mountain area (Fig. 6). The Joins is also extended downward to include the "Wade Zone" of the West Spring Creek as defined by Latham (1968) in southern Oklahoma. Derby (1973a) recognized the upper approximately 100 ft of the West Spring Creek to be Whiterockian in age along U.S. Highway 77 in the Arbuckle Mountains, so there appears to be faunal evidence as well as lithologic evidence for rethinking Joins and West Spring Creek stratigraphy.

The basis for including strata above the lowest occurrence of significant sandstone in the Joins is in keeping with the concept that the Simpson is the basal terrigenous deposit of the Tippecanoe Sequence. North America experienced tectonic change at the beginning of Whiterockian (Tippecanoe) time; therefore, the Simpson is united by a common tectonic and depositional history, which began with an initial influx of quartz sand into the southern Midcontinent, to be followed by thicker sand layers. The position of this sequence boundary differs from that of Schutter (1992) and Derby and others (1991), who place the sub-Tippecanoe unconformity at the base of the McLish and St. Peter. This study indicates, however, that the well-documented unconformity at the base of the St. Peter of the northern Midcontinent extends under Simpson sandstones older than the McLish in the southern Midcontinent (see Sloss, 1984, fig. 1; Dake, 1921, pl. 2). Older Whiterockian sands (although missing in northern Midcontinent sections) are the most basinally restricted deposits of the Tippecanoe Sequence; they transgressed over a widely exposed, partly karsted, Arbuckle land surface, the unconformity of which is readily observed on the Ozark dome and the South Ozark arch. Only much later were they buried by the McLish and St. Peter sand events (Fig. 7). Therefore, the contact at the base of Whiterockian strata represents the Sauk–Tippecanoe unconformity, a major unconformity of the Paleozoic Era.

On the Texas arch in southwestern Oklahoma, about 100 ft of sandy oolitic carbonates, traditionally referred to as *Ellenburger "A"* or *upper Ellenburger,* are correlative with the Joins. The density log is generally used to define the base of these sandy carbonates, since the gamma-ray and spontaneous-potential logs are not meaningful across this interface. Also, the Joins is generally characterized by lower resistivity than that of the underlying nonsandy carbonates of the Arbuckle. Sandy dolomites of the Joins are productive in southern Love County, Oklahoma, and various parts of the Fort Worth basin in Texas, according to W. E. McCommons (personal communication, 1992).

The upper contact of the Joins is placed at the base of the Basal Oil Creek Sandstone. However, the Basal Oil Creek Sandstone may be ill defined where it interdigitates with carbonates; the contact in this instance is placed at the base of one of the arbitrarily selected thicker sandstones. Where the Basal Oil Creek Sandstone is absent entirely, through a facies change to carbonates of the Joins—as in the Anadarko and Ardmore basins and parts of the Oklahoma shelf—the top of the Joins is placed at the base of the Oil Creek Formation. The Joins exhibits low gamma-ray and high-resistivity curves that contrast with "spiky" high gamma-ray and low-resistivity signatures of the Oil Creek Formation (Fig. 6). The contact is conformable and generally sharp except in deeper parts of the Anadarko and Ardmore basins, where it is gradational.

In areas of the South Ozark platform, the Joins is locally unconformable with the Basal Oil Creek Sandstone. On the South Ozark arch, the Joins and equivalents in Arkansas are absent by unconformable overstep of the overlying Burgen and Newton Sandstones (Fig. 13).

In Arkansas, carbonate equivalents of the Joins and upper West Spring Creek Formations are in the interval of the lower Everton—between the Powell (Arbuckle) below, and member C of the Everton Formation above. The lower Everton includes the Sneeds Dolomite Member, limestone–sandstone member A (facies of the Calico Rock Sandstone), limestone–sandstone member B (facies of the Newton Sandstone), and unnamed Everton dolomites (Suhm, 1970, 1974). The affinity for limestone (versus dolomite) to be below and slightly lateral to massive quartz sandstones seems characteristic. It is believed that removal of clay and organic particles in high-energy environments bordering the sand complexes inhibited dolomitization (Lindholm, 1969; Friedman, 1991; Slaughter and Hill, 1991). Dolomite of the Sneeds was deposited in peritidal and lagoonal environments protected by the barrier sands of the Calico Rock (Suhm, 1974). As the barrier transgressed, so did the facies of the Sneeds (Fig. 7).

Lower Everton carbonates are distinguished from the underlying Powell (Arbuckle) by lithology. Dolomites of the Powell are light gray, dull, silty, partly cherty, and very finely crystalline, whereas dolomites of the Sneeds and lower Everton are sandy and very finely crystalline. This contact is seen on well logs at a change from "spiky" high gamma-ray curves of the Powell to relatively lower gamma-ray signatures for the lower Everton (Fig. 14). The Simpson–Arbuckle contact also can be generally placed from the spontaneous-potential curve, even in eastern Oklahoma; the upper Arbuckle has a gradually decreasing spontaneous potential coincident with an increasing gamma ray to a shape of concavity extending over a vertical interval of several hundred feet. The contact is arbitrarily placed a hundred feet or so above the point of maximum concavity.

Throughout much of the outcrop belt in northern Arkansas, the Sneeds Member of the basal Everton consists of a basal conglomerate containing angular to subrounded granules and pebbles of detrital chert and dolomite in a sandy dolomite matrix. The chert and dolomite pebbles were derived from the erosion of the subjacent cherty carbonates of the Powell and Cotter that

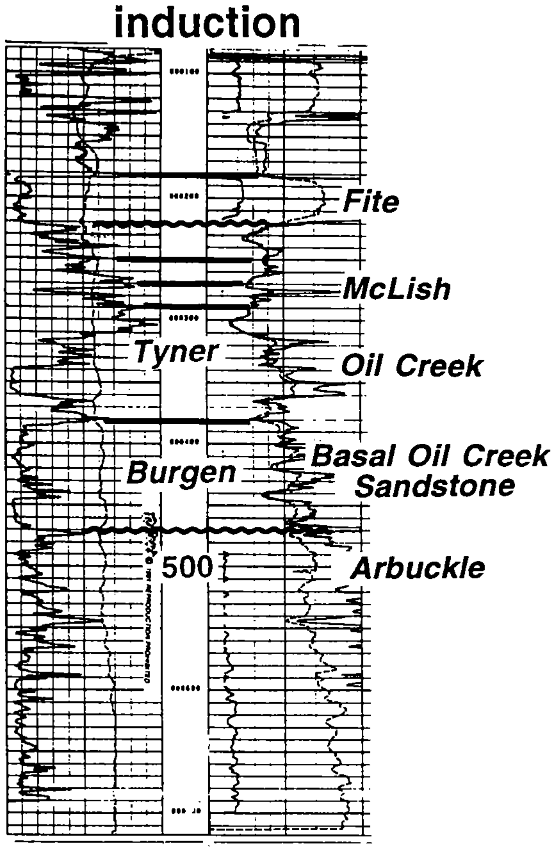


Figure 13. Subsurface well log (I-Mac Petroleum No. 1–19 Acres) for the Simpson Group in the South Ozark arch province, sec. 19, T. 15 N., R. 20 E., Muskogee County, Oklahoma. The Bromide and part of the Tulip Creek have been truncated by the Viola (Fite).

were exposed on the Ozark dome at the beginning of Whiterockian time. Additionally, strata of the Powell have slight angularity to the Everton (McKnight, 1935; Suhm, 1974), suggesting that the Ozark dome was uplifted prior to Everton deposition. This contact also corresponds to a magnetic polarity reversal that is consistent with a sedimentary gap (Farr and others, 1993). Cave-fill and collapse breccias, probably the result of karst solutional processes, are present not only in the Powell and Cotter but also in limestone–sandstone members A and B and in dolomites of the lower Everton (Suhm, 1970; McKnight, 1935; Minke, 1969; Purdue and Miser, 1916). The breccias host mine-grade lead and zinc sulfides that may have been precipitated by the reaction of metal-bearing brines with hydrogen sulfide gas trapped in paleokarst breccias. Lagoonal algal-mat deposits of the Everton may have been the source of hydrogen sulfide gas in stratiform deposits (Suhm, 1976). Interestingly, Gonzales (1974) shows that hydrocarbon accumulations appear to be common downdip from stratiform ore deposits.

In eastern Arkansas, the lower Everton thickens into the Reelfoot basin. The Powell also thickens, and its upper part

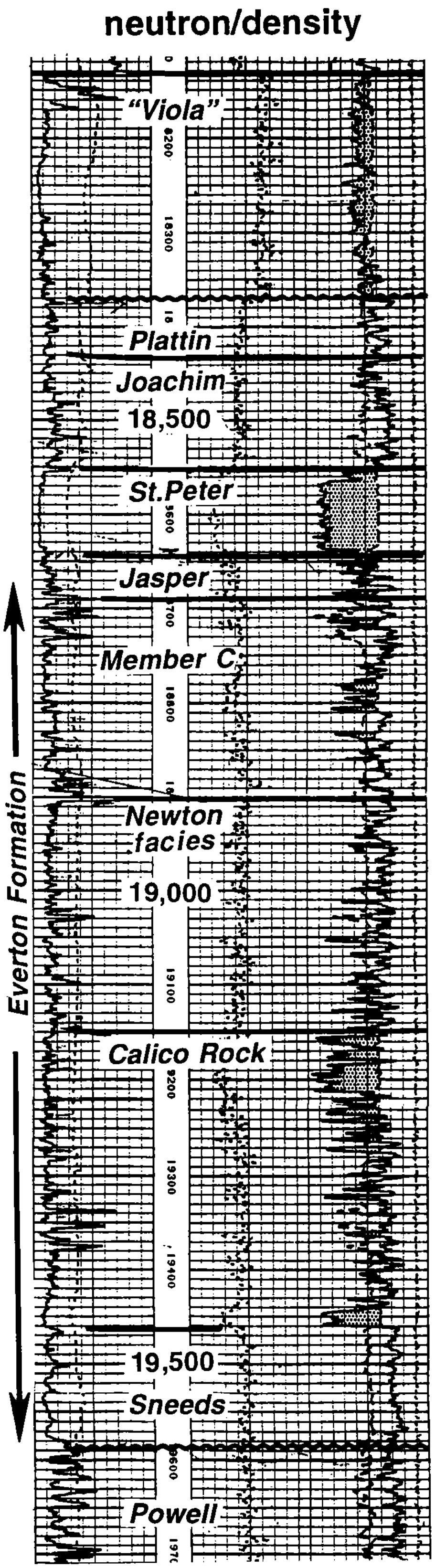


Figure 14 (right). Subsurface reference well log (Oxy No. 1 Danville) for Simpson Group equivalents in Arkansas, South Ozark platform province, sec. 33, T. 5 N., R. 22 W., Yell County, Arkansas.

grades to less silty carbonates of the Smithville and Black Rock Formations (Hedden, 1976). Unfortunately, the similarity of these carbonates with those of the Everton makes defining the contact difficult, especially where stratigraphic markers, such as quartz sandstones of the Calico Rock, Newton, and St. Peter, are absent. The lower Everton may even grade into upper beds of the Smithville in deeper parts of the basin. The contact is arbitrarily drawn from samples and wireline logs at the base of dominantly sandy carbonates of the Everton. Farther southeast, in the Black Warrior basin, Thomas (1988) alludes to a similar problem in distinguishing Everton equivalents from Knox (Arbuckle) carbonates.

Calico Rock Sandstone Member of Everton (Arkansas)

The Calico Rock Sandstone Member of the Everton Formation is the oldest of the St. Peter–like sandstones. It approaches thicknesses of 200 ft in the outcrop belt of the Ozarks and in the subsurface (Fig. 11). Lithologically, the Calico Rock is composed of medium-sized, frosted, rounded quartz grains bounded by varying amounts of silica as secondary quartz overgrowths or carbonate cements. Quartz overgrowths are most common in well-sorted and coarser grained sandstones.

The Calico Rock Sandstone is ripple marked and locally cross-bedded. Ripples were studied, and together with data of Giles (1930) it was determined that the sand was distributed by southwesterly moving longshore currents (Suhm, 1975). The Calico Rock Sandstone was recognized in a few water wells in southeastern Missouri, where it is about 150 ft thick. Northward in Missouri, the Calico Rock is absent through overstep by younger Everton beds. Sand of the Calico Rock was derived from the Canadian shield and transported across Missouri by rivers, perhaps braided streams, and by eolian processes. In Arkansas, the Calico Rock is interpreted to be an amalgamated barrier-sand complex with a back-barrier lagoonal system and a seaward marine platform. Its basinward position with respect to younger Simpson sands indicates that sea level was at its lowest stand during its deposition. Therefore, this sand and its carbonate facies (Joins, lower Everton) are included with the basal deposits of the Tippecanoe Sequence. The oldest barrier complex, barrier 1, fringed the Reelfoot basin with an embayed sea behind it. During this time, a broad area of northern Arkansas and eastern Oklahoma was subjected to subaerial exposure; carbonates of the Smithville, Powell, Cotter, and Arbuckle were selectively karstified.

Barrier complex 2, slightly younger and more landward (transgressive) than barrier complex 1, reflects another flood of sand that entered the southern Midcontinent. Lagoonal carbonates of limestone–sandstone member A and the Sneeds were deposited lateral to the Calico Rock sand. The Calico Rock is usually conformable on limestone–sandstone member A, but diastems and cut-and-fill structures can be observed locally at its base. Solution-collapse breccias and cave-fill structures occasionally observed in these carbonates suggest that they were subjected to meteoric karst development during temporary exposure. It is possible that similar karst features were generated in the lagoonal complex of barrier system 1, but subsurface data are lacking.

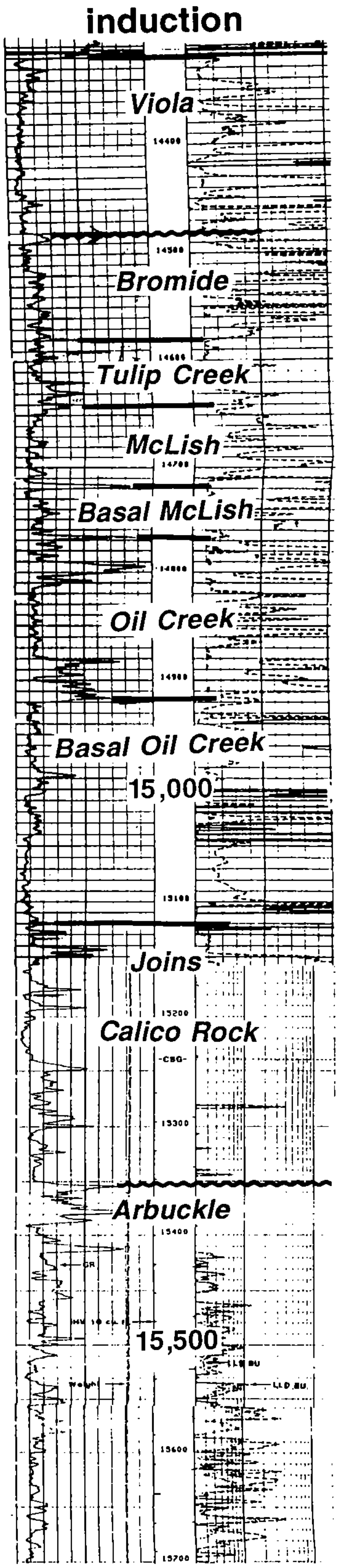
Within a horizontal distance of about 30–40 mi to the northwest, the Calico Rock Sandstone changes facies to secondary dolomite, which then grades into the lower and middle parts of the Newton Sandstone (Figs. 7,11,12). The Calico Rock is conformably succeeded by fine- to medium-crystalline dolomite, arenaceous dolomite, and dolomitic sandstone, which, by stratigraphic position, are an offshore facies of the upper Newton Sandstone.

The Oxy No. 1 Danville, Yell County, Arkansas, encountered a thick interval of Calico Rock sandstones above limestone and dolomite of member A and the Sneeds (Fig. 14). This indicates that the Calico Rock Sandstone and lower Everton members thicken southward near the junction with the Ouachita trough. However, the southern limit of sand is unknown, owing to a lack of well control. The sand could have entered the Ouachita trough to form the Crystal Mountain Sandstone via a channel system in Garland County, Arkansas, described by Lowe (1989), although present biostratigraphic information places this sand in the Canadian Series. The Calico Rock Sandstone is present as thin beds in some wells in eastern Oklahoma below the Basal Oil Creek Sandstone (Fig. 15). Farther west, however, these sands grade into the Joins and upper West Spring Creek.

Basal Oil Creek and Burgen Sandstones (Oklahoma); Newton Sandstone (Arkansas)

The Basal Oil Creek, Burgen, and Newton Sandstones form an elongated sand body extending from northwestern Arkansas to south-central Oklahoma (Fig. 12). The sandstone is remarkably similar to the St. Peter and Calico Rock Sandstones; it is usually medium grained but can range from fine to coarse grained. It contains well-rounded to rounded, frosted quartz grains cemented by variable amounts of silica or carbonate. Complete occlusion of porosity by quartz or carbonate cement may be encountered at greater depths; however, porosity can be preserved through the early entrapment of hydrocarbons (Bjorlykke and Egeberg, 1993).

The geometry of the sand body is striking (Fig. 12). It is linear and generally parallel to, yet transgressive with respect to, the Calico Rock Sandstone. Sand accreted to the southwest from a northeast source that crossed Missouri, possibly in a braided-stream system. At the junction with marine environments in the southern Midcontinent, tidal and longshore processes became dominant. The Basal Oil Creek and Newton Sandstones accumulated in a composite of barrier, back-barrier, and peritidal complexes. The geometry of the sand body denotes rapid progradation of large quantities of sand by longshore and tidal currents on a low gradient in poorly defined, shallow channels. Lesser rates of subsidence encountered on the South Ozark platform enabled the quartz grains to remain in this "littoral" environment long enough to be transported laterally for significant distances along the shoreline. The sand body is 50 mi wide and 200 ft thick in northwestern Arkansas but expands to twice that width on the South Ozark platform of Oklahoma, where it is over 350 ft thick. The sand also apparently transgressed to the northwest in response to rising sea levels. In its



transgression, the barrier complex was modified by marine processes. Its extent in southeastern Oklahoma is unknown because of a lack of well control. In the Sohio No. 1 Weyerhaeuser, McCurtain County, Oklahoma, sand was not well developed in the stratigraphic interval where it was supposed to occur.

The southwest migration of sand across the South Ozark platform terminated at deeper water near the junction with the Ardmore basin, where sand piled up on the upthrown side of a syndepositional fault (Fig. 10). The sand was redistributed to the northwest by platform-edge currents. Some very fine- to fine-grained sand spilled over into the Ardmore basin, and some was directed through Bryan County, Oklahoma, south of the southern terminus of the syndepositional fault (Fig. 12). At this hinge line, conditions approached normal-marine shelfal environments (Lewis, 1982; McPherson and others, 1988). Basinward from the hinge line, quartz sands of the Basal Oil Creek grade to limestone and argillaceous carbonates of the Joins.

The upper Joins in parts of Stephens and Carter Counties, Oklahoma, displays a "hot" gamma-ray spike coincident with low density that is traceable across extensive areas. This zone may be indicative of a biokill associated with an ash fall. Bentonites are common and widely distributed in the uppermost Simpson equivalents in the eastern parts of the United States. None, however, has been reported in lower Simpson beds in the southern Midcontinent. If, indeed, this is an altered bentonite, volcanism, perhaps in Llanoria, may have taken place in early Whiterockian time.

In central Oklahoma, an extensive sand, referred to here as the upper part of the Basal Oil Creek Sandstone, is stratigraphically above, and difficult to separate from, the principal body of the Basal Oil Creek Sandstone. It is a lateral facies equivalent of the lower part of the Oil Creek Formation and so represents a "true" basal Oil Creek sandstone. However, it is not to be confused with a sandstone in the middle part of the Oil Creek Formation in eastern Oklahoma correlated with member C "sandstone" of the Everton Formation, to be discussed later. Eastward, the Basal Oil Creek Sandstone gradually oversteps the Joins to grade into the Burgen Sandstone, exposed in Cherokee and Adair Counties, Oklahoma. In Arkansas, the Newton is the lateral equivalent of the Burgen.

The Newton Sandstone grades seaward (eastward) into limestone–sandstone member B and unnamed Everton dolomites with a restricted marine fauna (Fig. 7). In spite of a facies change, its top can be determined across extensive areas of the South Ozark platform by a high gamma-ray deflection indicative of a thin shale. This thin shale is often overlooked in well-cutting examination. In Searcy and Stone Counties, Arkansas, the Newton Sandstone changes facies to dolomite and dolomitic sandstone, interpreted as a product of a supratidal to intertidal shoal (Fig. 12). The basal contact of the Newton Sandstone is commonly conformable with limestone–sandstone member B, but in some areas in the outcrop belt several feet of relief was noted at a disconformity. Farther north in Carroll County, Arkansas, the unconformity is more widespread; the Newton rests with considerable relief on karsted carbonates of limestone–sandstone member B, and, in their absence, karsted limestones of the Sneeds and Arbuckle (Purdue and Miser, 1916). In outcrops in northeastern Oklahoma, the Burgen Sandstone rests directly on the Arbuckle (Fig. 13).

The Basal Oil Creek and Burgen Sandstones are overlain by the Oil Creek and Tyner Formations, respectively, and the Newton is conformably succeeded by sandy dolomite and dolomitic sandstone of member C of the Everton Formation.

Oil Creek Formation and Lower–Middle Tyner (Oklahoma); Member C of Everton Formation (Arkansas)

The Oil Creek Formation is readily identified on well logs, because it occupies an interval between two of the most widespread sandstones in Oklahoma, the Basal Oil Creek and the overlying Basal McLish Sandstones. This interval is informally referred to as the Oil Creek "Shale" in Oklahoma, but the word *shale* incorrectly describes the gross lithologic composition because shale is a

Figure 15 (left). Subsurface reference well log (Arco No. 1–9 Runestone) for the Simpson Group in the South Ozark platform province, sec. 9, T. 6 N., R. 25 E., Le Flore County, Oklahoma.

minor component relative to limestone and dolomite. However, although minor, it represents the first incursion of significant quantities of clay into Oklahoma following deposition of the Basal Oil Creek Sandstone. The clays were probably derived from weathered terranes on Llanoria to the south and from areas to the west. The contact with the subjacent Basal Oil Creek Sandstone is conformable, as is the contact with the overlying McLish, with the exception of parts of the Southwest Ozark lineament, where the Oil Creek Formation is cut by a channel occupied by the Basal McLish Sandstone.

The Oil Creek isopach map (Fig. 16) reflects tectonic provinces similar to those defined from the middle to upper Simpson map (Fig. 9). More clearly defined, however, are tectonic hinge lines or syndepositional faults that flank the southern margin of the Anadarko basin and the northern margin of the Ardmore basin. The greatest thickness of the Oil Creek Formation is within the Ardmore basin. Thinning in southeastern Stephens County and northern Carter County, Oklahoma, reflects the inferred junction of the Anadarko and Ardmore basins.

In the Anadarko and Ardmore basins, where the Oil Creek attains maximum thicknesses greater than 900 ft, the formation consists of thinly interbedded fossiliferous limestone, dolomite, varicolored shale, and sandstone. Shale beds are generally thinner and less numerous than limestone beds. In the Arbuckle Mountain area, the Oil Creek contains a marine offshore fauna (Lewis, 1982). On wireline logs, the Oil Creek Formation exhibits characteristic thinly alternating high and low gamma-ray and resistivity curves in response to its sequence of interbedded limestones and limy shales (Figs. 5,6). The middle part of the Oil Creek Formation is the most argillaceous and is denoted by the lowest resistivity. This interval probably reflects a maximum highstand (greatest basinal subsidence) that, together with greater clay influx, inhibited carbonate deposition.

The Oil Creek is increasingly limy toward the top, grading to a limestone termed the *Pruitt Ranch Member,* or what is commonly referred to by petroleum geologists as the "Birdseye Limestone," a petroleum reservoir and a good reflector on seismic records. The Pruitt Ranch covers a broad area in the Anadarko and Ardmore basins in southern Oklahoma (Fig. 17). It consists of sublithographic to lithographic limestone with stromatolites and beds of ooids, intraclasts, pellets, and scattered fossil fragments (Harris and Harris, 1965). The absence of terrigenous clay and silt is notable. The lithologies and fauna of the Pruitt Ranch suggest deposition in a restricted "clear-water" marine embayment with fluctuating shallow-subtidal to intertidal and shoal environments. The profound change in environmental conditions in the Anadarko and Ardmore basins from "deep-water" muds and limestone to shallow-water carbonates is best explained by a diminished terrigenous influx coincident with a fall in sea level. But also, it is believed that this facies is expressive of a major climatic change toward aridity that affected a large region including the northern Midcontinent—the precursor "desert" for St. Peter sand sheets. The combination of aridity, which shut down the production of clay, and shallow water favored "clear-water" carbonate deposition in a shallow, hypersaline seaway, perhaps embayed by algal banks and oolite shoals that further inhibited the dwindling influx of terrigenous muds. It is doubtful that the basins were "filled in," since over 200 ft of Pruitt Ranch limestone was deposited in the depocenter of the Ardmore basin. Rather, the basins continued to subside—carbonate deposition keeping up with, or exceeding, subsidence. At several places in the Ardmore basin, close to the junction with the South Ozark platform, the upper part of the Pruitt Ranch limestone appears to grade into the Basal McLish Sandstone, implying complementary facies resulting from a change in the depositional and climatic

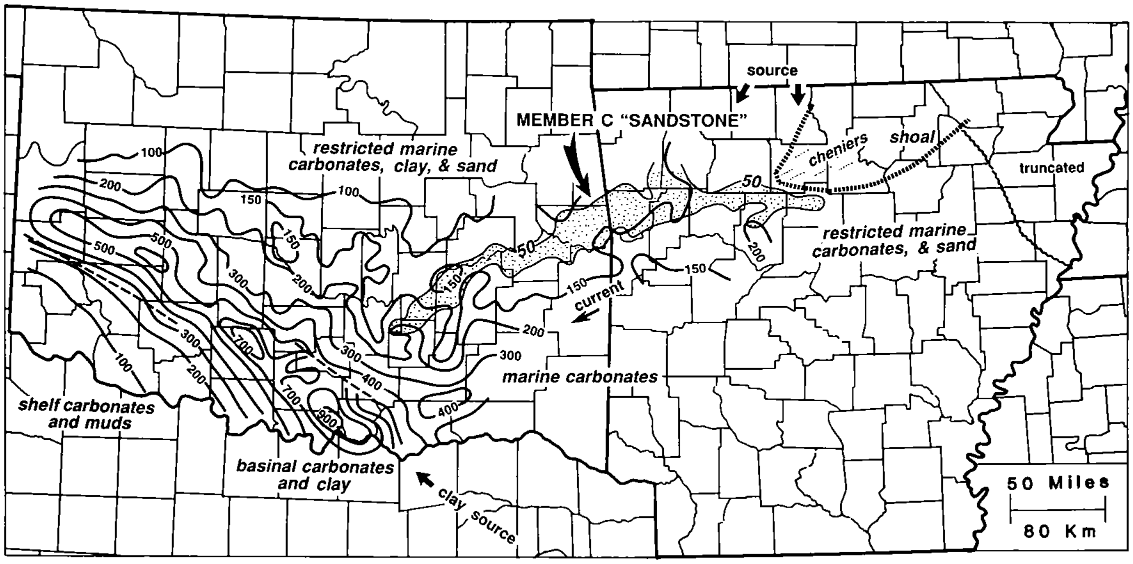


Figure 16. Isopach map of the Oil Creek Formation (excluding the Basal Oil Creek Sandstone) and member C of the Everton Formation. The member C "sandstone" 50-ft isolith is superimposed. Dashed lines adjacent to the Anadarko and Ardmore basins represent syndepositional faults.

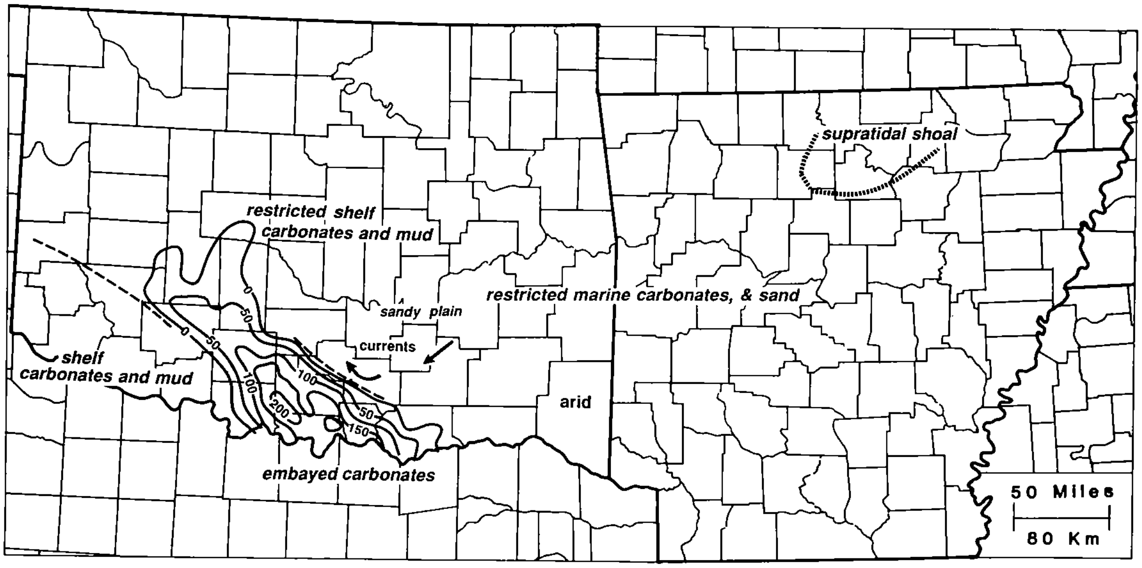


Figure 17. Pruitt Ranch ("Birdseye" limestone) isolith. Aridity accompanied by lowered sea level resulted in deposition of carbonates concurrent with a diminished supply of terrigenous muds to the Ardmore and Anadarko basins. Dashed lines represent positions of syndepositional faults.

history of the area to shallow-water, arid environments.

Southwest and northwest of the Anadarko basin, the Pruitt Ranch grades to shale and limestone. On the Texas arch, the Oil Creek Formation consists of argillaceous dolomite and some shale; it is apparently conformable with sandy dolomite of the Joins below and limestones of the McLish above. The Oil Creek retains its characteristics of poor spontaneous-potential, low-resistivity, and "spiky" gamma-ray log signatures. This characteristic log response enables correlation into the Tobosa basin of Texas (Wright, 1965) and throughout the Oklahoma shelf into northeastern Oklahoma, where the Oil Creek Formation correlates with the lower Tyner and the lower half of the middle Tyner Formation. Here, it consists of green to dark-gray, partly sandy shale and thin beds of sandy to very sandy and finely crystalline dolomite with gastropods and ostracodes (Huffman, 1965; Bauer, 1989).

On the South Ozark platform, shale is notably absent; the Oil Creek Formation consists of variable amounts of limestone, dolomite, and sandstone. In Arkansas, the Oil Creek is correlative with dolomitic sandstone of member C of the Everton Formation. Member C is conformable with the underlying Newton Sandstone and the overlying Jasper Member of the Everton. In outcrop, member C consists of dark, stromatolitic dolomite of presumed supratidal origin and dolomitic to slightly dolomitic sandstone interpreted to be cheniers (Suhm, 1974). In the subsurface, this dolomitic sandstone grades to a widely distributed calcareous to siliceous sandstone termed member C "sandstone" (Fig. 16). This sand is linear, very narrow, and generally parallel to the isopach trend and, presumably, the paleoslope. It may be a chenier sand complex representing stillstands along a regressive shore marked by longshore currents that accreted sand to the southwest.

Member C "sandstone" is an excellent marker bed, which helps to confirm correlations between Arkansas and Oklahoma. It correlates with what some subsurface geologists, such as Frezon (1962), in eastern Oklahoma erroneously call the "upper" basal Oil Creek Sandstone. This particular sand, however, is actually in facies relations with the middle part of the Oil Creek Formation and is not to be confused with the sand in the lower part of the Oil Creek Formation, which is included with the Basal Oil Creek Sandstone.

In the Reelfoot basin, member C is not amenable to differentiation, since it is lithologically similar to the overlying Jasper and the underlying carbonate facies of the Newton Sandstone.

Basal McLish Sandstone and "Middle" Tyner (Oklahoma); Jasper Member of Everton Formation (Arkansas)

The Basal McLish Sandstone is one of the most widespread and persistent quartz sandstones of the Simpson Group. It is present throughout Oklahoma except in the western and southern parts of the Anadarko and Ardmore basins and the Texas arch (Fig. 18). The Basal McLish Sandstone is composed of fine- to medium-sized, rounded, frosted quartz grains cemented by variable amounts of silica or carbonate. The sandstone is usually white in color but commonly takes on a light-green hue because of green clay coating and thin green-shale partings. It is locally cross-bedded.

The Basal McLish has a regionally characteristic log signature; upward from the Oil Creek Formation it has an increasingly better developed spontaneous potential coincident with decreasing resistivity (Fig. 5). This reflects a change from calcareous-cemented sandstone to more porous sandstone and also a generally coarsening-upward pattern, which is likely the result of a decrease in water depth and increased terrigenous input.

On the South Ozark platform, the top of the Basal

McLish is defined by a high gamma-ray deflection caused by a shale streak (Fig. 15). The sand is overlain by carbonates or calcareous to very calcareous and dolomitic sandstones of the McLish Formation, which display higher resistivities. On the Texas arch in Tillman County, Oklahoma, the Basal McLish is less than 10–20 ft thick and is recognized as a porous, slightly sandy dolomite with a well-developed spontaneous potential and low resistivity.

The principal sand body of the Basal McLish and Jasper (Everton) is more strike-oriented (east–west) and is positioned slightly seaward (regressive) compared to the Basal Oil Creek and Newton Sandstones, suggesting that when it was deposited, sea level was relatively low with emergent land areas to the north in eastern Kansas and Missouri. This resulted in a faunal hiatus between the Oil Creek Formation and the McLish, as documented by Derby and others (1991). In parts of Seminole County, Oklahoma, the Basal McLish Sandstone cuts into the underlying Oil Creek and abruptly thickens in a narrow, linear configuration that is suggestive of a channel system (Fig. 18). Although this channel may have contributed considerable sand to the principal Basal McLish sand body, most sand was probably transported through northwestern Arkansas later to be reworked and distributed northward by transgressing seas. The Basal McLish represents deposition in a southward-thickening peritidal sand complex on a marine platform with southwestward-trending currents. The southern limit of this sand on the South Ozark platform has not been determined, owing to a lack of well control. Thicknesses greater than 150 ft are common in the more actively subsiding parts of the South Ozark platform. Here, sand banks accumulated in shallow water at the hinge line that marks the junction with the Ardmore basin. At the platform edge, strong currents flowing parallel to the Anadarko and Ardmore basins redistributed some of the sand to the northwest. Some sand, however, spilled into the Ardmore basin.

In northeastern Oklahoma, the Basal McLish correlates with what Huffman (1965) describes as dolomitic to very dolomitic sandstone and finely to very finely crystalline dolomite of the middle part of the middle Tyner Formation. With present subsurface control, the Basal McLish and middle Tyner grade to the Jasper Member of the Everton Formation in Arkansas. However, with future drilling and more subsurface information, refined correlations may show that the Basal McLish correlates with the St. Peter.

The Jasper is variable in lithologic composition; from the western end of the Buffalo River, the Jasper changes from a St. Peter–like sandstone eastward to limestone, and farther east to dolomite (Suhm, 1974). The limestone facies has the greatest diversity of fauna within the Everton. At a few localities, sandstone of the Jasper is unconformable with slight relief on member C, but the limestone and dolomite appear conformable on member C. Moreover, where the Jasper consists of dolomite, it is difficult to separate from the dolomites of member C, especially in the vicinity of the Reelfoot basin. The Jasper extends into southeastern Missouri, where, together with member C, it oversteps older Everton strata and thins northward. It is overlain with noticeable disconformity by the St. Peter Sandstone in the outcrop belt. The extent of this unconformity in the subsurface is unknown, since it is difficult, if not impossible, to delineate a disconformity from wireline logs. On the South Ozark arch, the Jasper is overlain by "Plattin"-like lithologies that probably represent a dense phase of the Viola, equivalent to the upper Tyner and the Fite of northeastern Oklahoma.

McLish Formation and "Middle" Tyner (Oklahoma); Lower St. Peter Sandstone (Arkansas)

The McLish, above the Basal McLish Sandstone, consists of limestone, dolomite, sandstone, and minor beds of green to gray shale. Sandstone is common near the base and is mostly calcareous or dolomitic. Limestone, which dominates over dolomite, is common in the upper parts. It is commonly fossiliferous but contains interbeds of litho-

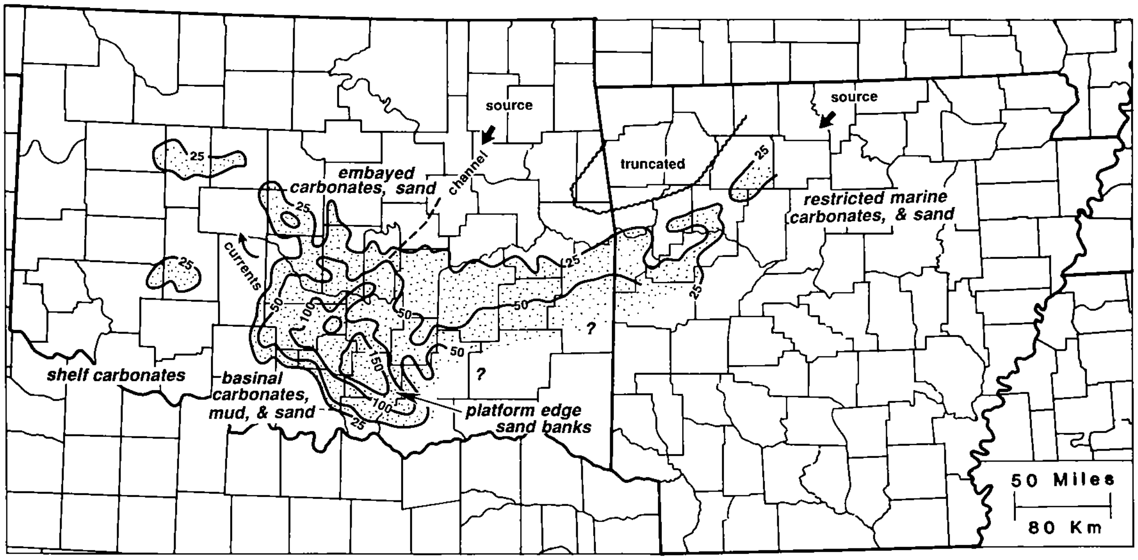


Figure 18. Basal McLish Sandstone and Jasper sandstone isolith map.

graphic limestone and thin beds of slightly green glauconitic limestone. The McLish Formation represents a continuation of clear-water, shallow-marine sedimentation, perhaps in arid environments that began with deposition of the Pruitt Ranch Member of the Oil Creek Formation.

Generally, the McLish is readily identified from wireline logs throughout Oklahoma. The McLish is conformable on the widespread Basal McLish Sandstone, discussed previously. The upper contact is arbitrarily placed at a change from principally limestone to shale, shaly sandstone, or argillaceous carbonates of the Tulip Creek. The contact is characterized by abrupt to gradual changes from relatively high resistivity of the McLish to lower resistivity of the Tulip Creek (Figs. 5,6). Additionally, the top of the McLish is placed at the highest gamma-ray deflection coincident with the poorest spontaneous potential, generally across a broad interval of concavity. The contact is more difficult to recognize in eastern Oklahoma and Arkansas, where both the Tulip Creek and McLish consist of carbonates and sandy carbonates. In the western Anadarko basin and parts of southern Oklahoma, where the Tulip Creek sandstone is absent, the top of the McLish is placed at the top of a sequence dominated by high-resistivity limestone and very calcareous shale.

On the Oklahoma shelf, the McLish and the upper parts of the Middle Tyner are represented by limestone, dolomite, and some shale, whereas on the South Ozark platform, sandstone and sandy carbonates are dominant. In both areas, however, the upper McLish appears to be segregated into generally three, somewhat persistent calcareous sandstones or sandy limestone beds, each separated by shaly intervals (Fig. 5). Combined sand thicknesses seldom exceed 50 ft (Fig. 19). Apparently, the sand was somewhat evenly distributed by currents that flowed southwestward across the platform. An exception to this is somewhat thicker sands that accumulated in shallow water at the platform edge adjacent to the Ardmore and Anadarko basins.

Eastward in Arkansas, McLish carbonates change facies to the St. Peter Sandstone (Fig. 19). The St. Peter is widely distributed and is readily identified on neutron-density logs. In many places it consists of both a lower and an upper sand separated by limestone. The lower sand, usually the thicker, and the overlying limestone are correlative with the McLish; the upper sand and the overlying Joachim dolomite correlate with the Tulip Creek (Figs. 7,8). The St. Peter is noticeably disconformable on Everton (Jasper) carbonates in the outcrop belt, with tens of feet of relief. In spite of this relief, the Jasper is always present under the St. Peter. Perhaps pre–St. Peter erosion, emphasized in the literature as the sub-Tippecanoe unconformity (Derby and others, 1991; Schutter, 1992), was not of long enough duration to remove it. In western segments of the Ozarks, the St. Peter rests on a sandstone facies of the Jasper Member. The two sands are lithologically similar and cannot be separated by well-cutting examination. However, differentiation can be made from well logs; the Jasper sandstone generally has a high gamma-ray shale streak at its upper contact, which allows it to be separated from the overlying St. Peter. Many thin shale breaks, such as this, are continuous across several townships and are excellent correlation markers.

Quartz sandstones of the St. Peter are supermature, with well-sorted, well-rounded, spherical quartz grains and with a limited heavy-mineral assemblage dominated by zircon and tourmaline. They are siliceous to calcareous and in places display cross-laminations and ripples. The purity and textural maturity of the St. Peter and other Simpson sandstones suggest that they were derived from earlier generation quartz sands (Dake, 1921; Bunker and others, 1988). Direct evidence for an eolian influence comes from the characteristic frosting and pitting of the quartz-grain surfaces and by their bimodality. Undoubtedly, eolian-distributed sand and sand-dune complexes existed on exposed land surfaces

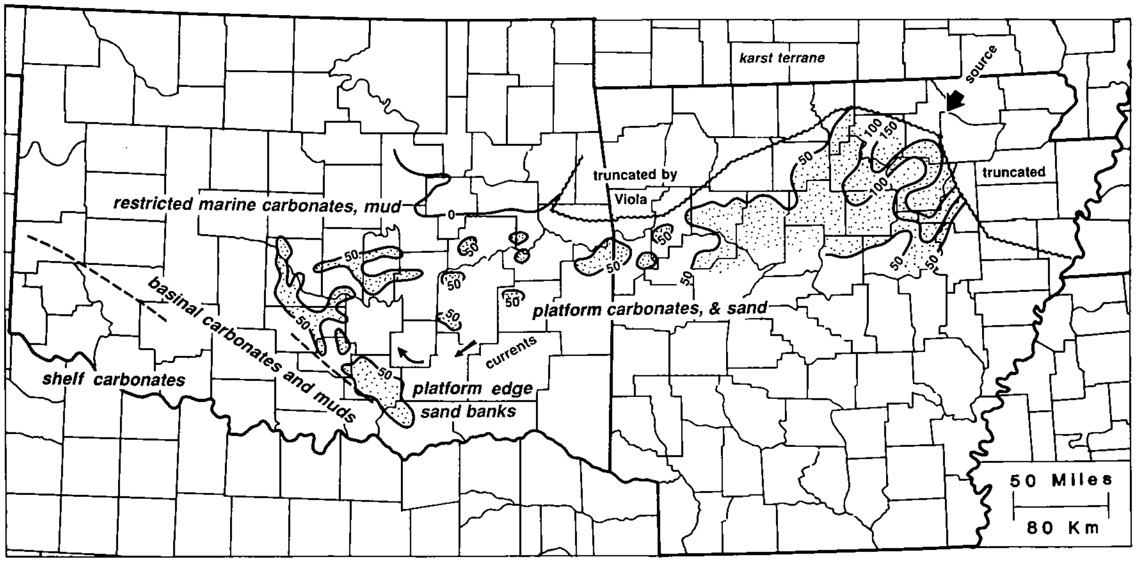


Figure 19. Isolith map of the St. Peter Sandstone and sandstone of the McLish. Dashed lines represent syndepositional faults.

before being reworked into sheets by generally transgressive marine processes.

The St. Peter in Arkansas represents the southernmost extent of the extensive sand sheets that covered the Midcontinent. Its southern limit in Arkansas has not been determined from well control; it is likely that some sand was carried into the Ouachita trough to compose the Blakely Sandstone. The St. Peter exceeds 150 ft in north-central Arkansas but diminishes in thickness westward across the South Ozark platform. This indicates a decrease in sand supply and a reduction in energy of transporting currents. Stillstands in the general transgression could be responsible for sand buildups trending northeast–southwest. On the western edge of the Reelfoot basin, in the Deep Rock No. 1 Sample well, White County, Arkansas, the St. Peter is very fine to fine grained and siliceous. Farther east, the St. Peter thins into the Reelfoot basin through a facies change to dolomitic sandstone, dense to medium-granular dolomite, and lithographic to sublithographic limestone of the lowest Joachim. The hiatus between the St. Peter and the Everton is absent; apparently deposition was continuous across this interface. In far northeastern Arkansas, the St. Peter is absent because of post-Ordovician truncation but reappears in southeastern Missouri, where it is over 150 ft thick.

Tulip Creek Formation and "Middle" Tyner (Oklahoma); Upper St. Peter and Joachim Formations (Arkansas)

The Tulip Creek Formation is latest Whiterockian in age (Bauer, 1990; Derby and others, 1991). At its type section in the Arbuckle Mountains, the top of the Tulip Creek is traditionally placed at a faunal change within or near the top of a shale sequence below the basal Bromide sandstone (Harris, 1957; Decker and Merritt, 1931). A short distance north and east of the type section, this shale interval wedges out, with the effect that the top of the Tulip Creek at its type section coincides with the top of the Tulip Creek sandstone. Because of the erratic occurrence of the basal Bromide sandstone, and to facilitate subsurface correlation, the top of the Tulip Creek in this report is placed at the top of the "basal" sandstone of the Tulip Creek, or, in the absence of this sandstone, at a sandy limestone marker in an equivalent stratigraphic position.

The Tulip Creek sandstone is fine to medium grained, with rounded, frosted, well-sorted quartz grains. It is siliceous to dolomitic and is locally crossbedded. In central Oklahoma, Smith (1993) reported poorly cemented green chloritic sand, and Cronenwett (1956) noted black-shale fragments in the sandstone and thin interbeds of dark shales. Shale and clay minerals impart a low resistivity to the sand. However, the most distinctive well-log characteristic of the Tulip Creek is its upward-increasing sand content. In most areas of its occurrence (Fig. 20), this is readily seen as a funnel-shaped curve on the gamma-ray and spontaneous-potential signatures; from its base upward, the spontaneous potential becomes better developed and the gamma ray decreases, reflecting a change to better sorted, coarser grained sandstone with less clay (Figs. 5,6,15).

This signature is quite distinctive over the Oklahoma shelf and on the northeastern margin of the Anadarko and Ardmore basins. However, the lower and upper boundaries of the Tulip Creek sandstone are sometimes difficult to establish in other areas, such as at places in central and north-central Oklahoma where the Tulip Creek and overlying Bromide sands are in direct contact with one another and appear to coalesce. Under such circumstances, the top of the Tulip Creek is placed above the sandstone displaying lower resistivity or under a thin limestone interval that separates the two sandstones at some localities. Local variations in thickness of the Tulip Creek sandstone in north-central Oklahoma suggest that the Bromide sand may have scoured the Tulip Creek during a post-Whiterockian uplift. Evidence of truncation at this contact is lacking where the Tulip Creek is overlain by shales of the Bromide.

Eastward, on the South Ozark platform, the Tulip Creek sand complex gradually changes character to a sandy-carbonate complex. Since the Bromide sand also grades to carbonates at about the same place, the contact is within an interval of indistinguishable carbonates. Generally, however, the Tulip Creek is characterized by better developed spontaneous-potential and low gamma-ray curves as well as by lower resistivity relative to the Bromide.

The typical funnel-shaped log signature for the Tulip Creek indicates a regional change from low-energy marine conditions to higher energy shallow-water environments. This indicates either a fall in sea level (or a decrease in subsidence) or increased terrigenous input or both. The geometry of the sand body is strikingly fan shaped, almost of deltaic configuration (Fig. 20). The Tulip Creek was derived from a stream-fed (braided?) system that traversed northwestern Arkansas and southern Missouri. Sand entered the sea in Oklahoma under the influence of strong southwest-moving tidal and longshore currents that fanned out in deeper water to form a deltalike distributary system. The Tulip Creek is interpreted to be a shallow-water subaqueous fan deposit or a deltalike system that was subsequently modified by marine processes under rising sea levels. Another alternative is that the Tulip Creek represents a broad stillstand sand in the advancing St. Peter sea in a manner described by Dapples (1955). Regardless, progradation was rapidly aided by low subsidence rates. The influx of sand was so great that it spilled into the Anadarko and Ardmore basins to be current-distributed along the strike of those basins.

In southeastern Grady County, Oklahoma, the Tulip Creek sandstone consists of several 10- to 30-ft sandstone beds amounting to about 150 ft (Flores and Keighin, 1986). Many of these beds fine upward from medium-grained sand near the base to fine-grained sand at the top. Some even have basal conglomerates with limestone and shale granules and pebbles. The sands also show scour features and high- to low-angle cross-laminations. Flores and Keighin (1986) interpret the sand to have accumulated in subtidal channels with the locus of sand transport influenced by bottom currents from the northeast. Within deeper parts of the Anadarko and Ardmore basins, the Tulip Creek sandstone changes facies

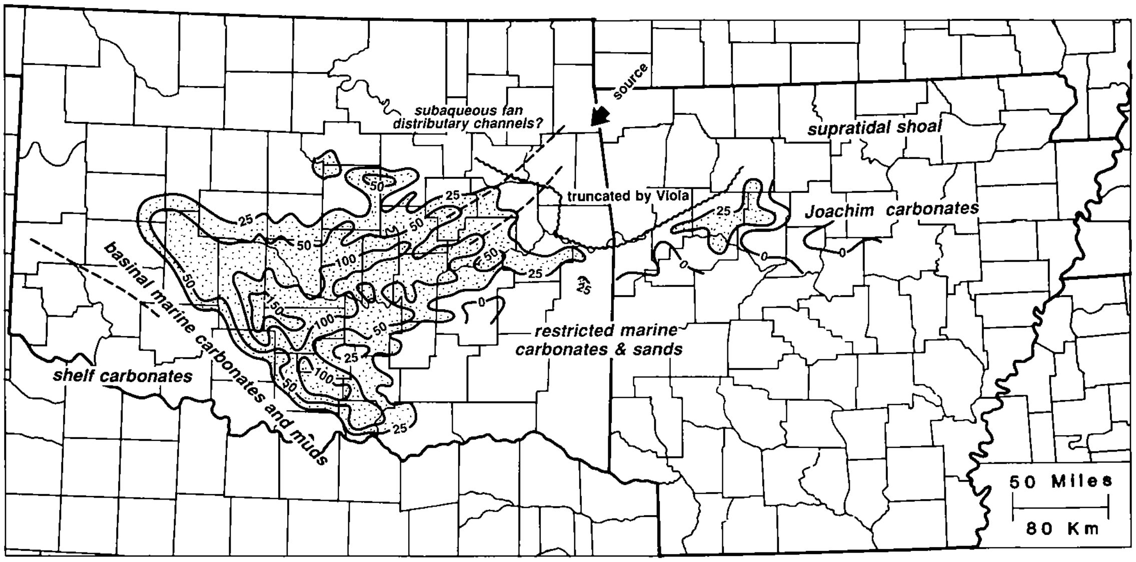


Figure 20. Isolith map of the Tulip Creek sandstone and upper St. Peter sandstone and equivalent facies.

to shale that is indistinguishable from shale of the Bromide. Here, the absence of sands and marker beds in the Tulip Creek precludes its recognition as a distinct stratigraphic unit. Consequently, in this area, strata above the McLish and below the Viola are referred to as the upper Simpson. North and west of Canadian County, Oklahoma, Tulip Creek sands thin and also begin to lose their identity through interdigitation with shale and thin carbonates. In southwestern Oklahoma on the Texas arch, the Tulip Creek grades to shales and shaly limestone that are, in places, unconformable under the Viola.

In northeastern Oklahoma, Tulip Creek equivalents include sandy shale and sandy dolomite of upper parts of the middle Tyner. These lithologies are interpreted to be interchannel tidal-flat deposits. The middle Tyner is unconformable under Viola equivalents—the upper Tyner and Fite (Huffman, 1965; Bauer, 1989).

In Arkansas, Tulip Creek sandy carbonates grade to the upper part of the St. Peter Sandstone and to dolomites of the Joachim (Fig. 7). The Joachim Formation thickens to 150 ft in the eastern part of the Ozarks (Miser, 1922). Lower Joachim beds are very sandy, with medium- to coarse-sized, well-rounded, frosted quartz grains and thin interbeds of St. Peter–like sandstone. Fossils are rare. Dolomicrites and very finely crystalline dolomite host various sedimentary structures such as rip-up clasts, mud cracks, and stromatolites that are indicative of supratidal and tidal-flat environments (Craig and others, 1986). Craig and others (1986) collected conodonts from the Joachim that suggest general equivalency to those described by Bauer (1990) from the upper Whiterockian of Oklahoma and perhaps to those of the St. Peter of Missouri.

The Joachim is overlain by the "Plattin" Limestone, but it may also interfinger with Plattin-like limestone in its upper part in a manner described by Young and others (1972) and Jee (1984). On wireline logs, the Joachim tends to have a better developed spontaneous potential, lower resistivities, and densities reflective of minor amounts of quartz, whereas the "Plattin" has a poor spontaneous potential, high resistivities, and densities indicative of limestone.

In the Reelfoot basin, in the absence of the St. Peter Sandstone, the Joachim cannot be satisfactorily distinguished as a stratigraphic entity.

Bromide Formation (Oklahoma); "Plattin" Limestone (Arkansas)

The Bromide Formation consists of varying amounts of sandstone, limestone, dolomite, and shale. Sublithographic to lithographic (dense) limestone and dolomite of varying crystallinity occupy the upper part of the Bromide, whereas sandstone and shale are common near the base. The limestones are informally called the "upper Bromide limestone" because it aptly describes an upper limestone facies of the Bromide sandstone. This would include the upper Mountain Lake Member and the Pooleville Member of the Bromide (Cooper, 1956)—terms that are seldom used in subsurface studies. The Corbin Ranch, although it consists of only 19 ft of Bromide-like dense limestone at the type section in the Arbuckle Mountain area, is included with the Viola, because ostracodes and other fauna appear to be Trenton in age and correlative with the Fite of northeastern Oklahoma (Amsden and Sweet, 1983; Sweet, 1992; Harris, 1957). Additionally, the Corbin Ranch exhibits an angular relationship to the underlying Simpson in a regional cross section prepared by Amsden and Sweet (1983, fig. 16).

The Bromide sandstone is the most areally extensive of the Simpson Group sands (Fig. 21). It is medium to coarse grained, with rounded and frosted quartz grains and varying types and amounts of cement. The sandstone becomes finer grained basinward (Longman, 1981). Ripples, cross-laminations, and burrows were noted by Flores and Keighin (1986). The sands, however, vary greatly in thickness and number; one massive sand may occupy the entire interval from the Tulip Creek to the base of the Viola, as in parts of central and north-central Oklahoma, or there may be up to 30 individual sandstones near the fringe of the sand body where it changes facies to carbonates, or sand may be absent entirely. Where sandstone of the Bromide is in contact with sandstone of the subjacent Tulip Creek, Bromide sands generally tend to be more calcareous as indicated by higher resistivities. In the Anadarko and Ardmore basins and deeper parts of the Oklahoma shelf, green to black basinal shales occupy the interval from the base of the Bromide sandstone to the top of the Tulip Creek sandstone. These shales are tentatively assigned to the Bromide. On the Oklahoma shelf, Bromide sandstones thicken to a maximum of over 300 ft in Canadian County and central Grady County, Oklahoma. The overlying Bromide limestones also thicken. The anomalous thickening relative to the underlying Whiterockian Simpson, here and in other areas, suggests that the Oklahoma shelf experienced a tectonic change in early Blackriveran time, resulting in increased basinal subsidence. The adjoining South Ozark platform was not affected; if anything, the South Ozark platform experienced the opposite effect—one of less subsidence. The Ozark dome and the South Ozark arch were becoming positive in Blackriveran time.

The Bromide sand body in Oklahoma has the geometry and sedimentary characteristics of a shallow-water subaqueous fan or marine-modified delta (Fig. 21). The Bromide sandstone is believed to be the basinward equivalent of the Starved Rock Sandstone, the youngest member of the St. Peter Sandstone as described by Nunn (1986), Templeton and Willman (1963), and Fraser (1976). The Starved Rock interfingers with lateral equivalents of the Joachim and Glenwood Formations (Templeton and Willman, 1963) and possibly the Plattin. The Starved Rock quartz sand was transported southwestward from the Canadian shield across parts of Illinois, Iowa, Missouri, and on the western side of the Ozark dome in eastern Kansas. In eastern Kansas, the St. Peter (probably the Starved Rock) is generally less than 50 ft thick, but some wells have drilled through 200–400 ft of sand that filled stream and karst depressions on the underlying Arbuckle (Cole, 1975; Lee and others, 1948). Upon entering relatively deeper water in Oklahoma, transport energy dissipated, and the sand spread out to become fanlike to sheetlike in geometry. Sand was even carried into the Anadarko and Ardmore basins, where it appears to be confined by a fault syndepositional with the Texas arch.

In southern parts of the Ardmore basin, the Bromide sandstone is absent by facies change to shale; the upper Bromide limestone is also poorly defined. Here, and on the Texas arch, the lower contact of the Bromide with the Tulip Creek cannot be defined from well logs, since the Tulip Creek is also predominantly shale. Additionally, on the Texas arch, the Bromide is thin to absent because of truncation by the overlying Viola. Shale also becomes increasingly more dominant in western Oklahoma. Some of the green shales of the upper Bromide may correlate with shales of the Platteville of the upper Midcontinent of Missouri, Illinois, and Iowa and may even correlate with bentonites found in the upper Plattin in eastern Missouri and Tennessee, where they are rather continuous and excellent chronostratigraphic markers (Huff and Kolata, 1990; Samson and others, 1989). In consideration of Witzke's (1980) work, the source of some terrigenous clay was from the Transcontinental arch to the north. However, much of the clay, especially in the Ardmore basin, appears to have been derived from a southern Llanorian landmass.

The contact of the Bromide Formation with the Viola Group is usually indicated by gamma-ray and spontaneous-potential deflections: a poor spontaneous potential and a higher gamma ray for the Bromide limestone versus a generally well-developed spontaneous potential and a low gamma ray for crystalline limestone of the Viola. Bromide limestones are characterized by a lithographic or "dense" texture and a lack of chert. However,

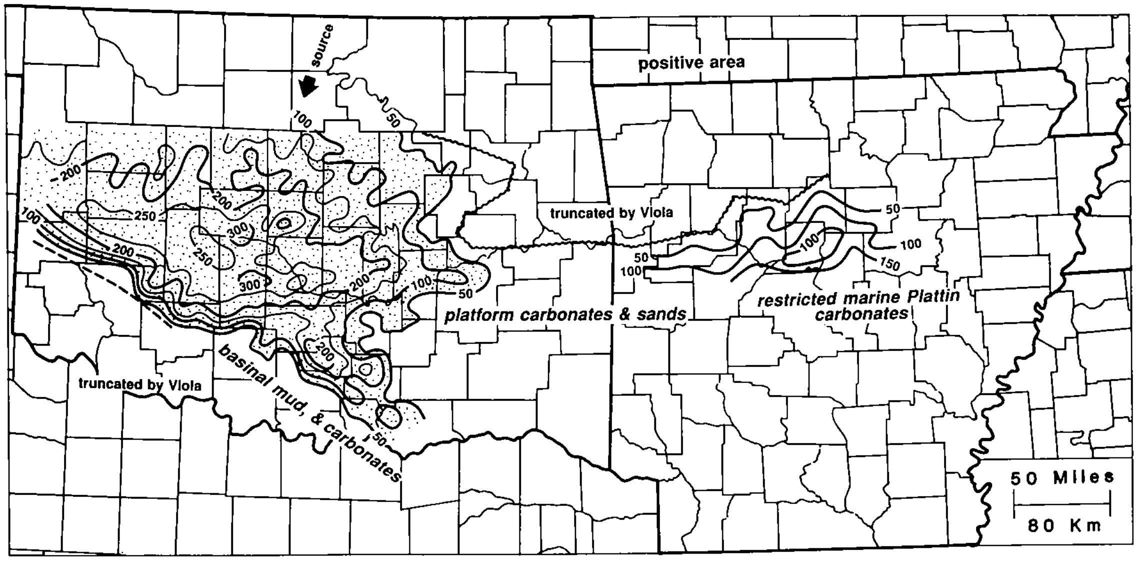


Figure 21. Isolith map of sandstone of the Bromide and isopach map of the "Plattin" limestone. Dashed line depicts the trace of a syndepositional fault.

the lower Viola may also have a "dense" phase, such as the Corbin Ranch and the Fite and upper Tyner of northeastern Oklahoma, making it difficult to recognize the contact solely on lithologic criteria. An understanding of regional subsurface and surface stratigraphy is helpful. In central and north-central Oklahoma on the Oklahoma shelf, the Bromide is unconformably overlain by a Simpson-like sandstone facies of the Viola termed the Seminole Sandstone ("First Wilcox"). The contact is generally easy to recognize but may be difficult to place where sandstone of the Bromide is directly under the Seminole Sandstone. In fact, the Seminole Sandstone is so lithologically similar to Simpson sands, it has been erroneously referred to as the "First Wilcox." However, careful stratigraphic correlation helps to differentiate Bromide sands from those of the Seminole.

In eastern Oklahoma on the South Ozark platform, Bromide sandstones change facies to sandy limestone and dolomite of marine origin. Coincidentally, the underlying Tulip Creek sandstone also grades to carbonates at about the same place, making the contact difficult to discern. However, Bromide carbonates generally exhibit a poorly developed spontaneous potential and a higher resistivity than those of the Tulip Creek. Eastward, the Bromide Formation becomes depositionally thinner and partially to completely truncated by the Viola, suggesting that the South Ozark arch and the Ozark dome ceased to subside. Moreover, these areas were eventually uplifted and eroded before deposition of the Viola. Basal chert pebbles in the upper Tyner and Fite (Viola equivalents) mark the unconformity with the Simpson (Huffman, 1965).

The Bromide Formation is correlative with the "Plattin" Limestone of Arkansas by lithology and well-log characteristics; however, the upper part of the "Plattin" may correlate with the lower Viola. The "Plattin" Limestone is sublithographic to lithographic, with several very thin green-shale beds remarkably similar to those in the upper Bromide limestone. From outcrops, Jee (1984) describes and classifies several facies of the "Plattin," ranging from subtidal to supratidal. "Plattin" limestones have a poorly developed spontaneous potential and a higher resistivity relative to the underlying Joachim Formation. The "Plattin" thickens to over 150 ft in southeast parts of the South Ozark platform and supposedly also into the Reelfoot basin. Unfortunately, in much of the Reelfoot basin, the "Plattin" and older Simpson formations are truncated by a post-Ordovician (Acadian?) erosional event.

A disconformity between the Joachim and "Plattin" was noted in outcrops by McKnight (1935) and Miser (1922), and local angular discordance was reported by Jee (1984). It appears that this unconformity is reflective of minor positive structural adjustment that took place on the Ozark dome and the South Ozark arch during Blackriveran time. The unconformity with the Joachim becomes less pronounced east and south of the outcrop belt, where deposition was more continuous.

There are two areas in Arkansas where the "Plattin," as defined in outcrop, does not correlate with the Plattin that is equivalent to the Bromide in the subsurface: (1) in western outcrops, in parts of Newton County, Arkansas, where the Joachim is truncated and the "Plattin" rests unconformably on the St. Peter (Craig and others, 1988); this relationship is inconsistent with subsurface data (Fig. 21), which show the Plattin that is equivalent to the Bromide to be absent by Viola truncation directly south of those outcrops; and (2) in the eastern parts of the outcrop belt, in Stone and Independence Counties, Arkansas, where Miser (1922) reported 240 ft of "Plattin," an amount that far exceeds the thickness illustrated in Figure 21. The anomalous "Plattin" in question in both areas may actually represent a dense phase of the Viola. Craig and others (1986) show the upper "Plattin" to be texturally similar to Viola equivalents (Corbin Ranch and Fite) in northeastern Oklahoma. Craig and others (1986) and Jee (1984) suggest that the upper one-third of the "Plattin" belongs to the transgressive depositional phase, as contrasted with a supratidal to protected subtidal phase of the lower two-thirds. The lower two-thirds is interpeted to be Bromide, and the upper one-third Viola or Corbin Ranch. This stratigraphic interpretation is generally confirmed by conodont evaluation and field studies of Craig and others (1986). Craig and others (1986) also note that the dominance of older fibrous conodonts in the "Plattin" of Arkansas, contrasted with "younger" non-fibrous conodonts of the Plattin in Missouri, suggests that the Plattin in Missouri is younger than the "Plattin" in Arkansas.

Seminole Sandstone of Viola Group (Oklahoma)

The Seminole Sandstone is a Simpson-like basal sandstone of the Viola Group that is present in much of central and north-central Oklahoma (Fig. 22). Regional cross sections, not included here, show the Seminole Sandstone to change facies basinward (downdip) to crystalline, commonly sucrosic dolomite referred to as the "dolomite fringe," and farther basinward to limestone of the lower Viola. This evidence, plus the northwest-to-southeast orientation of the Seminole Sandstone (which contrasts with the northeast-to-southwest trend of Simpson sands) provides support that the Seminole is younger than the Simpson and had a different depositional and tectonic history.

Because of stratigraphic proximity and lithologic similarity to the Simpson sandstone, the Seminole Sandstone has been erroneously termed the "First Wilcox" sandstone. The name *"First Wilcox"* implies a relationship to the "Second Wilcox" of the Simpson Group that is correlative with the Bromide sandstone; but the "First Wilcox" may or may not be. So, when the "First Wilcox" is referred to in subsurface data, it should be viewed with skepticism. Compounding the problem, porous dolomite and dense limestone above the Seminole Sandstone has been erroneously called the "Marshall Zone" and the "Bromide Dense," respectively—terms usually reserved for the Simpson Group. Since the name *"First Wilcox"* invokes confusion, it is recommended that its name and usage be abandoned completely and substituted by *Bromide* if the interval comprises the Simpson, or *Seminole Sandstone* if the sandstone is of Viola affinity. The recommendation was first proposed by White (*in* Levorsen, 1930) and was later supported by Cronenwett (1956), Schramm (1965), Statler (1965), and more recently by O'Brien and Derby (1997).

The Seminole Sandstone consists at places of one bed of sandstone up to 60–70 ft thick or several sandstones that interdigitate with sandy carbonates. The Seminole is unconformable on the Bromide Formation. Lithologically, the Seminole Sandstone is fine grained, with frosted, rounded quartz grains remarkably similar to older Simpson and St. Peter–like sandstones. Its likeness is attributed to its origin; the Seminole Sandstone was derived from the erosion of preexisting Bromide and Tulip Creek sands exposed on the southwest flank of the Ozark dome by post-Bromide uplift. The 50-ft Bromide sand isolith line taken from Figure 21 is superimposed on Figure 22. Along this trend line and slightly to the east, the Bromide sand was exposed, eroded, and incorporated with the Seminole Sandstone during Viola time. This sand, a strandline or shoreface sand, marks the position of the shoreline at the beginning of Viola time. Downdip, the Seminole Sandstone grades to dolomite of the "dolomite fringe" that is finely to coarsely crystalline with fair to good porosity and is often productive. The distribution of dolomite relative to the sand suggests that the source of part of the dolomite was from the erosion of older dolomites exposed on the Ozark dome. This detrital dolomite, when mixed with subtidal lime deposits, may have served as seeds that promoted dolomitization in a fashion described by Lindholm (1969).

Northeast of the zero isolith line (Fig. 22) on the Oklahoma shelf and the South Ozark arch, the Seminole Sandstone grades into or is overstepped by limestone of the Viola, such as the Corbin Ranch, upper Tyner, and Fite. The limestones rest on truncated Simpson with regional angular unconformity (Figs. 7,8) commonly with basal conglomerates. In addition to stratigraphic evidence, the unconformity at the base of the Viola (Corbin Ranch) is documented paleontologically from the Arbuckle Mountains northeastward to McSpaddin Falls in northeastern Oklahoma (Harris, 1957; Amsden and Sweet, 1983; O'Brien and Derby, 1997).

In Arkansas, equivalents of the Seminole Sandstone may be sandy intervals in the middle to upper parts of the "Plattin."

Ouachita Facies

Simpson equivalents of the Ouachita facies are exposed in the orogenic belt of the Ouachita Mountains of Oklahoma and Arkansas. The Ouachita allochthon was transported great distances northward from its depositional site and so is structurally complex. Movement was facilitated by glide planes in thick shale sequences of the Mazarn, Blakely, and Womble (Simpson equivalents), resulting in imbricate thrust sheets, repeated sections, tight folds, and overturned strata, which make stratigraphic interpretation difficult. Also complicating stratigraphic synthesis are small, noncontinuous outcrops displaying thickness variations that are due more to structural anomalies than depositional vagaries. Additionally, lithologic similarity of the Mazarn Shale with the Womble Shale (Miser and Purdue, 1929), and the Crystal Mountain Sandstone with the Blakely Sandstone, results in correlation and mapping errors. Disagreement concerning correlations of these sandstones of the Benton uplift in Arkansas with equivalents in the Broken Bow uplift in Oklahoma is discussed by Tomlinson and Pitt (1955), Pitt and others (1961), and Lowe (1989). Because of these problems, it is virtually impossible to produce a composite stratigraphic section or a standard reference section of the Ordovician Ouachita facies with which to correlate (C. G. Stone, personal communication, 1978); Craig and others (1993), however, published several disjunct measured sections. It can be agreed, however, that in Arkansas the traditional stratigraphic succession is, from bottom to top, Crystal Mountain Sandstone, Mazarn Shale, Blakely Sandstone, and Womble Shale.

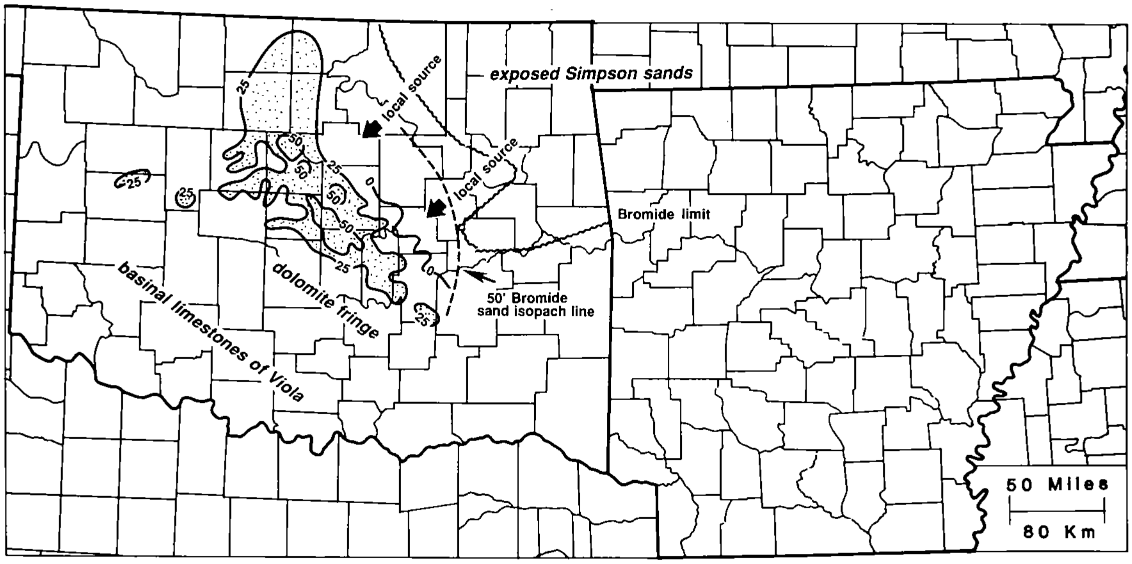


Figure 22. Seminole Sandstone (Viola) isolith map. Its distribution north of Kingfisher and Logan Counties is from Holden (1961). The sand represents the approximate position of the early Viola shoreline. Superimposed is the 50-ft Bromide sand isopach line and the erosional limit of the Bromide Formation; the Bromide sand is unconformable under the Viola near its limit and is completely truncated by the Viola northeast of its limit. The sand of the Seminole was derived from the erosion of Bromide and older Simpson sands exposed on the Ozark dome.

From conodonts evaluated by Repetski and others (1994), Simpson equivalents in the Ouachita facies are in the interval of the Blakely Sandstone (which is lower, but not lowest, Whiterockian to middle Whiterockian) and the Womble Shale (upper Whiterockian to Blackriveran). Apparently, no lowest Whiterockian conodonts have been found, but they are assumed to be present below the Blakely in the Mazarn Shale.

The age of the Mazarn Shale and the underlying Crystal Mountain Sandstone and their stratigraphic equivalents on the platform are in question. Could the Mazarn Shale and the Crystal Mountain Sandstone be equivalent to the Whiterockian Everton and Calico Rock Sandstone, respectively? Graptolites from the Mazarn Shale appear to be earliest Whiterockian (Ethington, 1984), but Repetski and others (1994) suggest that conodonts of the Mazarn are late Canadian and equivalent to the Kindblade and West Spring Creek (Arbuckle). Ethington and others (1989) note that the Mazarn contains long-ranging conodont species that could be equivalent to the Smithville (upper West Spring Creek?) of Arkansas. The upper part of the West Spring Creek is established as Whiterockian (Derby, 1969). In consideration of faunal discrepancies and structural complexities of the Ouachita allochthon, the Mazarn likely may be equivalent to the lower Everton Formation in Arkansas and the expanded Joins in Oklahoma. Of particular concern, however, is the age of the underlying Crystal Mountain Sandstone that was derived from the craton to the north. Was the sand transported during deposition of the Arbuckle or the Simpson, or at the Sauk–Tippecanoe hiatus? Since time-significant fossils have not been reported from the Crystal Mountain Sandstone, this unit must be evaluated lithostratigraphically.

The Crystal Mountain Sandstone ranges in thickness from 100 to 800 ft (Stone and Bush, 1984; Pitt, 1955) and is texturally and mineralogically similar to St. Peter–like sandstones of the Simpson Group (Pitt, 1955), but it usually contains minor amounts of feldspar and carbonate grains (Craig and others, 1993). It is predominantly medium grained with well-sorted, rounded quartz grains, some of which exhibit secondary quartz overgrowths. The sandstone is calcareous to siliceous and is commonly massive bedded with obscure cross-laminations that were noted by Bierschenk (1989) and Davies and Williamson (1977). It commonly contains a basal chert and limestone conglomerate, like that of the basal Everton in Arkansas and those in the Joins and upper West Spring Creek in Oklahoma. In the Hot Springs area, Garland County, Arkansas, the Crystal Mountain contains granitic and limestone (Arbuckle) boulders that were apparently deposited in a channel system adjacent to submarine fault scarps (Lowe, 1989). The Crystal Mountain represents deposition in either shallow water with strong bottom-traction transport currents (Davies and Williamson, 1977) or deeper water by submarine gravity flows (Lowe, 1989). Quartz sand was derived from the craton to the north (Reid and others, 1994; Lowe, 1989), probably the Canadian shield, and carried southward across the platform, perhaps on the western margin of the Reelfoot basin at a lowstand of sea level. Lowe (1989) and Craig and others (1993) suggest that these Ordovician sands, once in the Ouachita trough, were transported westward to southwestward toward Oklahoma, which would explain why the Crystal Mountain and Blakely Sandstones are thinner in Oklahoma than in Arkansas.

There should be some record of this great sandstone body in rocks of the craton, especially in basinal positions where gaps at unconformities are filled. Assuming a range in age of the Crystal Mountain Sandstone from Canadian to earliest Whiterockian, any "parent" sand from the north would be in the stratigraphic interval from Arbuckle (Canadian) to lowest Simpson or Everton (Whiterockian).

Quartz sandstones are relatively rare in the Arbuckle Group. The West Spring Creek of Oklahoma and the Rubidoux and Smithville of Missouri and Arkansas have few beds of sandstone, hence they are unlikely to have been the source of the 100–800 ft of Crystal Mountain sand. The oldest sandstone complexes in the Everton, the Calico Rock Sandstone and even older Everton sands, are considerably thicker and, moreover, were deposited at extremely low sea levels close to the junction with the Ouachita trough. These sands appear to be genetically related to the Crystal Mountain. Also, the geographic trend of the thickest part of the Calico Rock Sandstone (Fig. 11) coincides with the paleovalley defined by boulders in the Crystal Mountain Sandstone (see fig. 5 of Lowe, 1989). In northeastern Arkansas, the Deep Rock No. 1 Sample, White County; the Deardorf No. 1 Doggett, Jackson County; and the Magnolia No. 1 Sturgis, Woodruff County, encountered pre–Calico Rock sands 30–80 ft thick, which, together with associated sandy carbonates, apparently fill the hiatus at the sub-Tippecanoe unconformity. The sandstone in these wells contains frosted, rounded, fine- to coarse-sized quartz grains cemented by varying amounts of dolomite. Although not as thick as the Calico Rock Sandstone, this sand may represent the first major influx of St. Peter–like quartz sand of the Tippecanoe Sequence at the lowest stand of sea level and hence the oldest sand available to serve as the source of the Crystal Mountain Sandstone. This interval of sand is generally above the Smithville and Powell Formations; unfortunately, this interval has not been dated by fossils.

The Blakely (middle Whiterockian), above the Mazarn, is about 500 ft thick in outcrop, but, according to Davies and Williamson (1977), shale can constitute up to 90% of the Blakely. Lowe (1989) and Reid and others (1994) state that the fine- to medium-grained quartz sand was derived from northerly cratonic sources at lowered sea levels. Transportation to depositional sites was accomplished by strong bottom currents (Davies and Williamson, 1977). The St. Peter (middle Whiterockian) is the only southward-thickening sand that was in close proximity to the Ouachita trough (Fig. 19), so it is likely that sands of the Blakely were derived from spillover of the lower St. Peter sands at lowered sea levels. Southwestward-moving bottom currents, as suggested by Lowe (1989) and Craig and others (1993), would be required to explain the occurrence of this sand west of where it spilled over. In Oklahoma, the slightly older Basal McLish sands also thicken to the south, but since the Blakely is poorly represented in southeastern

Oklahoma, the Basal McLish probably contributed little sand to the Blakely.

The Womble Shale, up to about 1,600 ft thick (Stone and Bush, 1984), is late Whiterockian to Blackriveran in age (Repetski and others, 1994); thus, equivalency to Joachim and Plattin carbonates is likely. Thick, dark limestones interpreted to be Joachim and Plattin in the Reserve No. 1 Hazen, Prairie County, Arkansas, probably represent the transition to the Womble Shale of the Ouachita facies. The Womble consists principally of dark, organic-rich fissile shales with some dark-gray fine-grained limestone. Presumably, these units were deposited in deeper water under conditions of depleted oxygen as a result of restriction. Sandstone is uncommon. This is in keeping with the paleogeographic framework, since there were no proximal sand sources on the South Ozark platform in Blackriveran time. A northerly source for fine-grained terrigenous material is not likely, either, since shales are rare in coeval rocks on the South Ozark platform. Moreover, Dix and others (1994) and Lowe (1989) report a southerly source for clay and graywacke in the Womble of the Ouachita trough. Lowe (1989) envisions the source area, which Miser (1921, 1929) called *Llanoria,* to be part of the continental crust disjoined along the axis of the Ouachita trough from crust to the north. It probably consisted of a mixture of sedimentary, metasedimentary, and mafic igneous rocks (Dix and others, 1994).

PALEOGEOGRAPHY AND GEOLOGIC HISTORY

Setting the Stage

A reorganization of the structural fabric of North America took place before the beginning of Whiterockian time, ending widespread carbonate deposition of the Arbuckle. Differential uplift of the craton generated the extensive, well-documented sub-Tippecanoe unconformity in the Midcontinent region. The unconformity is the product of solution (Buschbach, 1961) and fluvial erosion (Mai and Dott, 1985; Dott and others, 1986). Karst is recognized in eastern Kansas (Lee and others, 1948), Missouri and Arkansas (Purdue and Miser, 1916; McKnight, 1935), Kentucky and Tennessee (Anderson, 1991; Kyle, 1976), and Texas (Adams, 1965; Wright, 1965). However, in the southern Midcontinent, the areal distribution of this karst surface is limited to the vicinity of the Ozark dome and parts of the South Ozark platform, Oklahoma shelf, and Texas arch. The Arbuckle was preferentially karstified as far south as the Arbuckle Wilburton field, Latimer County, Oklahoma (Carpenter and Evans, 1991), and in those areas where the Simpson is approximately less than 500 ft thick (Fig. 9). The Arbuckle may also have been karstified on syndepositional horst blocks in southern Oklahoma (Waddell and others, 1993). Elsewhere, in rapidly subsiding parts of the basins, deposition appears to have been continuous across the Arbuckle–Simpson interface.

Source areas of the Canadian shield were uplifted; Cambrian and older sandstones as well as Precambrian metamorphic and igneous rocks were subjected to weathering and erosion. Quartz detritus was carried southward, resulting in a sedimentologic change that marked the beginning of deposition of siliciclastics of the Simpson Group. So impressive is this change of depositional character that the Simpson (Everton) is designated as the basal terrigenous unit of the Tippecanoe Sequence. Absence of soil-binding vegetation in the Ordovician strongly suggests that wind was both a major erosive and transporting force in North America (Cotter, 1978). Streams were broad, shallow, and poorly channelized, such as braided stream systems. They carried mostly sand; the absence of a silt and clay fraction is suggestive of either aridity (a lack of chemical weathering) or a prolonged period of eolian winnowing of the sediment. Floods of sand in long dispersal routes were swept into seas at well-defined point sources to form amalgamated barrier and peritidal complexes that compose all Simpson sands. The St. Peter in the Midcontinent region, however, has a "blanket" geometry.

The Ozark dome exerted a major influence on dispersal patterns of quartz sand originating from the north. It was slightly positive in early Whiterockian time, and sand was transported principally on its eastern side. In Blackriveran (early Mohawkian) time, however, higher sea levels, coincident with source-area changes and minor uplift of the Ozark dome, resulted in quartz detritus that was redirected to the west side of the Ozark dome to form the Starved Rock/Bromide sand complex. The absence of appreciable quantities of clay in the Simpson east and south of the Ozark dome on the South Ozark platform suggests arid conditions. Shale, however, becomes an increasingly important lithologic component, especially in the upper Simpson, west of the Ozark dome. Apparently, clay was generated by chemical decomposition in humid source areas of the Transcontinental arch to the northwest (Witzke, 1980). Llanoria, to the south, was another clay source (Lowe, 1989). Pollastro (1991) suggests that some Simpson shales were derived from volcanic sources.

The Tobosa basin in west Texas became separated from the basins in Oklahoma by pre-Whiterockian uplift of the Texas arch (Adams, 1954). St. Peter–like quartz sands were deposited in parts of the Tobosa basin; however, excluding long-distance migration of sand from dune fields in the northern Midcontinent region, the source of the sand was probably the Pedernal massif. Exposed Cambrian and Canadian sandstones, such as the Bliss Sandstone, and Precambrian and Cambrian granitic plutons and metamorphic rocks provided a source of quartz sand and finer grained terrigenous sediments for transport to the Tobosa basin (Adams, 1965).

Quartz sand was transported by windblown saltation and streams to a variety of peritidal and marine environments in the southern Midcontinent. Principal deposition was in a coalescing complex of broad tidal- and current-influenced sand flats in combination with barriers, bars, and strandline systems. Individual sand bodies are linear to strike oriented, the result of strong currents. Wind probably diffused the sand dunes of the barriers and sand flats in the same direction as that of longshore and tidal currents. Linear transport of barrier and peritidal sands, however, diminished with increasing water depths. Dissipation of transport energy resulted in subaqueous fans with tidal distributary systems not unlike those of a delta. These shallow-marine fans were marked by low-relief subaqueous channels that were persistently supplied with sand that spilled over into interchannel areas. For Grady County, Oklahoma, Flores and Keighin (1986) document fining-upward sequences, cut-and-fill structures, and shale-pebble conglomerates, all of which are seemingly reserved for turbidites of deep-water submarine fans. Water depths, however, even in the Anadarko and Ardmore basins, were probably less than 150–200 ft. Sands transported across the South Ozark platform piled up as sand shoals at the junction with the Ardmore basin. Lacking sufficient energy to be transported into deeper water of the basin, the sands were distributed by currents paralleling the Ardmore basin, further contributing to the fan-shaped geometry.

Carbonates were precipitated in broad lagoonal systems behind sand complexes. High salinities or temperatures inhibited browsing and burrowing organisms and favored the development of algal flats and a restricted fauna. Intertidal sediments were periodically reworked to generate intraformational conglomerates and scour-and-fill contacts. Supratidal, sabkha-like tidal-flat environments were dominated by "primary" dolomite, lime mudstones, and quartz sandstone typical of arid zones. However, solution-collapse "karst" breccias, commonly found in the Everton (lower Simpson) of Arkansas, indicate incursions of fresh water either as rainfall or sheet flow during lowered sea levels. In Arkansas, island-like supratidal shoals are even found seaward of the sand complex.

Coarse-grained intraclastic, oolitic, and pelletal carbonates accumulated in intertidal to shallow subtidal environments seaward of the barriers. Dolomites are generally restricted to sites of shallow-water deposition in lithologies or sediments that are most permeable to dolomitizing fluids. Commonly, carbonates contain scattered or "floating" quartz grains, which invariably were wind transported from nearby peritidal sand complexes. Subtidal skeletal assemblages show low to high faunal abundance but low species diversity: e.g., gastropods and ostracodes. This is indicative of restricted conditions, likely owing to higher salinities and temperatures. However, in the vicinity of deeper water of the Anadarko and Ardmore basins, a diverse benthic fauna at some levels is suggestive of normal-marine salinities and circulation. The Ardmore basin was probably geographically close to the open seas of the Ouachita trough.

Geologic History

At the lowest stand of sea level in earliest Whiterockian time, the Calico Rock Sandstone formed two lobate to linear sand masses up to 150 ft thick (*shoreline A,* Fig. 23). Quartz sand was transported from a point source in eastern Missouri and western Illinois and deposited from longshore and tidal currents to form Calico Rock barrier 1. It is conceivable that this sand spilled over into the Ouachita trough to form the Crystal Mountain Sandstone. Interestingly, the Crystal Mountain has locally developed conglomerates with granitic and Arbuckle boulders that apparently were derived from the upthrown sides of high-displacement faults (Lowe, 1989). Under the influence of rising sea levels, large amounts of sand were added to Calico Rock barrier 2, which extended into eastern Oklahoma. Landward from these coalescing lobes was a broad lagoon in which limestone and sandstone of member A (Everton) accumulated. Seaward of the barrier complexes in the Reelfoot basin, limestone was precipitated in a shallow, warm, restricted sea. In deeper parts of this basin, deposition was continuous from Arbuckle to Simpson time, filling the hiatus that exists as a well-known unconformity in cratonic regions.

In Oklahoma, carbonates of the early Whiterockian Joins were deposited unconformably on the Arbuckle in shelf and platform settings, but in basinal positions deposition was essentially continuous. The near absence of terrigenous clay in the Joins is attributed to a lack of chemical weathering in source areas because of aridity. On the Texas arch, lime grainstones, later to be dolomitized, were deposited on the Arbuckle unconformity in intertidal to shallow subtidal environments far removed from terrigenous contamination with the exception of eolian contributions.

As the sea continued to transgress, the Calico Rock barrier was buried by sandy carbonates, and a new flood of sand from the shield formed the Newton, Burgen, and Basal Oil Creek barrier complex (*shoreline B,* Fig. 23). During accretion in a transgressing sea, the Newton Sandstone overrode lagoonal carbonates (mostly limestone) of member B (Everton) and the Sneeds. The Newton sand even filled sinks developed in limestones of member B, the Sneeds Dolomite, and older beds in the western Ozarks. In northeastern Oklahoma, the Burgen rests unconformably on the Arbuckle. The barrier complex was 50 mi wide and 200 ft thick in Arkansas and northeastern Oklahoma but expanded to over 100 mi wide and 400 ft thick at the junction of the South Ozark platform with the Ardmore basin. There was a change of current direction at this junction, and sand was redirected to the northwest in shallow water paralleling the edge of the Anadarko and Ardmore basins. Connection with the open sea was maintained in the Anadarko and Ardmore basins, where limestones and argillaceous limestones of the Joins were deposited. Joins dolomite and sandy dolomite accumulated behind the barrier in an embayed area of the sea. Floating quartz grains in many of these carbonates indicate a windblown origin. In Arkansas, seaward of the Newton sand, restricted marine carbonates of the middle Everton continued to be deposited. The Connell Sandstone, a Basal Oil Creek equivalent, was deposited in the Tobosa basin.

Following sand invasion, sedimentation exceeded subsidence in northern Arkansas. The sea became shallower, and beds of dolomitic sandstone of member C (Everton)—some beds of which are interpreted as chenier and supratidal dolomite—buried the Newton Sandstone and its lateral equivalents. A widespread linear sandstone about 50 ft thick represents the western extension of this chenier complex (Fig. 16). This sand was probably derived from the erosion and reworking of exposed older Newton and Calico Rock sands to the north. On the South Ozark platform and in the Reelfoot basin, carbonates were deposited without interruption. In northeastern Oklahoma, Tyner clays and carbonates were deposited on the Burgen in an embayed area north of member C "sandstone." In central and southern Oklahoma, the Oil Creek Formation was deposited above the Joins and the Basal Oil Creek Sandstone. Although there are very few shales in Simpson

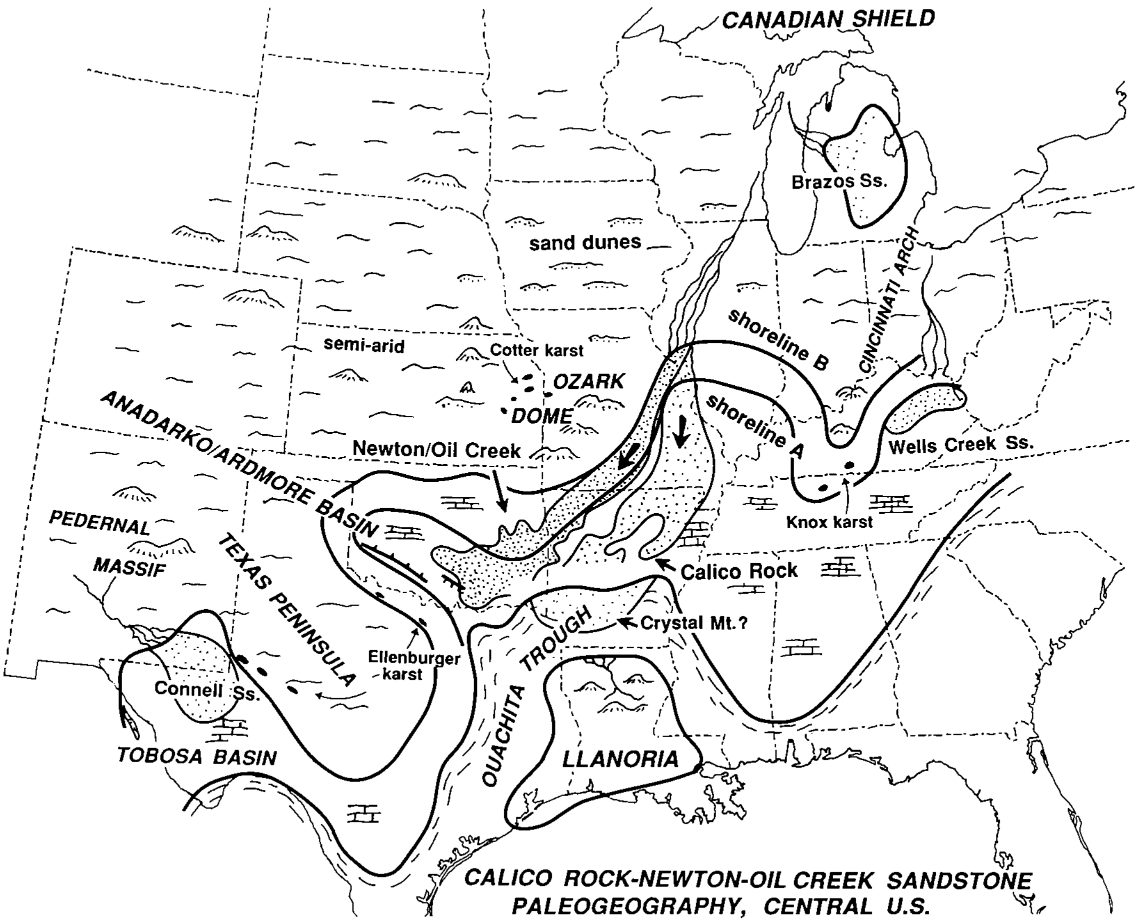


Figure 23. Early Whiterockian (lower Simpson, Everton) paleogeography. *Shoreline A* represents sea level during deposition of the Calico Rock Sandstone in Arkansas and Missouri and the "Wells Creek" sandstone in eastern Kentucky. *Shoreline B* represents sea level during Newton, Burgen, and Basal Oil Creek deposition in Oklahoma and Arkansas, and Connell Sandstone deposition in the Tobosa basin. Sand distribution in part of Missouri is reconstructed. The geometry of Llanoria is modified from Lowe (1989). Locations of Knox, Cotter, and Ellenburger karst are also shown; see Figure 11 for the location of Arbuckle karst. Interpretation from consideration of work of Droste and Shaver (1983), Edson (1935), Freeman (1953), Galley (1958), Smith and others (1993), Thomas (1985), and Wright (1965).

equivalents in Arkansas, the Oil Creek Formation of Oklahoma contains a relative abundance of clays mostly concentrated in the Anadarko and Ardmore basins. These basins, bordered by growth faults, accommodated thick sections of marine limestone and shale. This represents the first incursion of significant amounts of clay in Oklahoma during Simpson time. Clays were derived from an extensive weathered terrane west and north of the southern Midcontinent region and, perhaps, south of the Ouachita trough from Llanoria. The Oil Creek Formation is also recognized in the Tobosa basin (Wright, 1965).

Near the end of Oil Creek time, the influx of terrigenous clay diminished, and carbonate banks of oolites, lime mudstone, and stromatolitic limestone of the Pruitt Ranch Member were deposited in clear, shallow water of the Anadarko and Ardmore basins. Depositional rates of carbonates kept up with, and sometimes exceeded, subsidence of the basin, forming limestones over 200 ft thick. Deposition of the Pruitt Ranch and member C marks the beginning of an arid episode and a regression of the sea that was to become the precursor "desert" for St. Peter deposition.

At the beginning of the Basal McLish and Jasper (Everton) sand event, the position of the shoreline approximated that of shoreline A of the Calico Rock sand. Sand filtered down from the north, entered the sea, and was transported westward by longshore drift (Fig. 24). Sand accumulated to thicknesses of 150 ft at the southwest edge of the South Ozark platform; some sand spilled into the Ardmore basin, but most was redistributed to the northwest by a current system paralleling the Anadarko and Ardmore basins. The Basal McLish equivalent, the Waddell Sandstone, was deposited in the Tobosa basin.

At about this same time, sand dunes were accumulating in the northern Midcontinent. From lowstand positions in the southern Midcontinent, the St. Peter sand encroached over eroded beds of the Jasper with as much as 20 ft of relief. In comparison to older Ordovician sands, the St. Peter represents a more nearly continuous complex of coalescing peritidal sand sheets. Eolian and peritidal sands were reworked by transgressive marine processes to form the rather laterally extensive St. Peter sand sheet (Fig. 24). The St. Peter was washed into various parts of Oklahoma to mix with the more dominant marine limestone of the upper McLish. Seaward, toward the Reelfoot basin in Arkansas, the St. Peter sand changes facies to shallow-marine sandy carbonates. There is no stratigraphic or sedimentologic evidence to suggest an unconformity between St. Peter equivalents and the underlying Everton in this basin. The southern limit of the St. Peter is unknown. However, it is probable that the sand spilled over into the Ouachita trough to form the Blakely Sandstone.

Later in St. Peter time, sea level rose and the shoreline migrated northwestward to the Ozark dome, where southwest-moving currents transported sand across the southeast fringe of the Ozark dome. Older Newton sands exposed on the Ozark dome may have been introduced into the current system. Sand migrated into Oklahoma parallel to and on trend with the Southwest Ozark lineament to form the Tulip Creek sand complex (Fig. 24). As the Tulip Creek sand entered somewhat deeper water closer to the Anadarko and Ardmore basins, the sand fanned out, resulting in a deltaic or subaqueous fan configuration. The supply was so great that some of the sand started to fill the Anadarko and Ardmore basins. Unlike earlier Simpson sands, the maximum thicknesses of over 150 ft are found *within* the Anadarko basin in Grady and Garvin Counties, Oklahoma. Tulip Creek sands are absent in the deep-water southwest margin of the Anadarko and Ardmore basins and in shallow-water environments of the Texas arch. On the Texas arch the Tulip Creek consists of a monotonous section of shales, thin sandstones, and limestone. South of the Texas arch, the McKee sand was deposited.

In protected water north of the Tulip Creek sand sheet, clay and thin limes settled out. South of the Tulip

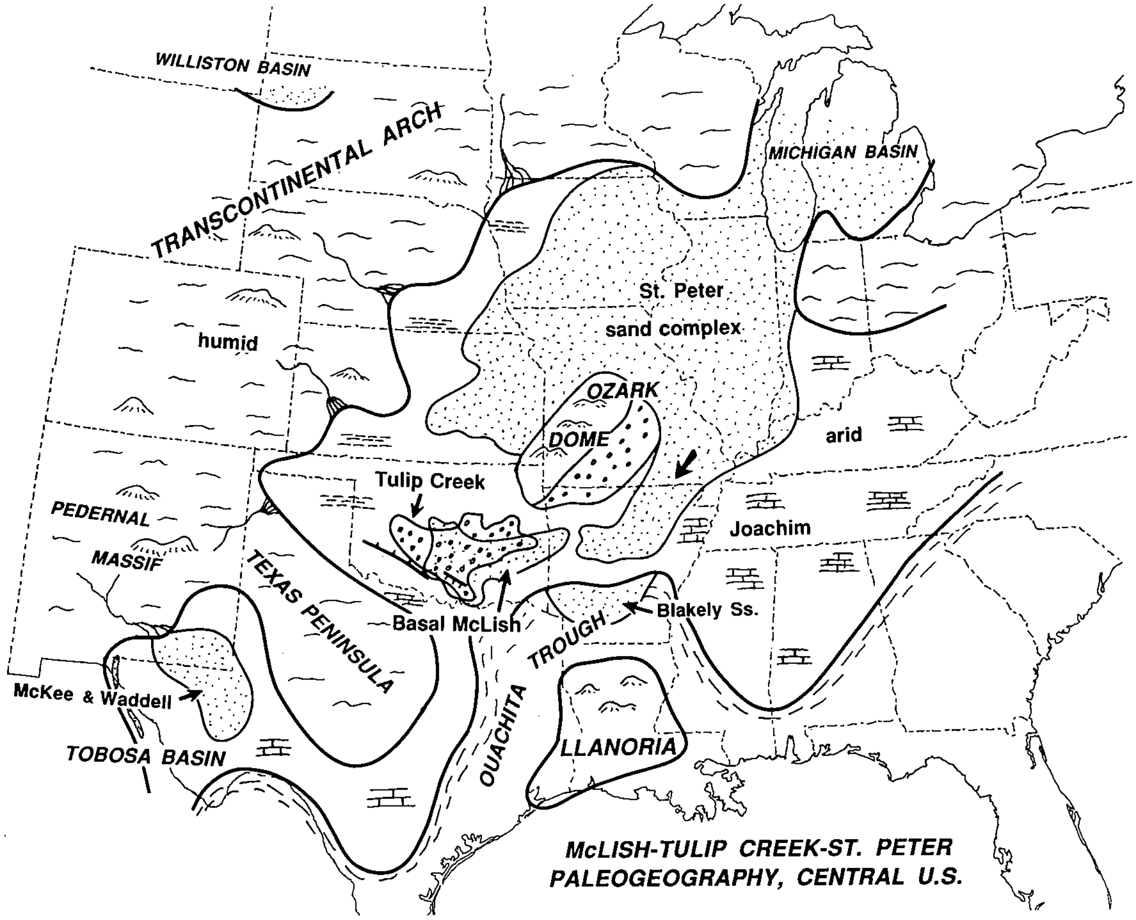


Figure 24. Late Whiterockian (middle Simpson) paleogeography, showing the distribution of Basal McLish, Tulip Creek, and St. Peter sandstones. The St. Peter in parts of Missouri and Kansas is reconstructed. The St. Peter is oldest on the east side of the Ozark dome in a manner described by Dapples (1955). The Newton Sandstone may have been eroded from the Ozark dome (circles) and partially incorporated into the Tulip Creek sand body. The Waddell and McKee sandstones in the Tobosa basin are also shown. Interpretation from consideration of work of Cole (1975), Droste and Shaver (1983), Galley (1958), Sloss (1988), Sweet (1992), Thompson (1991), Witzke (1980), and Wright (1965).

Creek sand body in eastern Oklahoma and Arkansas, restricted marine carbonates of the Joachim were deposited on the St. Peter Sandstone.

In Blackriveran time, the regional tectonic fabric changed. The Ozark dome was elevated, as was perhaps the Texas arch. In the Arkansas Ozarks, Jee (1984) and Craig and others (1988) mention the unconformity between the Joachim and the "Plattin." A new linear point source of sand, referred to as the Starved Rock barrier complex of the St. Peter, originated from the Canadian shield in Blackriveran time. Starved Rock sands were carried by strong tidal and longshore currents across northern Missouri and eastern Kansas into Oklahoma (Fig. 25). The Oklahoma shelf, which subsided at a rate greater than the adjoining South Ozark platform, accommodated these sands. Progradation was rapid; subsidence rates were low. Upon meeting deeper water of the Oklahoma shelf, transport energy diminished and sand "fanned out" in deltaic geometry. Subaqueous channels of the fan hosted coarser grained sand and rip-up clasts, whereas finer grained sand accumulated in the interchannel regime. Maximum thicknesses are present near the junction of the Oklahoma shelf with the Anadarko basin in central Grady and Canadian Counties, Oklahoma. The sand partially fills the Anadarko and Ardmore basins but also appears to be confined there by a syndepositional fault on the southwest side. In outcrops in the Slick Hills, Kiowa County, Oklahoma, cross-bedded Bromide sands indicate that paleocurrents flowed northwest and southeast parallel to the strike of the basins (Donovan and others, 1991). The youngest sands of the Bromide interfinger laterally with limestone and dolomite of the upper Bromide limestone. Farther south in the Ardmore basin, Bromide clays were deposited on shales of the Tulip Creek and are indistinguishable from them. These clays were probably derived from an area south of the Ouachita trough, but the green shale that commonly marks the top of the Bromide Formation is reflective of an influx of terrigenous clay from the Transcontinental arch. Green-shale partings are also seen in the "Plattin" limestone in northern Arkansas. The "Plattin" was deposited in shallow-marine waters with elevated salinities perhaps due to restricted circulation.

In the Ouachita trough, clays of the Womble accumulated to great thicknesses, probably from a southerly source inferred to be Llanoria (Dix and others, 1994; Lowe, 1989). The absence of appreciable amounts of quartz sand in the Womble confirms the paleogeographic interpretation that craton-derived quartz sand bypassed the South Ozark platform, Reelfoot basin, and Ouachita trough to be deposited in Oklahoma west of the Ozark dome.

The Bromide sand event ended with climatic and eustatic changes that brought in the Viola seas. At the end of Blackriveran time, source areas of the shield had been beveled to a peneplain, effectively cutting off the supply of terrigenous quartz to the interior of North America; however, the Ozark dome and its complement, the South Ozark arch, were uplifted, exposing older Bromide and Tulip Creek sandstones to erosion, which provided a local source of sand for the lower Viola Seminole Sandstone. The Seminole sand marks the position of the early Viola shoreline. Seaward of the sand, limestone, to be later dolomitized, and bioclastic limestone were deposited in shallow water, signifying a return to normal-marine salinities and circulation. Viola equivalents in northeastern Oklahoma, the upper Tyner and the Fite limestone, were deposited when Viola seas began their inundation of vast areas of the entire Midcontinent, even covering the Transcontinental arch and parts of the Canadian shield. Ross (1976) termed this the greatest inundation in North American history.

ACKNOWLEDGMENTS

Appreciation is extended to Bill Colton and Bill Caplan of the Arkansas Geological Commission; Jock Campbell, Robert Northcutt, and Ken Johnson of the Oklahoma Geological Survey; Bill Craig, Tony Statler, and Gerald Friedman for providing detailed and thoughtful reviews of the paper; and to all "Friends of the Ordovician" and others whose papers and knowledge I have drawn upon to gain a better understanding of the Ordovician System.

REFERENCES CITED

Adams, J. E., 1954, Mid-Paleozoic paleogeography of central Texas: Oklahoma Geological Society, Shale Shaker, v. 4, no. 6, p. 4–9.

_____1965, Stratigraphic–tectonic development of Delaware basin: American Association of Petroleum Geologists Bulletin, v. 49, p. 2140–2148.

Allison, M. D.; and Allen, R. W., 1997, Simpson–Arbuckle contact revisited in northwestern Oklahoma County, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 172–182.

Amsden, T. W., 1979, Welling Formation, new name for Upper Ordovician unit in eastern Oklahoma (formerly called "Fernvale"): American Association of Petroleum Geologists Bulletin, v. 63, p. 1135–1138.

Amsden, T. W.; and Sweet, W. C., 1983, Upper Bromide Formation and Viola Group (Middle and Upper Ordovician) in eastern Oklahoma: Oklahoma Geological Survey Bulletin 132, 78 p.

Anderson, W. H., 1991, Mineralization and hydrocarbon emplacement in the Cambrian–Ordovician Mascot Dolomite of the Knox Group in south-central Kentucky: Kentucky Geological Survey Report of Investigations 4, Series 11, 29 p.

Bauer, J. A., 1989, Conodont biostratigraphy and paleoecology of Middle Ordovician rocks in eastern Oklahoma: Journal of Paleontology, v. 63, p. 92–107.

_____1990, Stratigraphy and conodont biostratigraphy of the upper Simpson Group, Arbuckle Mountains, Oklahoma, *in* Ritter, S. M. (ed.), Early to middle Paleozoic conodont biostratigraphy of the Arbuckle Mountains, southern Oklahoma: Oklahoma Geological Survey Guidebook 27, p. 39–53.

Bierschenk, A. F., 1989, Sedimentary character and provenance of the Crystal Mountain Sandstone, Broken Bow uplift, McCurtain County, Oklahoma [abstract]: Geological Society of America, South-Central Section, Abstracts with Programs, v. 21, p. 3.

Bjorlykke, K.; and Egeberg, P. K., 1993, Quartz cementation in sedimentary basins: American Association of Petroleum Geologists Bulletin, v. 77, p. 1538–1548.

Bunker, B. J.; Witzke, B. J.; Watney, W. L.; and Luduigson, G. A., 1988, Phanerozoic history of the central midcontinent, United States, *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. 243–260.

Burchfield, M. R., 1985, Map of Oklahoma oil and gas fields: Oklahoma Geological Survey Map GM-28, scale

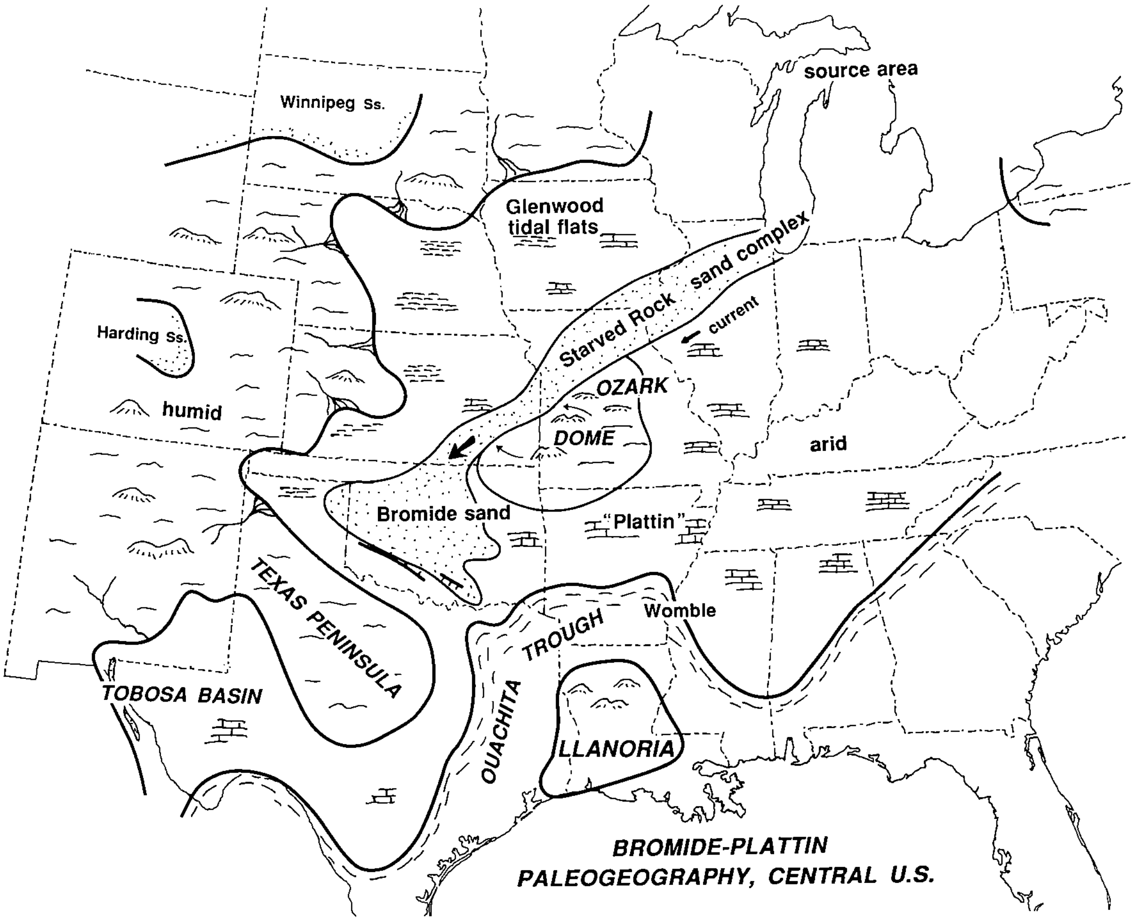


Figure 25. Early Mohawkian or Blackriveran (upper Simpson) paleogeography. The Bromide sand was derived from the Starved Rock sand and possibly older St. Peter sandstones exposed on the Ozark dome. The Bromide appears to be absent in Kansas by truncation, and its distribution is inferred. The Texas Peninsula is the above-water portion of the Texas arch. Interpretation from consideration of work of Droste and Shaver (1983), Nunn (1986), Sloss (1988), Sweet (1992), Templeton and Willman (1963), and Thompson (1991).

1:500,000.

Buschbach, T. C., 1961, The morphology of the sub–St. Peter surface of northeastern Illinois: Illinois Academy of Science Transactions, v. 54, p. 83–89.

_____1971, Stratigraphic setting of the eastern interior region of the United States, *in* Background materials for symposium on future petroleum potential of NPC region 9 (Illinois basin, Cincinnati arch, and northern part of Mississippi embayment): Illinois State Geological Survey, Illinois Petroleum 96, p. 3–20.

Carpenter, B. N.; and Evans, M. C., 1991, Comparison of the Arbuckle Group at Wilburton Field, Latimer County, with the N.E. Alden Field, Caddo County, Oklahoma, *in* Johnson, K. S. (ed.), Arbuckle Group core workshop and field trip: Oklahoma Geological Survey Special Publication 91-3, p. 111–132.

Cole, V. B., 1975, Subsurface Ordovician–Cambrian rocks in Kansas: Kansas Geological Survey Subsurface Geology Series 2, 18 p.

Cooper, G. A., 1956, Chazyan and related brachiopods: Smithsonian Miscellaneous Collections, v. 127, pt. 1, 1024 p.

Cotter, E., 1978, The evolution of fluvial style, with special reference to the central Appalachian Paleozoic, *in* Miall, A. D. (ed.), Fluvial sedimentology: Canadian Society of Petroleum Geologists Memoir, v. 5, p. 361–384.

Craig, W. W.; Ethington, R. L.; and Repetski, J. E., 1986, Guidebook to conodont paleontology of uppermost Lower Ordovician through Silurian strata, northeastern Arkansas: Geological Society of America, South-Central and Southeastern Sections, Field Trip 5, 58 p.

Craig, W. W.; Deliz, M. J.; and Legendre, K. J., 1988, Tidal flat deposits of the Plattin Limestone (Middle Ordovician), northern Arkansas, *in* McFarland, J. D. (ed.), Contributions to the geology of Arkansas, volume 3: Arkansas Geological Commission Miscellaneous Publication 18-C, p. 1–49.

Craig, W. W.; Bellis, J. K.; Danielson, D. A., Jr.; and Bessler, J., 1993, Field trip guidebook of geology of Ouachita Mountain core area, vicinity of east shore of Lake Ouachita, Garland County, Arkansas: American Association of Petroleum Geologists, 1993 annual meeting (published by New Orleans Geological Society), 39 p.

Craig, W. W.; Danielson, D. A.; and Bellis, J. K., 1994, Stratigraphic and depositional framework of Cambro–Ordovician strata, Ouachita Mountain core area in vicinity of east shore of Lake Ouachita, Garland County, Arkansas [abstract]: Geological Society of America Abstracts with Programs, v. 26, p. 5.

Cronenwett, C. E., 1956, A subsurface study of the Simpson group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

Dake, C. L., 1921, The problem of the St. Peter sandstone: Missouri School of Mines and Metallurgy Bulletin, Technical Series 6, 225 p.

Dapples, E. C., 1955, General lithofacies relationship of St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Dart, R. L., 1992, Catalog of pre-Cretaceous geologic drill-hole data from the upper Mississippi embayment: A revision and update of Open-File Report 90-260: U.S. Geological Survey Open-File Report 92-685, 253 p.

Davies, D. K.; and Williamson, E. A., 1977, Paleoenvironments and paleobathymetry of lower Paleozoic Crystal Mountain and Blakely Formations, Ouachita Mountain core, *in* Stone, C. G. (ed.), Symposium on the geology of the Ouachita Mountains: Arkansas Geological Commission, v. 1, p. 115–131.

Decker, C. E.; and Merritt, C. A., 1931, The stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Derby, J. R., 1969, Revision of Lower Ordovician–Middle Ordovician boundary in western Arbuckle Mountains, Oklahoma, *in* Ham, W. E., Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Guidebook 17, p. 35–37.

_____1973a, Lower Ordovician–Middle Ordovician boundary in western Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, p. 24–26.

_____1973b, Remarks on the age of the Everton and Smithville–Blackrock Formations of Arkansas and correlation to Oklahoma formations [abstract]: Geological Society of America Abstracts with Programs, v. 5, p. 254–255.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle, and Simpson Groups, Cambrian and Ordovician, Oklahoma: a review of correlation tools and techniques available to the explorationist, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Dix, M. C.; Reid, D. R.; and Casey, J. F., 1994, Womble "shale" (Middle Ordovician): A Taconian-derived submarine fan complex in the Broken Bow uplift, Ouachita allochthon, Oklahoma [abstract]: Geological Society of America Abstracts with Programs, v. 26, p. 6.

Donovan, R. N.; Busbey, A. B.; Bridges, S. S.; Collins, K.; Ditzell, C.; Jenkins, D.; and Wilhelm, R., 1991, On three outcrops of the Simpson Group in the northwestern part of the Slick Hills, southern Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 Symposium: Oklahoma Geological Survey Circular 92, p. 85–97.

Dott, R. H., Jr.; Byers, C. W.; Fielder, G. W.; Stenzel, S. R.; and Winfree, K. E., 1986, Aeolian to marine transition in Cambro–Ordovician cratonic sheet sandstone of the northern Mississippi Valley, USA: Sedimentology, v. 33, p. 345–367.

Droste, J. B.; and Shaver, R. H., 1983, Atlas of early and middle Paleozoic paleogeography of the southern Great Lakes areas: Indiana Geological Survey Special Report 32, 32 p.

Edson, F. C., 1935, Resume of St. Peter stratigraphy: American Association of Petroleum Geologists Bulletin, v. 19, p. 1110–1130.

Ethington, R. L., 1984, Conodonts from Ordovician rock, Ouachita Mountains, Arkansas, *in* Stone, C. G.; and Haley, B. R. (eds.), A guidebook to the geology of the central and southern Ouachita Mountains, Arkansas: Arkansas Geological Commission Guidebook 84-2, p. 93–98.

Ethington, R. L.; Finney, S. C.; and Repetski, J. E., 1989, Biostratigraphy of the Paleozoic rocks of the Ouachita orogen, Arkansas, Oklahoma, west Texas, *in* Hatcher, R. D., Jr.; Thomas, W. A.; and Viele, G. W. (eds.), The Appalachian–Ouachita orogen in the United States: Geological Society of America, The Geology of North America, v. F-2, p. 563–574.

Farr, M. R.; Sprowl, D. R.; and Johnson, J., 1993, Identification and initial correlation of magnetic reversals in the Lower to Middle Ordovician of northern Arkansas, *in* Aissaoui, D. M.; McNeil, D. F.; and Hurley, N. F. (eds.), Applications of paleomagnetism to sedimentary geology: Society for Sedimentary Geology (SEPM) Special Publication 49, p. 83–93.

Fay, R. O., 1969, Geology of the Arbuckle Mountains along Interstate 35, Carter and Murray Counties, Oklahoma: Ardmore Geological Society Guidebook, 75 p.

Flores, R. M.; and Keighin, C. W., 1986, Lithofacies description and interpretation of selected intervals in the upper part of the Ordovician Simpson Group in a core from the Mazur well, southeast Anadarko basin, Oklahoma: U.S. Geological Survey Open-File Report 86-564, 39 p.

Fraser, G. S., 1976, Sedimentology of a Middle Ordovician quartz arenite–carbonate transition in the upper Mississippi Valley: Geological Society of America Bulletin, v. 86, p. 833–845.

Freeman, L. B., 1953, Regional subsurface stratigraphy of the Cambrian and Ordovician in Kentucky and vicinity: Kentucky Geological Survey Bulletin 12, Series 9, 352 p.

Frezon, S. E., 1962, Correlation of Paleozoic rocks from Coal County, Oklahoma, to Sebastian County, Arkansas: Oklahoma Geological Survey Circular 58, 53 p.

Frezon, S. E.; and Glick, E. E., 1959, Pre-Atoka rocks of northern Arkansas: U.S. Geological Survey Professional Paper 314-H, p. 171–187.

Friedman, G. M., 1991, Methane-generated lithified dolostone of Holocene age: Eastern Mediterranean: Journal of Sedimentary Petrology, v. 61, p. 188–194.

Galley, J. E., 1958, Oil and geology in the Permian Basin of Texas and New Mexico, *in* Weeks, L. G. (ed.), Habitat of oil: American Association of Petroleum Geologists, Tulsa, p. 395–446.

Giles, A. W., 1930, St. Peter and older Ordovician sandstones of northern Arkansas: Arkansas Geological Commission Bulletin 4, 187 p.

Glick, E. E.; and Frezon, S. E., 1953, Lithologic character of the St. Peter sandstone and the Everton Formation in the Buffalo River valley, Newton County, Arkansas: U.S. Geological Survey Circular 249, 39 p.

Golden, J. B., 1969, Lower Middle Ordovician conodonts from the Everton Formation in northern Arkansas and southeast Missouri: University of Missouri, Columbia, unpublished M.A. thesis, 94 p.

Gonzales, S., 1974, Relationship between petroleum accumulations and stratiform ore deposits with Paleozoic carbonate sequences [abstract]: American Association of Petroleum Geologists Annual Meeting Abstracts, v. 1, p. 39.

Ham, W. E., 1955, Regional stratigraphy and structure of the Arbuckle Mountain region, *pt. 2 of* Geology of the Arbuckle Mountain region: Oklahoma Geological Survey Guidebook 3, p. 29–61.

Harris, R. W., 1957, Ostracoda of the Simpson group: Oklahoma Geological Survey Bulletin 75, 333 p.

Harris, R. W.; and Harris, R. W., Jr., 1965, Pruitt Ranch, new member of Oil Creek (Simpson) in Criner Hills, Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 144–161.

Hedden, W. J., 1976, The stratigraphy and tectono-depositional history of the Smithville and Black Rock lithosomes (Canadian) of northeastern Arkansas with revisions of Upper Canadian stratigraphy in the Ozarks: University of Missouri, Rolla, unpublished Ph.D. dissertation, 462 p.

Hendricks, T. A., 1959, Structure of the frontal belt of the Ouachita Mountains, *in* Cline, L. M.; Hilseweck, W. J.; and Feray, D. E. (eds.), The geology of the Ouachita Mountains, a symposium: Dallas Geological Society and Ardmore Geological Society, p. 44–56.

Herndon, Thomas (ed.), 1965, Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, 305 p.

Holden, F. T., 1961, Geologic history of the mid-continent: Company report, Exploration Department, Humble Oil and Refining Co., Oklahoma City, Oklahoma.

_____1965, The Simpson Group of the Arkoma Basin, Oklahoma and Arkansas, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 134–143.

Howe, J. R.; and Thompson, T. L., 1984, Tectonics, sedimentation, and hydrocarbon potential of the Reelfoot rift: Oil and Gas Journal, Nov. 12, p. 179–190.

Huff, W. D.; and Kolata, D. R., 1990, Correlation of the Ordovician Deicke and Millbrig K-bentonites between the Mississippi Valley and the southern Appalachians: American Association of Petroleum Geologists Bulletin, v. 74, p. 1736–1747.

Huffman, G. G., 1965, Simpson Group in northeastern Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 109–129.

Jackson, D. E., 1964, Observations on the sequence and correlation of Lower–Middle Ordovician graptolite faunas of North America: Geological Society of America Bulletin, v. 75, p. 523–534.

Jee, J. L., 1984, Stratigraphy and depositional environments of the Plattin Limestone (Middle Ordovician), parts of Independence, Izard, and Stone Counties, Arkansas, *in* Hyne, N. J. (ed.), Limestones of the Midcontinent: Tulsa Geological Society Special Publication 2, p. 307–326.

Kyle, J. R., 1976, Brecciation, alteration, and mineralization in the central Tennessee zinc district: Economic Geology, v. 71, p. 892–903.

Lapworth, C., 1879, On the tripartite classification of the lower Paleozoic rocks: Geological Magazine, Great Britain, New Series, v. 6, p. 12–14.

Latham, J. W., 1968, Petroleum geology of the Arbuckle Group (Ordovician), Healdton field, Carter County, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 52, p. 3–20.

Leander, M. H.; and Legg, T. E., 1988, Potential for subthrust gas fields: results of recent deep drilling in the Ouachitas [abstract]: American Association of Petroleum Geologists Bulletin, v. 72, p. 211.

Lee, W.; Leatherock, C.; and Botinelly, T., 1948, The stratigraphy and structural development of the Salina basin of Kansas: Kansas Geological Survey Bulletin 74, 155 p.

Levorsen, A. I., 1930, Geology of Seminole County, *in* Oil and gas in Oklahoma: Oklahoma Geological Survey Bulletin 40, v. 3, pt. BB, p. 289–352.

Lewis, R. D., 1982, Depositional environments and paleoecology of the Oil Creek Formation (Middle Ordovician), Arbuckle Mountains and Criner Hills, Oklahoma: University of Texas, Austin, unpublished Ph.D. dissertation, 351 p.

Lillie, R. J.; Nelson, K. D.; deVoogd, B.; Brewer, J. A.; Oliver, J. A.; Brown, L. D.; and Kaufman, S., 1983, Subsurface structure of the Ouachita Mountains, Arkansas, from COCORP deep seismic reflection profiles, *in* Bally, A. W. (ed.), Seismic expression of structural styles: American Association of Petroleum Geologists Studies in Geology Series 15, v. 3, p. 3.41-83-87.

Lindholm, R. C., 1969, Detrital dolomite in Onondaga Limestone (Middle Devonian) of New York: Its implication to the "dolomite question": American Association of Petroleum Geologists Bulletin, v. 53, p. 1035–1042.

Longman, M. E., 1981, Deposition of the Bromide Formation, Arbuckle Mountains, Oklahoma: ontogeny of an ancient carbonate shelf: Oklahoma City Geological Society, Shale Shaker, v. 32, no. 2, p. 1–18.

Lowe, D. R., 1989, Stratigraphy, sedimentology, and depositional setting of pre-orogenic rocks of the Ouachita Mountains, Arkansas and Oklahoma, *in* Hatcher, R. D., Jr.; Thomas, W. A.; and Viele, G. W. (eds.), The Appalachian–Ouachita orogen in the United States: Geological Society of America, The Geology of North America, v. F-2, p. 575–590.

Mai, H.; and Dott, R. H., Jr., 1985, A subsurface study of the St. Peter Sandstone in southern and eastern Wisconsin: Wisconsin Geological Survey Information Circular 47, 26 p.

McKnight, E. T., 1935, Zinc and lead deposits of northern Arkansas: U.S. Geological Survey Bulletin 853, 311 p.

McPherson, J. G.; Denison, R. E.; Kirkland, D. W.; and Summers, D. M., 1988, Basal sandstone of the Oil Creek Formation in the quarry of the Pennsylvania Glass Sand Corporation, Johnston County, Oklahoma, *in* Hayward, O. T. (ed.), Centennial field guide: Geological Society of America, South-Central Section, v. 4, p. 165–170.

Mellen, F. F., 1974, Possible Ordovician carbonate reservoirs in Mississippi: American Association of Petroleum Geologists Bulletin, v. 21, p. 870–876.

Mescher, P. K.; Schultz, D. J.; Hendrick, S. J.; Ward, M. A.; and Schwarz, J. A., 1993, Lithology and reservoir development of the Arbuckle dolomite, Wilburton field, Latimer County, Oklahoma, *in* Johnson, K. S.; and Campbell, J. A. (eds.), Petroleum-reservoir geology in the southern Midcontinent, 1991 symposium: Oklahoma Geological Survey Circular 95, p. 240–245.

Milliken, J. V., 1988, Late Paleozoic and early Mesozoic geologic evolution of the Arklatex area: Rice University, Houston, unpublished M.A. thesis, 222 p.

Minke, J. G., 1969, Petrology of dolomites in the Everton Formation, Marion County, Arkansas: University of Missouri, Columbia, unpublished Ph.D. dissertation, 89 p.

Miser, H. D., 1921, Llanoria, the Paleozoic land area in Louisiana and eastern Texas: American Journal of Science, v. 2, p. 61–89.

_____1922, Deposits of manganese ore in the Batesville district, Arkansas: U.S. Geological Survey Bulletin 734, 273 p.

_____1929, Structure of the Ouachita Mountains of Oklahoma and Arkansas: Oklahoma Geological Survey Bulletin 50, 30 p.

Miser, H. D.; and Purdue, A. H., 1929, Geology of the DeQueen and Caddo Gap quadrangles, Arkansas: U.S. Geological Survey Bulletin 808, 195 p.

Nicholas, R. L.; and Rozendal, R. A., 1975, Subsurface positive elements within the Ouachita foldbelt in Texas and their relationship to Paleozoic cratonic margin: American Association of Petroleum Geologists Bulletin, v. 59, p. 193–216.

Nicholas, R. L.; and Waddell, D. E., 1989, The Ouachita system in the subsurface of Texas, Arkansas, and Louisiana, *in* Hatcher, R. D., Jr.; Thomas, W. A.; Viele, G. W. (eds.), The Appalachian–Ouachita orogen in the United States: Geological Society of America, The Geology of North America, v. F-2, p. 661–672.

Nunn, J. R., 1986, The petrology and paleogeography of the Starved Rock Sandstone in southeastern Iowa, western Illinois, and northeastern Missouri: University of Iowa, Iowa

City, unpublished M.S. thesis, 144 p.

O'Brien, J. E.; and Derby, J. R., 1997, Progress report on Simpson and Viola correlations from the Arbuckles to the Ozarks, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 260–266.

Patterson, J. R., 1961, Ordovician stratigraphy and correlation in North America: American Association of Petroleum Geologists Bulletin, v. 45, p. 1364–1377.

Pitt, W. D., 1955, Geology of the core of the Ouachita Mountains of Oklahoma: Oklahoma Geological Survey Circular 34, 34 p.

Pitt, W. D.; Cohoon, R. R.; Lee, H. C.; Robb, M. G.; and Watson, J., 1961, Ouachita Mountain core area, Montgomery County, Arkansas: American Association of Petroleum Geologists Bulletin, v. 45, p. 72–94.

Pollastro, R. M., 1991, Composition, clay mineralogy, and diagenesis of the Simpson Group (Middle Ordovician), Grady County, Oklahoma: U.S. Geological Survey Bulletin 1866, chapter H, p. H1-H19.

Purdue, A. H.; and Miser, H. D., 1916, Description of the Eureka Springs and Harrison quadrangles (Arkansas–Missouri): U.S. Geological Survey, Geologic Atlas of the United States, Folio 202, 21 p.

Reid, D. R.; Dix, M. C.; and Casey, J. F., 1994, Provenance of Ordovician–Silurian siliciclastic rocks in the Broken Bow uplift, Ouachita allochthon, Oklahoma [abstract]: Geological Society of America Abstracts with Programs, v. 26, p. 25.

Repetski, J. E.; Ethington, R. L.; Chludzinski, G. T.; Stone, C. G.; and Krueger, D. M., 1994, Ouachita Mountains Cambrian–Ordovician conodonts revisited [abstract]: Geological Society of America Abstracts with Programs, v. 26, p. 26.

Ross, J. P.; and Ross, C. A., 1992, Ordovician sea-level fluctuations, *in* Webby, B. D.; and Laurie, J. R. (eds.), Global perspectives on Ordovician geology: Balkema, Rotterdam, p. 327–335.

Ross, R. J., Jr., 1976, Ordovician sedimentation in the western United States, *in* Bassett, M. G. (ed.), The Ordovician System: Proceedings of a Palaeontological Association symposium, Birmingham, University of Wales Press and National Museum of Wales, Cardiff, p. 73–105.

Ross, R. J., Jr.; and 27 others, 1982, The Ordovician System in the United States, correlation chart and explanatory notes: International Union of Geological Sciences Publication 12, 73 p.

Salvador, A., 1985, Chronostratigraphic and geochronometric scales in COSUNA stratigraphic correlation charts of the United States: American Association of Petroleum Geologists Bulletin, v. 69, p. 181–189.

Samson, S. D.; Patchett, P. J.; Roddick, J. C.; and Parrish, R. R., 1989, Origin and tectonic setting of Ordovician bentonites in North America: isotopic and age constraints: Geological Society of America Bulletin, v. 101, p. 1175–1181.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

_____1965, Resume of Simpson (Ordovician) stratigraphy, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 26–34.

Schutter, S. R., 1992, Ordovician hydrocarbon distribution in North America and its relationship to eustatic cycles, *in* Webby, B. D.; and Laurie, J. R. (eds.), Global perspectives on Ordovician geology: Balkema, Rotterdam, p. 421–432.

Schwalb, H. R., 1982, Paleozoic geology of the New Madrid area: Illinois State Geological Survey NUREG/CR 2909 RA, 61 p.

Slaughter, M.; and Hill, R. J., 1991, The influence of organic matter in organogenic dolomitization: Journal of Sedimentary Petrology, v. 61, p. 296–303.

Sloss, L. L., 1984, Comparative anatomy of cratonic unconformities, *in* Schlee, J. S. (ed.), Interregional unconformities and hydrocarbon accumulation: American Association of Petroleum Geologists Memoir 36, p. 1–6.

_____1988, Tectonic evolution of the craton in Phanerozoic time, *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. 25–51.

Smith, G. L.; Byers, C. W.; and Dott, R. H., Jr., 1993, Sequence stratigraphy of the Lower Ordovician Prairie Du Chien Group on the Wisconsin Arch and in the Michigan Basin: American Association of Petroleum Geologists Bulletin, v. 77, p. 49–67.

Smith, P. W., 1993, Factors controlling Simpson Group production in central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 43, no. 2, p. 12–26.

Statler, A. T., 1965, Stratigraphy of the Simpson Group in Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 162–211.

Stone, C. G.; and Bush, W. V., 1984, Summary of the geology of the central and southern Ouachita Mountains, Arkansas, *in* Stone C. G.; and Haley, B. R. (eds.), A guidebook to the geology of the central and southern Ouachita Mountains, Arkansas: Arkansas Geological Commission Guidebook 84-2, p. 65–75.

Suhm, R. W., 1970, Stratigraphy of the Everton Formation (Early Medial Ordovician) along the Buffalo–White River traverse, northern Arkansas: University of Nebraska, Lincoln, unpublished Ph.D. dissertation, 421 p.

_____1972, Subsurface Everton stratigraphy, northeastern Arkansas: Consultant report for Cockrell Corp., Houston, Texas, 212 p.

_____1974, Stratigraphy of Everton Formation (Early Medial Ordovician), northern Arkansas: American Association of Petroleum Geologists Bulletin, v. 58, p. 685–707.

_____1975, Calico Rock Member of Everton Formation (Ordovician), northern Arkansas: Arkansas Academy of Sciences Proceedings, v. 29, p. 70–74.

_____1976, Stratiform zinc in the Everton Formation (Middle Ordovician), northern Arkansas: Consultant report for Boliden-Preussag Exploration, Canada, and International Oil and Gas, Memphis, Tennessee.

_____1978, Stratigraphic delineation of the Reserve Oil #1 Hazen, Prairie County, Arkansas: Consultant report for International Oil and Gas, Memphis, Tennessee.

_____1979, Hydrocarbon potential of Simpson equivalents in Arkansas' Arkoma basin: Oil and Gas Journal, Feb. 12, p. 150–153.

Suhm, R. W.; and Ethington, R. L., 1975, Stratigraphy and conodonts of the Simpson Group (Middle Ordovician), Beach and Baylor Mountains, west Texas: American Association of Petroleum Geologists Bulletin, v. 59, p. 1126–1135.

Suhm, R. W.; Patterson, J. R.; and Calvert, W. L., 1977, The Cambrian–Ordovician boundary in North America [abstract], *in* Sweet, W. C., and others (eds.), Third International Symposium on the Ordovician System, program and abstracts: Ohio State University, Columbus, p. 7.

Sweet, W. C., 1992, Middle and Late Ordovician conodonts from southwestern Kansas and their biostratigraphic significance, *in* Chaplin, J. R.; and Barrick, J. E. (eds.), Special papers in paleontology and stratigraphy: a tribute to Thomas W. Amsden: Oklahoma Geological Survey Bulletin 145, p. 181–191.

Tanner, J. H., 1967, Wrench fault movements along Washita Valley Fault, Arbuckle Mountain area, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 51,

p. 126–141.

Templeton, J. S.; and Willman, H. B., 1963, Champlainian Series (Middle Ordovician) in Illinois: Illinois State Geological Survey Bulletin 89, 260 p.

Thomas, W. A., 1985, The Appalachian–Ouachita connection: Paleozoic orogenic belt at the southern margin of North America: Annual Review of Earth and Planetary Sciences, v. 13, p. 175–199.

_____1988, The Black Warrior 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. 471–492.

Thompson, T. L., 1991, Paleozoic succession in Missouri, Part 2—Ordovician System: Missouri Department of Natural Resources, Division of Geology and Land Survey, Report of Investigations 70, pt. 2, 292 p.

Tomlinson, C. W.; and Pitt, W. D., 1955, Recent studies in the Ouachita Mountains: Tulsa Geological Society Digest, v. 23, p. 89–97.

VanArsdale, R. B.; and Schweig, E. S., III, 1990, Subsurface structure of the eastern Arkoma Basin: American Association of Petroleum Geologists Bulletin, v. 74, p. 1030–1037.

Waddell, R. T.; Forgotson, J. M., Jr.; and Liu, H., 1993, Geologic study of the upper Arbuckle Group in the Healdton Field, Carter County, Oklahoma, *in* Johnson, K. S.; and Campbell, J. A. (eds.), Petroleum-reservoir geology in the southern Midcontinent, 1991 symposium: Oklahoma Geological Survey Circular 95, p. 126–139.

Whiteside, J. R.; and McCommons, W. E., 1991, Results of a deep Cambro–Ordovician drilling program, northern Fort Worth basin, Texas, *in* Johnson, K. S. (ed.), Arbuckle Group core workshop and field trip: Oklahoma Geological Survey Special Publication 91-3, p. 157–162.

Whittington, H. B., 1968, Zonation and correlation of Canadian and early Mohawkian Series, *in* Zen, E-A.; White, W. S.; and Hadley, J. B. (eds.), Studies of Appalachian geology, northern and maritime: Wiley, New York, p. 49–60.

Witzke, B. J., 1980, Middle and Upper Ordovician paleogeography of the region bordering the Transcontinental arch, *in* Fouch, T. D.; and Magatham, E. R. (eds.), Paleozoic paleogeography of the west-central United States, Paleogeography Symposium 1: Society of Economic Paleontologists and Mineralogists, Rocky Mountain Section, Denver, p. 1–18.

Wright, W. F., 1965, Petroleum geology of the Simpson Group, west Texas and southeast New Mexico, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 62–73.

Young, L. M.; Fiddler, L. C.; and Jones, R. W., 1972, Carbonate facies in Ordovician of northern Arkansas: American Association of Petroleum Geologists Bulletin, v. 56, p. 68–80.

Contrasting Sedimentation Inside and Outside the Southern Oklahoma Aulacogen During the Middle and Late Ordovician

Rodger E. Denison
The University of Texas at Dallas
Richardson, Texas

ABSTRACT.—Outcrop evidence has revealed a marked contrast in Middle and Upper Ordovician strata deposited on Cambrian basement in the southern Oklahoma aulacogen (Arbuckle anticline) and those deposited outside (Hunton uplift) on massive Precambrian rocks. These strata comprise, in ascending order, the Simpson and Viola Groups, the Sylvan Shale, and the Keel Formation.

The original Cambrian rift margin is believed essentially to coincide with the Washita Valley fault, the Pennsylvanian master fault of the Arbuckle Mountains.

Simpson strata represent the first introduction of significant terrestrial material since the Cambrian transgression. These rocks comprise five formations: the Joins is present in the Arbuckle Mountains and extends just beyond the aulacogen; the Oil Creek overlies the Joins within and adjacent to the aulacogen and overlies Arbuckle Group rocks (Lower Ordovician) outside the aulacogen; the McLish is marginally thinner within the aulacogen; the Tulip Creek is restricted to the aulacogen area; and the Bromide is thicker within the Arbuckle anticline (aulacogen) than at the type locality, outside the aulacogen, where uppermost Bromide deposits record subtidal to supratidal environments, which grade to open-marine environments within the old rift.

Following a brief marine withdrawal, Viola seas transgressed over the exposed peritidal upper Bromide carbonates. The Viola Group consists of the lower Viola Springs Formation (the former Trenton), and the upper Welling Formation (the former Fernvale). Within the aulacogen, the Viola Springs is composed mainly of organic-rich, finely laminated lime mudstones, and the Welling, of pelmatozoan-rich grainstones. Outside the aulacogen, the basal Viola Springs is composed of packstones and wackestones; here, the combined Viola Group is markedly thinner.

The Viola Group carbonate platform, having operated with little terrigenous input, ended abruptly as the system was flooded wih clays of the overlying Sylvan Shale. The Sylvan is the lowest interval in the southern Oklahoma Paleozoic section that is consistently composed of substantially thick shale. The unit is significantly thicker within the aulacogen than outside.

The end of the Ordovician occurred during deposition of the Keel Formation, a thin oolite that represents the oldest unit of the Hunton Group. The Keel is thickest (about 15 ft) outside the aulacogen.

INTRODUCTION

Cambrian rifting and subsequent igneous activity in southern Oklahoma had a profound effect on later Paleozoic sedimentation and on structural style and direction. The effect on sedimentation is marked for all the Paleozoic but is perhaps most dramatic and well displayed in rocks of Late Cambrian and Ordovician age.

The documentation of the contrast in sedimentation is possible because the western Arbuckle Mountains lie within the aulacogen and the eastern Arbuckles just outside. Ham and others (1964) showed that it was the events recorded in basement rocks that were responsible for such a profound difference in later geologic history. Ham (1969) framed the contrast in Paleozoic sedimentation across the Cambrian rift boundary. Hoffman and others (1974) introduced the concept of the aulacogen and provided an instructive sequence of evolutionary cross sections that tied the rift and later Paleozoic history.

The object here is to contrast Middle and Upper Ordovician strata deposited on Cambrian basement in the aulacogen with those deposited outside on massive Precambrian rocks. This will essentially be a formation-by-formation comparison of rocks exposed in the Arbuckle anticline (inside) and those in the Hunton uplift (outside) of the Arbuckle Mountains (Fig. 1). The original Cambrian rift margin is believed, on good evidence, essentially to coincide with the Pennsylvanian master fault of the Arbuckle Mountains, the Washita Valley fault.

THE SETTING

Except for the aulacogen, the basement surface in Oklahoma had undergone erosion for a minimum of ~800 million years. There is no recorded geologic event between the youngest Precambrian igneous activity around 1,400 Ma and the Cambrian rifting event. Late Cambrian seas transgressed across a gently rolling land-

---

Denison, R. E., 1997, Contrasting sedimentation inside and outside the southern Oklahoma aulacogen during the Middle and Late Ordovician, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 39–47.

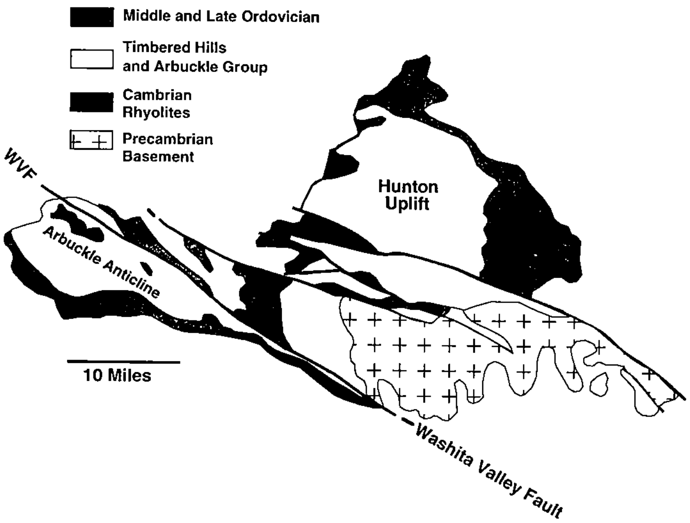


Figure 1. Simplified map of the Arbuckle Mountains, showing distribution of Ordovician and older rocks.The Arbuckle anticline is separated from the Hunton uplift and related structures by the Washita Valley fault. This fault is believed to trace the original northeastern rift margin for the aulacogen. Thus all rocks to the south of the Washita Valley fault are interpreted to have been deposited within the boundary of the aulacogen. Post-Ordovician rocks have no pattern.

scape of Cambrian rhyolites and generally peneplained massive Precambrian granite and granite gneiss. Isolated hills rose more than 1,000 ft above the surrounding plain (Ham, 1955). After deposition of the locally derived Reagan basal sandstone, a vast peritidal platform developed on the peneplained continental surface.

It was a peritidal platform of exceptional size and stability (Fig. 2). For the next ~30 million years carbonates dominated the platform. In Oklahoma, the domination of carbonates was almost complete. The source of potential terrigenous material was so distant and the transportation across the platform so difficult, that Oklahoma received only a trivial amount of sand and clay during this period. The weakened aulacogen site was sinking considerably faster than areas underlain by massive Precambrian rocks outside the aulacogen. Everywhere carbonates could grow and precipitate at a much faster rate than any part of Oklahoma could sink. As a consequence of this efficiency, storms played an important role in sedimentation inside the aulacogen.

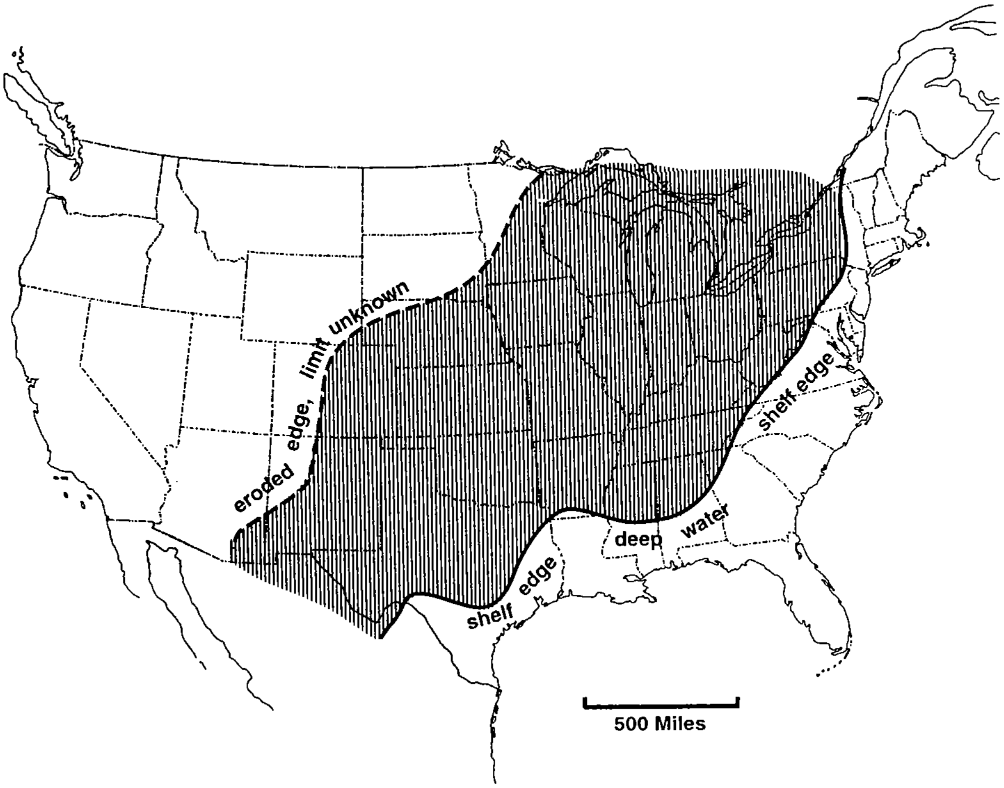


Figure 2. The Late Cambrian–Early Ordovician platform covered a vast area in the United States. The simplified and approximate limits of the platform are interpreted from Cook and Bally (1973).

Outside the aulacogen, even small changes in sea level must have alternately flooded or exposed vast areas of the platform for considerable periods of time. Some of the dolomites in the Arbuckle were probably developed during these alternating sea-level fluctuations. The increased subsidence rate in the aulacogen is believed to have been caused by sediment loading of the rift-weakened crust.

Near the end of Ibexian (= Canadian = Early Ordovician) time there was a significant lowering of sea level, and for the first time since the basal transgression the continent was drained and the vast peritidal platform was exposed—except for the aulacogen site in southern Oklahoma where a finger of the sea remained. The drained platform must have been one of the most remarkable sights of all geologic history. Stretching from eastern Canada to northern Mexico, it was a white plain with essentially no relief, no established drainage, and no life other than bacteria and algae.

SIMPSON GROUP

During the ultra-regional post-Arbuckle sea-level lowering, the Joins Formation, the oldest unit in the Simpson Group, was deposited in the finger of sea remaining in southern Oklahoma. Strata within the Simpson represent the first introduction of significant terrestrial material into the depositional system since the Cambrian transgression. Sandstones of unusual thickness and purity are conspicuous in this sequence. In the following discussion, most of the outcrop data are taken from the classic study of Decker and Merritt (1931). Schramm (1964) published a comprehensive subsurface study of Simpson distribution, thickness, and bulk composition in Oklahoma, and Dapples (1955) tied the Simpson to age-equivalent rocks to the north of Oklahoma. Derby and others (1991) reviewed the correlation and biostratigraphy of all Late Cambrian and Ordovician rocks (Fig. 3).

The Simpson Group consists of five formations within the aulacogen area and was deposited over a period of about 25 million years, representing all of Whiterockian and the earlier part of Mohawkian time. A comparison of the thickness, lithology, and distribution of the units with the Simpson is shown in Figure 4. The oldest formation, the Joins, is followed by four similar formations, which, over most of the area, are marked by distinctive basal sandstones.

The Joins is never well exposed and is generally marked by weak ground between the top of the Arbuckle and the overlying Oil Creek Formation. The Joins consists of thin limestones and shales with a persistent thin conglomerate at the base. The Joins thickness is as great as 300 ft on the south side of the Arbuckle anticline. The Joins outcrop distribution in the Arbuckle Mountains extends just beyond the aulacogen, absent apparently through nondeposition over most of the Hunton anticline. The shales within the Joins were the first strictly terrigenous beds of substance in southern Oklahoma since deposition of the Reagan. The conglomerate at the base does not necessarily represent an unconformity but is a clear demonstration of nearby subaerial exposure. The basal conglomerate is believed to have been derived from the West Spring Creek, exposed adjacent to the Joins sea.

Each of the four overlying formations of the Simpson Group shares a common lithologic sequence. A basal sandstone is overlain by limestones containing variable amounts of shale. Within the Arbuckle Mountain area, there are also local sandstones, some quite substantial, within the middle parts of the McLish and Oil Creek Formations. Each of the four formations shows differences in both thickness and composition inside and outside the aulacogen (Fig. 5).

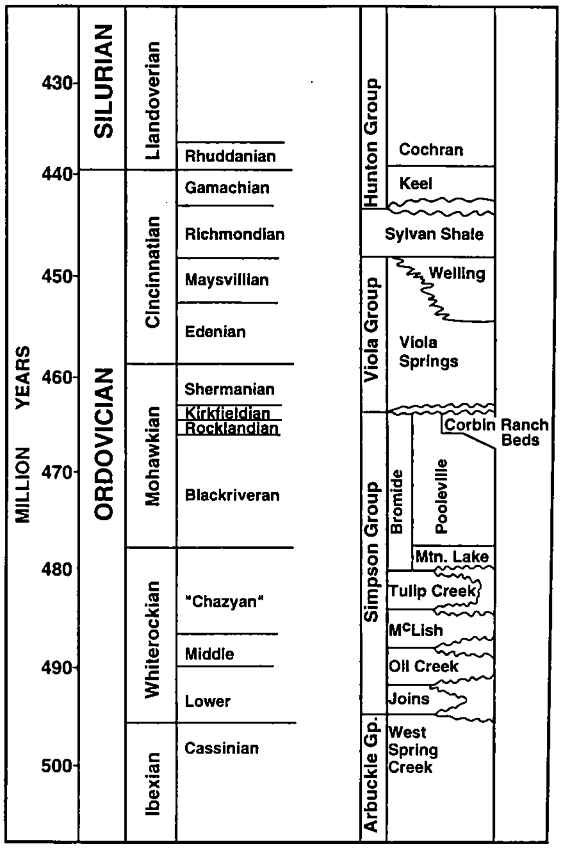


Figure 3. Age of post-Arbuckle strata in the Arbuckle Mountains. Numerical age boundaries for the Ordovician are taken from Harland and others (1990), subdivisions and proportional time intervals are from Ross and others (1982), and age assignment of the units is interpreted mostly from Derby and others (1991) and Amsden and Barrick (1986).

The Oil Creek Formation overlies the Joins within and adjacent to the aulacogen and overlies Arbuckle Group rocks outside the aulacogen. The basal Oil Creek sandstone is the thickest (up to 400 ft) of all the Simpson sandstones. Like all Simpson sandstones, it varies greatly in thickness and is absent over much of the Arbuckle anticline and the Ardmore basin. The isopach map of Lewis (1982) shows the thickness varying parallel to the aulacogen margin, with the greatest thickness on the northeast (Precambrian) side of the original rift. The zero sand isopach in the subsurface has been used to argue for as much as 40 mi of left-lateral offset on the Washita Valley fault by Tanner (1967). The validity of the offset was challenged by Brown (1984) and Lewis

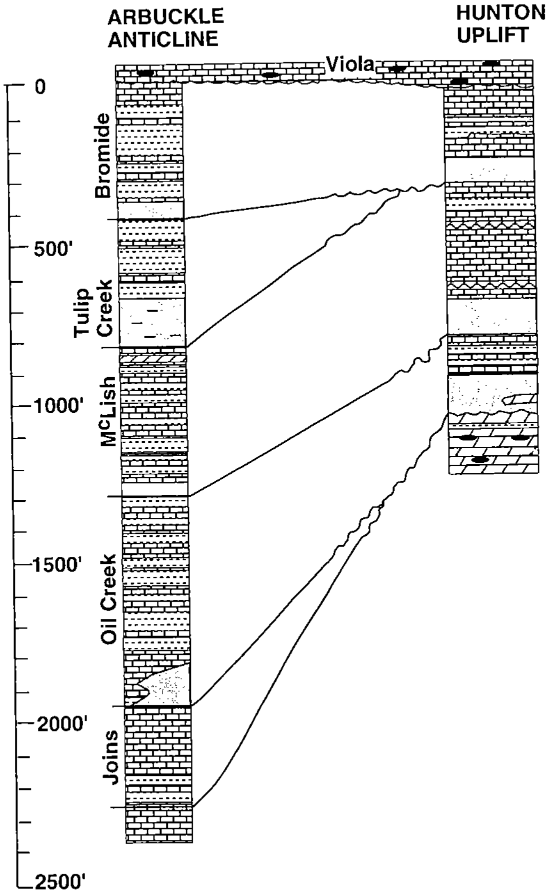


Figure 4. Contrast in thickness, distribution, and composition between rocks of Simpson age in the Arbuckle anticline and those exposed in the Hunton uplift. Modified from Ham (1955).

(1982). The upper Oil Creek is composed of shales and thin-bedded limestones with some calcite-cemented sandstones (Decker and Merritt, 1931; Lewis, 1982).

The McLish Formation overlies the Oil Creek and is composed of the same sequence of rocks. The basal sandstone is overlain by shales and shallow-water carbonates, which include the famous birdseye limestones (Ham, 1955). The basal sandstone is thinner than that of the Oil Creek but still reaches a substantial 165 ft. Like the Oil Creek, it is thinnest in the Arbuckle anticline and thickest near the old rift margin (Ham, 1945). The McLish is marginally thinner inside the aulacogen (Fig. 3).

The Tulip Creek Formation, overlying the McLish, is restricted to the aulacogen area. It is the least studied of the Simpson formations. Decker and Merritt (1931) measured nearly 400 ft of Tulip Creek in the eastern Arbuckle anticline. Ham (1955) shows a higher percentage of shale in the upper Tulip Creek than in adjacent formations. The basal sandstone can be more than half the total thickness and is probably the "Third Bromide" of some Arbuckle area oil fields.

The Bromide Formation overlies the Tulip Creek in the aulacogen area, and the McLish outside the rift (Fig. 3). It is the best studied of the Simpson formations (Longman, 1976; Sprinkle, 1982; Amsden and Sweet, 1983, and references therein). The formation is divided into two members. The lower Mountain Lake Member is composed of a basal sandstone with overlying shales and limestones. The upper Pooleville Member is essentially all peritidal carbonates. Longman (1982b) provided a complete description of the Bromide lithologies and interpreted depositional environments. His cross sections (his figs. 7–11) show that each facies of the Bromide is controlled by the aulacogen margin. Longman (1982b) interprets a shoreface environment of deposition for the Bromide sandstones. The Bromide within the aulacogen is shalier and was deposited in deeper still water. The Arbuckle anticline (aulacogen) section is substantially thicker (430 ft) than the type locality (230 ft) near the town of Bromide, outside the aulacogen.

Simpson deposition lasted about 25 million years and ended with deposition of the Corbin Ranch beds of the Bromide Formation and withdrawal of the seas. Amsden (*in* Amsden and Sweet, 1983, fig. 15) shows the distribution of the terminal beds. Outside the aulacogen, the uppermost Bromide records subtidal to supratidal environments, grading to open-marine environments within the old rift.

Over much of the area, each of the post-Joins formations contains a remarkable basal sandstone (Fig. 4). Sandstones of similar composition and age are distributed from Minnesota to Oklahoma (the St. Peter problem of Dake, 1921) and into west Texas. Each sandstone is overlain by a sequence of shale and limestone. Because most of the sandstones are poorly cemented, there are few quality outcrops of the sandstones and the internal sedimentary structures that might be definitive in establishing an environment of deposition. Attempts to core the poorly consolidated sands are invariably unsuccessful. The limestones overlying the sands were deposited in a shallow-water, peritidal environment.

The purity of the Simpson sandstones has been exploited as glass sands. The sandstones are composed of supermature, multicycle sand. The sands are mined hydraulically and washed to remove the clays. The resulting sand is >99.5% SiO_2 (Ham, 1945) and is composed almost entirely of unstained, monocrystalline quartz grains. Traces of zircon, tourmaline, garnet, microcline, and albite are the only other detrital minerals. Beds of dolomite- or calcite-cemented sandstone up to 6 ft thick are present within the massive Oil Creek sandstone.

The reservoir quality of the Simpson sandstones is remarkable. Measurements of outcrop samples of the Oil Creek sandstones show porosities greater than 30% and permeabilities in the 1- to 2.5-darcy range (McPherson and others, 1988). These exceptional values are due to excellent rounding and sorting of the sand grains and preservation of the pore space by clay coats on individual sand grains. Although the measured values are close to ideal, the special conditions for the clay coats, rounding, and sorting were not universal. Nonetheless, the Simpson sandstones have a deserved reputation for exceptional reservoir performance.

The origin of these sands, how they were transported to the depositional site, and the environment of deposition have been the subject of much speculation. The

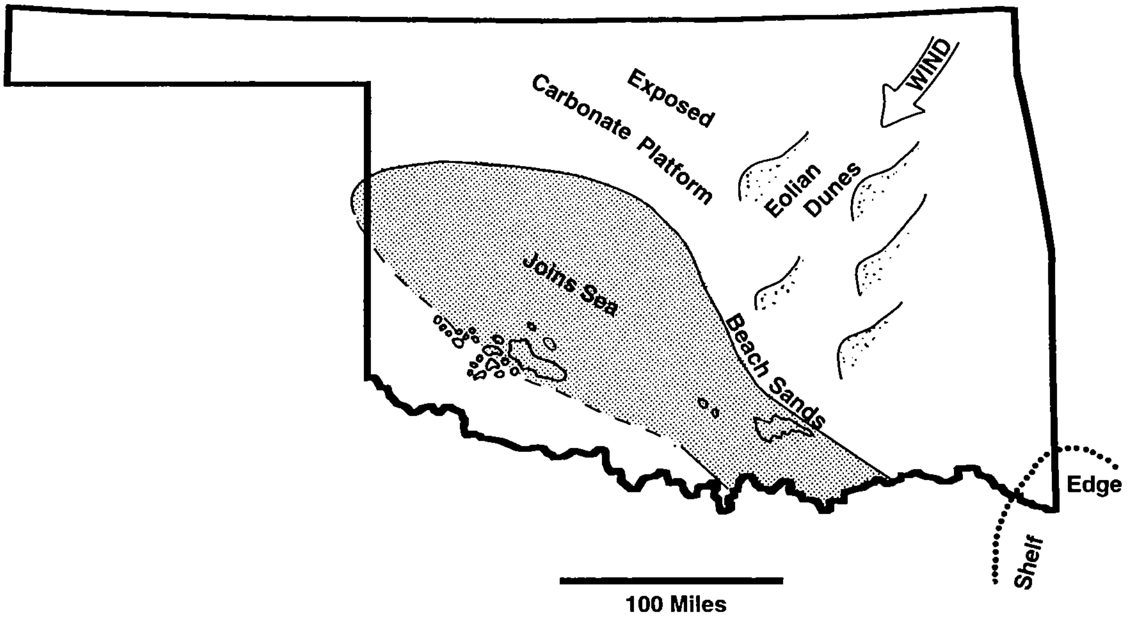


Figure 5. Approximate distribution of the Joins sea and the transportation of eolian sands across the drained carbonate platform during the post-Arbuckle ultraregional unconformity. Speculative limit of the Joins sea is shown in relation to present basement-rock outcrops.

problem of origin centers around the underlying carbonate platform. The sands must have come from outside the vast limits of the platform, from at least hundreds of miles away (Fig. 2). With the extreme flatness of the platform, what mechanism transported the sand to the depositional site? The pitting and frosting of the sand grains (see SEM photomicrographs in Ham, 1973, fig. 46) have long been regarded as a criterion of wind transport. But the few exceptional quarry exposures of the Simpson in the Arbuckles do not show eolian sedimentary structures. The uniform horizontal bedding seen in quarries is defined by the occurrence of varying amounts of green illite clay as coatings on the sand grains (Ham, 1955; Denison and Ham, 1973).

McPherson and others (1988) showed that outcrops in Oil Creek quarries north of Mill Creek were the result of storm deposition. Each of the horizontal beds represents a single storm episode that transported the sand and clay from shallow, nearshore localities to deeper water for deposition below storm wave base. Their model brought the sands across the exposed Arbuckle carbonate plain as eolian dunes during a post-Arbuckle lowstand until the sands reached the edge of the Joins sea. Here, the sand was deposited in a beach environment, later to be reworked during a subsequent transgression or into deeper water during storms. Longman (1982a) shows a reconstruction at the beginning of Bromide time that is basically identical to the paleogeographic Joins–Oil Creek model of McPherson and others.

The McLish, Tulip Creek, and Bromide Formations that overlie the Oil Creek all contain basal sandstones, overlain by peritidal limestone interbedded with shale. The upper four formations, in fact, are so similar on the outcrop that Ham (1945) could distinguish the units only on the basis of fossil content and stratigraphic position. Because the post-Joins formations are so similar, a common depositional model may well be appropriate for all four. The Oil Creek is considered a reasonably general model—sand brought from a great distance by wind during lowstands to be reworked during subsequent transgressions. Donovan and others (1991) use the same circumstances to formulate a Bromide model of deposition. As marine transgression proceeds, the carbonate platform is flooded, and sands can no longer be introduced as eolian dunes. The platform is probably too flat and too vast to allow sand transport by tidal or longshore currents. In any case, as the source of sand is largely shut off, sedimentation evolves into alternating limestones and shales. Therefore, in the model advocated here, the base of each of the upper four Simpson formations is marked by a draining of the platform outside the aulacogen, allowing eolian sand transport. This is followed by a transgression that redistributed the eolian sands into the marine environment, eventually shutting off sand transport and evolving into a peritidal carbonate platform, with the interbedded clay brought in by suspension.

The hydrocarbon source potential of the shale within the overlying sands in the upper four formations of the Simpson is debatable. Certainly, the greenish shales that characterize much of the Simpson are lean. Published values for total organic carbon and extractable organic matter are unexceptional; some zones have acceptable source potential, but these are not common (Burruss and Hatch, 1989). Some oil in the Simpson has the distinctive character common to oils having their source in rocks of Ordovician age (Wavrek, 1992). The structural complexity, particularly within the aulacogen, could have put the Simpson in the migratory path of younger source rocks of exceptional quality. There are billions of barrels of oil and gas equivalent within the Simpson throughout Oklahoma, but it is not possible to estimate how much their source is owed to the interbedded shales.

In early Bromide time, terrigenous material in southern Oklahoma was diminishing, and by the late Bromide it was no longer part of the depositional system. Either the source of sand and shale was playing out, the transportation path diverted, or the mechanisms that carried the sand such a great distance to Oklahoma were no longer operable. There would be no significant sand in the depositional systems of southern Oklahoma for the next 100 million years. Amsden (*in* Amsden and Sweet, 1983) shows that outside the aulacogen the carbonates of the uppermost Bromide were deposited in shallow subtidal to supratidal environments grading to open-marine, peritidal environments within the old rift. With deposition of the uppermost Bromide Corbin Ranch beds, Simpson deposition ended with withdrawal of the seas.

VIOLA GROUP

After a brief withdrawal, Viola seas transgressed over the exposed peritidal Bromide carbonates. Amsden (*in* Amsden and Sweet, 1983) defines the Viola Group as the strata between the Bromide and the Sylvan Shale. The group is divided into a lower, lime mud–rich Viola Springs Formation (the former Trenton), and an upper, organo-detrital limestone, the Welling Formation (the former Fernvale). Gaining an understanding of the Viola Group benefits from exceptional natural and quarry exposures both in and out of the aulacogen. A modern understanding of the Viola Group rocks began with the work of Glaser (1965) and Alberstadt (1967).

In the Arbuckle anticline the contact of the basal Viola Springs with the peritidal Corbin Ranch limestones of the Bromide is well exposed. The Bromide surface is eroded but has virtually no relief and is not marked by any significant detritus but rather a zone of oxidized pyrite. The cherty, finely laminated lime mudstones of the basal Viola Springs are organic rich and were deposited in stratified waters below storm wave base. Finney (1988) estimates the water depth at the base to be 600–1,600 ft. The section of laminated and burrowed mudstones is greater than 600 ft thick and as much as 850 ft. The mudstones grade upward into the pelmatozoan-rich grainstones of the Welling Formation. These grainstones within the aulacogen are generally less than 20 ft thick and are much thinner in the westernmost Arbuckle anticline (Glaser, 1965). The mudstones of the Viola Springs have been recrystallized to microspar (Reid, 1980; Smith, 1982) for reasons that are not fully understood.

Outside the aulacogen, in the Hunton uplift, Glaser and Alberstadt (*in* Alberstadt, 1973) report the basal Viola Springs to be composed of packstones and wackestones with much less lamination. Here, the combined Viola Group section is only about 350 ft thick, with about 80 ft of Welling grainstones (Amsden *in* Amsden and Sweet, 1983).

It is clear that the rift margin plays an important role in both thickness and facies of Viola Group rocks. The regional cross section of Amsden (*in* Amsden and Sweet, fig. 16) is particularly instructive. He shows that northeast of the aulacogen the Viola Springs is replaced by the Welling, which rests directly on the Bromide equivalent. The Viola Springs within the aulacogen was deposited in deeper water and as a consequence is thicker, muddier, more laminated, and organic rich. The Viola Group section within the Arbuckle anticline, based on physical evidence, must record unbroken sedimentation and is so shown by Amsden and Barrick (1986). The equivalent Hunton anticline section, outside the aulacogen, preserves numerous hardgrounds and evidence of exposure (Sykes and others, 1997).

In the old rift, particularly in the lowermost Viola Springs, there are thin but very decent source beds (Kirkland and others, 1992, p. 61). The oil stored in the Viola Group rocks probably had its source in these thin intervals and was almost certainly generated by source rocks of Ordovician age. Wavrek (1992) distinguishes Viola oils as a distinctive type.

The only systematic pore space is developed in the Welling grainstones, but the Viola Springs mudstones developed a closely spaced fracture network during Pennsylvanian deformation. The mercurial reservoir qualities of Viola Group rocks have broken many a heart.

The Viola Group is a classic shallowing-upward sequence. The Viola Springs strata in the aulacogen were deposited in relatively deep water and yet are at the base of an unconformity and overlie the shallow-water Corbin Ranch beds that have many hardgrounds near the top. This indicates that during the lowstand at the end of Bromide deposition, the aulacogen continued to sink at a rate faster than the area outside but remained above sea level. The flooding that signaled the beginning of Viola deposition must have been rapid, with a substantial sea-level rise. Outside the aulacogen, in eastern Oklahoma, the basal Viola Group beds are the shallow-water Welling grainstones. Within the aulacogen the sedimentation rate exceeded that outside, and the area of deeper water was eventually filled by increasingly shallow-water carbonates. The Viola Group carbonate platform, operating with little terrigenous input, ended abruptly as the system was flooded with clay brought in suspension from distant sources.

SYLVAN SHALE

The Sylvan Shale is the lowest interval in the southern Oklahoma Paleozoic section that is consistently composed of shale of substantial thickness. The velocity and lithologic contrast with the underlying Viola Group rocks is a mark difficult to mistake.

The Sylvan is poorly exposed and has attracted few workers. Amsden (*in* Johnson and others, 1988) believes that the Sylvan does not represent a dramatic increase in water depth but simply a muddying of the water. There is no evidence of an unconformity at the base of the Sylvan, which means that the grainstone formation in the Welling came to an abrupt end as the clay choked off the carbonate sedimentation that had been running steadily, in shallow and deep water, for some 30 million years—since Pooleville time. Although the Sylvan contains Late Ordovician graptolites (Decker, 1935) and chitinozoans (Jenkins, 1970), the length of deposition is probably best estimated by subtraction, the difference between the better defined top of the Welling and the base of the Hunton (Fig. 3). This appears to be a brief interval of 3 million years or so but with substantial uncertainty as to the absolute value. The Sylvan is dolomitic in the upper part and is significantly thicker within the aulacogen than outside (Fig. 6). Amsden (*in* Amsden and Barrick, 1986) shows an isopach map with over 300 ft of Sylvan in the deep Anadarko basin, near 200 ft in the Arbuckle anticline, and generally 100 ft or less outside the aulacogen.

Some published data on the source character of the Sylvan show it to be unpromising (e.g., Burruss and Hatch, 1989). The Sylvan has a low total organic carbon content, and it must be concluded that although the Sylvan has acted as a good seal for hydrocarbons generated in the Viola, it probably has not been an appreciable source for oil or gas in southern Oklahoma.

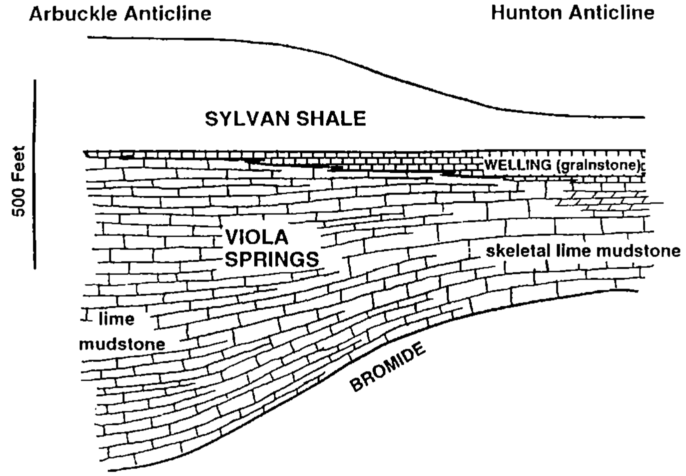


Figure 6. Cross section showing the difference in thickness of the Viola Group and the Sylvan Shale between the Arbuckle anticline and the Hunton uplift.

Just as quickly as the Sylvan ended Welling deposition, the transport of clays into Oklahoma ceased either by diversion or exhaustion of source. The elimination of the clay led to the renewal of carbonate deposition and what I regard as the most puzzling stratigraphic contact in Oklahoma, an oolite resting on a regional shale.

KEEL FORMATION

The end of the Ordovician occurred during deposition of the Keel Formation, a rather thin oolite that represents the oldest unit in the Hunton Group. Amsden (*in* Amsden and Barrick, 1986) summarized the thickness, age, distribution, and lithology of the Keel. The formation is generally less than 10 ft thick in most outcrop sections, and the greatest thickness, some 15 ft, is present outside the aulacogen. The Keel is absent at some Arbuckle Mountain sites through nondeposition or erosion. The Ordovician–Silurian boundary is at or near the top of the Keel and has been determined mostly on the basis of brachiopods and conodonts. Most correlations (e.g., Derby and others, 1991) indicate that Keel sedimentation took place over several million years, yet modern oolite sedimentation would suggest that a few thousand rather than a few million years would be more appropriate for an oolite of Keel thickness. There is no physical evidence of an unconformity at the base of the Hunton (Amsden, 1986), but there is a tremendous contrast in lithology, and the contact is physically enigmatic.

Modern oolite deposits form in clear, high-energy, peritidal environments (e.g., the Bahamas; Newell and others, 1960). It can be easily envisaged that the Sylvan clay source was cut off or diverted and that the waters cleared as quickly as they had been muddied to end Viola deposition. It is more difficult to envisage how a high-energy grainstone deposit, in this case an oolite, can form without incorporating a considerable amount of the underlying clays. Various data from Amsden show that the Keel is indeed a high-energy deposit (some oolites are broken) and that little terrigenous material remains as insoluble residue. One way the Sylvan could have been less likely to have been reworked was for the shale to have been lithified and hardened during subaerial exposure. This implies an unconformity at the Sylvan–Keel contact, for which there is no direct evidence.

Oolitic beds of this age have an amazing distribution. Amsden (*in* Amsden and Barrick, 1986) shows that they stretch from Oklahoma through Arkansas and Missouri into Illinois.

SUMMARY

The Ordovician ended unimpressively during later Keel deposition. For the previous ~55 million years, Simpson, Viola, Sylvan, and lowermost Hunton rocks had been strongly influenced by the rifting event that accompanied the opening of the Ouachita depositional basin. Virtually every aspect of depositional change (especially thickness) of each unit pivoted on the aulacogen margin (Fig. 7). Only a fortuitous circumstance allowed these changes to be clearly documented: late Paleozoic deformation cutting across the aulacogen margin. Thus, exposures of the Arbuckle anticline within the aulacogen can be directly compared with less well-exposed strata outside the rift in the mildly deformed Hunton uplift. In no other area of the United States does a basement-rock contrast have such a continuing and profound effect on Paleozoic sedimentation. This inheritance continued to the end of the Paleozoic, when deformation centered on the weakened aulacogen, leaving the area underlain by Precambrian rocks uplifted but much less deformed.

REFERENCES CITED

Alberstadt, L. P., 1967, Brachiopod biostratigraphy of the Viola and "Fernvale" Formations (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 308 p.

_____1973, Articulate brachiopods of the Viola Formation (Ordovician) in the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Bulletin 117, 90 p.

Amsden, T. W.; and Barrick, J. E., 1986, Late Ordovician–Early Silurian strata in the central United States and

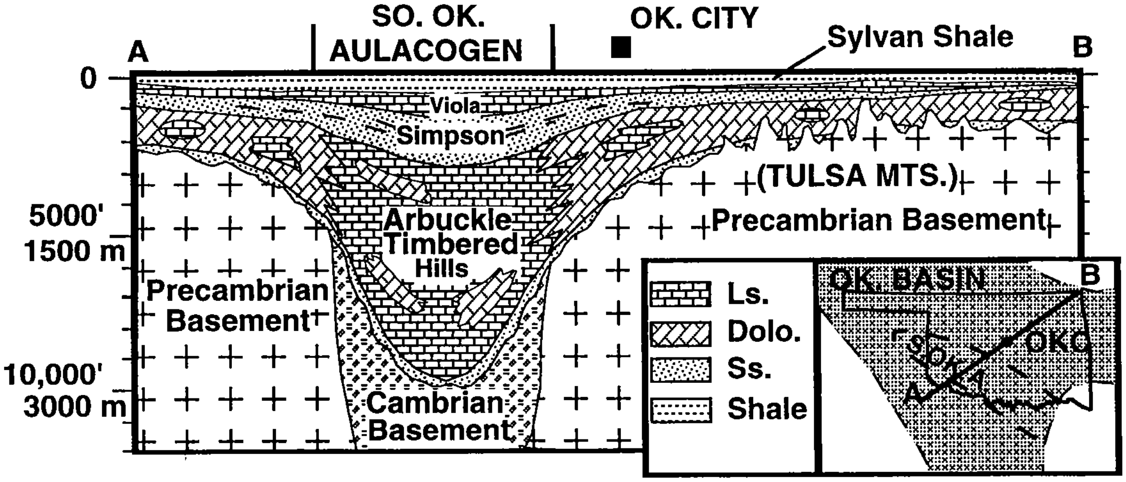


Figure 7. Summary cross section from Johnson (1991), showing the continued influence of the Cambrian rift zone on Late Cambrian and Ordovician sedimentation.

the Hirnantian Stage: Oklahoma Geological Survey Bulletin 139, 95 p.

Amsden, T. W.; and Sweet, W. C., 1983, Upper Bromide Formation and Viola Group (Middle and Upper Ordovician) in eastern Oklahoma: Oklahoma Geological Survey Bulletin 132, 76 p.

Brown, W. G., 1984, Washita Valley fault system: a new look at an old fault, in Borger, J. G., III (ed.), Technical proceedings of American Association of Petroleum Geologists, Mid-Continent Section, 1981 regional meeting: Oklahoma City Geological Society, p. 68–80.

Burruss, R. C.; and Hatch, J. R., 1989, Geochemistry of oils and hydrocarbon source rocks, greater Anadarko basin: evidence for multiple sources of oils and long-distance oil migration, *in* Johnson, K. S. (ed.), Anadarko basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 53–64.

Cook, T. D.; and Bally, Albert, 1975, Stratigraphic atlas of North and Central America: Princeton University Press, Princeton, New Jersey, 272 p.

Dake, C. L., 1921, The problem of the St. Peter sandstone: Missouri School of Mines and Metallurgy Bulletin, v. 6, 225 p.

Dapples, E. C., 1955, General lithofacies relationship of the St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Decker, C. E., 1935, Graptolites of the Sylvan shale of Oklahoma and the Polk Creek shale of Arkansas: Journal of Paleontology, v. 9, p. 697–708.

Decker, C. E.; and Merritt, C. A., 1931, The stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Denison, R. E.; and Ham, W. E., 1973, Stop 7, Oil Creek Sandstone (Middle Ordovician) in quarry of Pennsylvania Glass Sand Corp., *in* Ham, W. E. (ed.), Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, p. 49–50.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle and Simpson Groups, Cambrian and Ordovician, Oklahoma: A review of correlation tools and techniques available to the explorationist, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Donovan, R. N.; Busbey, A. B.; Bridges, S. S.; Collins, Kathryn; Ditzell, Curtis; Jenkins, Dee; and Wilhelm, Rosalyn, 1991, On three outcrops of the Simpson Group in the northwestern part of the Slick Hills, southern Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 85–97.

Finney, S. C., 1988, Middle Ordovician strata of the Arbuckle and Ouachita Mountains, Oklahoma: contrasting lithofacies and biofacies deposited in the southern Oklahoma aulacogen and Ouachita geosyncline, *in* Hayward, O. T. (ed.), Centennial field guide: Geological Society of America, South-Central Section, v. 4, p. 171–176.

Glaser, G. C., 1965, Lithostratigraphy and carbonate petrology of the Viola Group (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 197 p.

Ham, W. E., 1945, Geology and glass sand resources, central Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Bulletin 65, 103 p.

_____1955, Geology of the Arbuckle Mountain region: Oklahoma Geological Survey Guidebook 3, 61 p.

_____1969, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Guidebook 17, 52 p.

_____1973, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, 61 p.

Ham, W. E.; Denison, R. E.; and Merritt, C. A., 1964, Basement rocks and structural evolution of southern Oklahoma: Oklahoma Geological Survey Bulletin 95, 302 p.

Harland, W. B.; Armstrong, R. L.; Cox, A. V.; Craig, L. E.; Smith, A. G.; and Smith, D. G., 1990, A geologic timescale for 1989: Cambridge University Press, 262 p.

Hoffman, P.; Dewey, J. F.; and Burke, K., 1974, Aulacogens and their genetic relation to geosynclines with a Proterozoic example from Great Slave Lake, Canada, *in* Dott, R. H., Jr.; and Shaver, R. H. (eds.), Modern and ancient geosynclinal sedimentation: Society of Economic Paleontologists and Mineralogists Special Publication 19, p. 38–55.

Jenkins, W. A. M., 1970, Chitinozoans from the Ordovician Sylvan Shale of the Arbuckle Mountains, Oklahoma: Palaeontology, v. 13, p. 261–288.

Johnson, K. S., 1991, Geologic overview and economic importance of Late Cambrian and Ordovician rocks in Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 3–14.

Johnson, K. S.; Amsden, T. W.; Denison, R. E.; Dutton, S. P.; Goldstein, A. G.; Rascoe, Bailey, Jr.; Sutherland, P. K.; and Thompson, C. M., 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. [Reprinted in 1989 as Oklahoma Geological Survey Special Publication 89-2, 53 p.]

Kirkland, D. W.; Denison, R. E.; Summers, D. M.; and Gormly, J. R., 1992, Geology and organic geochemistry of the Woodford Shale in the Criner Hills and western Arbuckle Mountains, Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 38–69.

Lewis, R. D., 1982, Depositional environments and paleoecology of the Oil Creek Formation (Middle Ordovician), Arbuckle Mountains and Criner Hills, Oklahoma: University of Texas at Austin unpublished Ph.D. dissertation, 351 p.

Longman, M. W., 1976, Depositional history, paleoecology, and diagenesis of the Bromide Formation (Ordovician), Arbuckle Mountains, Oklahoma: University of Texas at Austin unpublished Ph.D. dissertation, 311 p.

_____1982a, Depositional setting and regional characteristics, *in* Sprinkle, James (ed.), Echinoderm faunas from the Bromide Formation, Middle Ordovician of Oklahoma: University of Kansas Paleontological Contributions, Monograph 1, p. 6–10.

_____1982b, Depositional environments, *in* Sprinkle, James (ed.), Echinoderm faunas from the Bromide Formation, Middle Ordovician of Oklahoma: University of Kansas Paleontological Contributions, Monograph 1, p. 17–29.

McPherson, J. G.; Denison, R. E.; Kirkland, D. W.; and Summers, D. M., 1988, Basal sandstone of the Oil Creek Formation in the quarry of the Pennsylvania Glass Sand Corporation, Johnston County, Oklahoma, *in* Hayward, O. T. (ed.), Centennial field guide: Geological Society of America, South-Central Section, v. 4, p. 165–170.

Newell, N. D.; Purdy, E. G.; and Imbrie, J., 1960, Bahamian oolitic sand: Journal of Geology, v. 68, p. 481–497.

Reid, F. S., 1980, Microfacies and diagenesis of the Viola Limestone (Ordovician) of south-central Oklahoma: Southern Methodist University unpublished M.S. thesis, 106 p.

Ross, R. J., Jr., and 27 others, 1982, The Ordovician System in the United States, correlation chart and explanatory notes: International Union of Geological Sciences Publication 12, 73 p.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

Smith, T. M., 1982, Sedimentology and diagenesis of the Viola Limestone (Middle Ordovician) in the northern Arbuckle Mountains, Oklahoma: Southern Methodist University unpublished M.S. thesis, 107 p.

Sprinkle James (ed.), 1982, Echinoderm faunas from the Bromide Formation, Middle Ordovician of Oklahoma: University of Kansas Paleontological Contributions, Monograph 1, 369 p.

Sykes, Michael; Puckette, Jim; Abdalla, Azhari; and Al-Shaieb, Zuhair, 1997, Karst development in the Viola Limestone in southern Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups (Middle and Upper Ordovician) in the southern Midcontinent: Oklahoma Geological Survey Circular 99 [this volume], p. 66–75.

Tanner, J. H., 1967, Wrench fault movements along Washita Valley fault, Arbuckle Mountain area, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 51, p. 126–141.

Wavrek, D. A., 1992, Characterization of oil types in the Ardmore and Marietta basins, southern Oklahoma aulacogen, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 185–195.

Major Simpson and Viola Oil and Gas Reservoirs in Oklahoma

Robert A. Northcutt
Independent Geologist
Oklahoma City, Oklahoma

Kenneth S. Johnson
Oklahoma Geological Survey
Norman, Oklahoma

ABSTRACT.—During Simpson deposition, in Middle and Late Ordovician time, high-purity silica sands were deposited over large areas of the Oklahoma basin. These sands, called the Oil Creek, McLish, Tulip Creek, Bromide, and "Wilcox" sands, are highly productive oil and gas reservoirs in a number of structural traps in Oklahoma. Giant fields that produce from these sands include the Oklahoma City, Golden Trend, and Sho–Vel–Tum fields. Other significant fields that produce from these reservoirs are on the Seminole uplift, in the Cleveland–McClain County area of central Oklahoma, and in the faulted fold belt of southern Oklahoma. Simpson sand reservoirs are of limited areal extent, but they are important enough to enable individual wells to produce more than 1 million barrels of oil. Oil and gas reservoirs also have been found in the Simpson dolomite above the Bromide sands.

Viola deposition in the Late Ordovician provided a thick sequence of carbonates. Viola oil and gas reservoirs generally are developed in fractured and solution-porosity carbonates on structural traps in the same areas as the Simpson reservoirs. Viola reservoirs yield significant oil and gas production, though generally less than the Simpson reservoirs. Additional stratigraphic-trap production from the Viola has been developed in the Marietta basin. In the Seminole area, the "Seminole" sand and "First Wilcox" sand are considered to be of Viola age and are highly productive. Other areas of "First Wilcox" sand production occur in central Oklahoma.

INTRODUCTION

Oklahoma is one of the leading petroleum-producing states in the nation. In 1992, it ranked fifth in crude-oil production, third in natural-gas production, and second in number of wells drilled. Much of the production comes from the Simpson and Viola Group rocks of Ordovician age. Unfortunately, the Simpson and Viola production commonly is commingled with production from other reservoirs in many major oil and gas fields, so precise data on Simpson and Viola yields commonly are not available.

This paper discusses the general geology of Middle and Upper Ordovician strata in Oklahoma, and then discusses the plays (types of traps) that have yielded the greatest amounts of oil and gas from these strata. An understanding of these major petroleum-producing plays should improve our search for new oil and gas fields or reservoirs, and should also improve our techniques of recovery from established fields.

GEOLOGIC SETTING

Oklahoma is a geologically complex region with a number of major depositional and structural basins, separated by orogenic uplifts and mountain ranges created during Pennsylvanian time (Fig. 1). However, the early and middle Paleozoic history of the State is tectonically and sedimentologically much simpler, and much of this discussion is modified from Johnson and Cardott (1992). Middle and Upper Ordovician strata in most parts of Oklahoma are characterized by interbedded sandstone and shale units and marine carbonates in the Simpson Group, and shallow-marine carbonates (limestone and dolomite) in the Viola Group. These strata were deposited in a broad, shallow epicontinental sea, the Oklahoma basin (Fig. 2), which extended across all parts of Oklahoma (except the Ouachita trough in the southeast) during Late Cambrian through Mississippian time (Johnson and others, 1988). Stratigraphic units deposited in most parts of the Oklahoma basin (Fig. 3) are remarkably widespread and laterally persistent, reflecting the stability of this part of the craton and the importance of epeirogenic (rather than orogenic) movements during early and middle Paleozoic time.

The depocenter for the Oklahoma basin was the southern Oklahoma aulacogen (SOA) (Fig. 2), a west-northwest-trending trough where subsidence and sediment accumulation were two to three times greater than on nearby shelf areas. The SOA comprised a region that now

---

Northcutt, R. A.; and Johnson, K. S., 1997, Major Simpson and Viola oil and gas reservoirs in Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 48–57.

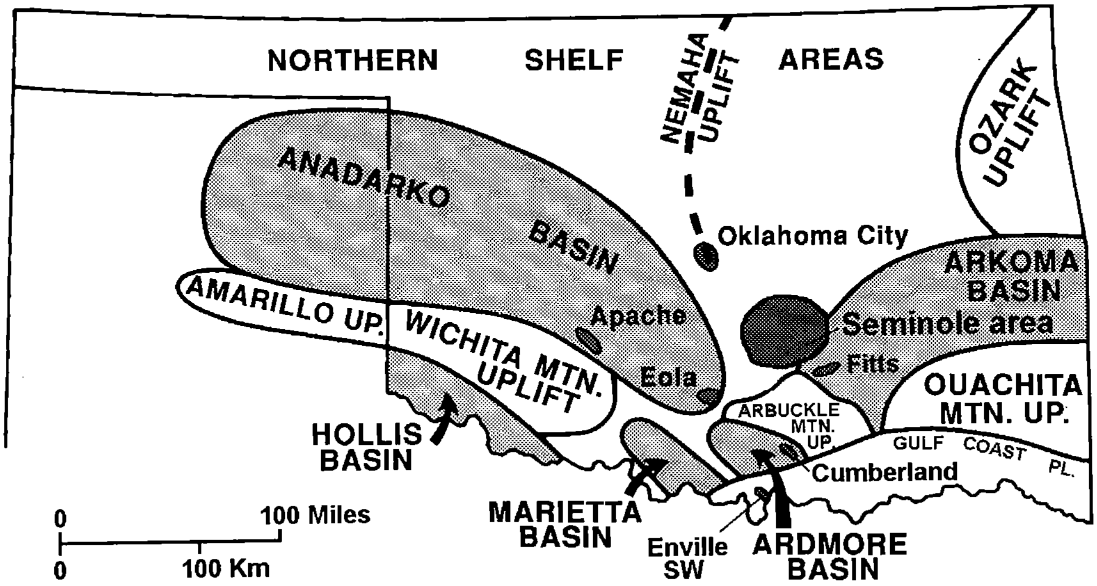


Figure 1. Major geological provinces of Oklahoma and selected Simpson and Viola oil and gas fields discussed in this paper (modified from Johnson, 1971).

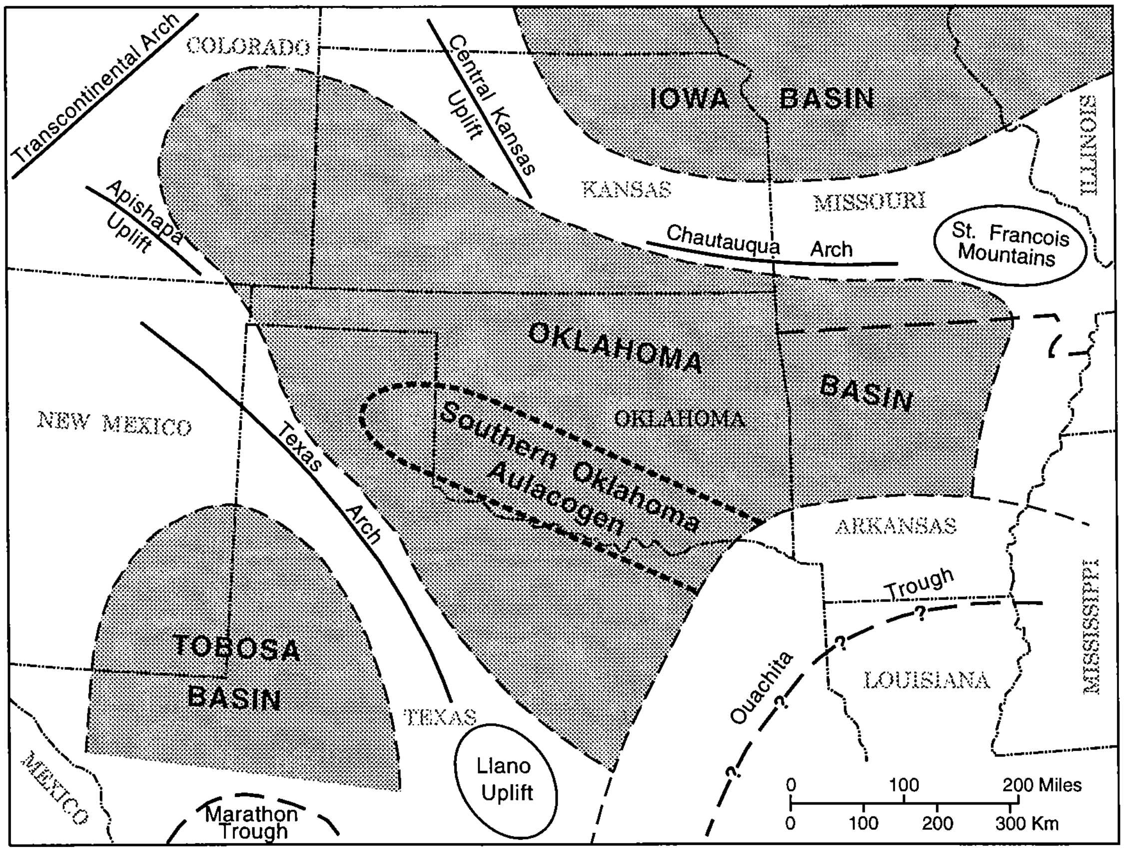


Figure 2. Map of southwestern United States showing outline of Oklahoma basin and other major features that existed in early and middle Paleozoic time (from Johnson and others, 1988).

			ARBUCKLE MTNS. SOUTHERN OKLA. (Surface)		CENTRAL OKLAHOMA (Subsurface)	
ORDOVICIAN	MIDDLE AND UPPER	CINCINNATIAN	SYLVAN SHALE		SYLVAN SHALE	
			WELLING FM	VIOLA GROUP	WELLING FM	"Fernvale"
		MOHAWKIAN	VIOLA SPRINGS FORMATION		VIOLA SPRINGS FORMATION	Trenton "First Wilcox" "Seminole"sand
		WHITEROCKIAN	BROMIDE FM TULIP CREEK FM MC LISH FM OIL CREEK FM JOINS FM	SIMPSON GROUP	SIMPSON GROUP	Simpson Dolomite "Second Wilcox"
	LOWER	IBEXIAN	ARBUCKLE GROUP			

Figure 3. Generalized correlation chart of Ordovician rock units in Oklahoma (modified from Johnson and others, 1988).

includes the Anadarko, Ardmore, and Marietta basins, along with the Arbuckle anticline, the Wichita Mountain uplift, and the Criner Hills. Schematic cross sections (Fig. 4) show the relationship of the restored strata in the Oklahoma basin at the end of Ordovician time.

Arbuckle Group strata, of Late Cambrian and Early Ordovician age, comprise a thick sequence of shallow-marine carbonates (limestone and dolomite) that underlie the Simpson Group (Figs. 4,5). The Arbuckle Group contains as much as 6,700 ft of limestone in the aulacogen and about 1,000–4,000 ft of dolomite in most shelf areas of the Oklahoma basin (Johnson and others, 1988).

Simpson Group strata in the Oklahoma basin are thick, cleanly washed quartzose sandstones interbedded with thick, shallow-water marine limestones and thin to moderately thick greenish-gray shales (Fig. 5). At the base of the Simpson Group are limestones of the Joins Formation: this unit is restricted to southern Oklahoma. The high-purity silica sands deposited over large areas of the Oklahoma basin are called the Oil Creek, McLish, Tulip Creek, Bromide, and "Wilcox" sands (Fig. 3). The total thickness of the Simpson Group typically is 300–2,000 ft in Oklahoma, and individual sandstones and limestones typically are 25–150 ft thick (Statler, 1965).

The Viola Group is a marine-limestone sequence that is widespread in the Oklahoma basin (Fig. 5). It contains chert at several stratigraphic levels and commonly is highly fossiliferous. Terrigenous detritus, organic matter, and graptolitic shale are present in the lower Viola, particularly in the aulacogen; these components decrease in abundance upward, and the strata grade into clean-washed skeletal limestones (Johnson and others, 1988). This vertical change indicates an upward decrease in water depth, and a corresponding increase in the energy level and aerobic activity of the depositional environment. A thick sandstone, up to 80 ft thick, is present in the basal part of the Viola in the Seminole area of central Oklahoma; it is a lateral facies change from the dolomite facies in the lower Viola (Cronenwett, 1956).

Overlying the Viola Group is the Sylvan Shale, a widespread green and greenish-gray shale in the Oklahoma basin; it is 300–400 ft thick in the aulacogen and 30–200 ft thick in most shelf areas. Locally abundant graptolites and chitinozoans, and well-developed laminations, suggest that the Sylvan was deposited in water deeper than other early Paleozoic formations (Ham, 1969).

Early and middle Paleozoic epeirogenic movements, accompanied by the deposition of relatively simple sequences of shelf carbonates (with some shales and sandstones) over vast regions in the Oklahoma basin, ended with a series of Pennsylvanian orogenic movements that subdivided the State into the tectonic provinces so easily recognized today (Fig. 1). First, an episode of Late Mississippian–Early Pennsylvanian epeirogenic uplift and erosion throughout most of the Oklahoma basin produced a widespread pre-Pennsylvanian unconformity, except where sedimentation apparently was continuous along the axis of the aulacogen (in the deep Anadarko and Ardmore basins). Then a series of orogenic pulses in the aulacogen and the Ouachita trough through Early, Middle, and Late Pennsylvanian time caused, or contributed to, the following: folding and thrusting of the Ouachita fold belt; raising of the Wichita, Criner, Arbuckle, Nemaha, and Ozark uplifts; and pronounced downwarping of the Anadarko, Ardmore, Marietta, Arkoma, and Hollis basins (Ham and Wilson, 1967; Johnson and others, 1988). This Pennsylvanian tectonic activity was also the major cause of development of structural traps that constitute the Simpson and Viola petroleum plays.

THE SIMPSON PLAY

High-purity Simpson sands are highly productive oil and gas reservoirs in structural traps that have minimal diagenetic influence. These structural traps are generally fault bounded, many with complex fault sequences, including thrusting. The dominant source of the hydrocarbons in these reservoirs is generally attributed to the Woodford Shale (Upper Devonian–Lower Mississippian). However, Carboniferous shales are also significant source rocks and may have contributed a later charge of hydrocarbons. Oil and gas production from Simpson sand reservoirs is widespread throughout the middle part of the State (Fig. 6). Giant fields (>500 MMBO [million barrels of oil] or 3.5 TCFG [trillion cubic feet of gas]) that contain significant Simpson sand reservoirs are the Oklahoma City field, Sho–Vel–Tum field, and the Golden Trend. Selected Simpson oil and gas fields discussed below, and listed in Table 1, include Oklahoma City, Eola, Cumberland, and Enville SW.

Oklahoma City Field, Oklahoma County

This giant oil field was discovered in December 1928 by drilling on a mapped surface anticline. Indian Territory Illuminating Oil Co. (I.T.I.O.) and Foster Petroleum Co. drilled their discovery well, the No. 1 Oklahoma City, in sec. 24, T. 11 N., R. 3 W. The Oklahoma City field produces from a large anticline near the south end of the Nemaha fault zone, on the east side of the Anadarko basin (Fig. 1). It is bounded on the east by a down-to-the-east normal fault with a maximum displacement of ~2,000 ft (Fig. 7). This anticlinal structure was exposed and truncated during post-Mississippian time, and remained exposed until Middle Pennsylvanian time, when it was buried by Desmoinesian sediments.

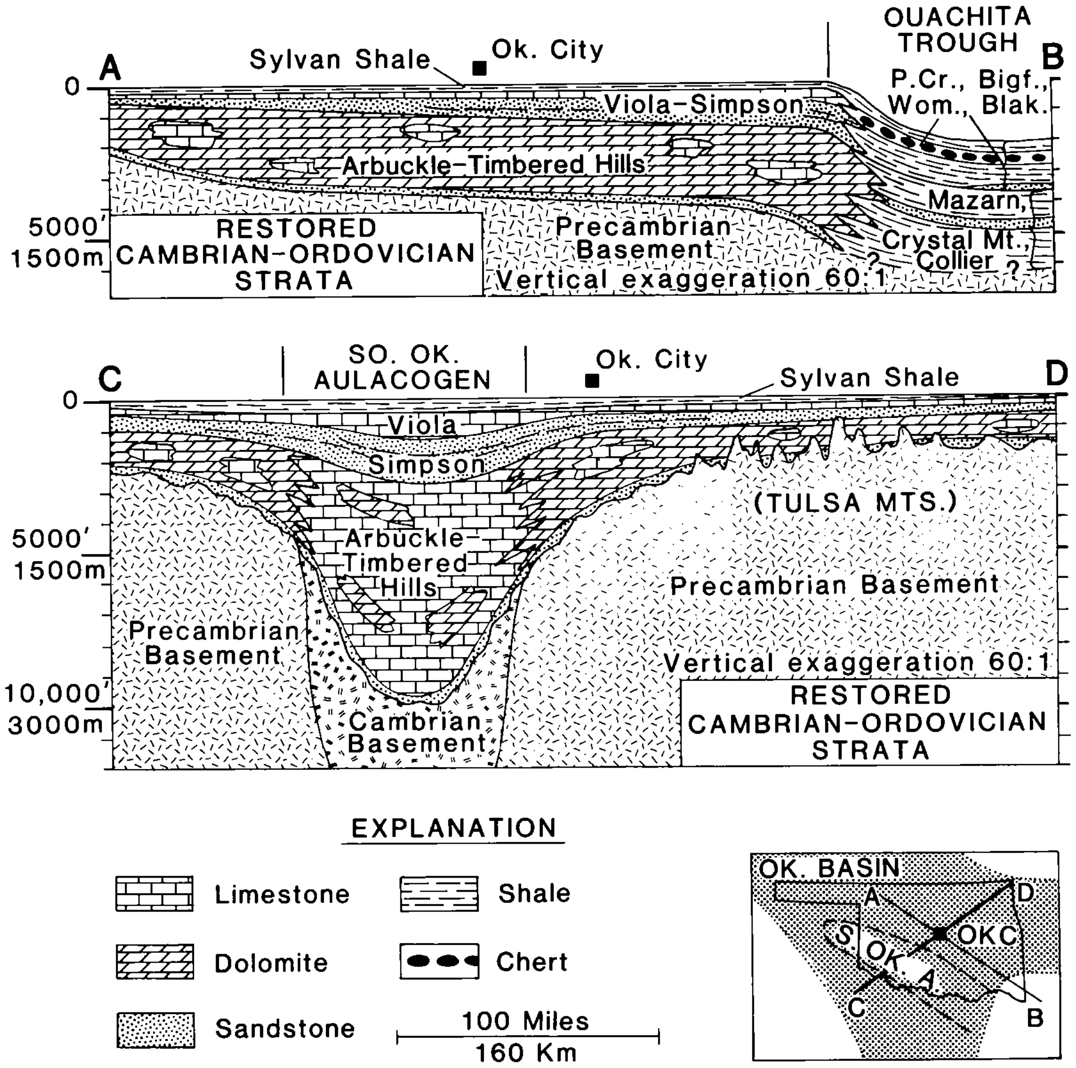


Figure 4. Schematic cross sections showing restored thickness of strata in Oklahoma at the end of Ordovician time, after deposition of the Sylvan Shale (from Johnson and Cardott, 1992).

The Oklahoma City field has 1,000 ft of producing closure on this structure. The Arbuckle dolomite, at the crest of the anticline, was the initial discovery reservoir, but this soon was surpassed by the more prolific and greater area of Simpson sand production. Average porosities of the Simpson sands are 18% in the Oil Creek, 15% in the McLish and Tulip Creek, and 21.5% in the "Wilcox." Initial flow rates from the Simpson sands were as high as 20,000 BOPD (barrels of oil per day) (Gatewood, 1970).

From its discovery through 1993, all reservoirs in the field have produced ~756.2 MMBO of oil and ~276.6 BCFG (Table 1). Gatewood (personal communication, 1978), using proprietary records, reported that Simpson production alone totaled 637.5 MMBO and 1.14 TCFG through June 1978; thus, Simpson production accounts for a significant part of the cumulative production of oil and gas from the Oklahoma City field. From 1979 to 1993, Simpson production (not counting Simpson oil and gas that was commingled with other production on some leases) was 5.3 MMBO and 10.5 BCFG (billion cubic feet of gas) (Table 1). Viola reservoirs in the Oklahoma City field have yielded oil and gas, but they are not significant (Table 1).

Eola Field, Garvin County

Eola field, now included with the older Robberson field to the south, has been renamed the Eola–Robberson field for nomenclature purposes. The original Eola field lies in southern Oklahoma at the southeast end of the Anadarko basin (Fig. 1). The discovery well for the field was the Sohio Petroleum Co. No. 1-A Howard, SE¼SE¼NW¼ sec. 17, T. 1 N., R. 2 W.; it was completed on January 23, 1947, in the Bromide sand at a depth

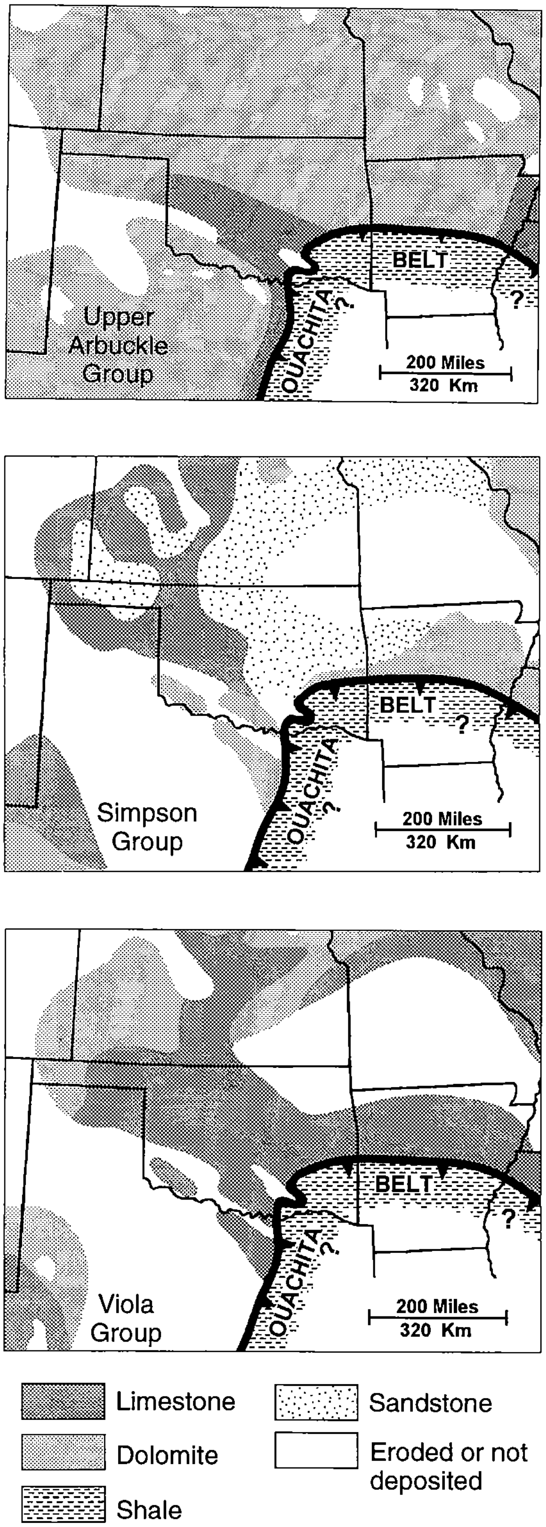


Figure 5. Major lithologies of Ordovician strata in the southern Midcontinent (modified from Ross, 1976). (Top map) Upper Arbuckle Group; Early Ordovician. (Middle map) Simpson Group; Middle and Late Ordovician. (Bottom map) Viola Group; Late Ordovician.

of 10,046 ft, with an initial flowing potential of 1,194 BOPD. Seismic surveys led to the discovery of the extremely complex thrusted and faulted anticline from which the field produces (Fig. 8). For a thorough study of this field and its structural complexity, the reader is referred to the articles by Swesnik and Green (1950) and Harlton (1964).

Development of this field established oil and gas production from other Simpson sands, as well as from shallower strata. Cumulative production from the Eola field at the end of 1993 was 121 MMBO and 234.4 BCFG.

Cumberland Field, Marshall and Bryan Counties

Cumberland field was discovered in March 1940 as a result of drilling on a seismic feature. The Pure Oil Co. No. 1 Little, the discovery well in the C W$\frac{1}{2}$NE$\frac{1}{4}$SE$\frac{1}{4}$ sec. 28, T. 5 S., R. 7 E., flowed oil from the Bromide sand during a drill-stem test (Cram, 1948). Cumberland field (Fig. 9) produces from a faulted anticline in the Ardmore basin, on the south flank of the Arbuckle Mountain system in southern Oklahoma. The Cumberland thrust fault, northeast of the Cumberland field, has over 7,000 ft of throw. Seismic closure on this structure is >1,000 ft, with 550 ft of effective closure at the Bromide sand level. Subsequent drilling established oil production from the Bromide, McLish, first Oil Creek, and second Oil Creek sands of the Simpson Group (Cram, 1948). Later development has established production from Arbuckle, Viola, Hunton, Woodford, and Sycamore reservoirs. The Bromide, McLish, and Oil Creek sands were unitized by the Oklahoma Corporation Commission in 1964. Cumulative field production was 72.3 MMBO and 44.5 BCFG through 1993 (Table 1).

Enville SW Field, Love County

The Texas Co. No. 1 Westheimer, NW$\frac{1}{4}$SW$\frac{1}{4}$NW$\frac{1}{4}$ sec. 17, T. 7 S., R. 3 E., was completed in March 1957, flowing 2,530 MCFGPD and 174 BOPD from the Oil Creek sand; it was the discovery well for the Enville SW field (Frederickson and others, 1965). This complexly faulted anticline is a southeast extension of the Criner Hills uplift (Fig. 10). A zone of reverse faulting separates the field into two pools or reservoirs. Northeast of the fault zone is the shallow Oil Creek sand gas reservoir; southeast of the fault zone and ~2,500 ft lower is the deep Oil Creek sand gas reservoir. The Oil Creek sand is the dominant producing reservoir in this field, which accounted for 10.5 MMBO and 203.5 BCFG through 1993 (Table 1). Other producing zones have contributed very little to the field production.

THE VIOLA PLAY

Thick sequences of carbonate rocks (limestone and dolomite) deposited during Viola time contain oil and gas reservoirs that generally are in the same structures that have Simpson production. The Viola carbonates, subjected to fracturing and dissolution during subsequent uplift and erosion, developed karst features and zones of vuggy porosity that now yield oil and gas. Viola oil and gas reservoirs in stratigraphic traps have been discovered in the Marietta basin of southern Oklahoma.

TABLE 1.—SELECTED OIL AND GAS FIELDS WITH SIMPSON OR VIOLA OIL AND GAS PRODUCTION

Field name; year discovered	Simpson[a] 1979–93 MMBO	Simpson[a] 1979–93 BCFG	Viola[a] 1979–93 MMBO	Viola[a] 1979–93 BCFG	Total field cumulative, 1993 MMBO	Total field cumulative, 1993 BCFG
Allen District, 1913[b]	0.6	0	0.2	0	169	8.3
Apache, 1941	5.4	2.8	0	0.4	67	4.6
Bowlegs, 1927[b]	2.0	0.2	0.1	0	165.5	1.3
Cumberland, 1940	2.3	10.3	<0.01	0.9	72.3	44.5
Earlsboro, 1926[b]	2.9	0.1	1.0	0.03	204.4	0.9
Enville SW, 1957	0.2	35.8	0.9	2.3	10.5	203.5
Eola–Robberson, 1947	8.6	39.5	<0.01	0	121	234.4
Fitts, 1933	0.3	0	0.3	2.1	204.9	50
Little River, 1927[b]	0.9	0.3	0.5	<0.01	138.7	17.1
Oklahoma City, 1928	5.3	10.5	0.6	4.6	756.2	276.6
Seminole, 1926[b]	1.3	<0.1	0.8	0.1	192.4	11.4
St. Louis, 1926[b]	7.0	2.2	3.7	1.3	240.5	24.1

[a] Seminole area.

[b] Commingled leases are not included.

Sources: Natural Resources Information System, University of Oklahoma (NRIS); Petroleum Data Systems, Dwights Energydata, Inc. (PDS); Petroleum Information Corporation (PI).

In the lower Viola, a facies change from carbonate to sandstone occurs in central Oklahoma, where the prolific "Seminole" and "First Wilcox" sands were deposited. These sands, discovered in the 1920s, were first thought to be the prolific Simpson sands, but later work by Cronenwett (1956) and Jordan (1957) established them as Viola sands.

The highly petroliferous Woodford Shale is the apparent hydrocarbon source rock for the Viola reservoirs, although there is evidence for an indigenous source in some fields. Viola reservoirs, though not as prolific as those of the Simpson, produce substantial quantities of oil and gas throughout the middle part of the State (Fig. 11). Selected fields with significant Viola reservoirs are listed in Table 1. Recorded Viola production from 1979 to 1993 was not very much, because most Viola production was depleted before data on reservoir production were being kept in official State records. Selected Viola oil and gas fields discussed below are Seminole area (consisting of several fields), Fitts, and Apache. All these fields also produce from the Simpson, but they are included here because they have yielded significant oil and gas production from Viola reservoirs.

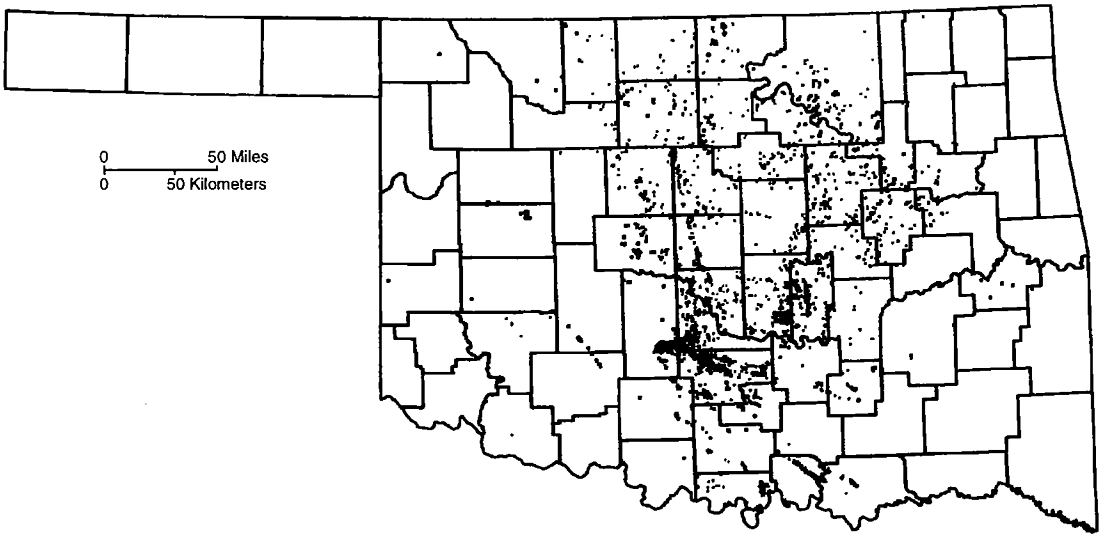


Figure 6. Map of Oklahoma showing distribution of leases producing oil and/or gas from Simpson Group reservoirs from 1979 to 1993. Data are from Natural Resources Information System (NRIS), University of Oklahoma.

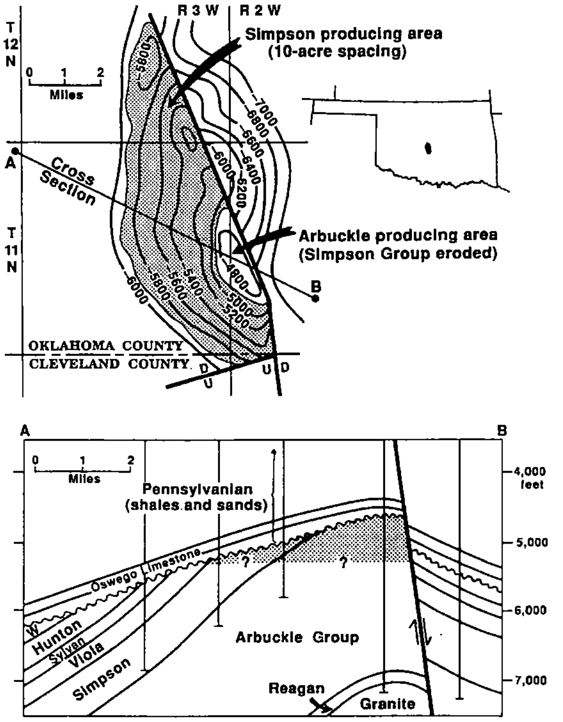


Figure 7. Structure map and cross section of the Oklahoma City field, Oklahoma County (modified from Gatewood, 1970). (Above) Structure map depicting the top of the Arbuckle Group (contour interval is 200 ft). Producing area of Simpson Group sands is shown by stipple pattern. (Below) Cross section *A–B*.

Seminole Area, Pottawatomie and Seminole Counties

The Seminole area is a structurally high feature that covers parts of 25 square townships, mostly in Pottawatomie and Seminole Counties. Within this area are several faulted structural traps with oil and gas fields producing from reservoirs of Pennsylvanian to Ordovician age (Fig. 12). Six of the fields in the Seminole area—Allen district, Bowlegs, Earlsboro, Little River, Seminole, and St. Louis—were discovered between 1913 and 1927 on the basis of surface mapping (Levorsen, 1929). In 1926, deeper drilling led to discoveries from the "Seminole" sand in the Seminole and Earlsboro fields. Deeper drilling in Bowlegs field during early 1927 discovered "Seminole" sand production. The initial discovery of the Little River field, later in 1927, was from the "Seminole" sand (Levorsen, 1929). These six structural traps contributed cumulative production of ~1,110.5 MMBO and 63.1 BCFG through 1993 (Table 1). Viola dolomite and Simpson sand reservoirs also have produced oil and gas, but the amounts from these and other formations were not separately reported for the fields prior to 1979.

Fitts Field, Pontotoc County

In July 1933, the E. H. Moore No. 1 Wirick, SE¼SE¼ SW¼ sec. 29, T. 2 N., R. 7 E., was completed as the discovery well for the Fitts field. The original discovery, completed in the Hunton, was followed with the Bromide sand discovery a year later (Mann, 1958). Viola production was combined with that of the Bromide sand for spacing purposes, so specific characteristics and performance of the Viola reservoir are difficult to obtain. The Fitts field lies in the Franks graben at the western limit of the Arkoma basin. Surface mapping of a structural nose led to the discovery of this large faulted anticline that forms the trap for the Fitts field oil and gas reservoirs (Fig. 13). Cumulative production from all reservoirs in the Fitts field was 204.9 MMBO AND 50 BCFG through 1993 (Table 1).

Apache Field, Caddo County

The Apache field was discovered May 30, 1941, by the Texas Co. No. 2 Z. N. Smith, SE¼NW¼ sec. 2, T. 5 N., R. 12 W.; the discovery well was completed in a Bromide sand that had an initial flowing potential of 10,000 BOPD. A reflection-seismograph survey in the area led to the discovery of this overturned and thrust-faulted anticline (Fig. 14). The No. 1 Z. N. Smith well, drilled earlier in the same section, had been completed as a dry hole; after drilling through the thrust fault, and then encountering the Simpson sands and ending in a repeated Viola section, the well had only shows of oil and gas (Scott, 1945). Subsequent development in the Apache

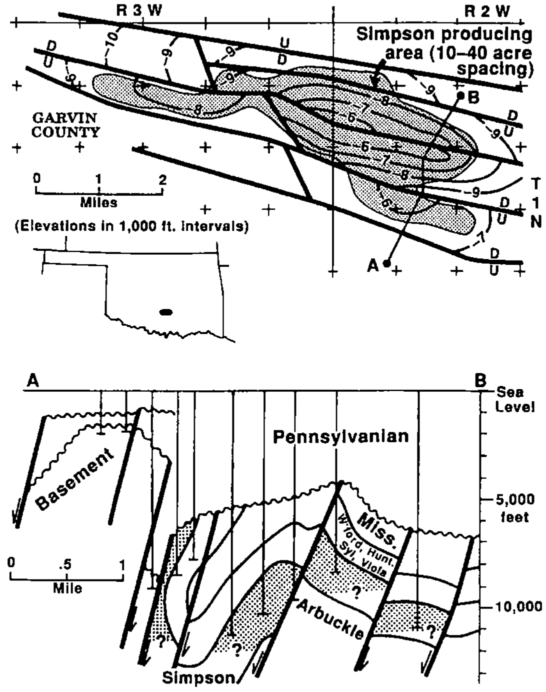


Figure 8. Structure map and cross section of the Eola field, Garvin County (modified from Harlton, 1964). (Above) Structure map depicting the top of the Viola Group (contour interval is 1,000 ft). Producing area of Simpson Group sands is shown by stipple pattern. (Below) Cross section *A–B* showing complex faulting, with Robberson horst to south (left). Stipple pattern indicates zone of Simpson sand production.

field led to discovery of the Viola reservoir in this structural trap. Cumulative production from the Apache field was 67 MMBO and 4.6 BCFG through 1993 (Table 1). Production from the Viola reservoir, developed in 1960, was commingled with Bromide production until 1967. Therefore, the amount of oil and gas produced from the Viola is unknown; it is a significant quantity, but the reservoir was depleted before 1979.

SUMMARY AND CONCLUSIONS

Reservoirs in the Simpson play have produced significant amounts of oil and gas in Oklahoma. These sandstone reservoirs are structurally trapped in anticlines that commonly are complexly faulted. The Woodford Shale is the primary source of the petroleum, although younger source rocks are known to have contributed petroleum to some of these reservoirs.

Reservoirs in the Viola play are generally found in conjunction with the Simpson producing structures, where fracturing and dissolution porosity have enhanced the reservoir properties of the carbonate rock. Stratigraphic traps in the Viola, which have been diagenetically enhanced by dissolution, produce oil and gas in limited areas in Oklahoma.

The prolific reservoirs in the Simpson and Viola plays were discovered during the time when rapid development of the major fields caused many similar, but smaller, reservoirs to be overlooked or inadequately evaluated. The opportunity to discover these bypassed Simpson and Viola reservoirs still exists. And with careful investigation of these older fields, using new reservoir-characterization techniques and borehole-logging tools to identify areas of compartmentalization, it should be possible to extend reservoirs that are within or adjacent to the known fields.

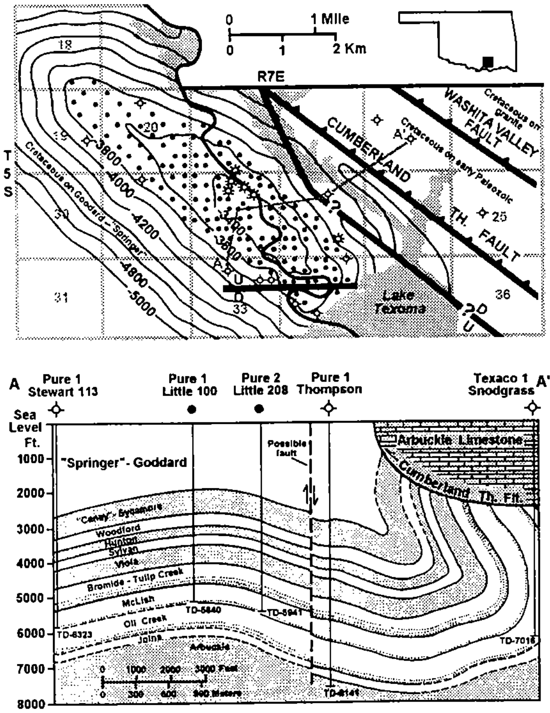


Figure 9. Structure map and cross section of the Cumberland field, Marshall and Bryan Counties (modified from Huffman and others, 1987). (Above) Structure map depicting the top of the Viola Group (contour interval is 200 ft). (Below) Cross section *A–A′*, showing relationship of the field to the Cumberland thrust fault to the northeast.

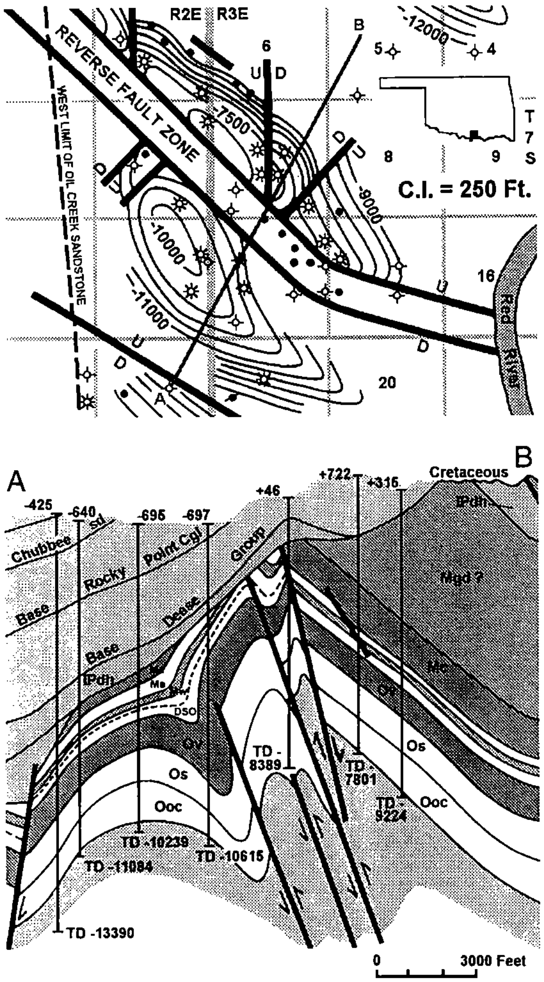


Figure 10. Structure map and cross section of the Enville SW field, Love County (modified from Frederickson and others, 1965). (Above) Structure map depicting the top of the Oil Creek sandstone of the Simpson Group (contour interval is 250 ft). The reverse fault zone divides the field into two reservoirs. (Below) Cross section *A–B* illustrates the complexity of this field.

REFERENCES CITED

Cram, I. H., 1948, Cumberland oil field, Bryan and Marshall Counties, Oklahoma, *in* Howell, J. V. (ed.), Structure of typical American oil fields: American Association of Petroleum Geologists, v. 3, p. 341–358.

Cronenwett, C. E., 1956, A subsurface study of the Simpson Group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

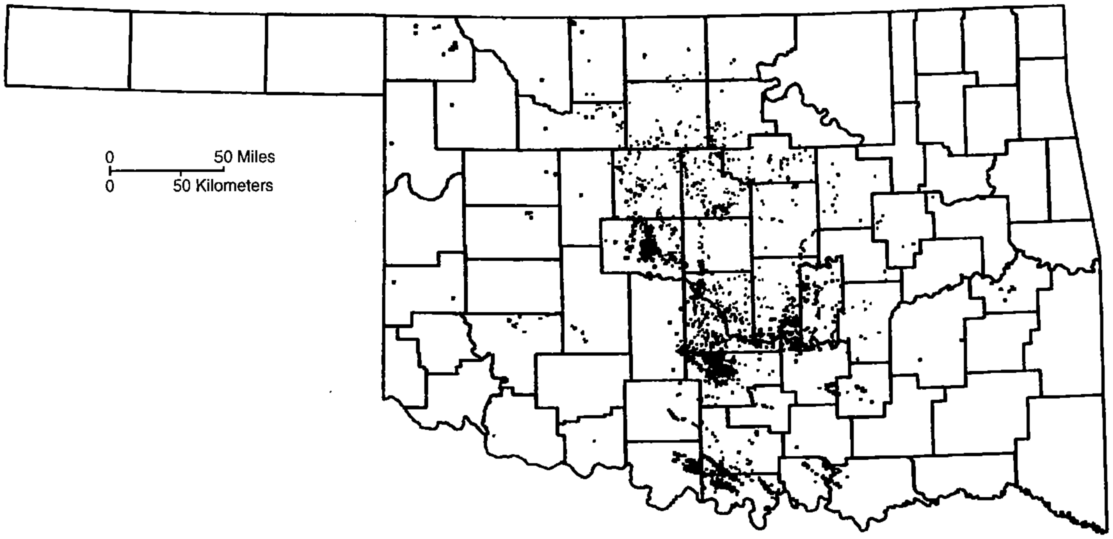


Figure 11. Map of Oklahoma showing distribution of leases producing oil and/or gas from Viola Group reservoirs from 1979 through 1993. Data are from Natural Resources Information System (NRIS), University of Oklahoma.

Fenstermaker, C. D., 1991, Structure map of the First Bromide sand: Oklahoma City Geological Society, Shale Shaker, v. 42, no. 3, cover.

Frederickson, E. A.; Redman, R. H.; and Westheimer, J. M., 1965, Geology and petroleum of Love County, Oklahoma: Oklahoma Geological Survey Circular 63, 91 p.

Gatewood, L. E., 1970, Oklahoma City field—anatomy of a giant, *in* Halbouty, M. T. (ed.), Geology of giant petroleum fields: American Association of Petroleum Geologists Memoir 14, p. 223–254.

Ham, W. E., 1969, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Guidebook 17, 52 p.

Ham, W. E.; and Wilson, J. L., 1967, Paleozoic epeirogeny and orogeny in the central United States: American Journal of Science, v. 265, p. 332–407.

Harlton, B. H., 1964, Tectonic framework of Eola and Southeast Hoover oil fields and West Timbered Hills area, Garvin and Murray Counties, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1555–1567.

Huffman, G. G.; Hart, T. A.; Olson, L. J.; Currier, J. D.; and Ganser, R. W., 1978, Geology and mineral resources of Bryan County, Oklahoma: Oklahoma Geological Survey Bulletin 126, 108 p.

Johnson, K. S., 1971, Introduction, guidelines, and geologic history of Oklahoma, *Book I of* Guidebook for geologic field trips in Oklahoma: Oklahoma Geological Survey Educational Publication 2, 15 p.

Johnson, K. S.; and Cardott, B. J., 1992, Geologic framework and hydrocarbon source rocks of Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 Symposium: Oklahoma Geological Survey Circular 93, p. 21–37.

Johnson, K. S.; Amsden, T. W.; Denison, R. E.; Dutton, S. P.; Goldstein, A. G.; Rascoe, Bailey, Jr.; Sutherland, P. K.; and Thompson, C. M., 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. [Reprinted in 1989 as Oklahoma Geological Survey Special Publication 89-2, 53 p.]

Jordan, Louise, 1957, Subsurface stratigraphic names of Oklahoma: Oklahoma Geological Survey Guidebook 6, 220 p.

Levorsen, A. I., 1929, Greater Seminole district, Seminole and Pottawatomie Counties, Oklahoma, *in* Structure of typical American oil fields: American Association of Petroleum Geologists, v. 2., p. 315–361.

Mann, Wallace, 1958, Subsurface geology of the Franks graben, Pontotoc and Coal Counties, Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 8, no. 5, p. 11–28.

Ross, R. J., Jr., 1976, Ordovician sedimentation in the western United States, *in* Bassett, M. G. (ed.), The Ordovician System: proceedings of a Palaeontological Association symposium, Birmingham, University of Wales Press and National Museum of Wales, Cardiff, p. 73–105.

Scott, V. C., 1945, Apache oil pool, Caddo County, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 29, p. 100–105.

Statler, A. T., 1965, Stratigraphy of the Simpson Group in Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 162–211.

Swesnik, R. M.; and Green, T. H., 1950, Geology of Eola area, Garvin County, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 34, p. 2176–2199.

Wheeler, R. E., 1953, Structural map of Oklahoma: Privately published, 1 sheet, scale 1:380,160 (approximately 1 in. = 32,000 ft).

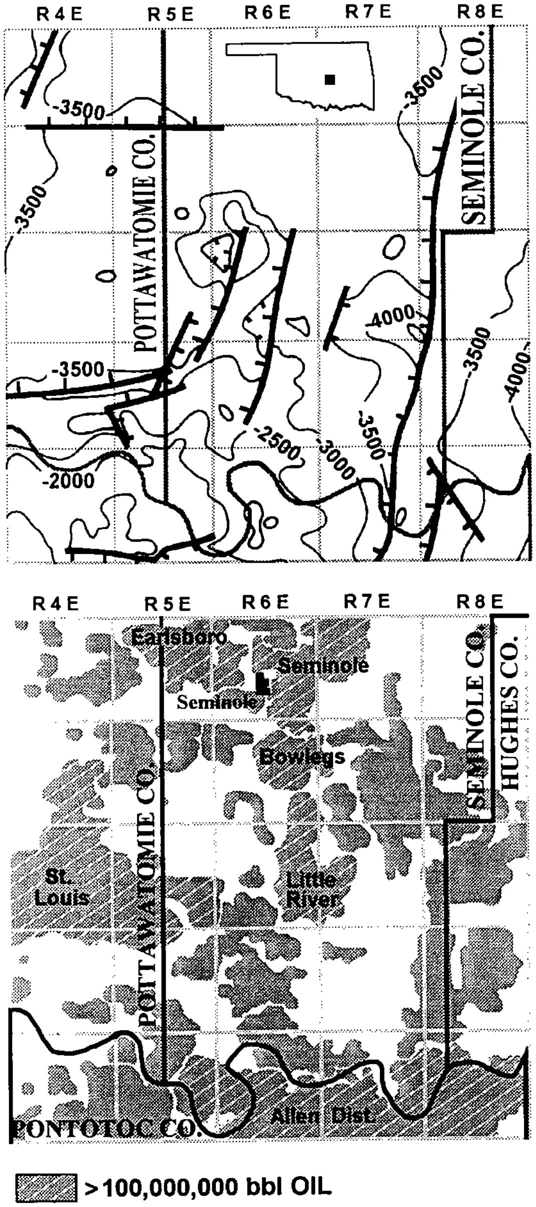


Figure 12. Structure map and producing fields in the Seminole area, mainly in Pottawatomie and Seminole Counties. (Above) Structure map depicting the top of the Viola Group in the Seminole area (contour interval is 500 ft) (modified from Wheeler, 1953). (Below) Oil and gas field map. Fields that have produced >100 MMBO are indicated by cross hatching. Field data were plotted by Natural Resources Information System (NRIS), University of Oklahoma.

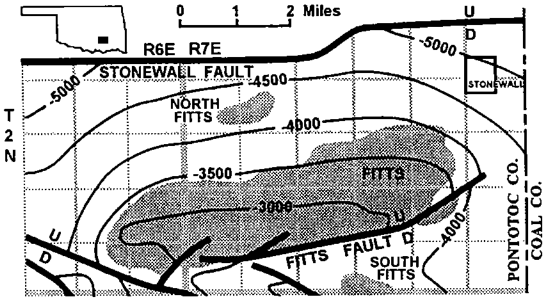


Figure 13. Structure map depicting the top of the Viola Group in the Fitts field, Pontotoc County (contour interval is 500 ft) (modified from Mann, 1958). Producing area is shown by stippled pattern.

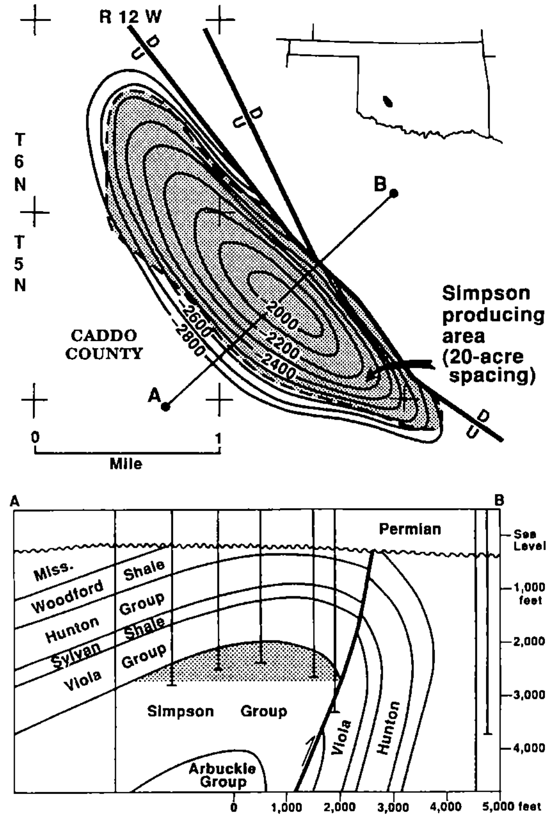


Figure 14. Structure map (modified from Fenstermaker, 1991) and cross section (modified from unpublished map by Fenstermaker) of the Apache field, Caddo County. (Above) Structure map depicting the top of the Bromide sand of the Simpson Group (contour interval is 100 ft). Producing area of Simpson sands shown by stipple pattern. (Below) Cross section *A–B* shows the northwest-bounding thrust fault.

Oklahoma Geological Survey Circular 99, 1997

Stratigraphy and Petroleum Potential of the Simpson and Viola (Ordovician) in Kansas and Nebraska

Marvin P. Carlson
Nebraska Geological Survey
Lincoln, Nebraska

K. David Newell
Kansas Geological Survey
Lawrence, Kansas

ABSTRACT.—Rocks of Middle and Late Ordovician age in the Kansas–Nebraska area are a part of the major marine transgression termed the Tippecanoe by Sloss in 1963. This stratigraphic interval contains a basal clastic unit (Simpson), a middle carbonate (Viola), and an upper shale (Maquoketa). However, in the more stable interior of the North American continent, both the lower and upper clastic units contain more carbonate. In southern Kansas, the Simpson Group consists of interbedded sand and shale and contains multiple zones of production. In northern Kansas and Nebraska, the Simpson consists of a basal sand (St. Peter) and an overlying sequence of shale and carbonate; only the basal sand has been productive. The Viola Formation is composed of limestone and dolomite with variable amounts of chert. Oil accumulations in the carbonate reservoirs in the Forest City basin (northeastern Kansas, southeastern Nebraska, and northwestern Missouri) have been attributed to the Viola. However, regional correlation suggests that they occur in the carbonate facies of the Maquoketa Formation. Cumulative production through 1992 for the 276 fields producing solely from the Simpson, Viola, and Maquoketa in Kansas, Nebraska, and Missouri was 92 million barrels of oil and 24 billion cubic feet of gas. Another 460 fields in Kansas (1.972 billion barrels and 672 billion cubic feet cumulative production) have a component of Middle and Upper Ordovician production. Additional exploration should extend production into areas of similar depositional and tectonic history.

INTRODUCTION

Oil production in the Kansas–Nebraska region has been established in all four of the major subdivisions of the Ordovician—the upper Arbuckle, the Simpson, the Viola, and the Maquoketa. This paper focuses on the Viola and Simpson rocks of Kansas and Nebraska. It should be kept in mind that the Viola, in oil-field terminology, commonly includes the carbonate facies that occurs in the Maquoketa of northern Kansas and Nebraska. Viola production in southeastern Nebraska and northeastern Kansas is from rocks equivalent to the lower Maquoketa as the term is applied in the type locality in Iowa.

Figure 1 illustrates the correlation of the Middle and Upper Ordovician in the Kansas–Nebraska area. The relationships are not precise, because contradictory evidence and uncertainty in lithologic and biostratigraphic correlation characterize many of these units. Facies variation in the Ordovician rocks is important in providing reservoirs for oil and gas accumulation. These facies are due both to original depositional patterns and to later diagenesis, particularly dolomitization. Maps are presented that illustrate some of these broad patterns, noting the influence of the Transcontinental arch. However, as has been noted (Carlson, 1989, 1993), this feature is neither a true uplifted arch nor a continuous structure across the continent. It is actually composed of a series of smaller positive features with intervening sags or lower lying areas that accommodated seaways at various times during the Ordovician. It is important to distinguish local paleotopography and source areas when interpreting depositional environments during a specific portion of geologic time.

PRODUCTIVE UNITS

Simpson Group

A transgressive unconformity separates the Middle Ordovician Simpson Group from the underlying Arbuckle Group. Figure 2 illustrates the paleogeography and dominant lithologies deposited during Chazyan–Blackriverian time. During this period, the trend of the Transcontinental arch was probably a low-lying peninsula separating waters of the encroaching Tippecanoe transgression. Westerly-moving trade winds near the equator aided longshore currents in moving sand off the

Carlson, M. P.; and Newell, K. D., 1997, Stratigraphy and petroleum potential of the Simpson and Viola (Ordovician) in Kansas and Nebraska, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 58–64.

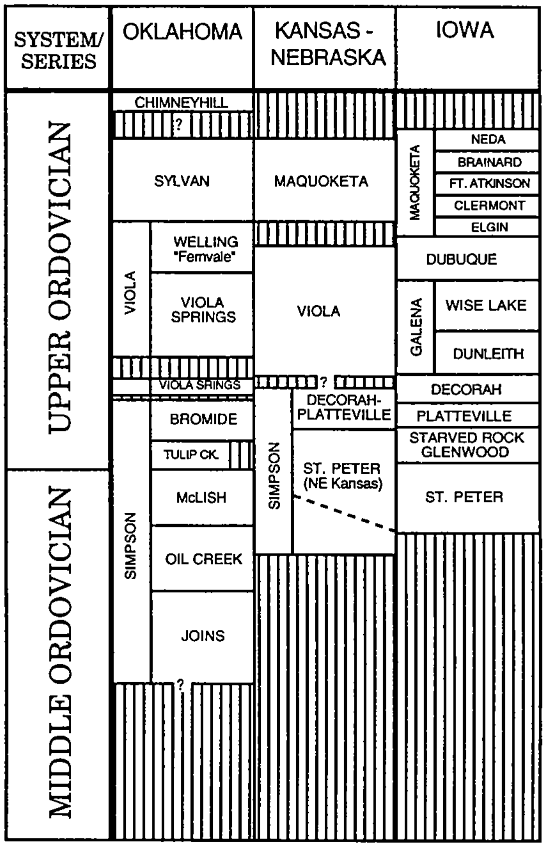


Figure 1. General correlation chart of the Middle and Upper Ordovician in the Kansas–Nebraska region (Oklahoma: Ireland, 1965; Amsden, 1980; Amsden and Sweet, 1983) (Iowa: Witzke, 1980).

Precambrian shield into the Midcontinent. Note that carbonate deposition characterizes the generally tectonically quiescent eastern flank of the North American craton.

In the southern Midcontinent, initial deposition of the Simpson began in Oklahoma, and the seas gradually spread northward into Kansas. The basal member of the Simpson, the St. Peter Sandstone, is the unit of interest in petroleum exploration. The thickness and sand/shale ratio in the St. Peter both vary according to local paleotopography on the underlying Arbuckle and regional facies patterns. Figure 3 shows the current thickness and distribution of the Simpson in Kansas and Nebraska. In southern Kansas, the Simpson consists of interbedded sands and shale that contain multiple zones of production. In northern Kansas and Nebraska, only the basal Simpson unit, the St. Peter Sandstone, is productive.

Fields producing from the Simpson (Fig. 4) occur under three general conditions: (1) in traps, mostly stratigraphic, that are subcrops sealed under Pennsylvanian rocks around the Central Kansas uplift, on the Pratt anticline in southern Kansas, and along the Nemaha uplift in eastern Kansas; (2) in traps, mostly stratigraphic, that are subcrops sealed under the Chattanooga Shale of Devonian–Mississippian age in southeastern Kansas; and (3) in structural traps in normal stratigraphic sequence below the Viola in the Forest City basin of eastern Kansas and Nebraska and the Sedgwick basin in south-central Kansas.

Viola Formation

The Late Ordovician seas probably constituted one of the more extensive inundations of the North American continent. Figure 5 illustrates the preserved dominant lithologies deposited during Rocklandian–Maysvillian time. Continued transgression of the sea resulted in Viola carbonates overstepping earlier siliciclastic deposition of the Simpson and St. Peter in western Kansas. The Transcontinental arch was breached by the seas at this time and was probably expressed as a series of islands. The Kansas–Nebraska region was a part of the broad carbonate shelf that encompassed central North America. Later diagenesis has altered the original fossiliferous limestone fabric with the addition of significant amounts of dolomite and chert. Only minor amounts of clastic material are found in the Viola Formation.

The current distribution and thickness of the Viola are shown in Figure 6. The carbonate facies of the lower Maquoketa is included in these thicknesses in northern Kansas and Nebraska. Erosion during pre-Devonian, pre-Mississippian, and pre-Pennsylvanian time removed the Viola from large areas of the Kansas–Nebraska region. Studies of the conodonts from several cores of the Viola in Kansas by Sweet (1992) indicated that, in any particular area, the Viola Formation is very incomplete. However, lithostratigraphic correlations in Nebraska by Carlson (1970, 1990) and in Kansas by Newell (1997) have defined consistent lithologic subdivisions of the Viola Formation in their areas of study.

Viola oil accumulations (Fig. 7) are of two major types: (1) structural–stratigraphic traps on the Central Kansas and Nemaha uplifts where the Viola is overlain unconformably by the Chattanooga Shale (Devonian–Mississippian) or Pennsylvanian shale, and (2) structural traps in the Forest City basin of Kansas, Nebraska, and Missouri, and in south-central Kansas where the Viola carbonates are overlain by the shale facies of the Sylvan–Maquoketa.

The oil accumulations in the Forest City basin have been attributed to the Viola. However, regional correlations (Witzke, 1983; Carlson, 1990) suggest that these accumulations occur in the carbonate facies of the Maquoketa. The lithology of the Viola reservoirs is similar across the Kansas–Nebraska–Missouri area as shown by the studies of Caldwell and Boeken (1985) in the Forest City basin and by St. Clair (1985) in southern Kansas. Both studies describe the Viola as bioclastic limestone (largely echinoderm fragments) that has been variably dolomitized. Figure 8 illustrates several Viola (Maquoketa) core sections from southeastern Nebraska. Selective dolomitization has localized productive porosity. Total permeability has been increased by vertical fracturing.

PRODUCTION

Table 1 provides a summary of oil production from the Maquoketa, Viola, Simpson, and from multipay combinations of these zones for Kansas, Nebraska, and

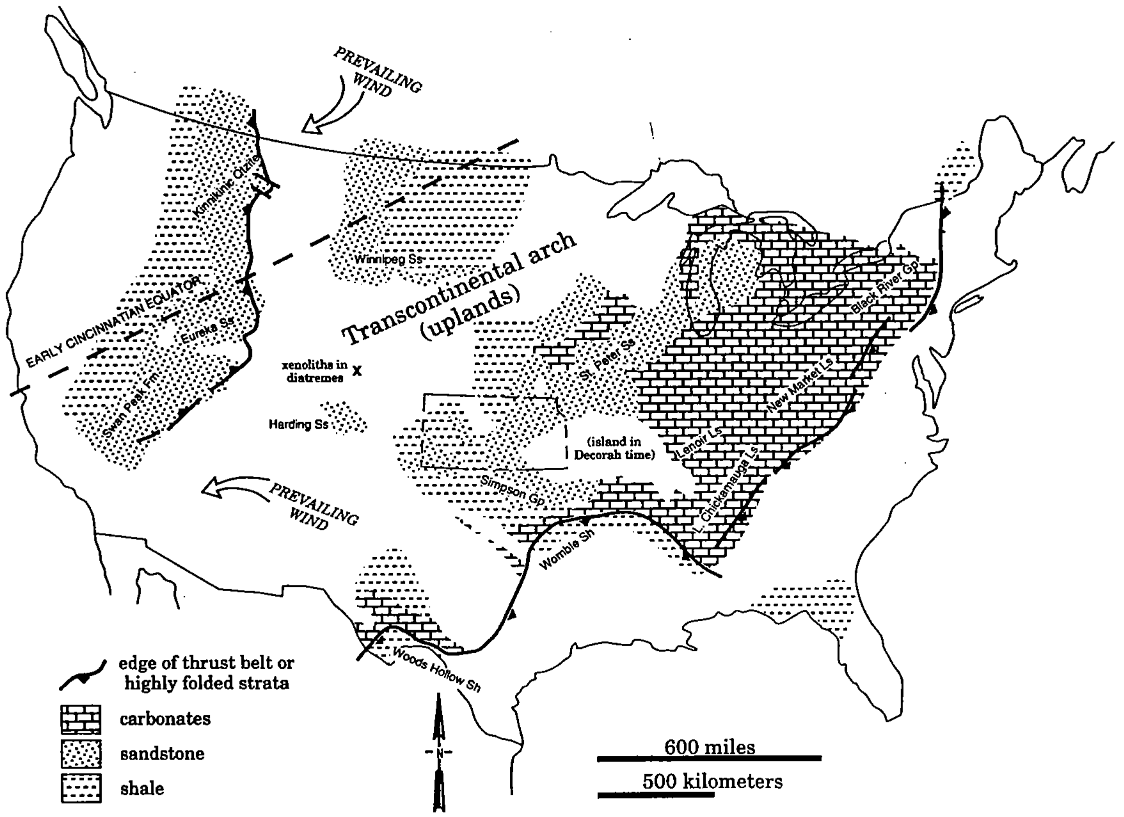


Figure 2. Paleogeography and preserved dominant lithofacies deposited during Chazyan–Blackriverian time (modified from Cook and Bally, 1975; Ross, 1976). Dashed line in center is outline of Kansas.

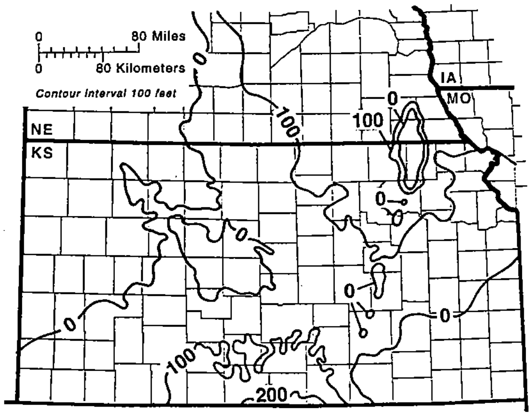


Figure 3. Thickness of the Simpson Group in Kansas and Nebraska. (modified from Cole, 1975; Carlson, 1970, 1990).

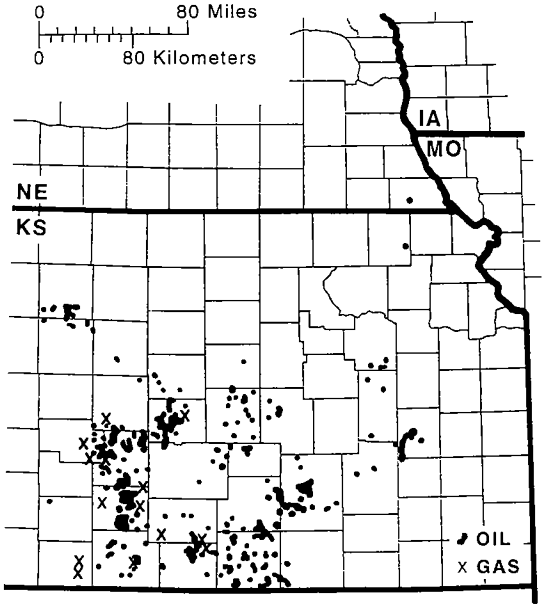


Figure 4. Map showing oil fields producing from the Simpson Group in Kansas and Nebraska.

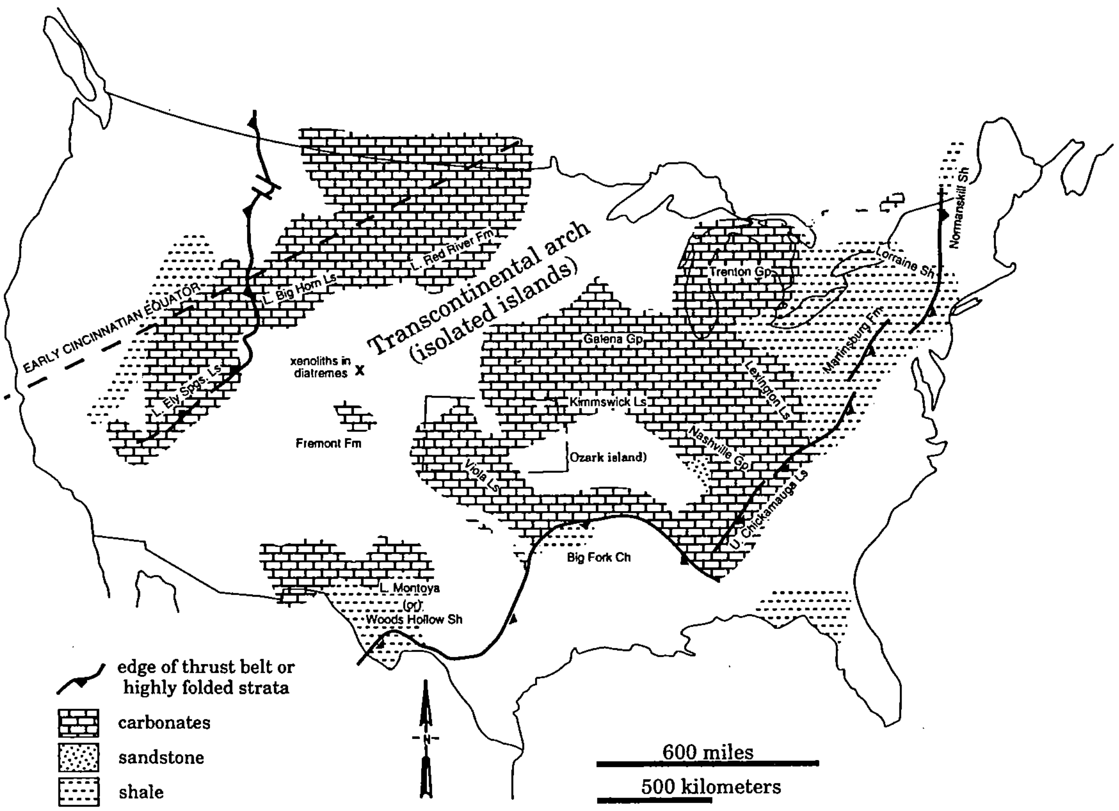


Figure 5. Paleogeography and preserved dominant lithofacies deposited during Rocklandian–Maysvillian time (modified from Cook and Bally, 1975; Ross, 1976; Keith, 1988). Dashed line in center is outline of Kansas.

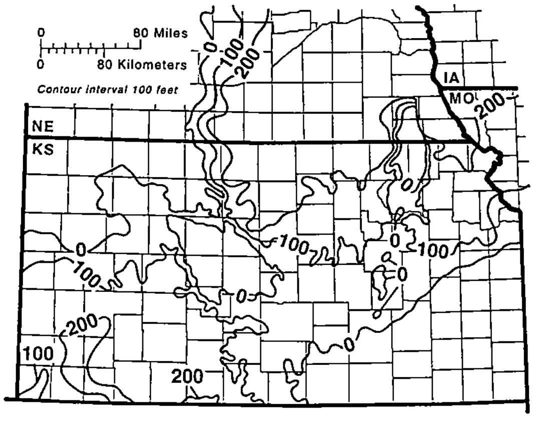


Figure 6. Thickness of the Viola in Kansas and Nebraska (includes the carbonate facies of the lower Maquoketa) (modified from Cole, 1975; Carlson, 1970, 1990).

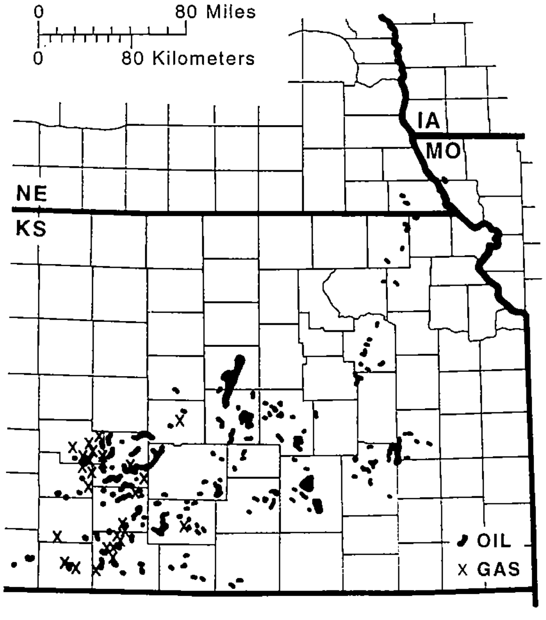


Figure 7. Map showing oil fields producing from the Viola and/or Maquoketa.

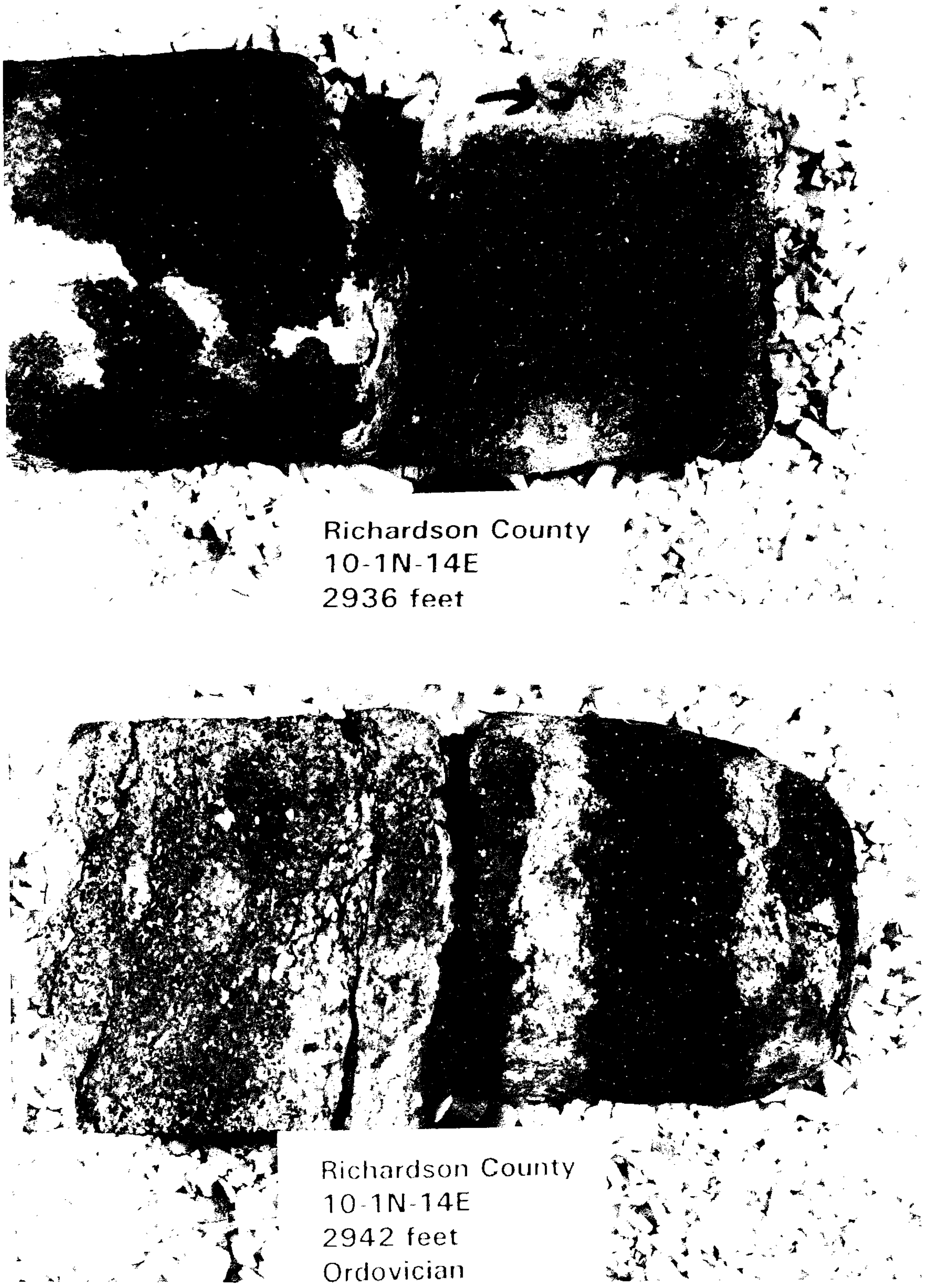


Figure 8. Cores from the Viola (Maquoketa) in southeastern Nebraska, illustrating the selective porosity and oil saturation resulting from dolomitization. (Skelly No. 1 Wiltse well, sec. 10, T. 1 N., R. 14 E.; Richardson County, Nebraska.)

TABLE 1.—OIL PRODUCTION FROM THE MAQUOKETA, VIOLA, AND SIMPSON[a]

State/producing zone	Number of fields	Number of wells, 1992	Cumulative barrels through 1992
Kansas			
Maquoketa	4	36	5,817,000
Viola	93	145	15,608,000
Simpson	120	174	25,584,000
Ordovician multipay	21	178	14,078,000
Nebraska			
Viola/Simpson	2	6	1,078,000
Missouri			
Viola	1	7	130,000

[a] Does not include multipay fields producing from other than Ordovician.

Missouri. Cumulative production through 1992 from these zones for all three states was 92 million barrels of oil and 24 billion cubic feet of gas. Another 460 fields in Kansas that are multipay, and which have some component of Middle and Upper Ordovician reservoirs, produced nearly 2 billion barrels of oil and 672 billion cubic feet of gas. Nearly all fields have significant amounts of produced water.

SUMMARY

Several broad stratigraphic patterns were described that control the occurrence of much of the oil accumulation in Middle and Upper Ordovician rocks. Figure 9 is a map of the Kansas–Nebraska area summarizing these stratigraphic relationships to indicate areas of potential stratigraphic traps in the Simpson and Viola. A large number of Simpson fields relate to the overlap of Pennsylvanian shale around the Central Kansas uplift. Additional potential exists as this unconformable relationship continues northward along the eastern flank of the Cambridge arch into Nebraska and along the western flank of the Nemaha uplift in both Kansas and Nebraska. A similar potential for additional stratigraphic traps under rocks of Pennsylvanian age exists for the Viola–Maquoketa interval northward from the present producing trends along the Cambridge arch and Nemaha uplift.

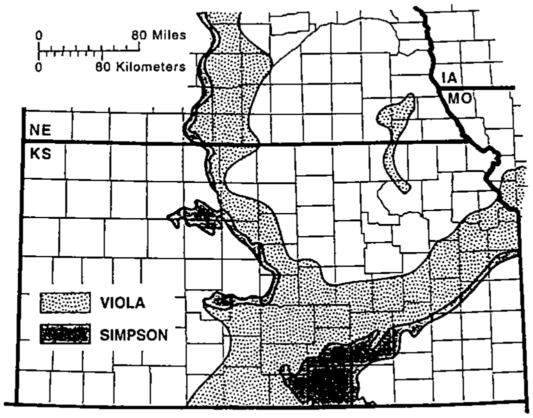


Figure 9. Map illustrating areas of potential stratigraphic traps in the Simpson and Viola of Kansas and Nebraska.

Potential still exists for additional stratigraphic traps under the Chattanooga Shale in south-central and southeastern Kansas within the Simpson and Viola. The possibility exists for additional structural traps in Ordovician rocks along the current trend in the Forest City basin northward across Kansas and Nebraska and into Missouri. Because the Nemaha uplift is a mid-Pennsylvanian feature, similar depositional and diagenetic features are common to the Ordovician rocks of the Forest City and Salina basins. By analogy, productive structures like those of the Forest City basin may be present within the Salina basin of Kansas and Nebraska. The variety of productive trends established in these states in rocks of Middle and Late Ordovician age are still worthy of continued exploration.

REFERENCES CITED

Amsden, T. W., 1980, Hunton Group (Late Ordovician, Silurian, and Early Devonian) in the Arkoma basin of Oklahoma: Oklahoma Geological Survey Bulletin 129, 136 p.

Amsden, T. W., and Sweet, W. C., 1983, Upper Bromide Formation and Viola Group (Middle and Upper Ordovician) in eastern Oklahoma: Oklahoma Geological Survey Bulletin 132, 76 p.

Caldwell, C. D.; and Boeken, R., 1985, Wireline log zones and core description of upper part of the Middle Ordovician Viola Limestone, McClain and McClain SW fields, Nemaha County, Kansas, *in* Watney, W. L.; Doveton, J. H.; and Walton, A. W. (compilers), Core studies in Kansas—sedimentology and diagenesis of economically important rock strata in Kansas: Kansas Geological Survey Subsurface Geology Series 6, p. 17–35.

Carlson, M. P., 1970, Distribution and subdivision of Precambrian and Lower and Middle Paleozoic rocks in the subsurface of Nebraska: Nebraska Conservation and Survey Division Report of Investigations 3, 25 p.

______1989, Transcontinental arch—backbone of North America [abstract]: 28th International Geological Congress Abstracts, v. 1, p. 238.

______1990, Petroleum potential of Lower and Middle Paleozoic rocks in the Nebraska portion of the Midcontinent: Transactions Vol. of 1989 American Association of Petroleum Geologists, Midcontinent Section Meeting, 12 p.

______1993, Transcontinental arch of North America—backbone or skeleton? [abstract]: Geological Society of America Abstracts, v. 25, p. A-471.

Cole, V. B., 1975, Subsurface Ordovician–Cambrian rocks in Kansas: Kansas Geological Survey Subsurface Geology Series 2, 18 p.

Cook, T. D., and Bally, A. W. (eds.), 1975, Stratigraphic atlas of North and Central America: Princeton University Press, Princeton, New Jersey, 272 p.

Ireland, H. A., 1965, Regional depositional basin and correlation of Simpson Group, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 74–89.

Keith, B. D., 1988, Regional facies of Upper Ordovician Series of eastern North America, *in* Keith, B. D. (ed.), The Trenton Group (Upper Ordovician Series) of eastern North America; deposition, diagenesis, and petroleum: American Association of Petroleum Geologists Studies in Geology 29, p. 1–16.

Newell, K. D., 1997, Correlation and distribution of reservoir and sealing facies within the Viola Formation, south-central Kansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 247–259.

Ross, R. J., 1976, Ordovician sedimentation in the western United States, *in* Bassett, M. G. (ed.), The Ordovician System: Proceedings of a Palaeontological Association symposium, Birmingham, University of Wales Press and National Museum of Wales, Cardiff, p. 73–105.

Sloss, L. L., 1963, Sequences in the cratonic interior of North America: Geological Society of America Bulletin, v. 74, p. 93–113.

St. Clair, P. N., 1985, Core studies of the Viola Limestone in Barber and Pratt Counties, *in* Watney, W. L.; Doveton, J. H.; and Walton, A. W. (compilers), Core studies in Kansas—sedimentology and diagenesis of economically important rock strata in Kansas: Kansas Geological Survey Subsurface Geology Series 6, p. 8–16.

Sweet, W. C., 1992, Middle and Late Ordovician conodonts from southwestern Kansas and their biostratigraphic significance, *in* Chaplin, J. R.; and Barrick, J. E. (eds.), Special papers in paleontology and stratigraphy: a tribute to Thomas W. Amsden: Oklahoma Geological Survey Bulletin 145, p. 181–191.

Witzke, B. J., 1980, Ordovician paleogeography of the Transcontinental arch, *in* Fouch, T. D.; and Magathan, E. R. (eds.), Paleozoic paleogeography of the west-central United States, Paleogeography Symposium 1: Society of Economic Paleontologists and Mineralogists, Rocky Mountain Section, Denver, p. 1–18.

______1983, Ordovician Galena Group in Iowa subsurface, *in* Delgado, D. J. (ed.), Ordovician Galena Group—deposition, submarine and later diagenesis, and paleoecology: Society of Economic Paleontologists and Mineralogists, Great Lakes Section, 13th Annual Field Conference Guidebook, p. D1–D26.

Oklahoma Geological Survey Circular 99, 1997

Tobosa Basin–Related Sedimentation of the Simpson–Viola in Trans-Pecos Texas

David V. LeMone
University of Texas at El Paso
El Paso, Texas

ABSTRACT.—The Middle Ordovician Simpson Group is observed to crop out only in the Baylor Mountains of west Texas, which lie directly northeast of Van Horn, Texas. The section consists of 35 m of fine-grained sandstones and argillaceous dolomites. The Simpson is probably restricted to the area east of the Diablo platform in the classical Tobosa basin. The Simpson is recognized in the subsurface of the Délaware basin, the Central basin platform, and the Midland basin of the Permian basin. Its presence is critical as a seal and potential source bed for the underlying Ellenburger karst reservoirs.

The Upper Ordovician (Cincinnatian) Montoya Group is equivalent to the Upper Viola Group and the Sylvan Shale of southern Oklahoma. In the El Paso border region, the Montoya consists of three formations: Upham, Aleman, and Cutter, which range in age from mid-Edenian to mid-Richmondian, determined primarily on the basis of conodont, nautiloid, and brachiopod studies. The basal, bioturbated dolomitic Upham Formation ranges in thickness from 30 to 31 m and is middle to upper Edenian. Some sections north and northwest of the Trans-Pecos region contain a thin, basal sandstone unit (Cable Canyon). The conformably overlying Aleman Formation consists of 46–54 m of carbonates with a distinctive black ribbon chert member. It is Edenian–Maysvillian in age, with the boundary approximately 10 m above the base. The uppermost Cutter Formation is a 49–51-m thin-bedded cherty dolomite unit of Maysvillian–Richmondian age, with the boundary about 13 m above the base. In the Franklin Mountains, the post-Montoya disconformity between the Montoya and the overlying Silurian Fusselman represents about 5 million years.

LeMone, D. V., 1997, Tobosa basin–related sedimentation of the Simpson–Viola in Trans-Pecos Texas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 65.

Karst Development in the Viola Limestone in Southern Oklahoma

Michael Sykes
Jim Puckette
Azhari Abdalla
Zuhair Al-Shaieb
Oklahoma State University
Stillwater, Oklahoma

ABSTRACT.—Karstic and paleokarstic features are evident in the Viola Group carbonates in southern Oklahoma. Paleokarstic episodes are identified by evidence of dissolution, collapse, and deposition including conduit-filling breccias, enlarged fractures, and channels. Active karstic processes are enlarging fractures and forming caverns.

Viola cores contain evidence of intra-Viola or pre-Sylvan uplift and meteoric diagenesis. Cavern-fill parabreccias, collapse breccias, crackle breccias, vugs, and solution-enlarged fractures are the most common dissolution features in the Viola Springs Formation. Fernvale (Welling) cores contain solution-enlarged fractures, vugs with sediment infill, channels, and a pre-Sylvan exposure surface. Following deposition of the Sylvan and the Hunton Group, the Viola was exhumed in some areas and likely underwent additional meteoric diagenesis. During the Pennsylvanian orogeny, the Viola was subjected to additional stress-induced dissolution and fractured.

Surface karstic and paleokarstic features are useful in interpreting the tectonic evolution of southern Oklahoma. Evidence from the Lawrence Quarry and I-35 outcrops suggests that sulfide mineralization accompanied the migration of hydrocarbons into Viola reservoirs. Asphalt-saturated collapse breccia/cave fill in the I-35 exposure contains noticeable pyrite mineralization. Solution cavities in oil-saturated Viola from the Lawrence Quarry contain sulfides that include pyrite, chalcopyrite, and sphalerite.

INTRODUCTION

Karstic processes and their resulting paleokarstic features are of increasing interest to the petroleum industry because of their importance as reservoirs. This study focuses on the identification of focused-flow rock fabrics that result from carbonate dissolution. It describes the paleokarstic and karstic features in outcrop and core, and interprets their origin. The area of study was restricted to the Arbuckle Mountain region, where the most extensive outcrops and available cores are evident (Fig. 1). All cores analyzed are stored in the Oklahoma Geological Survey Core and Sample Library. A total of 24 Viola cores were examined for evidence of paleokarstic features. A subset of seven cores displayed characteristic karstic features and were examined in detail. Viola outcrops identified on a geologic map of the Arbuckle uplift (Ham and others, 1954) were examined. Twelve outcrops having key karstic features were described. Field observations and core data were used to determine the timing of karstic events.

VIOLA STRATIGRAPHY

The Viola Group is Upper to Middle Ordovician (Black Riverian to Richmondian age) (Taff, 1902). The group consists predominantly of limestones that were deposited on a carbonate ramp. The lower part of the Viola Group, the Viola Springs Formation, is generally considered a deeper water carbonate (Grammer, 1983; Gentile, 1984; Reid, 1980). Lithofacies changes within the Viola Springs suggest cyclic sea-level changes within an overall shallowing trend (Becker, 1988). The Welling (Fernvale) Formation is dominantly a pelmatozoan grainstone that indicates deposition within a shallow subtidal to intertidal setting. Stratigraphic nomenclature and references to previous investigations of the Viola Group are shown in Figure 2.

KARSTIC PROCESSES

Karstification is a process that produces characteristic landforms and surface features. Esteban and Klappa (1983) described karst as a diagenetic facies that over-

---

Sykes, Michael; Puckette, Jim; Abdalla, Azhari; and Al-Shaieb, Zuhair, 1997, Karst development in the Viola Limestone in southern Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 66–75.

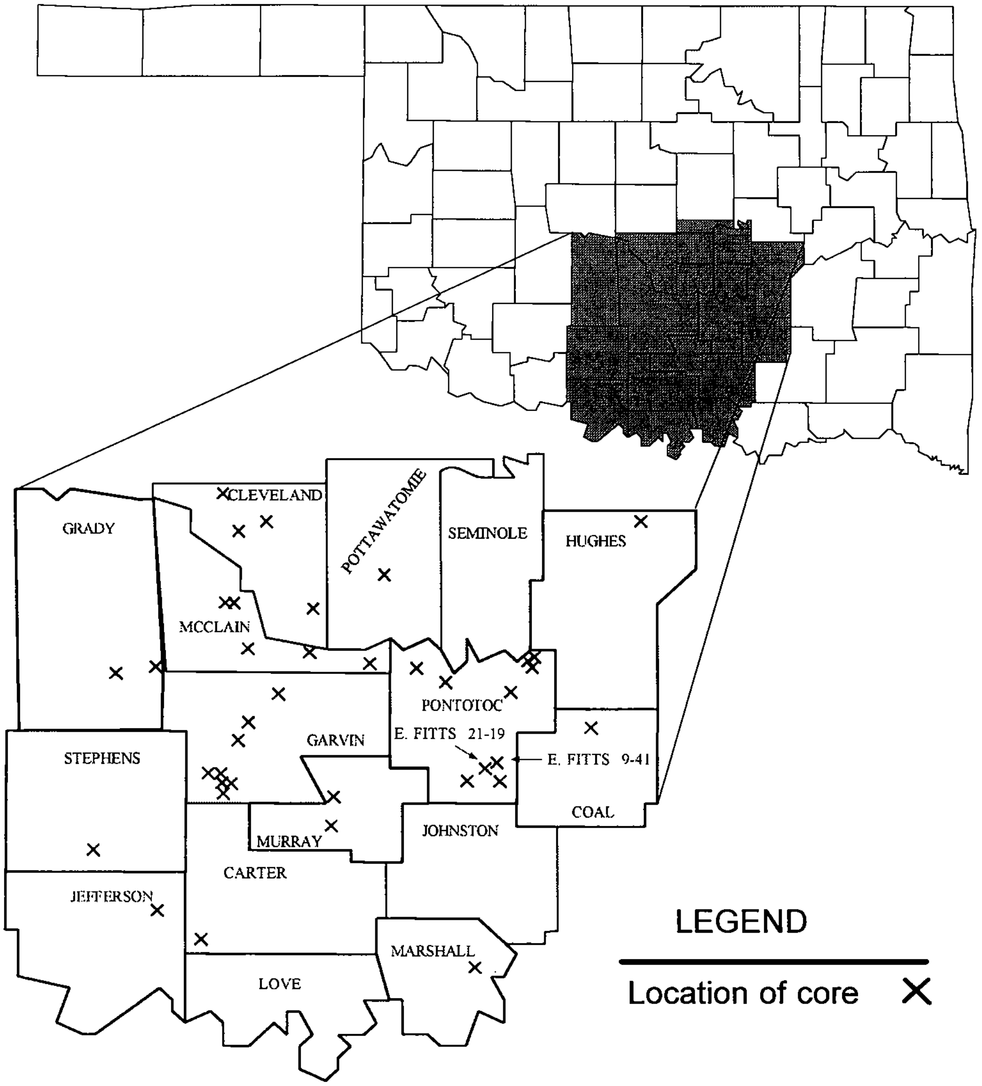


Figure 1. Map showing location of wells in the vicinity of the Arbuckle Mountains from which Viola Group cores were studied.

prints subaerially exposed carbonate. Paleokarst is ancient karst that was buried by younger sediments or otherwise removed from the sphere of active meteoric diagenesis (Choquette and James, 1988). Karst is controlled by the dissolution and migration of calcium carbonate in meteoric waters and can occur in a wide variety of climatic and tectonic settings. Characteristic features (Lynch, 1990; Choquette and James, 1988) of karst are summarized in Table 1.

Karst Profile.—The input and output of ground water in a carbonate terrain is influenced by the general architecture of the rock—matrix porosity, mineral composition, degree of fracturing, and thickness of beds (Matthews, 1992). Additional variables include environmental factors—climate, vegetation, position of the water table, and duration of exposure to meteoric water. The primary agent controlling the depth and style of karstic influences within a rock is the water-flow pattern. Porous rocks are characterized by diffuse flow and interparticle porosity. Water flow and dissolution in low-porosity rocks are focused along fractures or bedding planes.

Under ideal conditions, the formation of karst progresses through three stages of development: (1) initial stage, (2) main stage, and (3) final stage (Al-Shaieb, 1988). Initial-stage karst is controlled primarily by phreatic processes and results in the formation of conduits and enlarged fractures. As the dissolving solution moves through the rock and enlarges cavities, flow becomes more turbulent and erosive. Features formed during the initial stage may remain open or may fill with cave mud or other sediments. Main-stage karst is a complicated stage, as it involves both phreatic and vadose processes. This stage results in the formation of well-

Table 1.—Characteristic Features of Karst

Stratigraphic

<u>Karst landforms</u>

- Unconformities
- Truncated shallowing-upward cycles

Macroscopic

<u>Surface Karst</u>

- Karren
- Paleosols
- Caliche
- Nonsedimentary channels
- Lichen structures
- Boxwork structure
- Mantling nonsedimentary breccias

<u>Subsurface</u>

- Caves and dissolution channels
- Stratiform breccias
- Collapse structures
- Solution-enlarged fractures
- Sediment in nondepositional cavities
- Breccias in irregular bodies
- Speleothems

Macroscopic

- Eluviated soil in small pores
- Etched carbonate cements
- Reddened and micritized grains
- Meniscus. pendant, and needle-fiber vadose cements
- Subisopachous columnar-calcite phreatic cement
- Extensive dissolution, or enlargement of fabric-selective pores

(After Lynch, 1990, and Choquette and James, 1988.)
Note: Bullets designate features discernible in core.

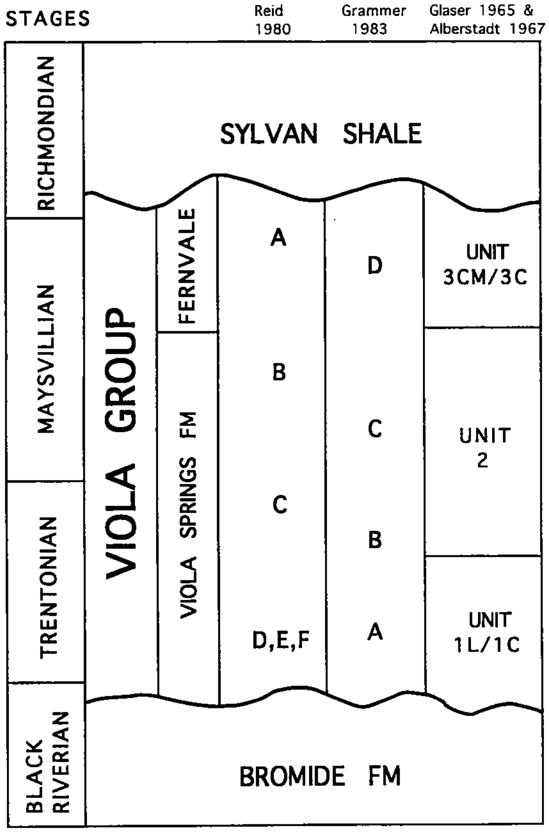


Figure 2. Generalized stratigraphic nomenclature of the Viola Group. Descriptions of the designated units (A, B, 1, 2, etc.) are available in the referenced studies.

developed single- and multi-level conduits. As the water table drops, upper levels in the vadose zone may become decorated with speleothems, while dissolution is actively occurring in the phreatic zone below. Cave-roof collapse and sediment infill are common during this stage. The final stage of karst is destructional. The passages and conduits of the cave system have collapsed, and the landscape is covered with remnants of the cave system, including large sinkholes, chasms, towers, and soil-filled karren. In a mature karstic regime where a sufficient thickness of carbonates exists, all three stages can take place simultaneously, and may develop spatially in both vertical and horizontal directions. The land surface might be a mature late-stage karstic terrain, while main-stage and initial-stage processes are occurring below (Musselman, 1994).

The most frequently recognized paleokarstic features preserved in cores and outcrops are related to the systematic breakdown of the karstic system. These include a variety of breccias formed by the collapse of passageways and sediment infill generated by the accretion of sediment transported in the cave system. Features such as vugs, solution-enlarged fractures, and phreatic meteoric cements are relatively common, but vadose speleothemic cements are rare.

Active dissolution of the Viola is represented by solution-enlarged joints and bedding planes, karren, and small caves. These features are common in the outcrops of the Arbuckle Mountains.

PALEOKARSTIC FEATURES IN CORE

Introduction

Paleokarstic features recognized in the Viola cores include (1) cavern-fill parabreccia, (2) collapse breccia,

(3) crackle breccia, (4) solution-enlarged fractures and vugs, (5) sediment infill, and (6) conduits and channels.

Cavern-Fill Parabreccia

Cavern-fill parabreccias are poorly sorted, matrix-supported breccias that exhibit structures suggesting subterranean deposition (Lynch, 1990). These breccias represent a chaotic deposition of angular to subrounded clasts in an uncollapsed cavern. They are apparently deposited during periods of turbulent flow and rapid discharge following storm events. The clasts may be derived from local passage collapse or consist of debris transported from other parts of the cavern system. The fine matrix is composed of cave mud weathered from the host rock or infiltrated sediment.

Figure 3 shows cavern-fill parabreccia in the Viola Springs Formation in the Mobil No. 21–19 East Fitts Unit (EFU) well. The breccia is composed primarily of angular to subrounded clasts of limestone and silicified limestone in a matrix of darker, clayey, slightly dolomitic mudstone.

Collapse Breccia

Collapse breccia is produced by the structural collapse of an open passage. Foundering of the passage roof or wall is typically induced by gravity following undermining by dissolution and erosion. Collapse breccias are characterized by angularity of clasts, poor sorting, and interstitial cement or matrix in a dominantly clast-supported fabric (Lynch, 1990).

The Mobil No. 21–19 EFU core contains a collapse breccia that is composed of angular clasts of the host packstone with a dark clayey dolomitic matrix (Fig. 4).

Crackle Breccia

The term *crackle breccia* is used to describe initial brecciation in highly fractured rocks in which the fragments have not been rotated, dislodged, or moved to any appreciable degree (Lynch, 1990). Since crackle breccias resemble tectonically fractured rocks, often they can be distinguished only by their spatial relationship to other karstic features. The relative position of crackle breccias to underlying collapse and cavern-fill breccias has contributed to the naming of these breccias as "cave roof facies" or fracture breccia (Kerans, 1989).

Crackle breccia in the Mobil No. 21–19 EFU core occurs above a parabreccia-filled conduit. A more problematic crackle breccia is present in the Mobil No. 9–41 EFU core. This breccia occupies a similar stratigraphic position to one in the No. 21–19 EFU well but lacks evidence of an underlying cavern.

Solution-Enlarged Fractures and Vugs

The type of porosity created by meteoric dissolution is fabric and lithology dependent. In low-permeability carbonates such as the Viola, vuggy and solution-channel porosity (Choquette and Pray, 1970) may be generated by the focusing of ground-water flow through high-permeability conduits such as fractures and bedding planes.

The most distinguishable dissolution features in the Viola cores are millimeter- to centimeter-scale solution-enlarged fractures, channels and vugs. Commonly, these features are completely or partially filled with sediment or cement. The most striking examples of solution-enlarged fracture porosity are from the Fernvale in the Sohio No. 1–A Hatcher core (Fig. 5). Dissolution at the intersection of several fractures generated an elliptical pore 5 cm long and 2 cm wide. Smaller (1- to 2-mm-wide) fractures are also present.

Millimeter-scale fractures contain evidence of several episodes of dissolution and cementation. These fractures were enlarged, cemented, and subsequently subjected to additional acidic fluids that corroded the pore-occluding calcite.

The vuggy porosity in the Fernvale consists of circular to elongated pores that range from 1.0 to 20 mm in diameter, although some exceed 2 cm (Fig. 5). The distinction between solution-enlarged fractures and vugs is somewhat arbitrary, especially where circular enlargement is associated with multiple fracture intersects. Some larger vugs in the Fernvale are lined with sparry calcite and partially occluded with fine sediment.

Sediment Infill

Infill sediment refers to the sediments that were deposited within the karst profile, including breccia matrix and pore-filling sediments. The composition of these sedi-

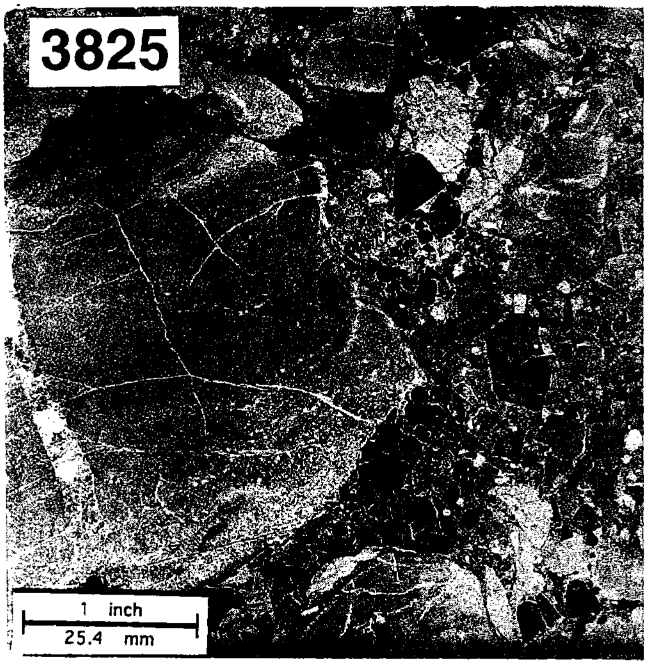


Figure 3. Cavern-fill parabreccia composed of angular to subrounded clasts in a mud-rich matrix. Fractures terminating at clast margins suggest pre-depositional origins. Mobil No. 21–19 East Fitts Unit (EFU). Depth, 3,825 ft.

Figure 4. Collapse breccia containing angular clasts with mud infill. Mobil No. 21–19 EFU. Depth, 3,906 ft.

ments may reflect the origin and timing of deposition within the karst system. Viola-age micrite fills solution-enlarged fractures, forming breccia matrix in the Viola Springs. Channel-fill parabreccia directly below the Sylvan contact in the Delaney No. 1 Phoenix core (Fig. 6) and vug-filling silt and clay in the Fernvale may represent Sylvan-age sediments.

Vug-filling laminated clay, mudstone, and silt occur in the Sohio No. 1–A Hatcher core (Fig. 7). A crosscutting fracture cemented with blocky calcite records post-infill tectonism and diagenesis and reflects the multiepisodic alteration history of the Viola.

Conduits and Channels

Conduits or cave passages are discernible in core if the top and basal boundaries of cavern-fill breccias can be identified. The limited sample size allows no estimation of the lateral boundaries in the subsurface. Conduits in the No. 21–19 EFU core are less than 1 m in height and completely breccia filled.

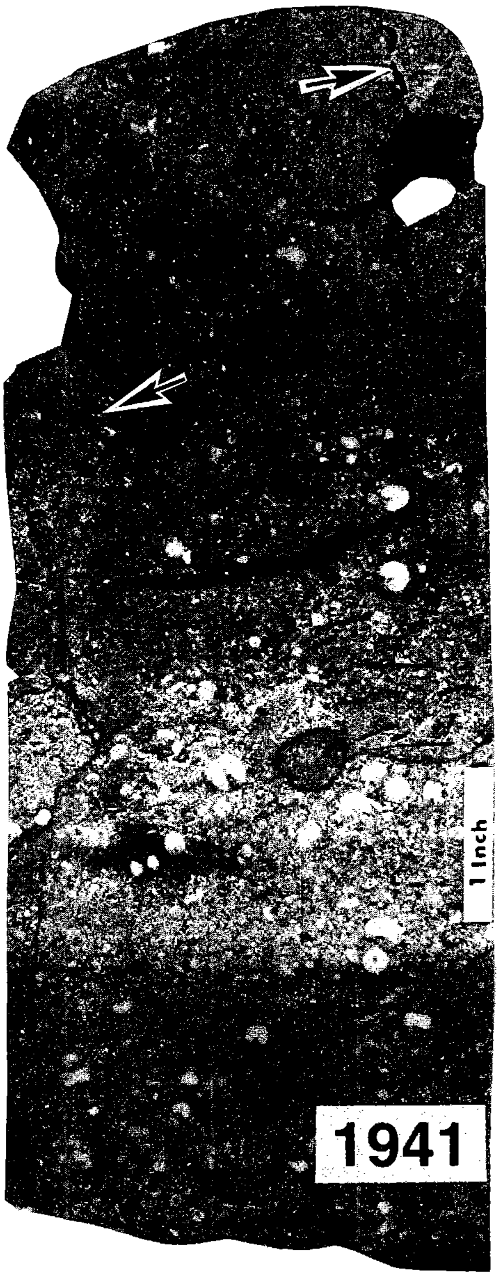


Figure 5. Solution-enlarged fractures (arrows) and resulting vuggy porosity. Sohio No. 1–A Hatcher. Depth, 1,941 ft.

Solution channels are enlarged fractures or vugs with elongate shapes. In the Delaney No. 1 Phoenix core, a possible solution channel occurs near the Sylvan contact in the Welling Formation. The channel is completely filled with parabreccia consisting of packstone–grainstone clasts in a clayey mudstone matrix. Porosity in this rock and other matrix-rich breccia is negligible.

Figure 6. Channel-filling parabreccia below Sylvan contact. Delaney No. 1 Phoenix. Depth, 2,950 ft.

KARSTIC AND PALEOKARSTIC FEATURES IN OUTCROP

Introduction

The more easily recognized karstic and paleokarstic features in outcrop are solution-enlarged joints and fractures, breccia-filled conduits, collapse features, and caverns. These features interrupt the continuity of bedding, and some contain fills that are compositionally different than the host rock. Excellent representative examples of dissolution and fill are found along I-35 on the south flank of the Arbuckle Mountains. The locations and complete descriptions of karsted Viola outcrops in southern Oklahoma can be found in Sykes (1995).

Breccia-Filled Conduits

A spectacular breccia-filled conduit was found along the west side of the northbound lane of the I-35 road cut (Fig. 8) (Al-Shaieb, 1994). This feature trends west-northwest and can be traced to the east side of the lane. The conduit is approximately 2.5 m high and 2 m wide. It contains limestone and chert clasts that range from 0.2 to 30 cm in diameter and average 10 cm. The breccia is grain supported and partially micrite cemented. Stratification is not obvious in this chaotic accumulation, and most clasts appear to have originated elsewhere.

Another breccia-filled conduit is found on the west side of the southbound lane of I-35. This solution-enlarged fracture is approximately 1.0 m high, 0.5 m wide near the top, and strongly tapered (Fig. 9). It is filled with parabreccia and micrite weathered from the host rock. The updip wall of the conduit is partially rimmed with blocky calcite cement that is 2 to 5 cm thick. The unstratified fill consists of highly angular clasts (0.2 to 8 cm in diameter) in a carbonate mud matrix. The orientation of the feature was difficult to determine, but it appears to parallel present strike. The original fracture is oriented perpendicular to bedding.

Collapse Feature

A large collapse feature is present near the south end of the west side of the northbound lane of I-35. The fill is primarily clay- to sand-size carbonate clasts with some larger blocks. A large block of the roof carbonate has foundered and has rotated into the cavity, where it appears to be supported by the fill (Fig. 10). The fill is crudely near-horizontally stratified, which contrasts with the 45° S. apparent dip of the host carbonate.

Active Karst

Many small-scale active karstic features are evident in the Arbuckle Mountains. Outcrops along Highway 377 near Fittstown, Pontotoc County, Oklahoma, contain solution channels with speleothems and vugs. A relatively "large" cave occurs in the Viola near Springer in Carter County, Oklahoma (Curtis, 1959).

MINERALIZATION AND PETROLEUM MIGRATION

Mineralization and petroleum residues occur in the karstic features along I-35. Hematite stains from oxidizing pyrite are common (Fig. 11). Asphalt-cemented breccia (Fig. 12) is found in a conduit on the east side of the southbound lane.

Sphalerite, copper sulfides, and pyrite are found in association with asphalt-impregnated Viola in the Lawrence Quarry in Pontotoc County. The sulfides line a vug that was cemented with sparry calcite. Petroleum saturates intergranular and fracture porosity in the host carbonate and occupies voids in the vug-filling calcite.

TIMING OF VIOLA KARSTIC EPISODES

The association of mineralizing fluids and petroleum suggests a pre-Pennsylvanian age for many Viola karstic features. Widespread generation and migration of petroleum occurred during the Pennsylvanian orogeny as source rocks in the neighboring basins were sufficiently buried to generate liquid hydrocarbons. In the Lawrence Quarry, these mineralizing and petroleum-bearing fluids filled existing dissolution porosity that was likely generated prior to deposition of the overlying Sylvan Shale. Core evidence also indicates pre-Sylvan karstic episodes. Vugs, solution-enlarged fractures, and channels in the Welling Formation indicate pre-Sylvan dissolution. Breccia-filled conduits in the Viola Springs suggest intra-Viola subaerial exposure and possible dissolution. On the other hand, horizontally stratified fill in the steeply dipping outcrops along I-35 identify a post-deformation (post-Pennsylvanian and possibly post-

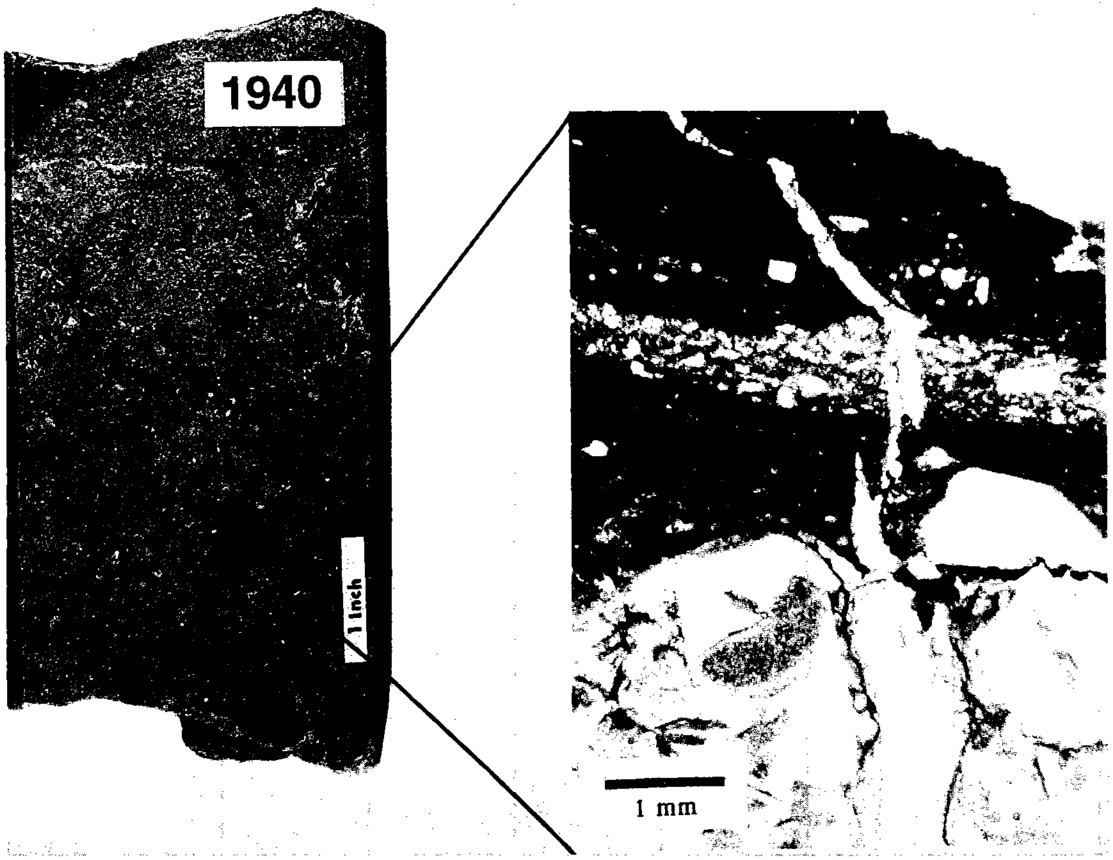


Figure 7. Vug containing fill of laminated clay, mudstone, and silt. Calcite-cemented fracture indicates post-infill tectonism and diagenesis. Sohio No. 1–A Hatcher. Depth, 1,940 ft.

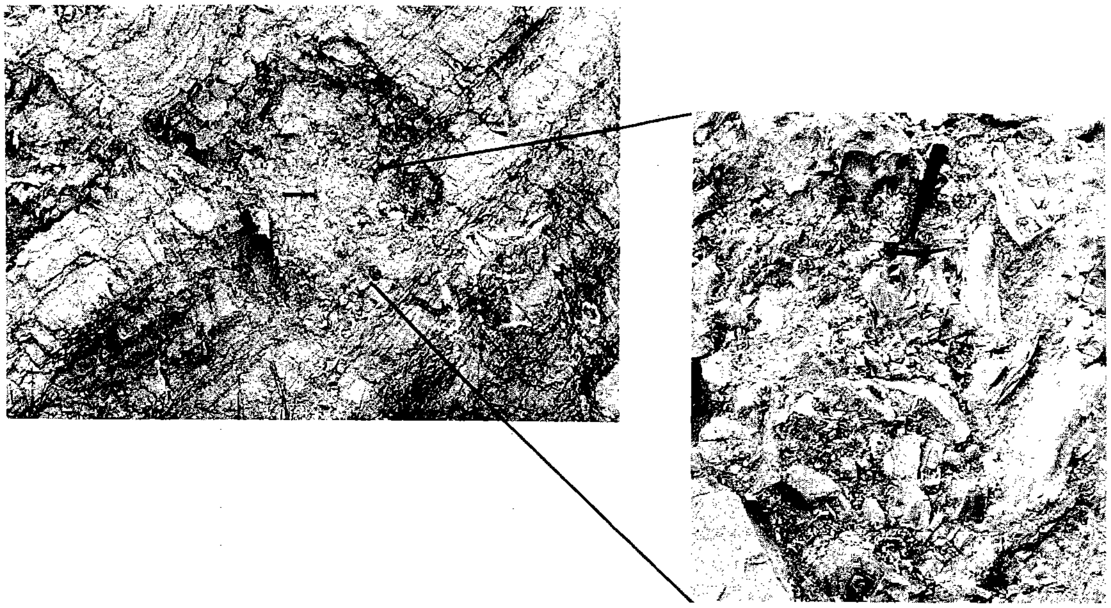


Figure 8. Breccia-filled conduit in I-35 road cut. Chaotic fill is composed of angular limestone clasts and carbonate mud matrix. Hammer is for scale.

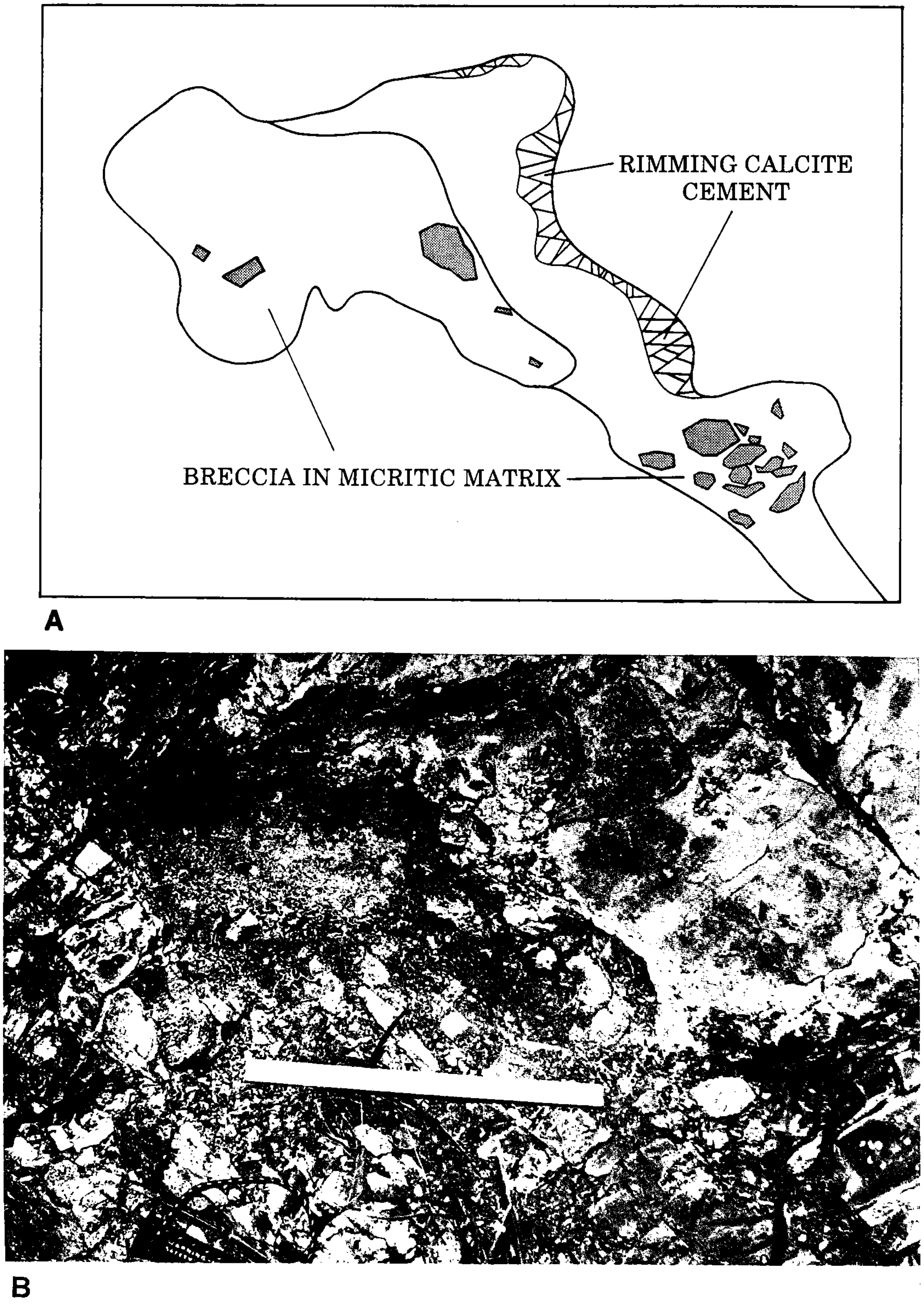


Figure 9. Breccia and mud filling solution-enlarged fracture in I-35 road cut. Passage is partially lined with blocky calcite cement. Ruler length is 1 ft. Upper figure (A) is sketch outline of features in photograph (B).

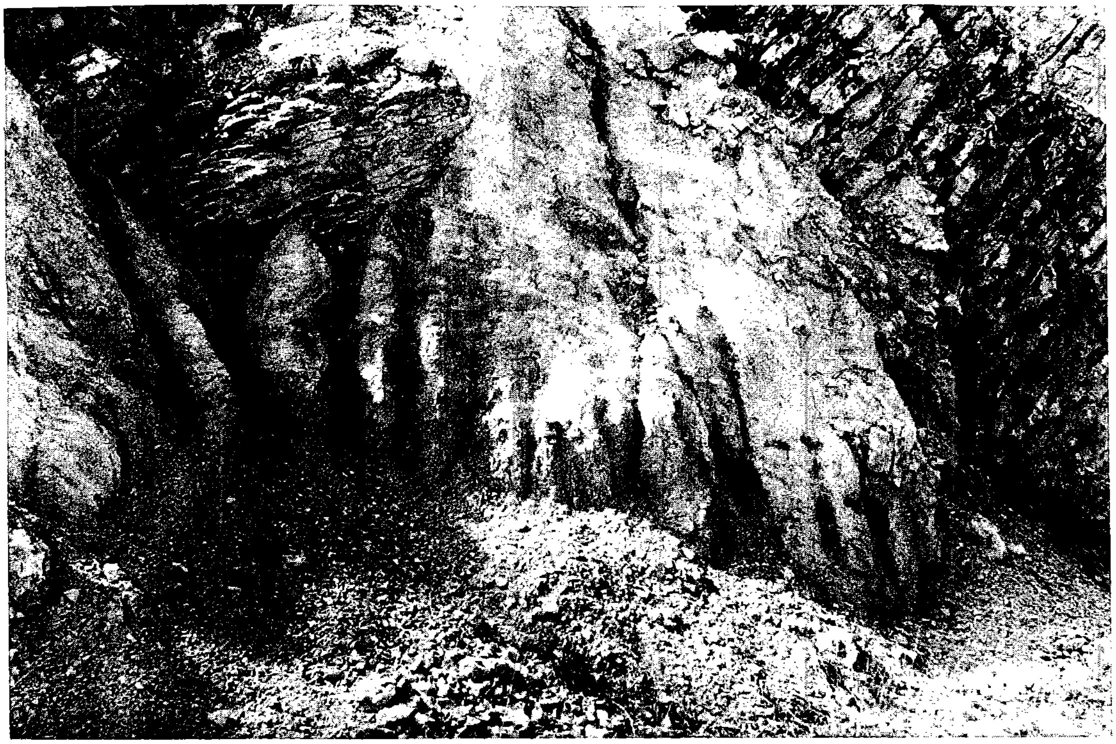


Figure 10. Collapse feature (sinkhole) filled with fine carbonate debris, mud, and large clasts. Note near-horizontal stratification that contrasts with apparent dip of host beds. Large ceiling block (above hammer) rotated into the cavern. I-35 road cut. Hammer for scale.

Laramide) karstic episode in the Arbuckle Mountains. Localized karstification may have occurred below the pre-Woodford or other major unconformities when the Viola was subaerially exposed, but these events have not been identified in core.

CONCLUSIONS

Paleokarstic episodes in the Viola Group contain evidence of dissolution, collapse, and deposition. The spatial relationships and structure of the these features suggest several episodes of Viola karstification including intra-Viola, pre-Sylvan, post-Pennsylvanian/Laramide, and recent. Localized dissolution may have occurred beneath other unconformities. The association of sulfides and petroleum indicate that mineralizing fluids accompanied petroleum migration. Active karstic features include channels, vugs, and caverns.

REFERENCES CITED

Alberstadt, L. P., 1967, Brachiopod biostratigraphy of the Viola and "Fernvale" Formations (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 308 p.

Al-Shaieb, Zuhair, 1988, Comparative analysis between karstic and paleokarstic features of the Ordovician Arbuckle Group of Oklahoma: Tulsa Geological Society, presentation, Tulsa, Oklahoma.

______1994, Paleokarst along I-35 in the Arbuckle Mountains, southern Oklahoma: Oklahoma State University unpublished field-trip guidebook, 14 p.

Becker, R. D., 1988, Stratigraphy and depositional characteristics of the Bromide "Dense" unit and Viola Limestone (Middle and Upper Ordovician), subsurface central Oklahoma: University of Tulsa unpublished M.S. thesis, 197 p.

Choquette, P. W.; and James, N. P., 1988, Paleokarst: Springer–Verlag, New York, 416 p.

Choquette, P. W.; and Pray L. C., 1970, Geologic nomenclature and classification of porosity in sedimentary carbonates: American Association of Petroleum Geologists Bulletin, v. 54, p. 207–250.

Curtis N. M., 1959, Caves in the Arbuckle Mountains area, Oklahoma: Oklahoma Geology Notes, v. 19, p. 20–31.

Esteban, M.; and Klappa, C. F., 1983, Subaerial exposure environment, *in* Scholle, P. A.; Debout, D. G.; and Moore, C. H. (eds.), Carbonate depositional environments: American Association of Petroleum Geologists Memoir 33, p. 1–54.

Gentile, L. F., 1984, Sedimentology and graptolite biostratigraphy of the Viola Group (Ordovician), Arbuckle Mountains and Criner Hills, Oklahoma: Oklahoma State University unpublished M.S. thesis, 104 p.

Glaser, G. C., 1965, Lithostratigraphy and carbonate petrology of the Viola Group (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 197 p.

Grammer, G. M., 1983, Diagenesis of the Viola Limestone (Middle Ordovician), southeast Arbuckle Mountains, Oklahoma: Southern Methodist University unpublished M.S. thesis, 151 p.

Ham, W. E.; McKinley, M. E.; and others, 1954 [1955], Geologic map and sections of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Map A-2, 1 sheet, scale 0.88 in. = 1 mi.

Kerans, C., 1989, Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas: Texas Bureau of Economic Geology Report of Investigations 186, 40 p.

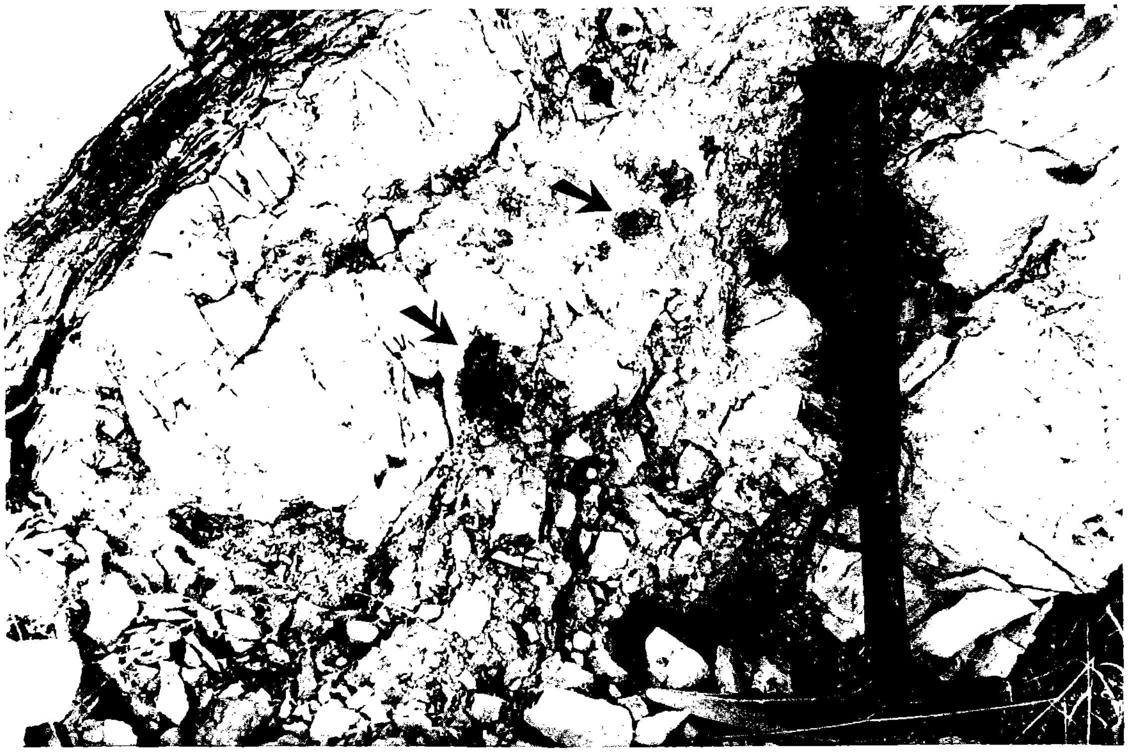


Figure 11. Oxidizing pyrite (arrows) in a breccia zone in I-35 road cut. Hammer for scale.

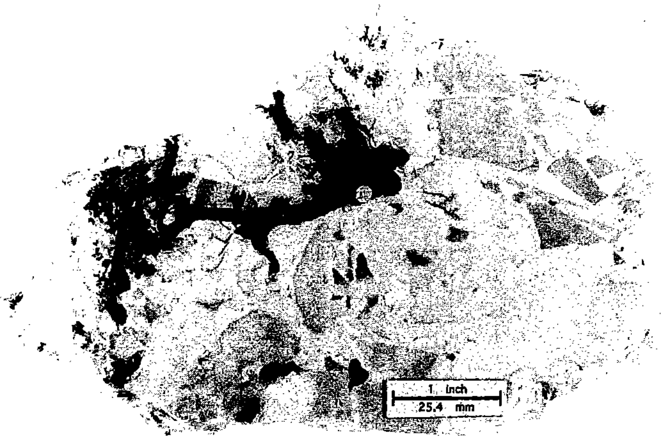


Figure 12. Asphalt-impregnated cavern-fill collapse breccia in I-35 road cut.

Lynch, M. T., 1990, Evidence of paleokarstification and burial diagenesis in the Arbuckle Group of Oklahoma: Oklahoma State University unpublished M.S. thesis, 163 p.

Matthews, F. D., 1992, Paleokarstic features and reservoir characteristics of the Hunton Group in the Anadarko Basin, Oklahoma: Oklahoma State University unpublished M.S. thesis, 174 p.

Musselman, J. L., 1994, Paleokarstic phenomena, depositional environments, and diagenesis of the Lower Ordovician West Spring Creek Formation, Arbuckle Group, in southern Oklahoma: Oklahoma State University unpublished M.S. thesis, 122 p.

Reid, F. S., Jr., 1980, Microfacies and diagenesis of the Viola Limestone (Ordovician) of south-central Oklahoma: Southern Methodist University unpublished M.S. thesis, 106 p.

Sykes, M. P., 1995, Paleokarst characteristics of the surface and subsurface in the Viola Limestone (Ordovician), Arbuckle Mountains, Oklahoma: Oklahoma State University unpublished M.S. thesis, 121 p.

Taff, J. A., 1902, Description of the Atoka quadrangle: U.S. Geological Survey Geologic Atlas 79, p. 1–8.

Viola Fractures—Friend or Foe?

Carlos M. Gonzalez
G&G International Consultants
Oklahoma City, Oklahoma

The Marietta basin (Fig. 1), in southern Oklahoma, was the site of a furious drilling play in the 1970s; the drilling targeted the fractured Viola Group limestones. Some wells were very good, but many were mediocre to poor producers. This play took place before horizontal-drilling technology was well developed.

The Ray Holifield/Mack Energy No. 1 Dickey (sec. 30, T. 5. S., R. 4 W.) was the first attempt at a truly horizontal well; the objective was to penetrate the Viola horizontally, in a north-northeast direction (Fig. 2). In those days, the effect of regional stresses and their application to rock mechanics was not a major part of horizontal-well planning. The first well was drilled parallel to sigma 1 (σ1), and, as a result, hardly any bit penetration was achieved in the Viola, and only a few feet of horizontal well was drilled. Many bit types were tried during the building of the curve. Considerable time and money were spent, and substantial shows were logged; but the curve was not completed, and the well was abandoned despite a geological recommendation to attempt a completion.

Southern Oklahoma is well known to have been subjected to great stresses, producing the shortening of the basins and creating significant structural complications with a great amount of fracturing.

Rock behavior under different degrees of stress has been known by civil engineers for decades, and rock-mechanics laboratories conduct these tests on cores taken from construction sites on a regular basis. Only recently, Dr. Karl Terzaghi's experiments and results (in the 1940s) have been applied to entire basin studies. The thick carbonates present in southern Oklahoma show all types of deformation resulting from stresses—from frac-

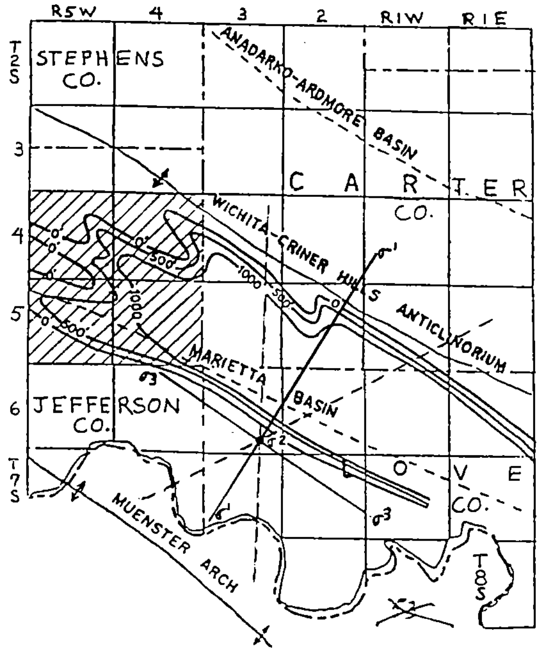
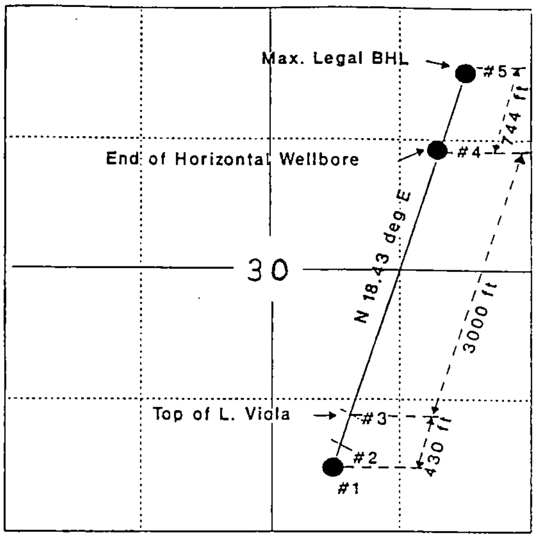


Figure 1. Location of the study area in the Marietta basin of southern Oklahoma and stresses sigma 1, 2, and 3. Also shown is the study area in T. 4–5 S., R. 4–5 W.



PLAN SUMMARY

No.	Item	Vertical Section	Location
#1	Surface location	0 ft	660' FSL, 1980' FEL
#2	9 5/8" Csg Pt	51 ft	908' FSL, 1897' FEL
#3	End of Build	430 ft	1084' FSL, 1839' FEL
#4	Total Depth	3430 ft	1350' FNL, 890' FEL
#5	Maximum Depth	4174 ft	660' FNL, 660' FEL

Figure 2. Map showing plan view for maximum distance design of a horizontal well, the Ray Holifield/Mack Energy No. 1 Dickey, sec. 30, T. 5 S., R. 4 W.

Gonzalez, C. M., 1997, Viola fractures—friend or foe?, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 76–77.

turing to plastic behavior. The Viola was successfully drilled in the Marietta basin perpendicular to sigma 1 by several wells operated by ARKLA and ARCO. All these wells were drilled from northwest to southeast; some were productive, and others drilled near existing production found only depleted fracture systems.

Another factor to consider in drilling carbonates bounded above and below by shales is the different reaction to sigma 1 by the shales. Figure 3 illustrates how a well may drift out of limestone into the overlying shale. Properly drilled in the limestone, perpendicular to sigma 1, the well will not collapse as long as it stays in the limestone, but the well will collapse if it drifts into the shale. To drill the shale safely, the well direction must be parallel to sigma 1.

I wish to emphasize the importance of the stress information. In order to determine the direction of sigma 1 in a particular geologic setting in any basin, one should obtain fresh, unfractured limestone and shale cores and have them analyzed as soon as possible. A second indirect method of analysis and orientation of sigma 1 could be developed by running "high-technology" fracture-identification logs and plotting the fracture conjugates on a map. The direction of sigma 1 will be in the center of the smallest angle between fracture conjugates (Fig. 4).

Figure 5 is a list of factors that affect horizontal-well behavior and a reservoir. All of them are important, but I believe the most damaging are (1) failure to remove the fine cuttings from the horizontal wells during the testing period, by not producing the well on a steady-flow regime; (2) shut-in periods that compound the precipitation of fine cuttings in the borehole, causing the sealing of the fracture face to hamper the flow of hydrocarbons; (3) drawdown tests in reservoirs with high fracture permeability that will produce a gas cone in each fracture, and, when the gas is produced, to have insufficient remaining energy to move the liquids. Moreover, the lack of fluids inside the fractures will accelerate the closing of the fracture system still under geologic stress. When fractures close, it is difficult to drain fluids from pores within the matrix of a rock (if the matrix permeability is low).

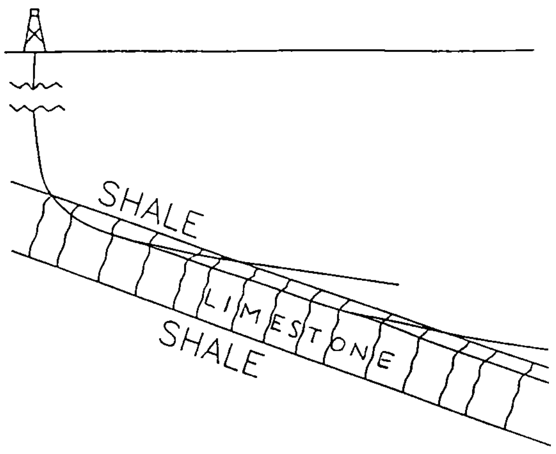


Figure 3. Schematic diagram showing how a horizontal well drilled into limestone can drift into an overlying shale.

In conclusion, Viola and other fractured carbonates can be exploited by using the proper technology and careful well supervision, but fractured reservoirs are delicate systems that can be ruined by a single mistake. Careful planning and supervision by experienced geologists and drilling/completion personnel can produce spectacular and long-lasting results.

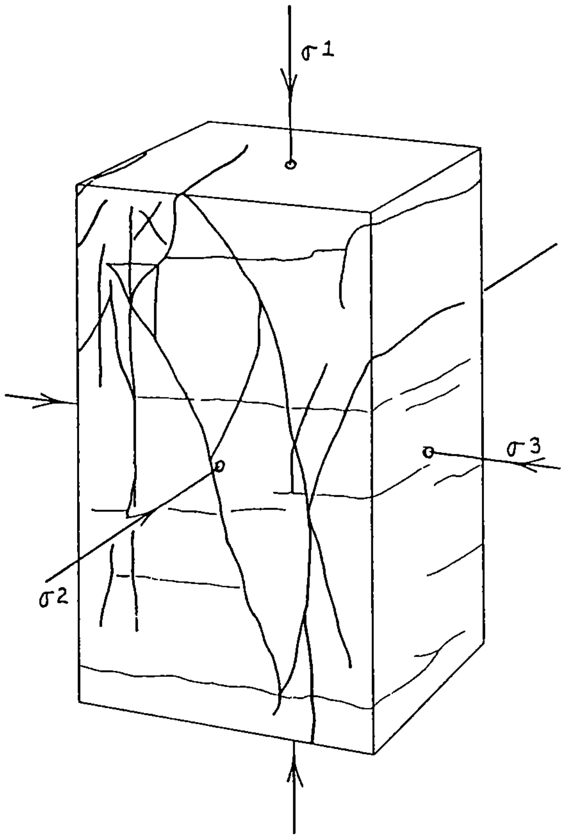


Figure 4. Schematic diagram showing orientation of sigma 1 (vertical, in this diagram) at the center of the smallest angle between fracture conjugates.

1. DRILLING PARALLEL TO SIGMA 1
2. IMPROPER ENGINEERING DESIGN
3. LACK OF COMPETENT AND EXPERIENCED GEOLOGIST ON LOCATION
4. LOW FLUID VELOCITY ACROSS FRACTURE FACES
5. DRAW DOWN TESTS
6. SHUT–IN PERIODS
7. DEPLETED RESERVOIR

Figure 5. Factors that can adversely affect behavior and production in drilling and completing horizontal wells.

Oklahoma Geological Survey Circular 99, 1997

The Viola Group as a Petroleum System: Implications for Horizontal-Drilling Prospects

David A. Wavrek
University of Utah
Salt Lake City, Utah

Michael A. Garcia
ARCO International
Plano, Texas

Clive D. Ferebee[1]
Occidental International
Bakersfield, California

ABSTRACT.—The petroleum-system concept is advanced on the premise that the essential elements required for commercial accumulation of hydrocarbons must be considered as interrelated items that are interpreted collectively. A key element is the accurate correlation between the oil and source rock. The oil fields assigned to the Viola Petroleum System are charged from source facies described as diluted kukersites; this designation emphasizes the diversity of the biogenic input. An element of the source facies is derived from the organism *Gloeocapsomorpha prisca*, but this contribution varies between minor and moderate. A fairway of reduced risk is defined where positive trends in the source-rock volume, organic richness, thermal stress, and tectonic evolution overlap. The critical moment for this petroleum system follows the Arbuckle deformation event (approximately 290 Ma, Virgilian). This event is responsible for a fault network that limited the source-rock drainage volume but contributed to the trap and reservoir configuration. The fairway can be exploited with a minimum number of horizontal wells.

INTRODUCTION

The basic elements required for the accumulation of commercial hydrocarbon reserves have been documented in numerous studies: source rock, reservoir, and seal. The petroleum-system concept is advanced on the premise that these essential elements are interrelated and should be interpreted collectively. As defined (Magoon, 1992), "a petroleum system encompasses a mature hydrocarbon source rock and all generated oil and gas accumulations and includes all the geologic elements and processes that are essential if the oil and gas deposit is to exist." The geologic elements include the petroleum source rock, reservoir rock, sealing units, and overburden rock. In this usage, the reservoir rock is considered to be synonymous with a migration conduit that is not filled with hydrocarbons because of the lack of a trapping mechanism. The geologic processes include the mechanism responsible for trap formation and those factors that drive the generation, migration, and accumulation of hydrocarbons. It is important that the essential elements and processes be correctly coordinated in time and space for the generated hydrocarbons to be trapped as commercial reserves (Wavrek and Barker, 1988).

The petroleum system is designated by the name of the source rock, followed by the major reservoir unit and the confidence indicator (Magoon, 1992). Three confidence indicators are recognized: (!) for known, (.) for hypothetical, and (?) for speculative. Where the source rock coincides with the reservoir unit, the name is simplified to a single element. With this premise, the Viola (!) Petroleum System in this study is restricted to the confines of the Ardmore and Marietta basins (Fig. 1). This paper expands the petroleum system concept by including a discussion of the application to horizontal drilling prospects.

Geologic Setting

The Ardmore and Marietta basins (Fig. 1) were the part of the Oklahoma basin that coincided with the east-

---

[1] Current address: Tecnosinergia C. A., Caracas, Venezuela.

Wavrek, D. A.; Garcia, M. A.; and Ferebee, C. D., 1997, The Viola Group as a petroleum system: Implications for horizontal-drilling prospects, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 78–86.

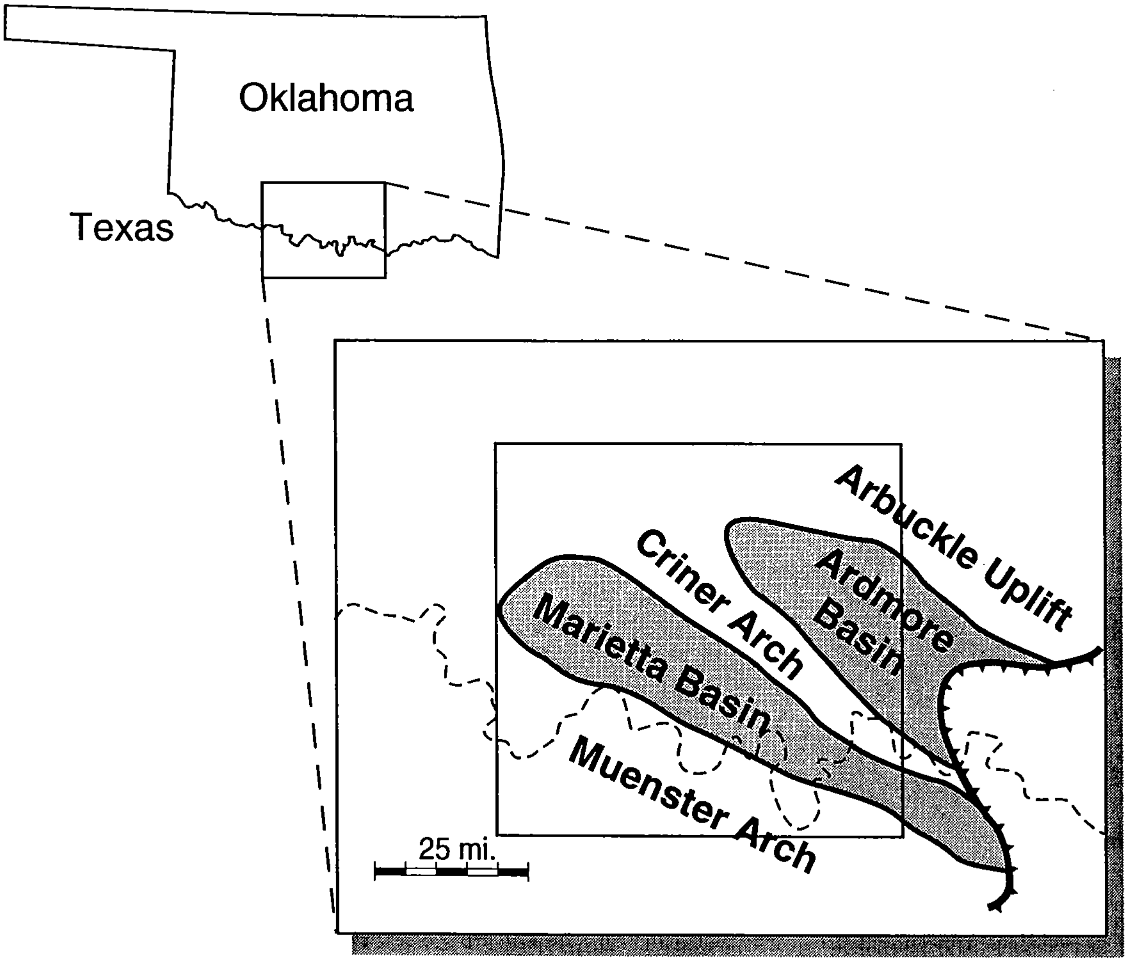


Figure 1. Geographic location of the Ardmore and Marietta basins. The two framed views represent the outlines for map figures in the text.

ern part of the southern Oklahoma aulacogen (Johnson and others, 1988), which is a west-northwest-trending structural feature that has been the subject of numerous studies (Hoffmann and others, 1974; Pruatt, 1975; Thompson, 1976; Wickham, 1978). The sedimentary column is almost entirely Paleozoic (Fig. 2), with the lower units dominated by carbonates and the higher units by clastics. The current structural configuration is the result of late Paleozoic deformation events.

The Viola Group (Fig. 2) is an Upper Ordovician marine-limestone sequence (Decker, 1933; Ham, 1955; Glaser, 1965; Galvin, 1983; Grammer, 1983; Teague, 1985; Finney, 1988) that was deposited throughout the Oklahoma basin during the mid-Mohawkian to early Cincinnatian Stages. The group is routinely subdivided into two formations: a lower Viola Limestone and an upper Fernvale Limestone. Lithofacies in the Viola Limestone include subunits 1L and 1C, and a middle unit, 2; subunits 3CM and 3C are part of the Fernvale Limestone (Fig. 3). The lithologic and paleontologic differences between the subunits are gradual and are interpreted to result from a systematic variation in the depositional energy and water depth in a carbonate-ramp setting. This study focuses on subunit 1L, which is described as siliceous laminated mudstones that were deposited in a deep-water anaerobic environment. It is proposed that the anoxic condition that existed during deposition of this subunit was enhanced by the aulacogen setting, which provided physical isolation from open-water circulation.

Materials and Methods

The oils (Table 1; Fig. 4) represent a subset of the samples interpreted by Wavrek (1992) as Type D, whereas the rock samples (Fig. 5) are the focus of a study by Garcia (in preparation). The rock samples were collected in the context of previous studies of subunit 1L depositional facies, and sources include outcrop, core, and cuttings. The cuttings were hand-picked to provide samples that conform to lithologic variation observed at outcrops, and they represent a channel sample through the basal chert facies. Positive picking is not usually advocated as a geochemical-sampling technique, but it is valid in this study because the focus is on a subunit

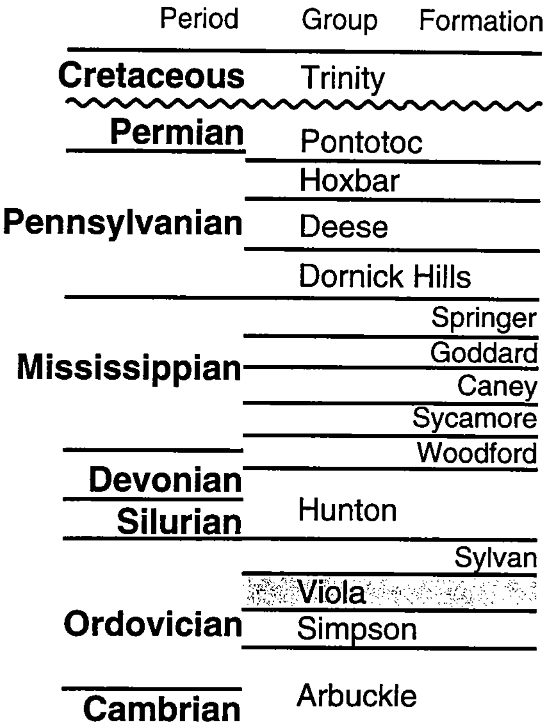


Figure 2. Generalized stratigraphic column for the region.

with a unique lithology and special care was paid to evaluate the potential for contributions from caving (e.g., casing points, examination of overlying sample lithologies). The tectonic and stratigraphic analyses used in this study are based on the examination of over 500 well logs (Ferebee, 1991). Calculations for the individual burial-history reconstructions (Fig. 6) were accomplished with the program BasinMOD (v. 4.02; 1-D for Windows; Platte River Associates).

The geochemical analysis of the rock samples includes total organic carbon (TOC) (Leco Instruments), Rock-Eval pyrolysis (Delsi Instruments), and Soxhlet extraction. The oil samples were analyzed for density (Parr Instruments), total sulfur (Leco Instruments), and metals (Inductive Coupled Plasma). Both sample sets were analyzed by gas chromatography–flame ionization detection (GC–FID) prior to separation into fractions by column chromatography and analysis by gas chromatography–mass spectrometry (GC–MS). Several samples were selected for stable- carbon-isotope analysis.

RESULTS AND DISCUSSION

Geologic Elements and Processes

As a petroleum system encompasses a mature hydrocarbon source rock and all generated oil and gas accumulations, an accurate correlation between the oil and source rock is an essential element. This correlation is established with a combination of analytical techniques: GC–FID for the general components and GC–MS for the biomarker fraction. Oils indigenous to the Viola (!) Petroleum System are characterized by a moderate odd-carbon preference in the nC_{11}–nC_{20} range, moderate amounts of acyclic isoprenoids, pristane to phytane ratios near 1.1, and moderate C_{20+} *n*-alkanes (Fig. 7). They tend to have a relatively high concentration of sulfur compounds, organic metal complexes, and moderate API gravities (Table 1). The carbon-isotope values measured for two of these oils provided average values of –31.1%, –31.3%, and –30.9% for the whole oil, saturate, and aromatic fractions, respectively (Wavrek, 1992). The biomarker analyses indicate that the steranes have dominant C_{29} members, with the $\alpha\beta\beta$ form preferred over the $\alpha\alpha\alpha$ configuration, plus a moderate amount of rearranged steranes (Fig. 8). The terpane fraction contains relatively abundant extended hopanes, minor amounts of gammacerane, a moderate abundance of 28,30-bisnorhopane, and a C_{24} tetracyclic that is greater than the C_{26} tricyclic terpanes (Fig. 9). The methyl hopanes are quantitatively significant, with 2α and 3β varieties in near-equal abundance. Distinctive peaks that are apparent on the GC–FID traces (Fig. 7) are identified by GC–MS SCAN analysis to be *n*-alkylcyclohexanes and *n*-alkylbenzenes with anomalous C_{21} and C_{23} members (Fig. 10). Wells that produce from this petroleum system are prone to paraffin precipitation during production and pipeline transport owing to the presence of quantitatively significant high-molecular-weight compounds (Wavrek and Dahdah, 1995).

The molecular composition of Viola Group rock extracts and correlative crude oils suggests that a diverse assemblage of organisms contributed to the source facies. An element of these source facies is derived from the organism *Gloeocapsomorpha prisca*, which is reported to be responsible for the distinctive Ordovician signature of oils and source rocks on a global scale (see Fowler, 1992, for review). This signature is readily apparent in the associated marls of subunit 1L (Fig. 11), whereas the chert facies provides the remainder of the Viola Group molecular signature. It is emphasized that the kukersite facies of *G. prisca* have not been observed in extracts from the Viola Group and that an oil composition represents the collective components of the individual source facies within the source rock. The kukersite facies of *G. prisca* appear to be restricted to the Simpson Group (Middle Ordovician, Champlainian), a conclusion that is reinforced by documentation that oils with the kukersite chemistry (Type E of Wavrek, 1992) are generally restricted to Simpson and Arbuckle Group reservoirs.

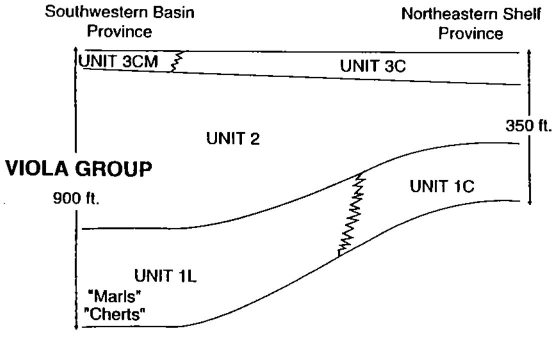


Figure 3. Diagrammatic section of the Viola Group (modified from Glaser, 1965; Grammer, 1983).

TABLE 1.—OIL WELLS THAT PRODUCE FROM THE VIOLA (!) PETROLEUM SYSTEM

Field	Operator	Well	Location	API well number	Reservoir formation	Perforations (ft)	API gravity	Total sulfur	Nickel (ppm)	Vanadium (ppm)	Comments
Marietta NE	L. E. Jones	No. 1 Daube–Sutton	27-6S-2E	35-085-20559	Viola	3580–3640	37.3	0.41%	11	15	Mixed?
Simon NW	Unocal	No. 1 Loving	16-6S-2W	35-085-20722	Viola	9300–12,060	42.2	0.21%	2	3	
Orr SE	Unocal	No. 1 Roosth	4-6S-3W	35-085-20567	Viola	9417–10,512	31.3	0.74%	8	11	
Atlee	L. E. Jones	No. 1 Lambeth	29-5S-4W	35-067-20684	Viola	6168–7143	35.6	1.40%	28	66	
Atlee	L. E. Jones	No. 1 Porter	21-5S-4W	35-067-20569	Viola	7844–8002	36.1	1.38%	28	64	
Atlee	L. E. Jones	No. 1 Allen	21-5S-4W	35-067-20567	Viola	7229–7802	36.6	1.68%	26	73	
Ringling West	Kaiser–Francis	No. 1–5 Zachary	5-5S-4W	35-067-20688	Viola	6696–7085	28.1	1.96%	36	94	
Simon North	Bogert	No. 35–3 Monson	35-5S-2W	35-019-21918	Viola	7427–8249	38.0	0.55%	7	8	
Reck East	Samedan	No. 1–15 Howard	15-5S-2W	35-019-21892	Viola	6283–7218	28.5	1.48%	27	44	
Joiner City SE	Chevron	No. 1 Bates	32-5S-2W	35-019-07305	Viola	10,126–10,360	38.9	0.41%	3	2	
Joiner City SE	Holden	No. 1 Anderson	28-5S-2W	35-019-22831	Viola	10,083–10,095	35.4	0.47%	7	15	
Wilson SE	Walker	No. 1 North	9-5S-2W	35-019-22647	Viola	5564–5718	36.6	0.61%	11	15	
Joiner City	Unocal	No. 1–18 Simmons	18-5S-2W	35-019-22398	Viola	7885–8105	40.3	0.52%	6	11	
Orr North	Jones	No. 1 Jones–Kalkman	31-5S-3W	35-019-22821	Viola	9152–9240	34.1	0.66%	6	16	
Simon NE	L. E. Jones	No. 1 Rockland	7-5S-2W	35-019-22183	Viola	7950–9118	38.1	0.57%	9	19	
Hewitt	Exxon	No. 1–16 Mullen	16-4S-2W	35-019-23493	Viola	3444–3828	26.6	1.27%	35	75	Mixed?
Sho–Vel–Tum	K. Walker	No. 1 Lina–Boggess	19-3S-2W	35-019-22936	Viola	7304–8127	41.7	0.25%	5	2	
Healdton	Kingery Drilling	No. 1 Isbell	34-3S-3W	35-019-21747	Viola	6576–6720	30.2	1.08%	15	47	
Caddo	O'Neal Drilling	No. 7 Smith	22-3S-1E	35-019-23368	Viola	6100–6472	28.5	0.47%	12	8	
Sho–Vel–Tum	Holden Energy	No. 9–1 Lamb	9-2S-4W	35-137-23077	Viola	5680–6610	30.3	0.47%	15	14	
Pike SW	K. Walker	No. 1 Jord Royalty	23-7S-2W	35-085-20255	Dornick Hills	9006–9177	23.5	1.41%	27	22	
Velma West	TXO	No. C–1 Brown Trust	13-1S-6W	35-137-24090	Viola	7484–8500	38.9	0.42%	3	2	

Note: Sample suite from Wavrek (1992).

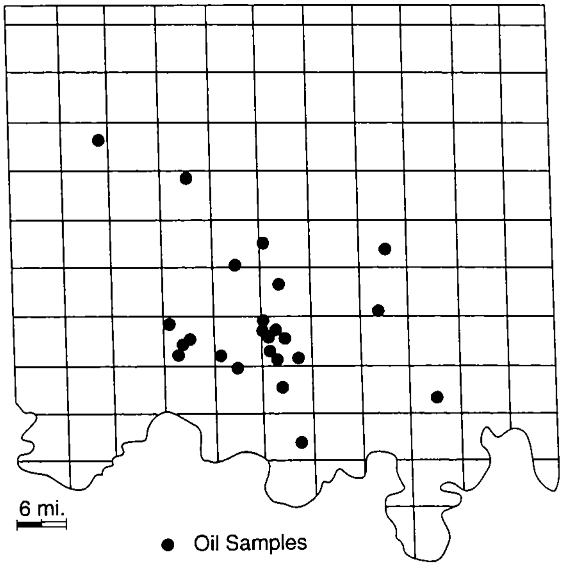


Figure 4. Geographic distribution of oil wells that produce from the Viola (!) Petroleum System (from Wavrek, 1992, sample suite).

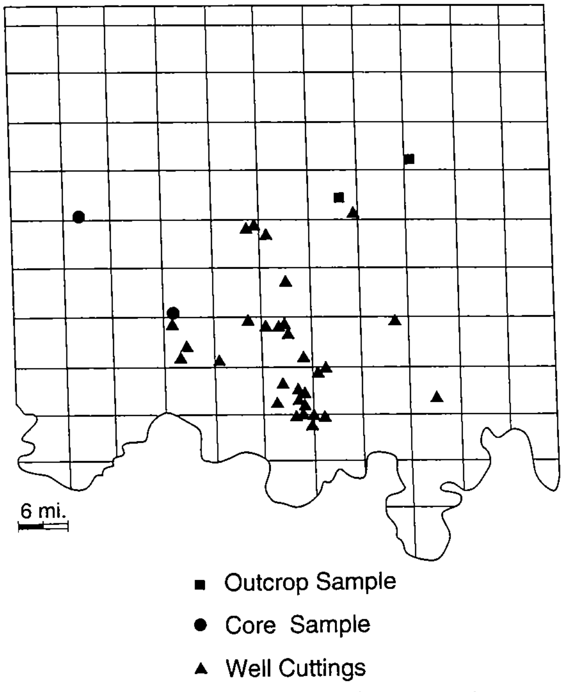


Figure 5. Geographic distribution of rock samples analyzed from Viola Group, subunit 1L (from Garcia, in preparation).

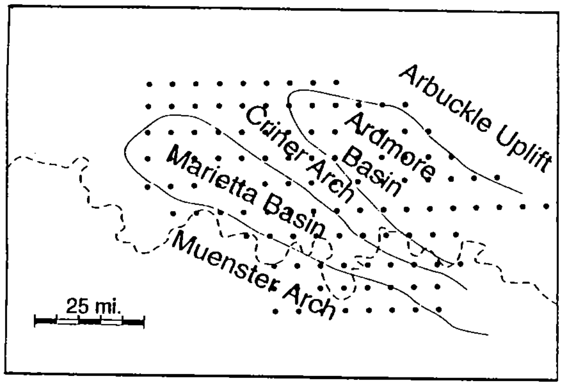


Figure 6. Geographic distribution of sites selected for individual burial-history reconstructions.

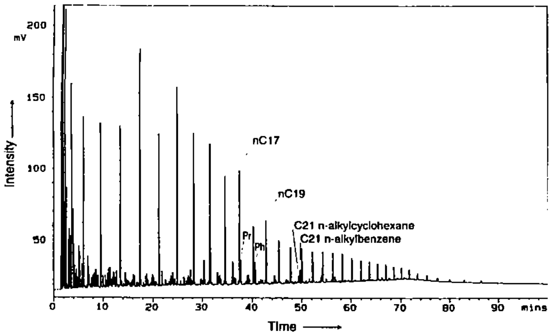


Figure 7. GC–FID of a typical oil from the Viola (!) Petroleum System.

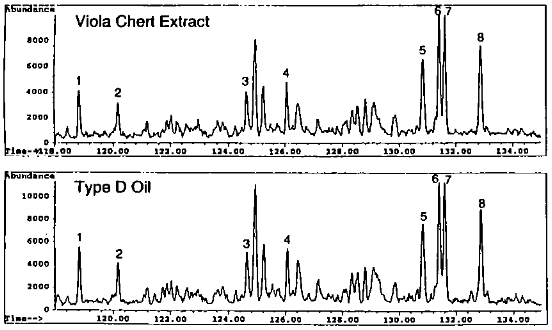


Figure 8. Sterane trace (m/z 217) from GC–MS analysis of saturate fractions.

1 = C_{27} rearranged sterane (20S)
2 = C_{27} rearranged sterane (20R)
3 = C_{27} sterane (20S)
4 = C_{27} sterane (20R)
5 = C_{29} sterane (20S)
6 = C_{29} sterane (20R)
7 = C_{29} sterane (20S)
8 = C_{29} sterane (20R)

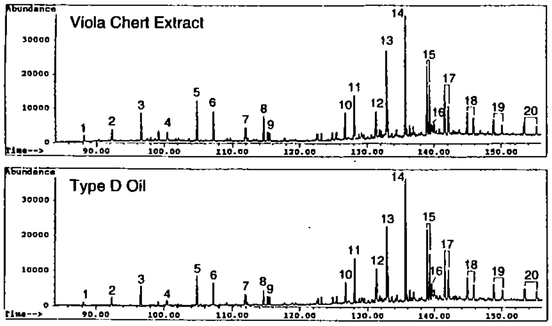


Figure 9. Terpane trace (m/z 191) from GC–MS analysis of saturate fractions.

1 = C_{19} tricyclic terpane
2 = C_{20} tricyclic terpane
3 = C_{21} tricyclic terpane
4 = C_{22} tricyclic terpane
5 = C_{23} tricyclic terpane
6 = C_{24} tricyclic terpane
7 = C_{25} tricyclic terpanes*
8 = C_{24} tetracyclic terpane
9 = C_{26} tricyclic terpanes*
10 = 18(H)-22,29,30-trisnorneohopane (Ts)
11 = 17(H)-22,29,30-trisnorhopane (Tm)
12 = 28,30-bisnorhopane
13 = C_{29} 17(H)-hopane (norhopane)
14 = C_{30} 17(H)-hopane (hopane)
15 = C_{31} 17(H)-hopanes*
16 = gammacerane
17 = C_{32} 17(H)-hopanes*
18 = C_{33} 17(H)-hopanes*
19 = C_{34} 17(H)-hopanes*
20 = C_{35} 17(H)-hopanes*

*= 22S and 22R configurations

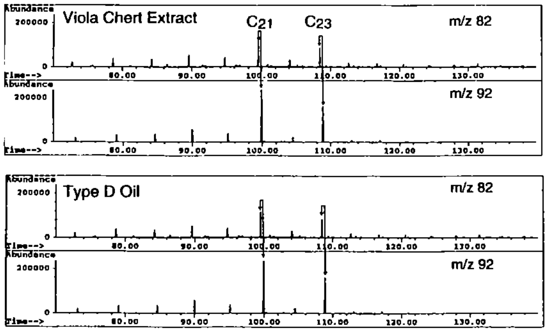


Figure 10. *n*-alkylcylohexanes (m/z 82) and *n*-alkylbenzenes (m/z 92) from GC–MS analysis of whole extract and crude oil.

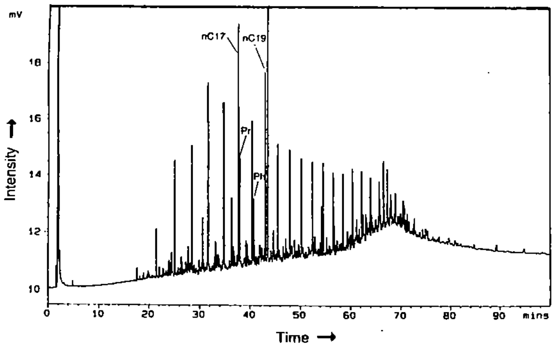


Figure 11. GC–FID of whole extract from Viola Group marl.

After the relationship between the Viola Group source facies and crude oils has been established, positive trends in source-rock volume, richness, and maturity can be addressed. A regional isopach map of Viola Group units 1L/1C (Fig. 12) shows that the thickness ranges from less than 100 to over 300 ft. The unit thickens toward the southwest, whereas thinning about the perimeter of the aulacogen and toward the Arbuckle Mountains is generally observed. The Viola Group contains effective petroleum source rocks within the laminated marls (TOC average = 2.4%; n = 7) and a basal chert (TOC average = 1.3%; n = 30). The geographic distribution of source-rock potential (Fig. 13) is distinctive, with poor source potential near the basin margins, particularly on the south flank of the Arbuckle uplift, but with progressive increases to good and excellent values

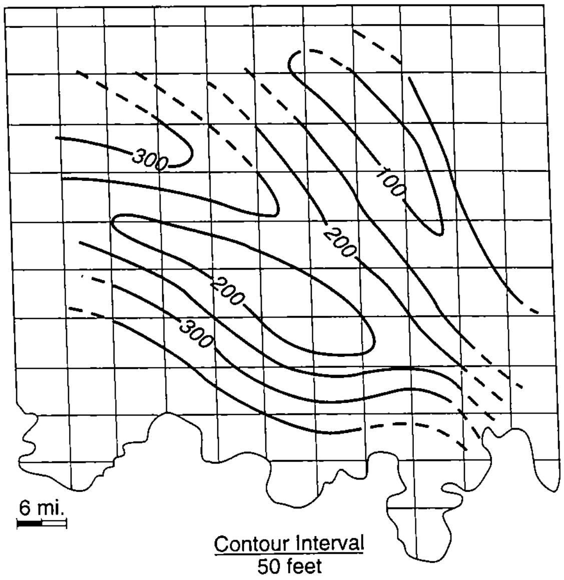


Figure 12. Regional isopach map of Viola subunits 1L/1C.

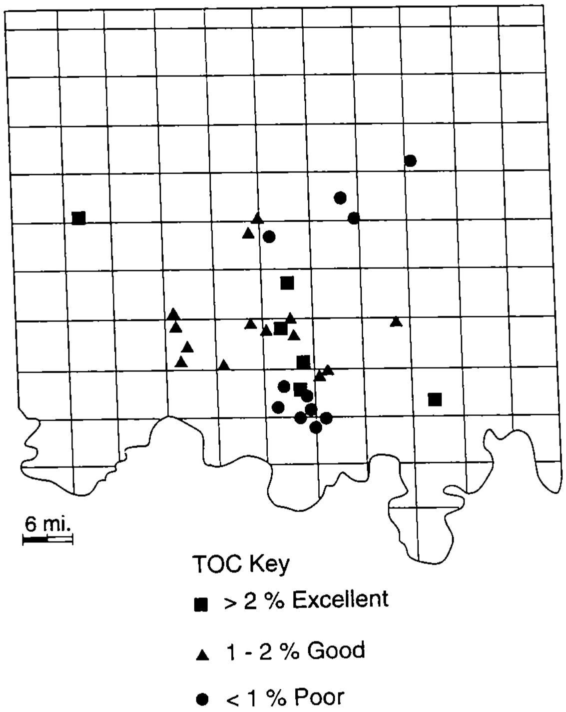


Figure 13. TOC data for Viola Group subunits 1L/1C.

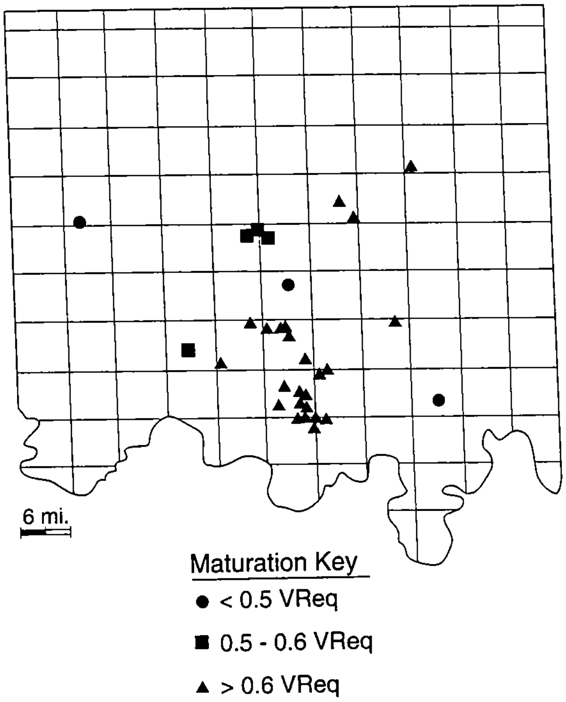


Figure 14. Maturation level of control points within Viola Group subunits 1L/1C. A maturity level of greater than 0.6% vitrinite reflectance equivalence (VReq) is generally sufficient for the sediments to have entered the oil window.

in the vicinity of the Marietta basin. Rock-Eval pyrolysis of these samples indicates oil-prone Type II/I and II kerogen with hydrogen indices up to 720 and 760 mg HC/g TOC for the chert and marl facies, respectively. Interestingly, the increase in source potential coincides with the direction of progressively deeper water setting in the depositional model for Viola Group unit 1L. Optical analysis indicates that the kerogen is dominantly derived from algal sources, with both structured and amorphous varieties present. The degradation of the kerogen to amorphous varieties is promoted by the reworking of the primary organic matter by bacterial populations. The thermal maturity of the source rock is also addressed, as adequate thermal stress is required for the transformation of the kerogen into a free hydrocarbon phase. As Figure 14 shows, the areas that have not reached the oil window coincide with the Criner uplift and the northwest extension of the Marietta basin.

The reservoirs that produce within the Viola (!) Petroleum System may include primary and secondary porosity, although the zones that produce from the siliceous laminates rely on a fracture network, since the matrix porosity and permeability are quite low (Evans, 1984; Northcutt and Johnson, 1997; Gonzalez, 1997; Candelaria and Roux, 1997). The fracture systems are developed as a function of the brittle nature displayed by the siliceous laminates, particularly in areas subjected to multiple episodes of tectonic deformation. The reports that these reservoirs generally produce water-free (Evans, 1984; Candelaria and Roux, 1997) may be related to the reservoirs being charged in-situ, as the expulsion event would only be into the fracture system of the source rock instead of into a water-wet carrier bed. This aspect of the expulsion–migration event would account for the water phase being undersaturated with respect to hydrocarbons and the water-free production. Noteworthy is the report of a similar phenomenon in the Williston basin (Price and Le Fever, 1991). The Viola Group reservoirs that rely on fractures are self-sealed by the limits of propagation, although the Sylvan Shale serves as an auxiliary regional seal. The Sylvan Shale (Fig. 2) is described as a widespread green to greenish-gray shale in the Oklahoma basin that ranges in thickness from 300–400 ft in the aulacogen to 30–200 feet in the shelf areas (Johnson and Cardott, 1992). The locally abundant graptolites and chitinozoans, and well-developed laminations, have been used to infer a depositional environment in a deep-water setting (Ham, 1969). The potential for this unit to have acted as a source rock is generally considered poor to marginal (Burruss and Hatch, 1989), although the unit has not been extensively studied.

Although a complete discussion of the structural evolution is beyond the scope of this paper, the aim of this study is to establish the relationship between deformation and the generation–expulsion event. Time-slice analysis (Wavrek and Barker, 1988) of the basin model indicates that the critical moment of the Viola (!) Petroleum System occurred near the end of the Arbuckle deformation event (Fig. 15). The *critical moment* (Magoon and Dow, 1994) represents the geologic moment during which the bulk of the hydrocarbons in the petroleum system experienced generation–migration–accumulation. Thus, it is important to recognize that the region had experienced significant tectonic deformation (Fig. 16) prior to the critical moment. The fault systems had the negative effect of limiting the source-rock drainage volume, but they contributed to the trapping mechanism of associated folds and faults and propagated the fractures within the reservoir units. Collectively, these events account for the relatively small fields that have been developed in the Viola (!) Petroleum System. By identifying the region in which the positive elements of the petroleum system overlap, a fairway is defined (Fig. 17) that will be associated with reduced risk. The lower risk is attributed to the combined factors of increased source rock volume (Fig. 12), organic richness (Fig. 13), adequate thermal stress (Figs. 14,15), and tectonic activity to promote the development of traps with fractured reservoirs (Fig. 16). The hydrocarbon resources in this fairway appear to be excellent candidates for exploitation with a minimal number of horizontal wells oriented perpendicular to the dominant fracture pattern.

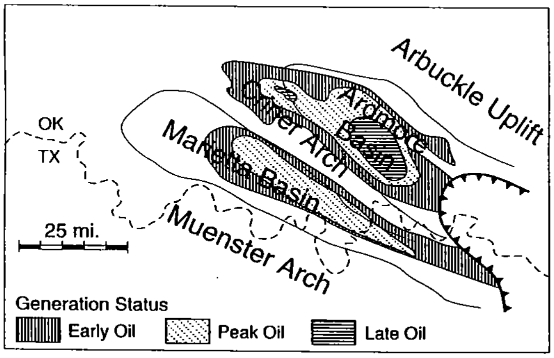


Figure 15. Thermal maturity of Viola (!) Petroleum System at the critical moment. This event occurred near the end of the Arbuckle deformation event (Late Pennsylvanian, Virgilian, approximately 290 Ma).

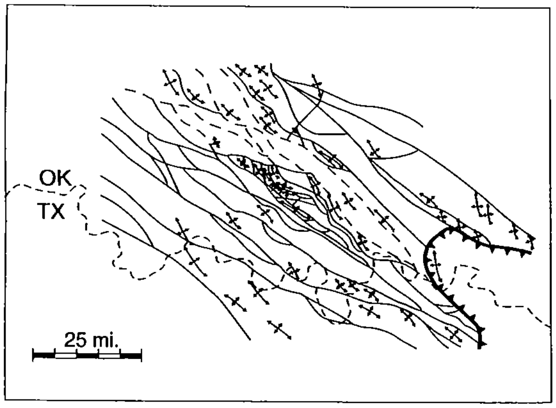


Figure 16. Structural configuration of the region at the critical moment near the end of the Arbuckle deformation event.

CONCLUSIONS

The Viola (!) Petroleum System can be developed with a minimal number of horizontal wells within a defined fairway. The exploitation model encompasses source-rock volume, organic richness, thermal stress, and tectonic activity to reduce exploration risk. The critical moment is defined to be 290 Ma; this period followed regional tectonic deformation. The fault network limited the source-rock drainage volume but contributed to the trap and reservoir configuration. The hydrocarbons within the Viola (!) Petroleum System are associated with a dilute kukersite chemistry to reflect the diverse assemblage of organisms that contributed to source facies.

ACKNOWLEDGMENTS

The original work described in this paper was supported by Amoco, ARCO, Chevron, Exxon, Mobil, Santa Fe Energy, TexCon, and Unocal. Subsequent support has been provided by Dr. Colin Barker at the University of Tulsa, and Dr. William H. Kanes at the University of Utah. Mr. Eldon R. Cox at the Oklahoma Geological Society and Mr. Charlie Clark at the Ardmore Sample Library are thanked for assistance in obtaining rock samples, and Dr. J. B. Fisher at Amoco Production Research for the total-sulfur and metal determinations. Mr. Jay Leonard at Platte River Associates is acknowledged for a complimentary copy of BasinMOD software. Mr. Nicolas Dahdah and Ms. Rula K. Kassicieh are thanked for assistance in the analytical laboratories. Finally, the operators that provided access to oil samples are gratefully acknowledged.

REFERENCES CITED

Burruss, R. C.; and Hatch, J. R., 1989, Geochemistry of oils and hydrocarbon source rocks, greater Anadarko basin: evidence for multiple sources of oils and long-distance oil migration, *in* Johnson, K. S. (ed.), Anadarko basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 53–64.

Candelaria, M. P.; and Roux, B. P., 1997, Reservoir analysis of a horizontal-well completion in the Viola Limestone "chocolate brown zone," Marietta basin, Oklahoma, *in* Johnson, K. S., (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Circular 99 [this volume], p. 183–193.

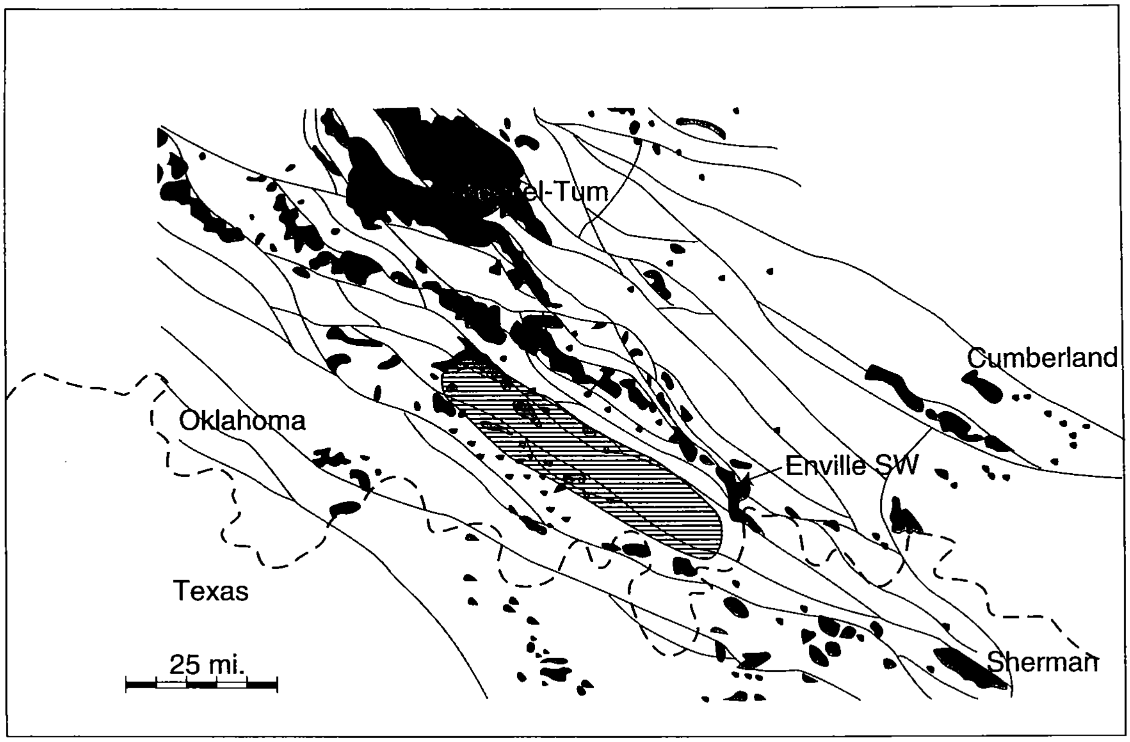


Figure 17. Fairway of opportunity (horizontal lines) for horizontal drilling targets in the Viola (!) Petroleum System.

Decker, C. E., 1933, Viola limestone, Arbuckle and Wichita Mountain regions, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 17, p. 1405–1435.

Evans, J. L., 1984, The future hydrocarbon potential of the Viola limestone in Oklahoma: Transactions of American Association of Petroleum Geologists, Midcontinent Section, 1981 regional meeting, Tulsa, p. 119–125.

Ferebee, C. D., 1991, Subsidence and basin development of the southern Oklahoma aulacogen: University of Tulsa unpublished M.S. thesis, 177 p.

Finney, S. C., 1988, Middle Ordovician strata of the Arbuckle and Ouachita Mountains, Oklahoma: contrasting lithofacies and biofacies deposited in southern Oklahoma aulacogen and Ouachita geosyncline, *in* Hayward, O. T. (ed.), Centennial field guide: Geological Society of America, South Central Section, v. 4, p. 171–176.

Fowler, M. G., 1992, The influence of *Gloeocapsomorpha prisca* on the organic geochemistry of oils and organic-rich rocks of Late Ordovician age from Canada, *in* Schidlowski, M., and others (eds.), Early organic evolution: implications for mineral and energy resources: Springer-Verlag, Berlin, p. 336–356.

Galvin, P. K., 1983, Deep to shallow carbonate ramp transition in Viola Limestone (Ordovician), southwest Arbuckle Mountains, Oklahoma [abstract]: American Association of Petroleum Geologists Bulletin, v. 63, p. 466–467.

Glaser, G. C., 1965, Lithostratigraphy and carbonate petrology of the Viola Group (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 197 p.

Gonzalez, C. M., 1997, Viola fractures—friend or foe?, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 76–77.

Grammer, G. M., 1983, Depositional history and diagenesis of the Viola Limestone (Ordovician), southeast Arbuckle Mountains, Oklahoma: Southern Methodist University unpublished M.S. thesis, 152 p.

Ham, W. E., 1969, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Guidebook 17, 52 p.

Hoffmann, P.; Dewey, J. F.; and Burke, K., 1974, Aulacogens and their genetic relation to geosynclines with a Proterozoic example from Great Slave Lake, Canada, *in* Dott, R. H., Jr.; and Shaver, R. H. (eds.), Modern and ancient geosynclinal sedimentation: Society of Economic Paleontologists and Mineralogists Special Publication 19, p. 38–55.

Johnson, K. S.; and Cardott, B. J., 1992, Geologic framework and hydrocarbon source rocks of Oklahoma, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 21–37.

Johnson, K. S.; Amsden, T. W.; Denison, R. E.; Dutton, S. P.; Goldstein, A. G.; Rascoe, Bailey, Jr.; Sutherland, P. K.; and Thompson, C. M., 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. [Reprinted in 1989 as Oklahoma Geological Survey Special Publication 89-2, 53 p.]

Magoon, L. B., 1992, The petroleum system—status of research and methods, 1992: U.S. Geological Survey Bulletin 2007, 98 p.

Magoon, L. B.; and Dow, W. C., 1994, Chapter 1. The petroleum system, *in* Magoon, L. B.; and Dow, W. C. (eds.), The petroleum system—from source to trap: American Association of Petroleum Geologists Memoir 60, p. 1–24.

Northcutt, R. A.; and Johnson, K. S., 1997, Major Simpson and Viola oil and gas reservoirs in Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 48–57.

Price, L. C.; and Le Fever, J., 1991, Horizontal drilling in the Bakken Formation—the hint for an elephant that never left the source system: American Association of Petroleum Geologists Bulletin, v. 75, p. 1137.

Pruatt, M. A., 1975, The southern Oklahoma aulacogen: a geophysical and geological investigation: University of Oklahoma unpublished M.S. thesis, 62 p.

Teague, R. D., 1985, Depositional environment and diagenesis of the Viola Group (Ordovician), Criner Hills and Marietta basin, southern Oklahoma: Oklahoma State University unpublished M.S. thesis, 117 p.

Thompson, T. L., 1976, Plate tectonics in oil and gas exploration of continental margins: American Association of Petroleum Geologists Bulletin, v. 60, p. 1463–1501.

Wavrek, D. A., 1992, Characterization of oil types in the Ardmore and Marietta basins, southern Oklahoma aulacogen, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 185–195.

Wavrek, D. A.; and Barker, Colin, 1988, The third dimension in burial history reconstructions [abstract]: American Association of Petroleum Geologists Bulletin, v. 72, p. 257–258.

Wavrek, D. A.; and Dahdah, N. F., 1995, Characterization of high molecular weight compounds—implications for advance-recovery technologies, SPE 28965: Proceedings of Society of Petroleum Engineers, International Symposium on Oil Field Chemistry, Feb. 14–17, San Antonio, Texas.

Wickham, J. S., 1978, The southern Oklahoma aulacogen, *in* Denison, R. E.; and Wickham, J. S. (eds.), Structural style of the Arbuckle region: Geological Society of America, South-Central Section, Guidebook for Field Trip 3, p. 8–41.

A Geochemical Study of Viola Source Rocks and Associated Crude Oils in the Anadarko Basin, Oklahoma

Huai Da Wang
and
R. Paul Philp
University of Oklahoma
Norman, Oklahoma

ABSTRACT.—Previous geochemical studies of Ordovician oils and source rocks have suggested that they have characteristic geochemical signatures based on a significant input of organic matter from *Gloeocapsomorpha prisca*. Examination of extracts from a number of Viola rock and oil samples has indicated that their characteristic fingerprints cannot always be associated with Ordovician samples from the Anadarko basin. Variations in the *n*-alkane and isoprenoid distributions may reflect variations in facies and depositional environments as they change from the anoxic Lower Viola subfacies to the less anoxic environment of the Middle Viola subfacies. Similarly, for oils that have been analyzed, whereas characteristic odd–even distributions of *n*-alkanes could be observed in the C_{17}–C_{21} regions of the chromatograms, it appeared that the oils were probably derived from mixed sources one of which was an Ordovician source.

Detailed qualitative and quantitative analysis of the characteristic biomarkers in the Viola rock extracts indicated much higher concentrations of microbial biomarkers, such as drimanes and hopanes, than in any other extracts examined from the Anadarko basin. The oils were also characterized by high concentrations of the C_{24}-tetracyclic terpane and 28,30-bisnorhopane, both of which are probably related to the bacterial population during deposition of these sediments. The steranes were dominated by the C_{29} steranes, which in are readily associated with an algal input and not higher plant material. The presence of 3β-methyl and 2α-methyl steranes and the absence of 4-methyl steranes have been suggested as a way of age-dating pre-Mesozoic oils and source rocks. A/B ring degraded steranes were present in relatively high concentrations in the Viola samples and provided another characteristic correlation parameter. It is thought that these compounds are formed by degradation of the regular steranes. The presence of abundant methylhopanes is characteristic of the Viola samples and reflects the highly reducing conditions under which the sediments were deposited. The isotopic composition of the oils and extracts is extremely depleted in its ^{13}C content in comparison with other formations studied in the basin. The depleted values reflect the assimilation of methane and recycled carbon by the methylotrophic bacteria, as indicated by the presence of methylhopanes.

Hence, although the Viola oils and rock extracts in the Anadarko basin do not all possess the characteristic fingerprints typically associated with Ordovician samples, a wide array of geochemical parameters can be used to characteristically identify Ordovician Viola oils and source rocks in the basin.

INTRODUCTION

The Anadarko basin extends from the central part of Oklahoma into the Oklahoma Panhandle and the northern Texas Panhandle. It is bounded on the south by the Wichita–Amarillo uplift, on the east by the Nemaha ridge, on the west by the Cimarron arch, and on the north by the Hugoton embayment (Johnson, 1989). The northern part of the Anadarko basin, also called the Northern shelf area, overlaps partially with the southern part of the Hugoton embayment. The Anadarko basin is the deepest sedimentary and structural basin in the cratonic interior of the North American Continent, and Paleozoic sedimentary rocks as thick as 40,000 ft are present along the basin's axis, near the southern margin of the asymmetrical basin. Even in the shallower northern part of the basin, the sedimentary sequence still ranges from 10,000 to 25,000 ft in thickness (Kennedy and others, 1982).

It is widely believed that the Woodford Shale (Late Devonian–Early Mississippian) is the major source rock in the Anadarko basin (Kennedy and others, 1982; Johnson and others, 1988; Rascoe and Hyne, 1988). Howev-

---

Wang, H. D.; and Philp, R. P., 1997, A geochemical study of Viola source rocks and associated crude oils in the Anadarko basin, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 87–101.

er, the volume of the Woodford Shale is limited (an average thickness of approximately 200 ft), and the variable geochemical features of crude oils produced in the Anadarko basin cannot all be correlated to the Woodford Shale. In all probability other source rocks, including several shale and carbonate formations, specifically the Viola Limestone, Lower Mississippian limestone, Woodford Shale, "Chester" formation, Springer Formation, and Morrow Group, have also made significant contributions to the oil and gas produced in the Anadarko basin. The present study will focus on results from the geochemical characterization of the Upper Ordovician Viola Limestone, which is widely distributed over the Anadarko basin. The Lower and Middle subfacies in the eastern Anadarko basin are especially rich in organic matter. A number of crude-oil samples from reservoirs ranging in age from Ordovician to Permian have been characterized as part of the study to determine whether or not any of these oils had their source in the Viola Formation.

Most samples came from the Northern shelf area and the northeastern part of the Anadarko basin, which is also the major oil- and gas-production area of the basin (Fig. 1). The Upper Ordovician Viola Limestone can be divided into three lithofacies, each representing different depositional environments (Sediqi, 1985). The Lower Viola has an average thickness of about 250 ft and was deposited in a quiet, shallow-marine environment under predominantly anaerobic conditions in the southern Anadarko basin, becoming progressively more aerobic toward the northern Anadarko basin. The remains of abundant surface-water biota were preserved on the anoxic, undisturbed sea floor. The thickness of the Middle Viola ranges from 250 to 400 ft. Similar to the Lower Viola, the Middle Viola also contains graptolites, sponges, brachiopods, and trilobites but shows signs of slightly more extensive bio-disturbance than the Lower Viola. The Upper Viola, which varies in thickness from 60 to 300 ft, contains fewer fossils and shows signs of extensive bio-disturbance, indicative of a more aerobic depositional environment. The Lower and Middle Viola are limited to the southeastern part of the Anadarko basin. This area, at the time of deposition, was near the depocenter of the cratonic paleo–Anadarko basin. The Lower and Middle Viola are richer in total organic matter (TOC values are generally greater than 1.0%) than the Upper Viola (less than 0.5%).

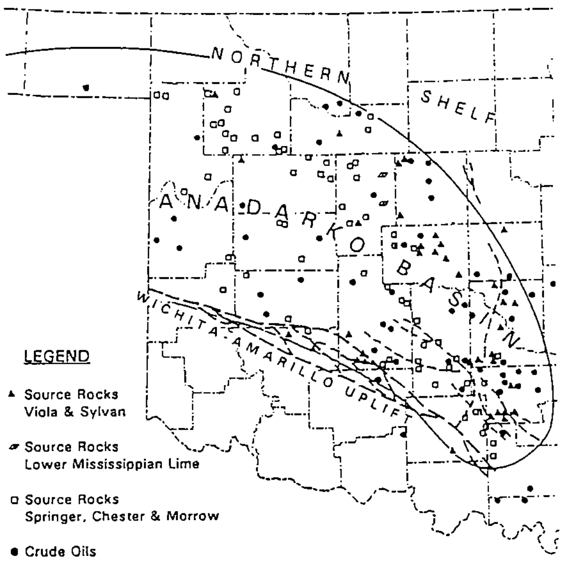


Figure 1. Map of the Anadarko basin within Oklahoma, showing locations of source-rock and oil samples.

SAMPLE PREPARATION AND EXPERIMENTAL METHODS

Most rock samples were treated with hydrochloric acid (HCl) to remove inorganic carbon and then analyzed using a LECO CR-12 carbon determinator to obtain the values of total organic carbon (TOC). Following the TOC analysis, the rock samples were pyrolyzed by using a RUSKA PYRAN Level I-FID System. T_{max} values were determined and hydrogen-index (HI) values were calculated from S_2 and TOC values. On the basis of the results of the screening analysis, rich and representative samples were chosen for further organic geochemical analyses.

Extraction and Fractionation Analyses

Source rocks were extracted by using a Soxhlet extractor with a methylene chloride-methanol 9:1 mixture for at least 48 hr, following which the asphaltene fractions of both the source-rock extracts and crude oils were precipitated with *n*-pentane. The deasphaltened source-rock extracts and crude oils were separated into saturate, aromatic, and polar (NSO) fractions by using thin-layer chromatography (TLC). A portion of each saturate fraction was treated with an S-115 molecular sieve to remove *n*-alkanes. The remaining branched and cyclic saturate fractions (B/C fractions) were used for GCMS and GCMSMS analyses.

Stable-Carbon-Isotope Analysis

Stable-carbon-isotope analyses of the saturate and aromatic fractions of oils and source-rock extracts were performed with a Finnigan Delta-E mass spectrometer, using the static combustion method described by Sofer (1984). The CO_2 samples were transferred directly to the inlet system of the mass spectrometer for stable-carbon-isotope analyses. The following formula was used to calculate the $\delta^{13}C$ values:

$$\delta^{13}C\ (‰) = [R_{sample}/R_{standard} - 1] \times 10^3$$

where R is the abundance ratio of the heavy to light isotopes of carbon (carbon ^{13}C over carbon ^{12}C; Weston and others, 1988). The reference employed was an NBS-22 working standard ($\delta^{13}C = -29.81‰$) relative to PDB carbonate ($\delta^{13}C = 0‰$).

Gas Chromatography

The saturate and aromatic fractions of source-rock extracts and crude oils were analyzed by using a Varian

3300 or an HP 5890A gas chromatograph to obtain the distribution of *n*-alkanes, isoprenoids, and aromatics with an FID detector, and sulfur compounds were determined by an FPD detector. The column (30 m × 0.25 mm ID fused silica capillary column coated with DB-5; a thickness of 0.25 μm) was programmed from 40° to 300°C at a rate of 4°C/min and then held at 300°C for 13.5 min.

GCMS and GCMSMS

Gas-chromatography–mass-spectrometry (GCMS) and tandem mass-spectrometry (GCMSMS) analyses were performed by using a Finnigan-MAT TSQ 70 system. The GC column (25 m × 0.25 μm fused silica capillary column coated with DB-5; 0.25 mm thickness) was temperature programmed initially from 40° to 140°C at a rate of 15°C/min, and then from 140° to 300°C at a rate of 1.8°C/min, and held at 300°C for 30 min. The mass spectrometer was operated at 70 eV electron energy, and the effluent of the column was monitored either in full scan mode or in MID mode. When used in MSMS parent mode, the electron energy was lowered to 30 eV. A solution of 5α(H)-androstane (base peak of m/z 245) was co-injected along with the samples as an internal standard to estimate the concentration of biomarkers.

Pyrolysis-GCMS Analysis

Selected extracted rock samples were analyzed by using a RUSKA PYRAN Level-II TC-MS system to obtain the distribution of biomarkers in kerogens. The pyrolysates were introduced to the GC column and trapped in the cold column at 0°C during the pyrolysis. When the pyrolysis was complete, the GC column (15 m × 0.25 mm ID fused silica capillary column coated with DB-5; 0.25 μm thickness) was programmed from 0°C to 300°C at a rate of 4°C/min, and held at 300°C for 15 min. A Finnigan-MAT INCOS-50 mass spectrometer was used as the mass detector and operated at 70 eV electron energy and operated in the MID mode for most of this study. A solution of poly-t-butyl styrene (base peak m/z 145) of known concentration value was co-injected with the samples as an internal standard to estimate the concentration of biomarkers.

Petrographic Analyses

A Leitz MPV compact microphotometer equipped with both white and fluorescent light sources was used to analyze these samples. Transmitted and reflected white-light and fluorescent-light observation and vitrinite-reflectance measurements were conducted in this study. Kerogen samples of the Viola Limestone were prepared for the petrographic and graptolite reflectance analyses. The source-rock samples were treated with hydrochloric acid (HCl) to remove the carbonates, and then treated with hydrofluoric acid (HF) to remove silicates. The demineralized samples were treated with hot HCl and organic solvent to remove any possible contaminants and soluble organic matter.

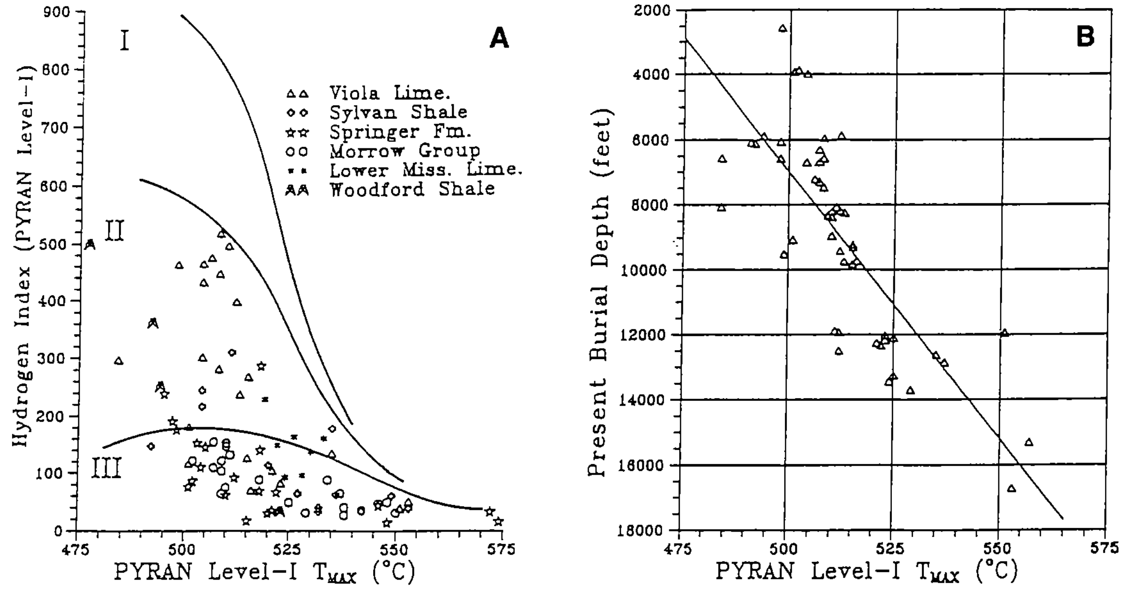
RESULTS

The average TOC value for the 39 Viola Limestone samples analyzed was 0.83%, including several organic-lean Upper Viola samples. Exclusion of the low TOC values of the Upper Viola samples gives an average TOC value for the Lower and Middle Viola samples greater than 1.0%. A limestone with a TOC value greater than 1.0% typically indicates a fairly good source rock (Tissot and Welte, 1984). A carbonate rock will adsorb fewer hydrocarbons than a shale, so that hydrocarbons can be expelled from a carbonate source rock more effectively with a TOC value as low as 0.2% (Katz, 1983; Tissot and Welte, 1984). A kerogen typing plot using hydrogen index (HI) versus T_{max} is shown in Figure 2A. The Viola Limestone is mainly a Type II kerogen. A few Viola data points fall within the region of Type III kerogen. These samples were mostly from the Upper Viola subfacies, which was deposited in a more aerobic environment and probably obtained more terrestrial input than the Lower and Middle Viola subfacies.

A plot of present burial depth versus PYRAN Level-I T_{max} for the Viola Limestone is shown in Figure 2B. The plot supports the geological interpretation that the Anadarko basin was mostly a tectonically quiet basin, with the linear relationship between burial depth and maturity level of the source rocks basically valid (Schmoker, 1986; Walker, 1986). Data points in the depth versus T_{max} plots are more or less scattered, probably owing to facies variation. The plot of Rock-Eval pyrolysis S_2 values versus TOC values for the Viola Limestone is shown in Figure 2C. Data points of samples whose TOC values are less than 0.5% were not used in making those S_2–TOC plots, because these low values cause large errors and such organic-lean samples are not good source rocks anyway. The S_2–TOC plots provide a better method for the interpretation of TOC and pyrolysis data (Langford and Blanc-Valleron, 1990), and the slope of the regression line represents the true HI. The maturity trend is along the regression line from the upper right corner to the lower left corner of the plot. The slope of the Viola Limestone is relatively high (4.15) and indicates that this source rock is mainly Type II kerogens. Langford and Blanc-Valleron (1990) suggested that the boundary (the slope of an S_2–TOC plot) between Type I and Type II kerogens is about 7.0, whereas the boundary between Type II and Type III kerogens is about 2.0. These boundaries are plotted as dashed lines in Figure 2C.

The carbon-isotope values for the saturate and aromatic fractions of selected source rocks and crude oils are plotted in Figure 3A and B, respectively (Sofer, 1984). Data points that fall on the upper left part of the plot are interpreted to be from nonmarine sources, whereas the data points that fall on the lower right part of the plot are interpreted to be from marine sources; but statistical studies have shown that many exceptions exist (Peters and others, 1986). The correlation between source rocks and oils also keyed by biomarker data can be observed. The oils are more depleted in ^{13}C than the source rocks, which may be due to migration effects (Sofer, 1984).

The saturate fractions of source rocks and crude oils were analyzed by gas chromatography, and, in general, the Viola source rocks can be divided into two groups according to the distributions of normal alkanes and acyclic isoprenoids. Group one samples include Vio-2, 4, 6, 14, and 16; representative gas chromatograms for this group are shown in Figure 4A. The ratios of Pr/Ph



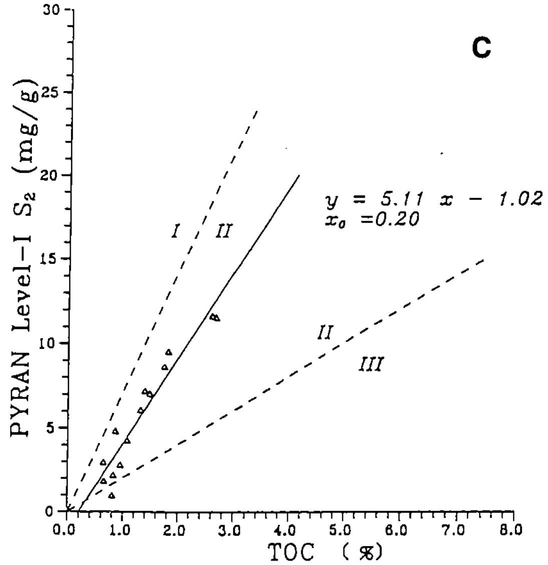


Figure 2. (A) Kerogen typing, using HI versus T_{max} methods. PYRAN Level-I pyrolysis. (B) Plot of T_{max} versus present burial depth for the Viola Limestone. (C) Plot of S_2 versus TOC for the Viola Limestone; dashed lines define kerogen types.

of Group one samples are slightly less than 1.0, indicative of a reducing depositional environment and assuming a common source for the Pr and Ph (Didyk and others, 1978; Tissot and Welte, 1984; ten Haven and others, 1987). The CPI values of the Group one samples are close to, or slightly less than, 1.0, and this even/odd predominance is one of the common features of carbonate source rocks (Palacas, 1984; Moldowan and others, 1985). The distribution of low-molecular-weight normal alkanes (C_{15} to C_{20}) exhibits an odd/even predominance, which has been suggested to be a feature of Ordovician oils and source rock (Reed and others, 1986; Hatch and others, 1987; Jacobson and others, 1988). The ratios of Pr/nC$_{17}$ and Ph/nC$_{18}$ of the Group one samples range from 0.2 to 0.5. The concentration of higher molecular-weight normal alkanes (C_{25+}) is relatively low compared to that of low-molecular-weight normal alkanes ($<C_{20}$). Since most of these source rocks are not highly mature, a high concentration of less than C_{20} normal alkanes is indicative of marine organic sources and is a feature of Ordovician sources (Jacobson and others, 1988).

Group two samples of the Viola source rocks include Vio-12, 18, 38, 52, 56, and 69; representative gas chromatograms are shown in Figure 4B. The ratios of Pr/Ph of the Group two samples are slightly greater than 1.0, indicative of a less reducing environment compared to that of the Group one samples. The CPI values of the Group two samples are also close to or slightly less than 1.0, which indicates carbonate source rocks (Palacas, 1984; Moldowan and others, 1985). The distribution of low-molecular-weight normal alkanes (C_{15} to C_{20}) of several Group two samples also exhibits odd/even predominance, which has been suggested as a feature of Ordovician oils and source rocks. Group two source rocks have slightly higher concentrations of C_{25+} higher molecular-weight normal alkanes than the Group one samples. The difference in the distributions of normal alkanes and isoprenoids between Group one and Group two may reflect a depositional environment changing gradually from anoxic in the Lower Viola subfacies to less anoxic in the Middle Viola subfacies.

Samples Vio-16 and Vio-18 have low ratios of Pr/nC$_{17}$ and Ph/nC$_{18}$ and a low concentration of C_{20+} higher molecular-weight normal alkanes, which were suggested by Reed and others (1986) and Jacobson and others (1988) as features of Ordovician source rocks.

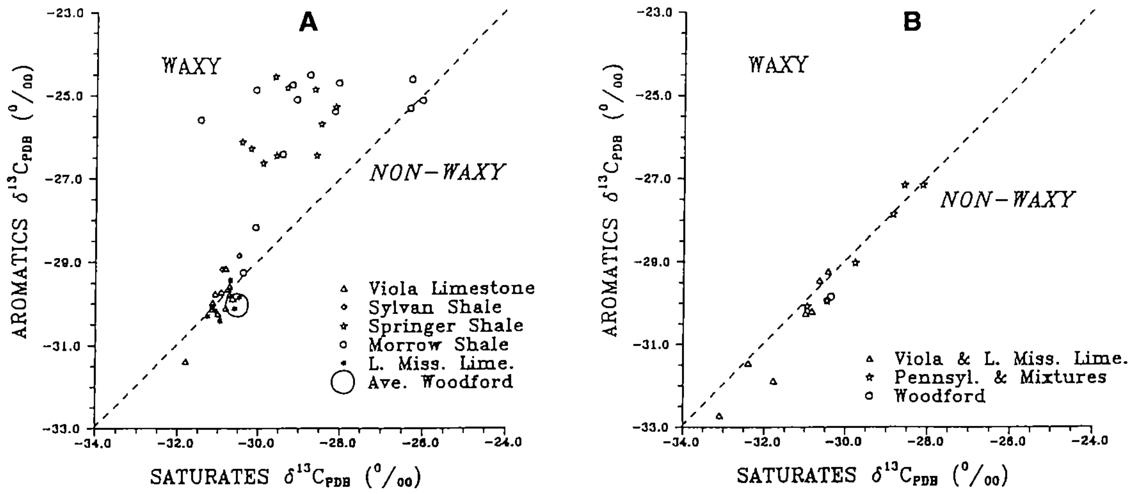


Figure 3. (A) Stable-carbon-isotope ($\delta^{13}C$) plot of source rocks. Saturate fractions versus aromatic fractions. (B) Stable-carbon-isotope ($\delta^{13}C$) plot of crude oils. Saturate fractions versus aromatic fractions.

However, these features were not as evident in the other Viola source-rock samples.

Oil sample P-20 is thought to have been generated mainly from the Viola Limestone. The features of this oil include a Pr/Ph ratio close to 1.0, an odd/even predominance between C_{12} to C_{19} normal alkanes, while exhibiting an even/odd predominance in the C_{20+} range of higher molecular-weight normal alkanes, characteristic patterns of the Viola source rock (Fig. 4C). Support for this correlation is obtained from the distribution of branched and cyclic biomarkers described below.

GCMS ANALYSIS

The Viola Limestone is a carbonate source rock of Late Ordovician age (440 Ma), and its age and nature are reflected by the distribution and occurrence of its biomarkers. A typical m/z 123 chromatogram showing the distribution of sesquiterpanes in the Viola source rock is given in Figure 5. The Viola source rock contains a high concentration of C_{16} 8ß(H)-homodrimane (peak 10) and several C_{15} sesquiterpanes. Eudesmane (peak 3) is thought to be related to higher plants, and the drimanes and homodrimanes are thought to be related to prokaryotic organisms (Alexander and others, 1983; Volkman, 1988). The high concentration of drimanes and homodrimanes (relative to other sesquiterpanes) found in the Viola source rock may be related to prokaryotic organisms that inhabited the Ordovician sea. The other sesquiterpanes, proposed to be related to higher plants, have relatively low concentrations compared to drimanes and homodrimanes in the Viola source rock. Since higher plants had not appeared in Ordovician time, these sesquiterpanes may have minor sources other than higher plants.

A partial m/z 191 chromatogram of the Viola source rock is shown in Figure 6 and illustrates the relatively high concentration of pentacyclic hopanes. If considered at approximately the same maturity level, the absolute concentration of pentacyclic hopanes (normalized to TOC) of the Viola source rock, particularly the C_{31}–C_{35} extended hopanes, is much higher than that of the other formations in the Anadarko basin. The distribution and occurrence of C_{31} to C_{35} homohopanes are valuable paleoenvironmental indicators, and it has been proposed that these homohopanes were derived from C_{35} bacteriohopanetetrol (Peters and Moldowan, 1991). High concentrations of homohopanes, especially C_{35} homohopanes, have been suggested to be associated with marine carbonate or evaporite environments (Palacas and others, 1984; Fu and others, 1986; Jones and Philp, 1990). Peters and Moldowan (1991) proposed that high concentrations of C_{31} to C_{35} homohopanes or high ratios of C_{35}/C_{34} or C_{35}/C_{31}–C_{35} homohopanes indicate marine environments with low redox potentials. Not all carbonate source rocks have high concentrations of homohopanes, and the concentration of homohopanes in the Viola source rock is not very high in comparison to examples in the literature (Palacas and others, 1984) with ratios for C_{35}/C_{34} homohopanes for most Viola samples being close to or less than 1.0.

The Ts/Tm ratio for most of the Viola source-rock samples is low (less than 1.0) regardless of maturity levels. The Ts/Tm ratio was initially used as a maturity indicator in the literature, but later it was found that the ratio is also source-related in many cases (Waples and Machihara, 1991). Price and others (1987) stated that a low Ts/Tm ratio is a feature of oils from carbonate sources and also varies with depositional environments. In this study, it was shown that the Ts/Tm ratio cannot be used solely as a maturity indicator because it may also reflect the carbonate nature of the Viola source rock.

Most Viola source rocks contain tricyclic terpanes in a range of C_{20} to C_{28} (Fig. 6), although the concentration of tricyclic terpanes is low compared to the concentration of pentacyclic hopanes. Peak 6 in Figure 6 is identified as a C_{24} tetracyclic terpane, which has been used as an indicator of an evaporite or a carbonate environment (Connan and others, 1986; Jones and Philp, 1990). Peak 14 in Figure 6 is identified as C_{28} 28,30-bisnorhopane, which is an indicator of anoxic depositional conditions (Mello and others, 1988), although it does not exist in all anoxic sediments. Its occurrence is probably dependent on a peculiar bacterial population whose environment has not been fully understood. Much lower concentrations of this compound were found in oils correlated to the Viola source rock, which may indicate that this compound is thermally unstable or less mobile compared to other terpanes. It may also be related to expulsion efficiency in oil generation.

Abundant 2α-methyl and 3ß-methyl hopanes were identified in the Viola source-rock extract (Fig. 7). Tentative identifications of these methyl hopanes were made by comparing the distribution and relative retention times with those in the literature (Summons and Jahnke, 1990, 1992). The carbon-number distributions were confirmed by using GCMSMS in the parent mode. The two questionable peaks in Figure 7 (with question marks) are tentatively identified as the C_{28} members of 2α-methyl and 3ß-methyl hopanes. The C_{29} to C_{35} members can be clearly demonstrated by GCMSMS (parent mode) by assignment of their respective parents to the m/z 205 daughter assignment (Fig. 7). The peaks marked 16, 20, and 22 in Figure 6 are regular hopanes. 3ß-Methyl hopanes are more abundant than 2α-methyl hopanes in Viola source-rock extract. The precursors of these methyl hopanes have been proposed as 2α-methyldiplopterol and 3ß-methylbacteriohopane polyols in *Acetobacter* sp. (Bisseret and others, 1985; Neunlist and Rohmer, 1985; Zundel and Rohmer, 1985a,b; Subroto, 1990) and produced by methylotrophic bacteria living in highly reducing environments. Therefore, methyl hopanes can be used as carbonate source indicators for highly reducing depositional environments. The methyl hopanes are absent or very low in concentration in the other formations under study from the Anadarko basin and appear to be characteristic for the Viola source rock and thus are useful for correlation purposes.

A typical partial m/z 217 chromatogram of the Viola Limestone is shown in Figure 8, which illustrates that the concentration of C_{29} regular steranes, especially the 5α(H), 14ß(H), 17ß(H) epimers, is very high compared

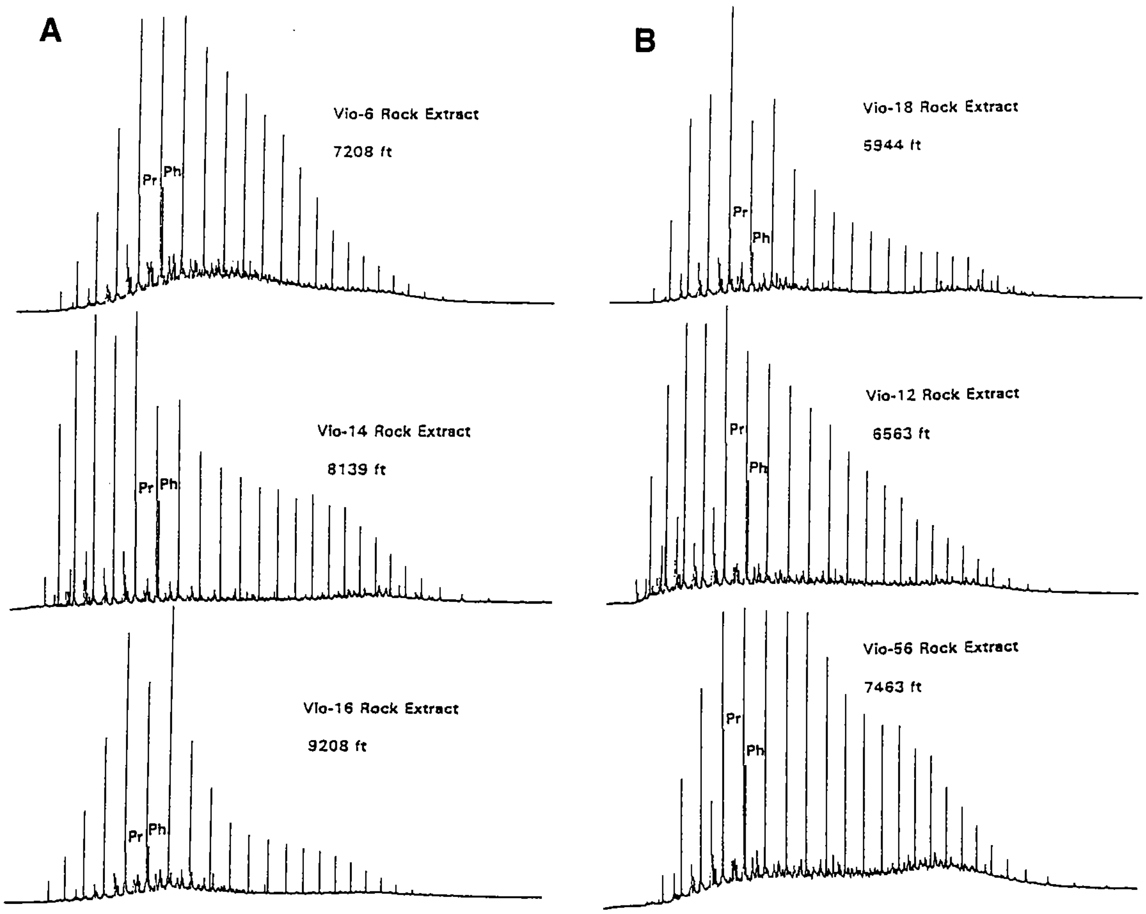
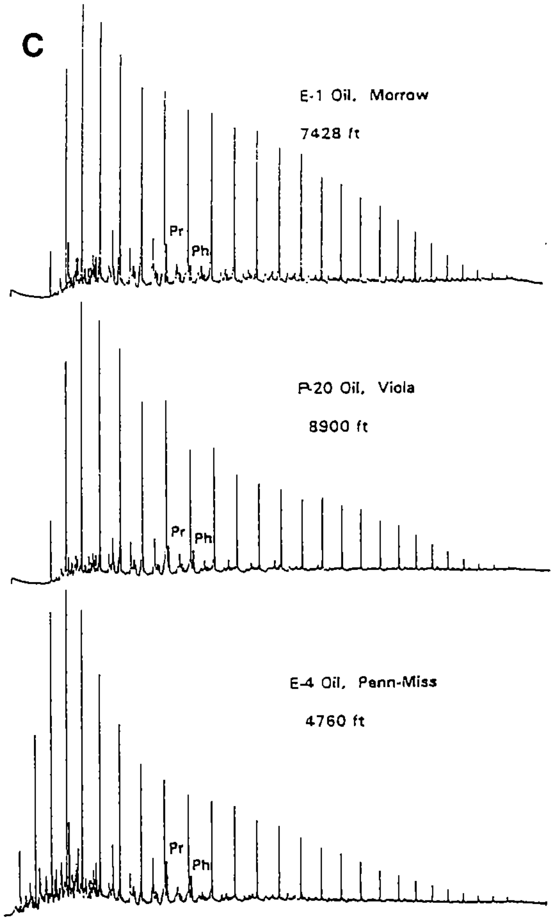


Figure 4. (A) Gas chromatograms of three Viola source rocks. Saturate fractions, Group one. (B) Gas chromatograms of three Viola source rocks. Saturate fractions, Group two. (C) (facing page) Gas chromatograms of three crude oils. Saturate fractions; names of formations are reservoirs.

to the C_{27} and C_{28} regular steranes. A high concentration of C_{29} steranes has been suggested usually to indicate a terrestrial contribution (Huang and Meinschein, 1979; Robinson, 1987), although there are many exceptions. Many researchers have pointed out that lower Paleozoic and Precambrian sediments commonly contain substantial amounts of C_{29} regular steranes, even though higher plants had not yet developed (Grantham, 1986; Rullkötter and others, 1986).

A ternary diagram for the C_{27}–C_{28}–C_{29} 14α(H),17α(H) 20R sterane isomers from the source-rock extracts is shown in Figure 9A. This type of ternary diagram was initially used with sterol distribution to interpret source inputs by Huang and Meinschein (1979) and to interpret depositional environments by Moldowan and others (1985). The area the Viola samples occupy (Fig. 9) was interpreted by Moldowan and others (1985) as incorporating marine source rocks greater than 350 million years in age, applicable to the Viola Formation, which is a Late Ordovician marine source rock with an age of more than 440 million years. The abundant C_{29} steranes are not due to higher plants but originate from marine algae or other microbial organisms. The steranes for the oil samples are labeled with the names of the formations that are believed to be the source rocks for the oils (interpreted by other geochemical data), and it can be



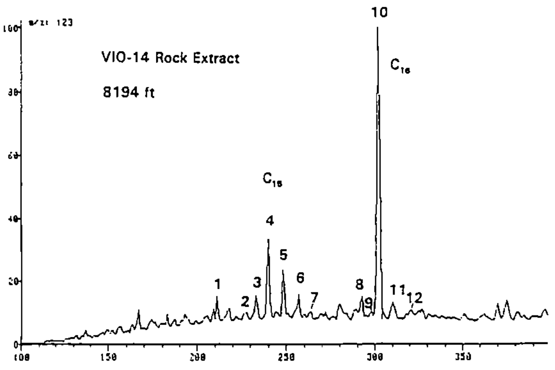


Figure 5. Typical distribution of sesquiterpanes in a Viola oil.

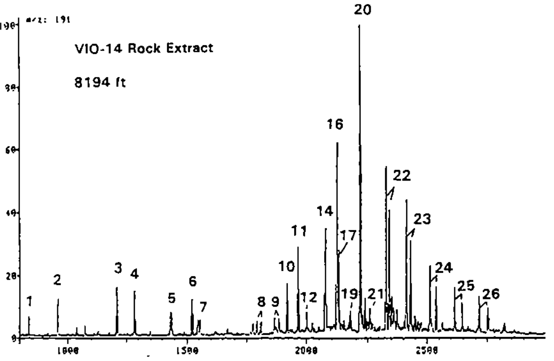


Figure 6. Typical distribution of di- and triterpanes in a Viola source-rock extract.

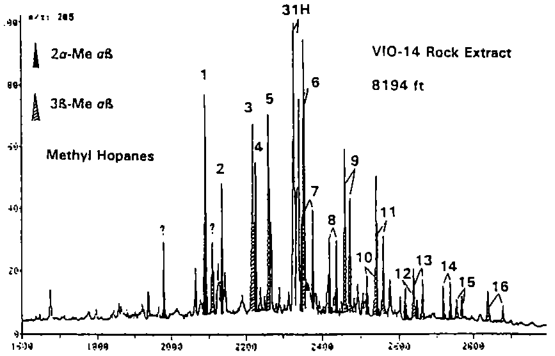


Figure 7. Typical distribution of methyl hopanes in a Viola source-rock extract.

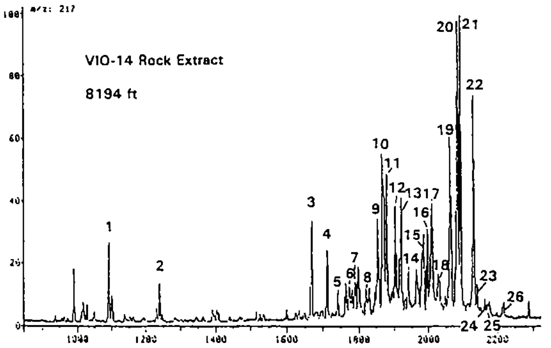


Figure 8. Typical distribution of steranes in a Viola source-rock extract.

seen that the Viola oils show a good correlation with the Viola source rocks (Fig. 9B).

The concentration of diasteranes is high in comparison to the concentration of regular steranes, considering that the Viola source rock is a limestone. Usually, a high ratio of diasteranes to regular steranes is a feature of oils and source rocks containing abundant clays. The clay works as a catalyst to convert sterols, the common precursors of steranes, to dia-[rearranged]steranes instead of regular steranes (Mello and others, 1988). However, high ratios of diasteranes to regular steranes have also been reported in carbonate source rocks. Clark and Philp (1989) listed several publications that report a high concentration of diasteranes in carbonate source rocks, especially in Paleozoic carbonate source rocks. Clay catalysis, highly oxic and organic lean (Moldowan and others, 1992), or high maturity (Peters and others, 1990), is not favorable for consideration of the Viola Limestone for several reasons: (1) the depositional environment of the Viola source rock is highly reducing and anoxic (e.g., a low Pr/Ph ratio, a high concentration of methyl hopanes); (2) the Viola source rock is fairly rich in organic matter; and (3) most Viola samples under study are not highly mature. This high ratio of diasteranes to regular steranes in the Viola Limestone is another feature of this Ordovician marine limestone and may be related to special sources or a specific depositional environment during Paleozoic time. C_{30} regular steranes were found in the Viola source-rock extract, but in relatively low concentration. The existence of C_{30} regular steranes has been proposed as strong evidence of a marine environment, because the C_{30} regular steranes represent contributions from marine algae (Moldowan and others, 1985; Peters and others, 1986). The identification of 3ß-methyl and 2α-methyl steranes (Fig. 10) was based on comparison of the distribution and relative retention times with those in the literature (Summons and others, 1987; Summons and Capon, 1988; Peters and Moldowan, 1993), and their carbon numbers have been confirmed by GCMSMS analyses. 3ß-methyl and 2α-methyl steranes, when found in the absence or near absence of 4-methyl steranes, as is the case for the Viola source rock, are potentially age-related biomarkers for pre-Mesozoic petroleum and source rocks and can be used for correlation (Summons and Capon, 1988). 3ß-methyl and 2α-methyl steranes have common sterol precursors, which change to methyl steranes via Δ^2-sterenes through bacteria processes in anoxic marine environments (Summons and Capon, 1988; Dahl and others, 1992).

Two series of bicyclic alkanes, with skeletons of alkyl-substituted hexahydroindanes, in the range of C_{19} to C_{22} were identified previously in a number of crude oils from a variety of sources (Jiang and others, 1987). These bicyclic alkanes were identified in relatively high concentration in the extracts of the Viola source rock and correlated oils. The series with CH_3 as the R_1 group has a base peak at m/z 110, whereas the series with C_2H_5 as the R_1 group has a base peak at m/z 124 (Fig. 11). The structures of these bicyclic compounds have been suggested as the same as the structure of the C-ring and D-ring of steranes, therefore suggesting in turn that both series of these bicyclic compounds are actually derived from sterol precursors by B-ring opening. It has been proposed that these bicyclic alkanes are resistant to the effects of biodegradation, which in turn enhances their role for correlation of biodegraded oil and source rocks (Jiang and others, 1987). The stereochemistry of these bicyclic alkanes is unknown at this time. A partial m/z 124 chromatogram is plotted together with a partial m/z 218 chromatogram, which enhances the peak strength of 14ß(H),17ß(H) steranes, and is shown in Figure 11. The similarities in distribution and relative abundance between these bicyclic alkanes and 14ß(H),17ß(H) steranes suggest that these bicyclic alkanes may be the decomposition products of the steranes and that they also possess the ßß configuration. Pyrolysis-GC/MS analysis was used in this study to investigate the distribution of biomarkers in extracted source rocks, kerogens, and asphaltene fractions of source-rock extracts. The distribution patterns of normal alkanes/alkenes of

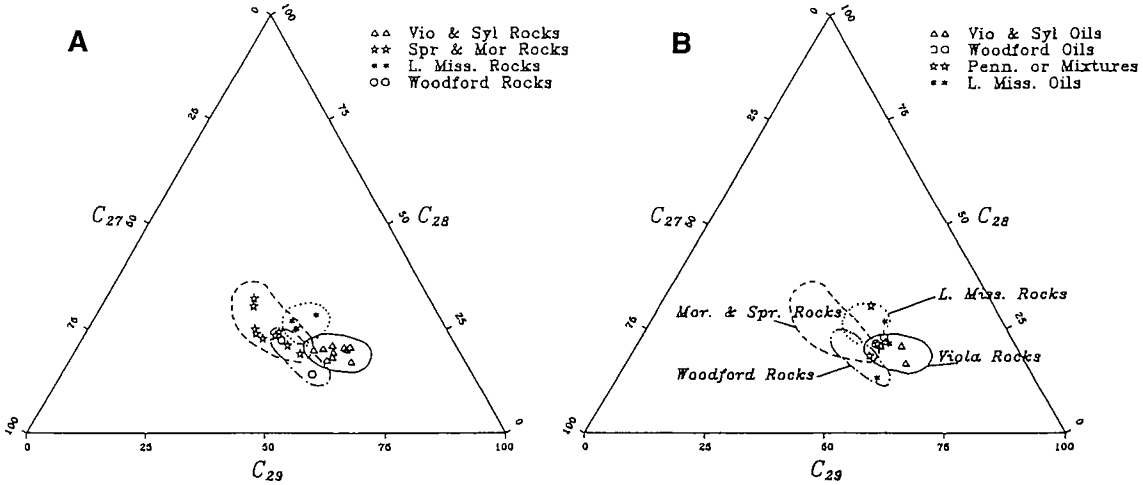


Figure 9. (A) Sterane ternary diagram of source rocks, using C_{27} to C_{29} 14α(H),17α(H) 20R regular sterane isomers. (B) Sterane ternary diagram of crude oils, using C_{27} to C_{29} 14α(H),17α(H) 20R regular sterane isomers.

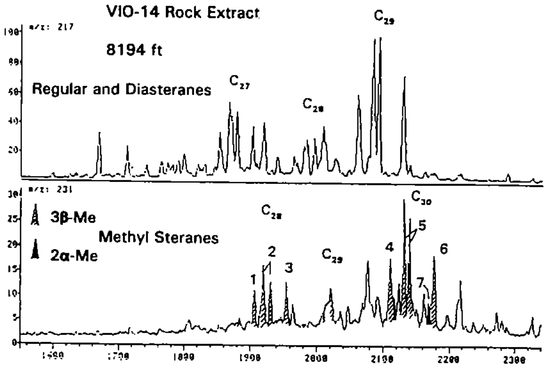


Figure 10. Typical distribution of methyl steranes in a Viola source-rock extract.

these three chromatograms are generally similar (Fig. 12). The large hump in the kerogen chromatogram is partially due to the fact that the amount of sample used for kerogen pyrolysis was smaller than that of the other two fractions. The kerogen sample has a relatively high ratio of aromatics/alkanes and a relatively high concentration of hopanes as compared to those of the other two fractions. This may be caused by the rock-matrix adsorption effect, which retains the aromatics and hopanes so that the normal alkanes are released more easily from rocks and are therefore more abundant in the extracted rock and asphaltene pyrolysates than in the kerogen. The pyrolysates of the asphaltene fraction contain more abundant C_{30+} higher molecular-weight normal alkanes/alkenes than those of the other two fractions, which may be due to components that were not incorporated into the original kerogen structure during diagenesis. Del Rio and others (1992) suggested that thermal breakdown of asphaltenes may be responsible for the production, or release, of naturally occurring high-molecular-weight hydrocarbons or di- and trimerization products of lower molecular-weight precursors.

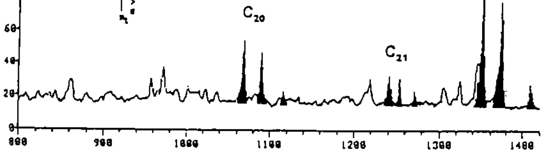


Figure 11. Comparison between the distribution of C_{20} to C_{22} bicyclic alkanes in a partial m/z 124 chromatogram and the distribution of C_{27} to C_{29} 14α(H),17α(H)-steranes in a partial m/z 218 chromatogram of a Viola source-rock extract.

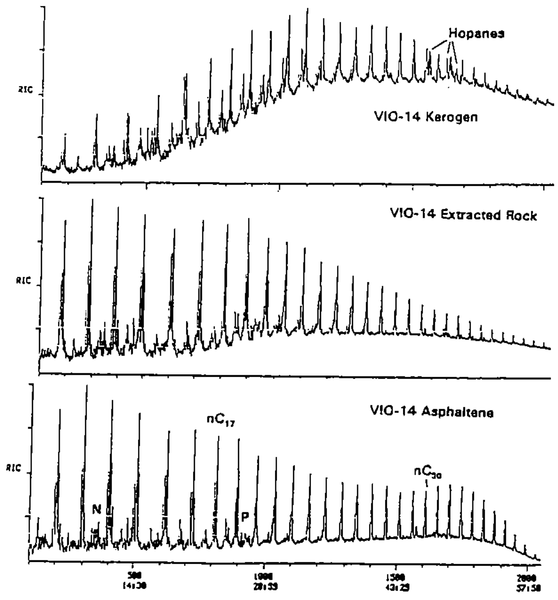


Figure 12. Pyrolysis-GC/MS RIC chromatograms of the pyrolysates of kerogen, extracted rock, and asphaltene fraction of one of the Viola source rocks.

The distribution of hopanes in the pyrolysates of extracted rock, asphaltene, and kerogen of a Viola source rock is shown in a partial m/z 191 chromatogram in Figure 13. The distribution of pentacyclic hopanes in the pyrolysates of these three fractions is basically similar, with the exception of the extracted rock, where the C_{29} 17α(H), 21ß(H)-norhopane is dominant; in the other two fractions, the C_{27} 17α(H)-trisnorhopane (Tm) is dominant. A comparison of these chromatograms with those of the rock extract (Fig. 6) shows a number of differences. In the rock extract, the C_{30} 17α(H), 21ß(H)-hopane is dominant, and the relative concentration of C_{31+} homohopanes is high compared to that of the pyrolysates of extracted rock, kerogen, and asphaltene fraction. These differences can be considered to reflect the differences in bond strengths in the structure of kerogen and the capacity of generation and migration of different compounds. The C_{30} hopane and C_{31+} homohopanes are either more easily released from kerogen than C_{29} norhopane and C_{27} trisnorhopane, or else parts of these C_{30} and C_{31+} homohopanes were never incorporated into the kerogen structure. As a result, C_{30} hopane and C_{31+} homohopanes become more abundant in the rock extract (Fig. 6), leaving a predominance of C_{29} norhopanes and C_{27} trisnorhopanes in the asphaltene and kerogen (Fig. 13). The biomarker distribution in the rock extract is the result of millions of years of natural processes of maturation and degradation working together, whereas the biomarker distribution in asphaltene or kerogen pyrolysates is the result of artificial thermal breakdown in a short time in which the effect of degradation is not significant. The rock extract appears to be more mature (e.g., it has a higher ratio of hopanes/moretanes) than the pyrolysates of the extracted rock, kerogen, or asphaltene fraction (compare Fig. 6

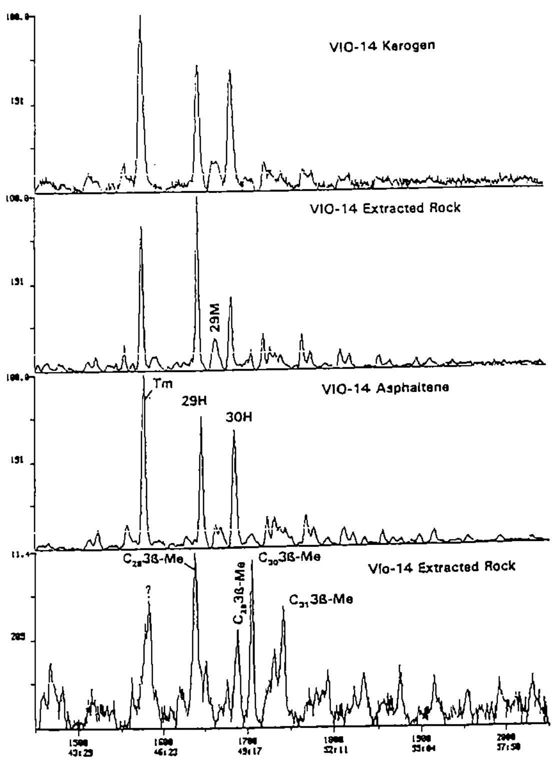


Figure 13. Pyrolysis-GC/MS partial m/z 191 and 205 chromatograms of the pyrolysates of kerogen, extracted rock, and asphaltene fraction of a Viola source-rock sample.

with Fig. 13). This can be explained by steric hindrance in kerogen or the asphaltene fraction inhibiting the rates of epimerization (Philp and Gilbert, 1986).

C_{28} 28,30-bisnorhopane exists in the rock extract but is absent in the pyrolysates of extracted rock, kerogen, and asphaltene fraction (Fig. 13). This is because this compound, or its precursor, has never been attached to the structure of kerogen or asphaltene and exists as a free component in the source rock (Moldowan and others, 1984; Noble and others, 1985; Tannenbaum and others, 1986; Philp and Gilbert, 1986). The concentration of C_{27} 18α(H)-trisnorhopane (Ts) in kerogen or the asphaltene fraction is very low compared to that of the rock extract. This can be explained as the rearrangement (from Tm to Ts) reaction, which occurs after the precursor molecule has been cleaved from the kerogen during the early stages of pyrolysis (Philp and Gilbert, 1986).

2α-methyl and 3ß-methyl hopanes exist in the pyrolysates of extracted rock, kerogen, and the asphaltene fraction as well as in the rock extract. A chromatogram showing the distribution of these methyl hopanes in the pyrolysates of the extracted rock sample is given at the bottom of Figure 13. The distributions of methyl hopanes in the pyrolysates of kerogen and the asphaltene fraction are similar to those of the pyrolysates of extracted rock. However, the distribution of methyl hopanes in the pyrolysates of extracted rock, kerogen, and the asphaltene fraction is different from that of the rock extract (Fig. 7). 3ß-methyl hopanes are dominant in the pyrolysates of extracted rock, kerogen, and the asphaltene fraction. This may be due to early expulsion of 2α-methyl hopanes compared to the 3ß-methyl isomers. Alternatively, a part of the 2α-methyl hopanes may not have been initially incorporated in the structure of kerogen or asphaltene.

BIOMARKER QUANTITATION

The concentration of the biomarkers is normalized to the TOC values of the source rocks. The concentration of hopanes is especially high in the Viola source-rock extracts in comparison to that of the other formations in the Anadarko basin and probably reflects the large contribution of prokaryotic (bacteria) organisms to the Viola source rock (Peters and Moldowan, 1993). The concentration of steranes is also high compared to that in the other formations and indicates that the contribution of algae and other marine organisms is also important (Tissot and Welte, 1984; Peters and Moldowan, 1993).

The absolute biomarker concentration decreases with maturity levels of the source rocks (Fu and others, 1986; Requejo, 1992). A plot showing how sterane concentration changes with burial depths of the Viola source rock is illustrated in Figure 14. Notice that the samples are not taken from a single well but from various localities, because the thickness of the Viola Limestone varies within the Anadarko basin. Therefore, facies variation is a factor to be considered. However, since the absolute concentration is normalized to TOC, the effect of facies variation is reduced to a minimum. The C_{29} αα sterane 20S/(20S + 20R) and C_{29} sterane ßß/αα ratios have been used as maturity indicators for source rocks and oils with low maturity (Seifert and Moldowan, 1986). The concentration of αα 20S, 20R, and ßß isomers can be seen to decrease rapidly with increasing burial depths and at approximately the same rate. This may indicate that pure conversion of 20R to 20S or ßß to αα (isomerization) is not the only reaction. As the isomerization occurs, thermal degradation con-

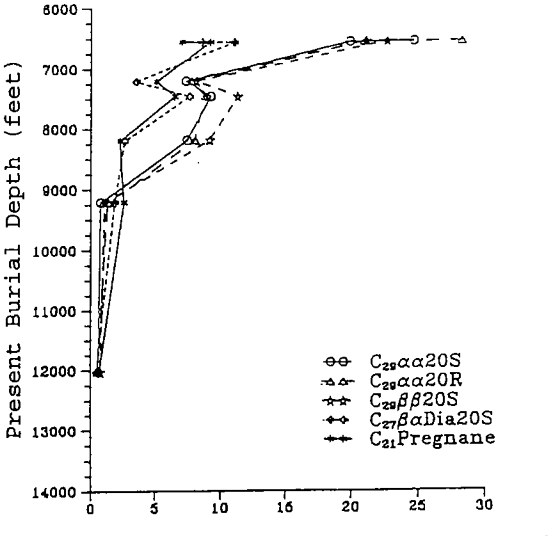


Figure 14. Relationship between the absolute concentration of steranes and present burial depth in the Viola Limestone.

sumes both 20R and 20S (or αα and ßß) isomers. The overall concentration of each sterane isomer depends on the rate summation of isomerization and degradation. The occurrence and distribution of ßß isomers and 20S isomers may also be source and environment related (McKirdy and others, 1983; ten Haven and others, 1986; Huang and others, 1990). The concentrations of pregnanes and diasteranes decrease relatively slowly when compared to those of regular steranes. This may indicate that diasteranes and pregnanes are more thermally stable than regular steranes.

A plot of tri- and pentacyclic terpane concentration shows changes with burial depths of the Viola source rock (Fig. 15). The concentrations of C_{30} regular hopane and C_{29} norhopane decrease rapidly with burial depths. Like the 20S and 20R sterane isomers, the concentration of the 22S and 22R homohopanes decreases at approximately the same rate. The concentrations of other biomarkers, such as C_{16} sesquiterpane, C_{23} tricyclic terpane, Ts, and Tm, are initially low and decrease relatively slowly.

PETROGRAPHIC FEATURES OF THE VIOLA

The Viola source-rock samples analyzed in this study are mostly from the Lower and Middle Viola subfacies. The common petrographic features of these Viola source rocks are (1) their mostly abundant, indigenous organic matter; (2) their mostly abundant fossils (Table 1); and (3) their varying degrees of dolomitization. Most Viola samples contain abundant pyrite, which indicates reducing depositional environments. Table 1 lists petrographic descriptions of selected Viola source-rock samples.

The common petrographic features of the Upper Viola subfacies can be summarized as being relatively poor in organic matter, containing less abundant fossils, showing more signs of bioturbation, and having higher degrees of dolomitization, in comparison to the Lower and Middle Viola subfacies.

The Viola kerogens are mostly amorphous and are gray to dark gray in transmitted white light. These kerogens do not contain vitrinite and inertinite, which are derived from the woody parts of higher plants, and are not as black as the kerogens from other formations. This is probably because the kerogens originated mostly from marine algae and other microbial organisms, so that the H/C ratios are higher than the "woody" kerogens, which receive large contributions from higher plants.

GRAPTOLITE REFLECTANCE OF THE VIOLA SOURCE ROCKS

Pre-Silurian sedimentary rock does not contain vitrinite (Hunt, 1979), so graptolite-reflectance measurement

TABLE 1.—PETROGRAPHIC ANALYSIS OF VIOLA SOURCE ROCKS

Sample no.	Depth (ft)	Classification	Description
Vio-35	2,549	Fossiliferous packstone	Fossils: abundant crinoids, bryozoans, brachiopods, and trilobites; dolomitized.
Vio-38	2,680	Fossiliferous wackestone	Fossils: ostracodes, brachiopods, trilobites, and other small fragments of fossils; slightly dolomitized.
Vio-18	5,945	Fossiliferous wackestone	Fossils: echinoderms, trilobites, and brachiopods; structure of bioturbation; not dolomitized.
Vio-4	6,566	Sandy wackestone	Few fossils; sandy and cherty, indigenous residual organic matter; dolomitized.
Vio-12	6,564	Muddy mudstone–wackestone	Few fossils and argillaceous; structure of bioturbation; dolomitized.
Vio-6	7,209	Fossiliferous wackestone	Fossils: abundant ostracodes, crinoids, brachiopods, and trilobites; slight bioturbation; slightly dolomitized.
Vio-56	7,464	Fossiliferous wackestone	Fossils: abundant crinoids, trilobites, and brachiopods; dolomitized.
Vio-14	8,194	Mudstone	Fossils not abundant; pieces of trilobites and sponge spicules; recrystallized calcite; slightly dolomitized.
Vio-16	9,209	Quartz packstone	Fossils: ostracodes, crinoids, brachiopods, trilobites; large quartz crystals may indicate beach deposits; slightly dolomitized.
Vio-22	12,025	Fossiliferous packstone	Fossils: echinoderms, bryozoans, and brachiopods; dolomitized.

was applied in this study to estimate the maturity level of the Viola source rock, which is of Late Ordovician age. Graptolites are an extinct class of colonial marine invertebrates found in carbonate and clastic rocks of Cambrian to Pennsylvanian age (Decker, 1959; Bulman, 1970; Bertrand and Héroux, 1987). Graptolite reflectance is a measurement of the percentage of incident white light reflected from the polished surface of the graptolite periderm (the organic skeleton of this invertebrate). Graptolite reflectance was assumed by the earliest workers to follow the same maturation trend as vitrinite reflectance (Kurylowicz and others, 1976; Teichmüller, 1978). In Oklahoma, graptolite-reflectance measurements were made on a number of rock samples, including the Viola Springs Formation, which is the Viola equivalent in the Arbuckle Mountain area (Decker, 1959; Ethington and others, 1989; Cardott and Kidwai, 1991).

Under the microscope (reflected white light), graptolite periderms appear in flat surface and gray color similar to the appearance and color of vitrinite. Graptolite periderms are both lobate (cortical and fusellar) and thin and elongated in shape (Cardott and Kidwai, 1991). The measurement of graptolite reflectance was based on the same standard procedures as vitrinite reflectance, and random reflectance (nonpolarized light, stationary stage) was measured. Usually it was not too difficult to identify enough points in most samples for measurements.

Nine Viola Limestone samples from depths of 2,680 to 12,025 ft have graptolite-reflectance values of 0.59% to 1.21%. Because there is no vitrinite in the Viola source rock, direct correlation or comparison of graptolite reflectance with vitrinite reflectance cannot be made. A comparison between the measured graptolite-reflectance values for the Viola Limestone and the calculated vitrinite-reflectance values for the Woodford Shale of Late Devonian–Early Mississippian age from the Anadarko basin is plotted in Figure 16. The R_o values of the Woodford Shale were calculated by using a least-squares regression equation developed by Cardott (1989):

$$R_o = 0.254\ e^{(0.0001152 \times Z)}$$

where Z is the present burial depth. This equation is based on measured R_o values of Woodford Shale samples from 80 wells. The R_G values of the Viola source rocks and the R_o values of the Woodford Shale were compared for the same depths. It was assumed that the age differences between the two formations are not significant for the reflectance measurements. This result supports the proposal that graptolite reflectance is a potential parameter when evaluating the thermal maturity of source rocks, especially for Paleozoic source rocks with little or no vitrinite (Kurylowicz and others, 1976; Teichmüller, 1978; Bertrand and Héroux, 1987).

The measured graptolite-reflectance values of the Viola source rocks are consistently and slightly higher (0.07% to 0.2%) than the calculated vitrinite-reflectance values of the Woodford source rock at equivalent depths. Possible reasons for this difference are (1) the Viola source rock is older than the Woodford source rock (440 versus 360 million years), so this time difference makes the Viola source rock appear more mature; (2) graptolites are different from vitrinite in terms of composition and reflectance value; and (3) a measurement error may have resulted from the difficulty in identifying representative graptolite periderms.

The use of graptolite-reflectance measurements to evaluate the thermal maturity of source rocks is a relatively new method about which discussions and debates

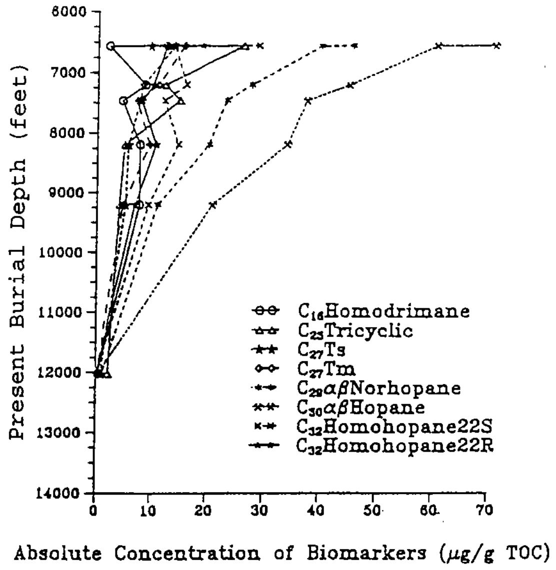


Figure 15. Relationship between the absolute concentration of terpanes and present burial depth in the Viola Limestone.

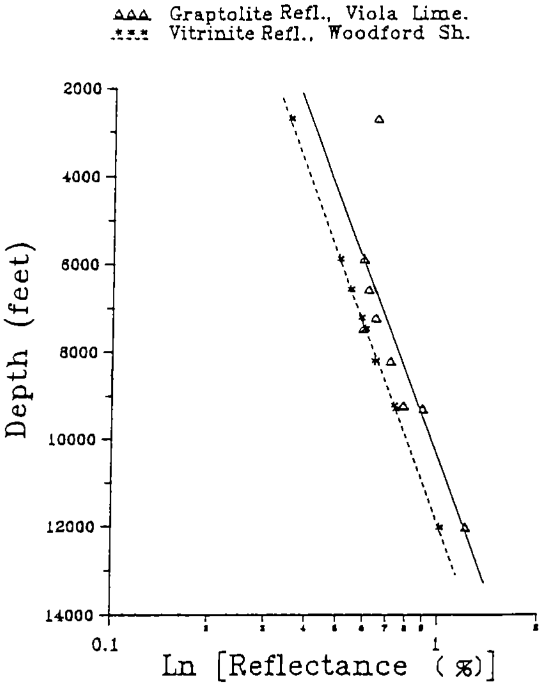


Figure 16. Comparison between graptolite reflectance in the Viola source rock and vitrinite reflectance in the Woodford source rock.

can be found in the literature. Bertrand (1990) indicated that at equivalent maturity, graptolite reflectance is slightly lower than vitrinite (telinite), whereas Goodarzi (1990) and Goodarzi and others (1992) indicated that graptolite reflectance is slightly higher than vitrinite reflectance. Goodarzi (1990) also indicated that graptolite reflectance is sensitive to lithology (slightly higher in shale than in carbonate). Additional data and investigations will help the development of this approach.

The method of using calculated reflectance, R_C (by means of aromatic parameters), has been undertaken successfully in certain cases to evaluate the thermal maturity of source rocks and for correlation with vitrinite reflectance (Radke and Welte, 1983; Radke,1988; Boreham, 1988). However, in this study the correlation between R_C and R_G (graptolite reflectance) from the Viola source rock was not readily apparent. This poor correlation may be due to the nature of the Viola source rock (a very old carbonate rock), so that the method of R_C is not applicable to this source rock.

REFERENCES CITED

Alexander, R.; Kagi, R.; and Noble, R., 1983, Identification of the bicyclic sesquiterpanes, drimane, and eudesmane in petroleum: Journal of the Chemical Society, Chemical Communications, p. 226–228.

Bertrand, R., 1990, Correlation among the reflectances of vitrinite, chitinozoans, graptolites and scolecodonts: Organic Geochemistry, v. 15, p. 565–574.

Bertrand, R.; and Héroux, Y., 1987, Chitinozoan, graptolite, and scolecodont reflectance as an alternative to vitrinite and pyrobitumen reflectance in Ordovician and Silurian strata, Anticosti Island, Quebec, Canada: American Association of Petroleum Geologists Bulletin, v. 71, p. 951–957.

Bisseret, P.; Zundel, M.; and Rohmer, M., 1985, Prokaryotic triterpenoids. 2. 2ß-Methyl-hopanoids from *Methylobacterium organophilum* and *Nostoc muscorum*, a new series of prokaryotic triterpenoids: European Journal of Biochemistry, v. 150, p. 29–34.

Boreham, C. J., 1988, Alternative calibration of the methylphenanthrene index against vitrinite reflectance: Application to maturity measurements on oils and sediments: Organic Geochemistry, v. 12, p. 289–294.

Bulman, O. M. B., 1970, *Graptolithina, Part 5 of* Treatise on invertebrate paleontology [2d edition]: Geological Society of America, Boulder, Colorado, 163 p.

Cardott, B. J., 1989, Thermal maturation of the Woodford Shale in the Anadarko basin, *in* Johnson, K. S. (ed.), Anadarko basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 32–46.

Cardott, B. J.; and Kidwai, M., 1991, Graptolite reflectance as a potential thermal-maturation indicator: Oklahoma Geological Survey Circular 92, p. 203–209.

Clark, J. P.; and Philp, R. P., 1989, Geochemical characterization and correlation of associated crude oils in the Black Creek Basin, Alberta: Bulletin of Canadian Petroleum Geology, v. 37, p. 401–416.

Connan, J.; Bouroullec, J.; Dessort, D.; and Albrecht P., 1986, The microbial input in carbonate–anhydrite facies of a sabkha palaeoenvironment from Guatemala: a molecular approach, *in* Leythaeuser, D.; and Rullkötter, J. (eds.), Advances in Organic Geochemistry, 1985: Pergamon, Oxford, p. 29–50.

Dahl, J.; Moldowan, J. M.; McCaffrey, M. A.; and Lipton, P. A., 1992, 3-Alkyl steranes in petroleum: evidence for a new class of natural products: Nature, v. 355, p. 154–157.

Decker, C. E., 1959, Correlation of lower Paleozoic formations of the Arbuckle and Ouachita areas as indicated by graptolite zones, *in* Cline, L. M.; Hilseweck, W. J.; and Feray, D. J. (eds.), The geology of the Ouachita Mountains, a symposium: Dallas Geological Society and Ardmore Geological Society, p. 92–96.

Del Rio, J. C.; Philp, R. P.; and Allen, J., 1992, Nature and geochemistry of high molecular weight hydrocarbons in oils and solid bitumens: Organic Geochemistry, v. 18, p. 541–553.

Didyk, B. M.; Simoneit, B. R. T.; Brassell, S. C.; and Eglinton, G., 1978, Organic geochemical indicators of palaeoenvironmental conditions of sedimentation: Nature, v. 272, p. 216–222.

Ethington, R. L.; Finney, S. C.; and Repetski, J. E., 1989, Biostratigraphy of the Paleozoic rocks of the Ouachita orogen, Arkansas, Oklahoma, west Texas, *in* Hatcher, R. D., Jr.; Thomas, W. A.; and Viele, G. W. (eds.), The Appalachian–Ouachita orogen in the United States: Geological Society of America, The Geology of North America, v. F-2, p. 563–574.

Fu, J. M.; Sheng, G. Y.; Peng, P. G.; Brassell, S. C.; Eglinton, G.; and Jiang, J. G., 1986, Peculiarities of salt lake sediments as potential source rocks in China, *in* Leythaeuser, D.; and Rullkötter, J. (eds.), Advances in organic geochemistry, 1985: Pergamon, Oxford, p. 119–126.

Goodarzi, F., 1990, Graptolite reflectance and thermal maturity of lower Paleozoic rocks, *in* Nuccio, V. F.; and Barker, C. E. (eds.), Applications of thermal maturity studies to energy exploration: Society of Economic Paleontologists and Mineralogists, Rocky Mountain Section, Denver, p. 19–22.

Goodarzi, F.; Centzis, T.; Harrison, C.; and Thorsteinsson, R., 1992, The significance of graptolite reflectance in regional thermal maturity studies, Queen Elizabeth Islands, arctic Canada: Organic Geochemistry, v. 18, p. 347–357.

Grantham, P. J., 1986, The occurrence of unusual C_{27} and C_{29} sterane predominance in two types of Oman crude oil: Organic Geochemistry, v. 9, p. 1–10.

Hatch, J. R.; Jacobson, S. R.; Witzke, B. J.; Risatti, J. B.; Abders, D. E.; Watbet, W. L.; Norwell, K. D.; and Vuletich, A. K., 1987, Possible late Middle Ordovician organic carbon isotope excursion: evidence from Ordovician oils and hydrocarbon source rocks, Mid-Continent and east-central United States: American Association of Petroleum Geologists Bulletin, v. 71, p. 1342–1354.

Huang, W. Y.; and Meinschein, W. G., 1979, Sterols as ecological indicators: Geochimica et Cosmochimica Acta, v. 43, p. 739–745.

Huang, D. F.; Li, J. C.; and Shang, D. J., 1990, Maturation sequence of continental crude oils in hydrocarbon basins in China and its significance: Organic Geochemistry, v. 16, p. 521–529.

Hunt, J. M., 1979, Petroleum geochemistry and geology: Freeman, San Francisco, 617 p.

Jacobson, S. R.; Hatch, J. R.; Teerman, S. C.; and Askin, R. A., 1988, Middle Ordovician organic matter assemblages and their effect on Ordovician-derived oils: American Association of Petroleum Geologists Bulletin, v. 72, p. 1090–1100.

Jiang, Z. S.; Philp, R. P.; and Lewis, C. A., 1987, Identification of novel bicyclic alkanes from steroid precursors in crude oils from Kelamayi Oilfield of China: Geochimica et Cosmochimica Acta, v. 52, p. 491–498.

Johnson, K. S., 1989, Geologic evolution of the Anadarko basin, *in* Johnson, K. S. (ed.), Anadarko basin symposium, 1988: Oklahoma Geological Survey Circular 90, p. 3–12.

Johnson, K. S.; Amsden, T. W.; Denison, R. E.; Dutton, S. P.; Goldstein, A. G.; Rascoe, Bailey, Jr.; Sutherland, P. K.; and Thompson, C. M., 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. [Reprinted in 1989 as Oklahoma Geological Survey Special Publication 89-2, 53 p.]

Jones, P. J., 1986, The petroleum geochemistry of the Pauls Valley area, Anadarko Basin, Oklahoma: University of Oklahoma unpublished M.S. thesis, 175 p.

Jones, P. J.; and Philp, R. P., 1990, Oils and source rocks from Pauls Valley, Anadarko Basin, Oklahoma, U.S.A.: Applied Geochemistry, v. 5, p. 429–448.

Katz, B. J., 1983, Limitation of "Rock-Eval" pyrolysis for typing organic matter: Organic Geochemistry, v. 4, p. 195–199.

Kennedy, C. L.; Miller, J. A.; Kelso, J. B.; and Lago, O. K., 1982, The deep Anadarko Basin: Petroleum Information Corporation, 359 p.

Kurylowicz, L. E.; Ozimic, S.; McKirdy, D. M.; Kantsler, A. J.; and Cook, A. C., 1976, Reservoir and source rock potential of the Larapinta Group, Amadeus Basin, central Australia: Australian Petroleum Exploration Association Journal, v. 16, part 1, p. 49–65.

Langford, F. F.; and Blanc-Valleron, M. M., 1990, Interpreting Rock-Eval pyrolysis data by using S_2–TOC graph: American Association of Petroleum Geologists Bulletin, v. 74, p. 799–804.

McKirdy, D. M.; Aldridge, A. K.; and Ypma, P. J. M., 1983, A geochemical comparison of some crude oils from pre-Ordovician carbonate rocks, *in* Bjøroy, M., and others (eds.), Advances in organic geochemistry, 1981: Wiley, New York, p. 99–107.

Mello, M. R.; Telnaes, N.; Gaglianone, P. C.; Chicarelli, M. J.; Brassell, S. C.; and Maxwell, J. R., 1988, Organic geochemical characterization of depositional palaeoenvironments of source rocks and oils in Brazilian marginal basins: Organic Geochemistry, v. 13, p. 31–46.

Moldowan, J. M.; Seifert, W. K.; Arnold, E.; and Clardy, J., 1984, Structure proof and significance of stereoisomeric 28,30-bisnorhopanes in petroleum and petroleum source rocks: Geochimica et Cosmochimica Acta, v. 48, p. 1651–1661.

Moldowan, J. M.; Seifert, W. K.; and Gallegos, E. J., 1985, Relationship between petroleum composition and depositional environment of petroleum source rocks: American Association of Petroleum Geologists Bulletin, v. 69, p. 1255–1268.

Moldowan, J. M.; Sundararaman, P.; Salvatori, T.; Alajbeg, A.; Gjukic, B.; Lee, C. Y.; and Demaison, G. J., 1992, Source correlation and maturity assessment of select oils and rocks from the Central Adriatic Basin (Italy and Yugoslavia), *in* Moldowan, J. M.; Albrecht, P.; and Philp, R. P. (eds.), Biological markers in sediments and petroleum: Prentice Hall, Englewood Cliffs, New Jersey, p. 370–401.

Neunlist, S.; and Rohmer, M., 1985, Novel hopanoids from the methylotrophic bacteria *Methylococcus capsulantus* and *Methylomonas methanica*, (22S)-35-aminobacteriohopane-30,31,32,33,34-pentol and (22S)-35-amino-3ß-methylbacteriohopane-30,31,32,33,34-pentol: Biochemistry Journal, v. 231, p. 635–639.

Noble, R.; Alexander, R.; and Kagi, R. I., 1985, The occurrence of bisnorhopane, trisnorhopane, and 25-norhopanes as free hydrocarbons in some Australian shales: Organic Geochemistry, v. 8, p. 171–176.

Palacas, J. G., 1984, Carbonate rocks as sources of petroleum: geological and chemical characteristics and oil-source correlations: Proceedings of the 11th World Petroleum Congress, 1983, London, v. 2, p. 31–43.

Palacas, J. G.; Anders, D. E.; and King, J. D., 1984, South Florida basin—a prime example of carbonate source rocks of petroleum, *in* Palacas, J. G. (ed.), Petroleum geochemistry and source rock potential of carbonate rocks: American Association of Petroleum Geologists Studies in Geology, v. 18, p. 71–96.

Peters, K. E.; and Moldowan, J. M., 1991, Effects of source, thermal maturity, and biodegradation on the distribution and isomerization of homohopanes in petroleum: Organic Geochemistry, v. 17, p. 47–61.

______1993, The biomarker guide, interpreting molecular fossils in petroleum and ancient sediments: Prentice Hall, Englewood Cliffs, New Jersey, 363 p.

Peters, K. E.; Moldowan, J. M.; Schoell, M.; and Hempkins, W. B., 1986, Petroleum isotopic and biomarker composition related to source rock organic matter and depositional environment: Organic Geochemistry, v. 10, p. 17–27.

Peters, K. E.; Moldowan, J. M.; and Sundararaman, P., 1990, Effects of hydrous pyrolysis on biomarker thermal maturity parameters: Monterey phosphatic and siliceous members: Organic Geochemistry, v. 15, p. 249–265.

Philp, R. P.; and Gilbert, T. D., 1986, Biomarker distributions in oils and predominantly derived from terrigenous source material, *in* Leythaeuser, D.; and Rullkötter, J. (eds.), Advances in organic geochemistry, 1985: Pergamon, Oxford, p. 73–84.

Price, P. L.; O'Sullivan, T.; and Alexander, R., 1987, The nature and occurrence of oil in Seram, Indonesia: Proceedings of Indonesian Petroleum Association, 16th annual convention, v. 1, Jakarta, p. 141–173.

Radke, M., 1988, Application of aromatic compounds as maturity indicators in source rocks and crude oils: Marine and Petroleum Geology, v. 5, p. 224–236.

Radke, M.; and Welte, D. H., 1983, The methyl-phenanthrene index (MPI): a maturity parameter based on aromatic hydrocarbons, *in* Bjøroy, M., and others (eds.), Advances in organic geochemistry, 1981: Wiley, New York, p. 504–512.

Rascoe, Bailey, Jr.; and Hyne, N. J. (eds.), 1988, Petroleum geology of the Mid-Continent: Tulsa Geological Society Special Publication 3, 162 p.

Reed, J. D.; Illich, H. A.; and Horsfield, B., 1986, Biochemical evolutionary significance of Ordovician oils and their sources: Organic Geochemistry, v. 10, p. 347–358.

Requejo, A. G., 1992, Quantitative analysis of triterpane and sterane biomarkers: methodology and application in molecular maturity study, *in* Moldowan, J. M.; Albrecht, P.; and Philp, R. P. (eds.), Biological markers in sediments and petroleum: Prentice Hall, Englewood Cliffs, New Jersey, p. 222–240.

Robinson K. M., 1987, An overview of source rocks and oils in Indonesia: Proceedings of Indonesian Petroleum Association, 16th annual convention, Jakarta, v. 1, p. 97–122.

Rullkötter J.; Meyers, P. A.; Schaefer, R. G.; and Dunham, K. W., 1986, Oil generation in the Michigan Basin: a biological marker and carbon isotope approach, *in* Leythaeuser, D.; and Rullkötter, J. (eds.), Advances in organic geochemistry, 1985: Pergamon, Oxford, p. 359–376.

Schmoker, J. W., 1986, Oil generation in the Anadarko basin, Oklahoma and Texas: modeling using Lopatin's method: Oklahoma Geological Survey Special Publication 86-3, 40 p.

Sediqi, A., 1985, A sedimentological and geochemical study of the Bigfork Chert in the Ouachita Mountains and the Viola Limestone in the Arbuckle Mountains: University of Oklahoma unpublished Ph.D. dissertation, 155 p.

Seifert, W. K.; and Moldowan, J. M., 1986, Use of biological markers in petroleum exploration, *in* Johns, R. B. (ed.), Methods in geochemistry and geophysics, v. 24, Biological markers in the sedimentary record: Elsevier, Amsterdam, p. 261–290.

Sofer, Z., 1984, Stable carbon isotope composition of crude oils: application to source depositional environment and petroleum alteration: American Association of Petroleum Geologists Bulletin, v. 68, p. 31–49.

Subroto, E. A., 1990, 30-Nor-17α(H)-Hopanes and their application in petroleum: Curtin University of Technology, Australia, unpublished Ph.D. dissertation, 518 p.

Summons, R. E.; and Capon, R. J., 1988, Fossil steranes with unprecedented methylation in ring A: Geochimica et Cosmochimica Acta, v. 52, p. 2733–2736.

Summons, R. E.; and Jahnke, L. L., 1990, Identification of the methyl-hopanes in sediments and petroleum: Geochimica et Cosmochimica Acta, v. 54, p. 247–251.

______1992, Hopenes and hopanes methylated in ring-A: correlation of the hopanoids from extant methylotrophic bacteria with their fossil analogues, *in* Moldowan, J. M.; Albrecht, P.; and Philp, R. P. (eds.), Biological markers in sediments and petroleum: Prentice Hall, Englewood Cliffs, New Jersey, p. 182–194.

Summons, R. E.; Volkman, J. K.; and Boreham, C. J., 1987, Dinosterane and other steroidal hydrocarbons of dinoflagellate origin in sediments and petroleum: Geochimica et Cosmochimica Acta, v. 51, p. 3075–3082.

Tannenbaum, E.; Ruth, E.; Huizinga, B. J.; and Kaplan, I. R., 1986, Biological marker distribution in coexisting kerogen, bitumen, and asphaltenes in Monterey Formation diatomite, California, *in* Leythaeuser, D.; and Rullkötter, J. (eds.), Advances in organic geochemistry, 1985: Pergamon, Oxford, p. 531–536.

Teichmüller, M., 1978, Identification of graptolite periderm in foliated rocks by means of coal petrological methods [in German]: Neues Jahrbuch für Geologie und Paläontologie, Monatshefte, v. 7, p. 430–447.

ten Haven, H. L.; de Leeuw, J. W.; Peakman, T. M.; and Maxwell, J. R., 1986, Anomalies in steroid and hopanoid maturity indices: Geochimica et Cosmochimica Acta, v. 50, p. 853–855.

ten Haven, H. L.; de Leeuw, J. W.; Rullkötter, J.; and Sininnghe Damste, J. S., 1987, Restricted utility of the pristane/phytane ratio as a palaeoenvironment indicator: Nature, v. 330, p. 641–643.

Tissot, B. P.; and Welte, D. H., 1984, Petroleum formation and occurrence [2d edition]: Springer–Verlag, Berlin, 699 p.

Volkman, J. K., 1988, Biological marker compounds as indicators of the depositional environments of petroleum source rocks, *in* Fleet, A. J.; Kelts, K.; and Talbot, M. R. (eds.), Lacustrine petroleum source rocks: Geological Society [London] Special Publication 40, p. 103–122.

Walker, P. E. G., 1986, A regional study of the diagenetic and geochemical character of the Pennsylvanian Morrow Formation, Anadarko Basin, Oklahoma: Oklahoma State University unpublished M.S. thesis, 156 p.

Waples, D. W.; and Machihara, T., 1991, Biomarkers for geologists: American Association of Petroleum Geologists Methods in Exploration, v. 9, 91 p.

Weston, R. J.; Engel, M. H.; Philp, R. P.; and Woolhouse, A. D., 1988, The stable carbon isotopic composition of oil from the Taranaki Basin of New Zealand: Organic Geochemistry, v. 12, p. 487–493.

Zundel, M.; and Rohmer, M., 1985a, Prokaryotic triterpenoids-1. 3ß-Methylhopanoids from *Acetobacter* species and *Methylococcus capsulatus:* European Journal of Biochemistry, v. 150, p. 23–27.

______1985b, Procaryotic triterpenoids-3. The biosynthesis of 2ß-methylhopanouds and 3ß-methylhopanoids of *Methylobacterium organophilum* and *Acetobacter pasteurianus* spp. *pasteurianus:* European Journal of Biochemistry, v. 150, p. 35–39.

Oklahoma Geological Survey Circular 99, 1997

Source Potential of the Viola Springs Formation, Southern Limb of the Arbuckle Anticline, Arbuckle Mountains, Oklahoma

Alton A. Brown
ARCO E. P. T.
Plano, Texas

Joe T. Sentfle
Vastar, Inc.
Houston, Texas

ABSTRACT.—Previous outcrop studies have indicated that the Viola Springs Formation (Upper Ordovician) in the Oklahoma aulacogen may be an oil source rock. To test the magnitude and variability of the source potential of this lean, carbonate source rock, the lower part of the Viola Springs Formation was systematically sampled and analyzed at a 0.3-m spacing along the western I-35 road cut on the southern limb of the Arbuckle anticline. The rock fabric, bulk composition, and interpreted depositional environments were also evaluated over the sampled section. This outcrop is relatively complete and unweathered over the lowermost Viola Springs section; however, the middle part of the Viola Springs Formation is not exposed, and the upper part of the lower Viola Springs exposure exhibits some intervals of weathering oxidation. Weathered samples were not analyzed; reported source characteristics are believed representative of the rock prior to weathering.

The source richness is as high as 7% total organic carbon (TOC), with a hydrogen index (HI) of 720 mg HC/g TOC. These values are deceptively rich, because only a single, stratigraphically distinctive, 25-cm-thick bed has a richness this high (referred to below as the *rich bed*). All other units have a TOC of less than 2% and a lower HI; most samples are of a quality insufficient for an effective source. The distribution of richness approximately follows a log-normal distribution, but even with log-normal distribution, the rich bed is anomalous.

The rich bed lies at a stratigraphically significant position; it is a suspension deposit overlying an anoxic hardground developed on deep-water contourite deposits. Underlying contourite deposits are uniformly organically lean. Overlying, moderately organically lean units are predominantly low-density turbidity-current deposits. The source richness in these deposits is correlated to lithologic characteristics. High-silica samples have a lower organic richness, whereas the thinner and more indistinct limestone laminations have a higher organic richness. Grab samples from the burrowed middle and upper parts of the Viola Springs Formation have a low TOC characteristic of aerobic sedimentation.

Graptolite reflectance indicates that the outcrop is thermally immature to marginally mature. The rich layer and overlying leaner source rocks have similar flash pyrolysis GC patterns, indicating that they belong to the same general kerogen family. Extracts do not have the characteristics of *Gloeocapsomorpha prisca* oils, which are widespread in Ordovician source rocks. This may be due to the relatively deep-water setting of this source rock compared to the shelf setting identified for *G. prisca* oils.

The Viola Springs Formation illustrates the problem with characterizing the source potential of a lean heterogeneous carbonate source rock. The source richness varies considerably from sample to sample. The TOC is linearly related to the total hydrocarbon yield (S_2) with a non-zero intercept, so HI decreases with decreasing TOC. Given the high variance of the log-normal distribution, even the large number of samples collected here is insufficient to characterize the mean source quality to a high degree of confidence. An inadequate sample size may limit the applicability of charge analysis techniques for lean heterogeneous source rocks, because more samples are required to characterize lean source rocks than are usually collected.

Brown, A. A.; and Sentfle, J. T., 1997, Source potential of the Viola Springs Formation, southern limb of the Arbuckle anticline, Arbuckle Mountains, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 102.

Oklahoma Geological Survey Circular 99, 1997

Ordovician Sea-Level Changes Recorded in Deep-Water, Continental-Margin Facies of North America

Stanley C. Finney
California State University
Long Beach, California

ABSTRACT.—Stratigraphic successions deposited in continental-slope, continental-rise, and basin-floor environments along the margins of North America (Laurentia) during the Ordovician Period include conspicuous records of sea-level changes. Sea-level lowstands are represented by thick submarine-fan facies composed primarily of turbiditic sandstone. Highstands are represented by graptolitic black shale and chert. Abundant graptolites and locally common conodonts allow stratigraphic records of relative sea-level change to be correlated with zonal-level resolution between successions deposited along the Cordilleran, Ouachita–Marathon, and Appalachian margins of Laurentia and to shallow-water successions deposited on inboard shelves. As a result, eustatic sea-level changes can be recognized confidently.

The Ibexian Series was deposited during a sea-level highstand. But at the end of the Ibexian, sea level dropped substantially to expose almost the entire craton and to produce the Lower–Middle Ordovician unconformity that separates Sloss's Sauk and Tippecanoe Sequences. The sea-level lowstand lasted until the mid-Whiterockian, when a sea-level rise again flooded the craton. The upper Whiterockian to lowest Mohawkian was a time of sea-level highstand, but the Tippecanoe transgression was interrupted by a short-lived sea-level drop in the early Mohawkian. By the mid-Mohawkian, sea level was again rising and continued to do so until the terminal Ordovician glacioeustatic sea-level drop associated with Gondwanan glaciation.

The Ordovician succession in the southern Oklahoma aulacogen includes many vertical facies changes that record relative sea-level changes. Many of these are third-order fluctuations of short duration and are not recorded, or have not been recognized because of lack of appropriate studies, in the basinal successions. Furthermore, some of the more prominent stratigraphic records of sea-level rise in the Oklahoma succession correlate with basinal records of sea-level falls or stillstands, suggesting that abrupt subsidence events in the aulacogen produced the relative sea-level rises.

INTRODUCTION

The recent development of sequence stratigraphy and the nearly universal application of its process-oriented approach to sedimentological analysis have focused attention on cycles of sea-level change within which stratal packages, termed sequences, were deposited (Wilgus and others, 1988). Relative sea-level change determines stratal patterns and lithofacies distributions. Although relative sea-level change is the *combined* effect of eustatic sea-level change, subsidence (tectonics, loading, and compaction), and sediment supply, it is eustatic sea-level change that receives the greatest attention as the forcing mechanism in sequence stratigraphy. Cycles of eustatic changes across a range of magnitudes and durations have been recognized and compiled into sea-level curves or cycle charts, which, in turn, have been promoted as powerful tools for effecting global correlations and understanding underlying forcing mechanisms. Global eustatic sea-level cycle charts were published for the Mesozoic and Cenozoic by Haq and others (1988) and for much of the Paleozoic by Ross and Ross (1988, 1992).

Paleozoic sea-level changes have been recognized mainly in thin stratigraphic successions deposited during transgressions and regressions of cratonic shelves (Ross and Ross, 1988, 1992). These shallow-water successions record minor as well as major sea-level changes; however, they also include substantial unconformities, and much of the sea-level record may be missing as a result. Furthermore, the impact of local subsidence and sediment supply may have been substantial in shallow-water environments, further obscuring the record of eustatic change. A more definitive record of eustatic change can be found in thick wedges of sediment deposited in deep water along continental margins. Only major sea-level changes may be recorded in deep-water stratigraphic successions, but these changes are more likely to be eustatic, and the successions are more complete than shallow-water cratonic successions.

Ordovician rocks in the Antler, Ouachita–Marathon, and Appalachian orogenic belts of North America provide an important opportunity for examining Paleozoic sea-level change (Figs. 1,2). They include thick succes-

---

Finney, S. C., 1997, Ordovician sea-level changes recorded in deep-water, continental-margin facies of North America, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 103–110.

sions of deep-marine strata deposited in slope, rise, and ocean-basin settings along both passive and tectonically active continental margins. These rocks of the "graptolitic facies" are considered to be deformed, poorly exposed, and unfossiliferous, and have been little studied as a result. However, graptolites and conodonts are found throughout them and provide a biostratigraphic basis for reconstructing the stratigraphy in considerable detail, correlating it to shallow-water cratonic successions, and recognizing eustatic sea-level changes. The purpose of this paper is to describe the stratigraphic records of eustatic sea-level changes in basinal strata deposited along the Cordilleran, Ouachitan, and Appalachian margins of North America. Three eustatic highstands and three eustatic lowstands, representing second- and third-order cycles, can be recognized in the graptolitic facies. They are associated with distinctive patterns of sedimentation that can be used to describe deposition across North America during the Ordovician, and they can be used to determine the relative influences of eustasy, subsidence, and sediment supply in the deposition of the Simpson and Viola Groups in Oklahoma.

SEDIMENTOLOGICAL RESPONSE TO SEA-LEVEL CHANGE

In inboard continental shelf and slope depositional settings, sea-level changes are recorded in complex, yet regular, patterns of systems tracts composed of a great variety of parasequence sets and parasequences. In contrast, sea-level changes are recorded in deep-water, outboard continental-rise, and ocean-basin depositional environments by alternation of only two facies: the basin-floor fan unit of the lowstand systems tract and the condensed section of the transgressive and highstand systems tracts (Van Wagoner and others, 1988; Posamentier and Vail, 1988; Loutit and others, 1988). Thus, it is the stratigraphic distribution of turbiditic sandstone and graptolitic black shale that is used to interpret deep-basinal records of sea-level change, and it is high-resolution correlation of these facies between widely separated areas that is used to recognize those sea-level changes that might be isochronous and thus eustatic.

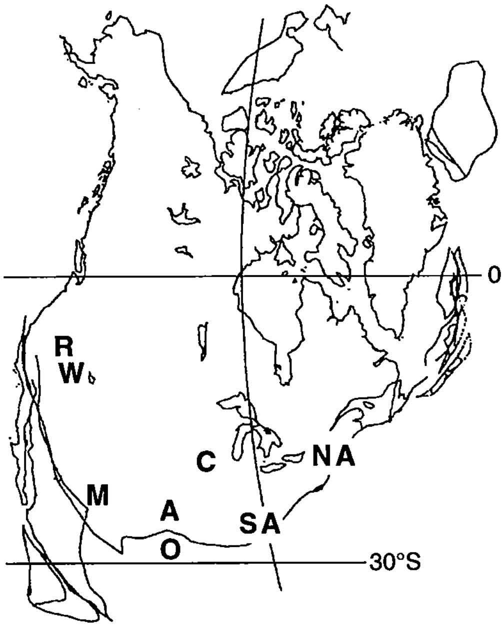


Figure 1. Paleogeographic reconstruction of North America (Laurentia) in the Middle Ordovician (modified from Scotese and McKerrow, 1990), showing location of stratigraphic records in Figures 2 and 3 for Roberts Mountains allochthon of central Nevada (*R*), Marathon region of west Texas (*M*), Ouachita Mountains of Oklahoma and Arkansas (*O*), western shelf (Cordilleran miogeocline) of central Nevada (*W*), central Midcontinent (*C*), southern and northern Appalachians (*SA, NA*), and southern Oklahoma aulacogen in Arbuckle Mountains of Oklahoma (*A*).

ORDOVICIAN RECORDS OF SEA-LEVEL CHANGE

Stratigraphic successions in the Antler, Ouachita–Marathon, and Appalachian orogenic belts include striking sedimentological records of relative sea-level change that are relatively complete for the Ordovician. Biostratigraphic control is available for high-resolution correlations for the upper Ibexian, Whiterockian, Mohawkian, and Cincinnatian Series (upper Lower to Upper Ordovician). Graptolites are common in the deep-water basinal facies of the orogenic belts, and conodonts are commonly abundant in interbedded limestone and debris-flow beds. Attention is focused, therefore, on the upper Ibexian to topmost Cincinnatian part of the succession that in southern Oklahoma includes the upper Arbuckle Group, the Simpson and Viola Groups, the Sylvan Shale, and the Keel Limestone (Fig. 3). The North American Ordovician series are used to illustrate correlations among stratigraphic columns in Figures 2 and 3. These series are well defined in terms of graptolite and conodont biostratigraphy, and most of the stratigraphic units in Figures 2 and 3 can be correlated with the resolution of graptolite and conodont zones. The series (and corresponding epochs) provide a convenient reference for discussing the Ordovician history of sea-level change.

During the late Ibexian, the Sauk transgression reached its maximum extent; almost all of North America (Laurentia) was flooded. The shallow shelf seas across the craton were the site of carbonate, predominantly dolomite, deposition. On the western shelf, the carbonate sediments of the Goodwin Formation were replaced by deeper water facies of the Ninemile Shale. The Mazarn Shale, a graptolitic black shale, was deposited in a continental-rise to basin-floor environment along the Ouachita margin. The Marathon Limestone accumulated in a more inboard, shallower water depositional setting in the Marathon region of west Texas (Finney, 1986). There, the height of the Sauk transgression is recorded in the deep-water character, perhaps slope environment, of the upper Marathon Limestone. With its rich graptolite fauna and micritic texture, it contrasts sharply with an underlying shallow-water, dolomitic facies. The Cordilleran margin was also a site of black-shale deposition in a deep basinal environment. In the lower part of the Vinini Formation within the Roberts Mountains allochthon, thick greenstone accumulations are overlain by upper Ibexian black shale, indicating that the outermost continental margin experienced rifting, submarine volcanism, and subsidence.

The Ibexian–Whiterockian boundary coincides with the most dramatic sedimentological change to affect Laurentia in the Ordovician, a major regression that ended the Sauk transgression and produced the post-Sauk unconformity (or Lower–Middle Ordovician unconformity) across the entire Laurentian craton. Most of the craton was exposed and subjected to deep erosion and karstification of the Ibexian carbonate rocks before transgression and deposition of the Tippecanoe Sequence resumed. In some cratonic sections, the duration of the unconformity represents the entire Whiterockian and the lower Mohawkian; in other areas, erosion stripped away much of the Ibexian. Although the western shelf in Nevada experienced shallowing as represented by the Ninemile Shale–Antelope Valley Limestone contact, the shelf must have continued to subside in order to accommodate the substantial thickness of shallow-water limestone that was deposited during the early Whiterockian. Carbonate deposition was also relatively continuous along the Appalachian margin in local outermost shelf environments that did not experience subaerial exposure during the regression. The regression is recorded in outboard basinal environments by the abrupt appearance of turbiditic sandstone above uppermost Ibexian black shale. The sandstone interval includes a complex mixture of fine- to coarse-grained siliciclastic sediment and represents submarine-fan complexes. The extrabasinal sediment—largely clean, mature quartz sands—was eroded off the craton and transported down submarine canyons to lower slope, rise, and basin-floor depositional sites. In the Vinini Formation in central Nevada, the submarine-fan facies is 2 km thick and was deposited within the duration of little more than one conodont zone. The Blakely Sandstone is a similar facies in the Ouachita Mountains. Although complex, facies patterns in correlative rocks in the Marathon region record an influx of debris flows and quartz sands into the depositional basin. The post-Sauk regression appears to have been rapid. Among sections where deposition was uninterrupted, the stratigraphic boundaries that record the regression, whether inboard or outboard, are nearly isochronous (Fig. 2).

By the mid-Whiterockian, the Tippecanoe transgression appears to have been well under way. Although much of the Laurentian craton remained subaerially exposed until the latest Whiterockian and earliest Mohawkian, carbonate facies were onlapping outer shelf margins. The sediment supply for submarine fans on the Cordilleran margin was shut off by the mid-Whiterockian. In the Vinini Formation in the Roberts Mountains allochthon, the turbiditic sandstone facies was gradually replaced by fine-grained contourite deposits and then by a condensed section of organic-rich, graptolitic black shale. A similar stratigraphic change does not occur until higher in the Ouachita and Marathon successions, where the Blakely Sandstone is overlain by the Womble Shale, and the Fort Peña Formation is followed by the Woods Hollow Shale, respectively. As the Tippecanoe transgression progressed, the Appalachian margin experienced the earliest phase of the Taconic orogeny. In the southern Appalachians, the outer carbonate shelf subsided rapidly in the mid-Whiterockian to produce the Sevier foredeep, which was subsequently filled first by pelagic and hemipelagic sediments and then by turbiditic, and later flysch, deposits.

Stratigraphic successions of outboard, deep-basinal environments indicate that the Tippecanoe transgression was interrupted by a regression in the early Mohawkian. Stratigraphic packages of mature quartz sandstone appeared in the early Mohawkian in the Roberts Mountains allochthon. The nature of the sandstone packages varies considerably among various mountain ranges in central Nevada (Finney and Perry, 1991) from kilometer-thick submarine-fan complexes to one to three successive, massive 10-m-thick beds that are interbedded with graptolitic black shale. The quartz-sandstone beds are very clean and mature and, in the case of massive beds, virtually identical to the Eureka Quartzite that was accumulating on the shelf at the same time. In the Ouachita Mountains of Oklahoma, the Bigfork Chert that overlies the Womble Shale is composed of interbedded graptolitic black shale and graded beds of carbonate clasts and rare thin beds of siliciclastic sediment (Finney, 1986, 1988). The carbonate and siliciclastic sediment in the Bigfork was derived from the inboard shelf and shelf edge and transported into the basin by turbidity currents and debris flows. The lower Maravillas Chert in the Marathon region also includes conglomerate with shallow-water carbonate clasts, suggesting deposition from debris flows. Although a substantial unconformity recognized at the contact between the Woods Hollow Shale and the Maravillas Chert indicates that the lowest debris-flow beds were not deposited until the latest Mohawkian to early Cincinnatian (Bergström, 1978; Goldman and others, 1995), the unconformity directly above graptolite shale does record a distinct drop in relative sea level. Along the Appalachian margin, the early Mohawkian was marked by dramatic tectonically driven changes in relative sea level. Subsidence of foredeeps and emplacement of allochthons shifted from the southern Appalachians to the central Appalachians of Pennsylvania in the earliest Mohawkian and slightly later to the classic Taconic area of eastern New York. These foredeeps were filled first with graptolitic black shale and later with turbiditic sandstone.

Although the stratigraphic successions in the basinal settings indicate a regression in the early Mohawkian, approximately coincident with the base of the *O. amplexicaulis* graptolite zone (Finney, 1986), cratonic successions suggest otherwise. The St. Peter Sandstone is clearly transgressive and was deposited across the central Midcontinent. The sands of the Eureka Quartzite prograded out across the Cordilleran shelf and spilled off into the basin, but the vertical facies change from carbonate to quartz sand in the stratigraphic succession of the western shelf may reflect increased sediment supply rather than a regressive shoreline. Alternatively, there may well have been a short-lived, early Mohawkian regressive phase during the Tippecanoe transgression, which began in the mid-Whiterockian and continued into the Silurian.

The late Mohawkian to late Cincinnatian was a time of relative sea-level highstand. In the central Midcontinent succession, deposition of the nearshore St. Peter sandstone facies was replaced by that of open-marine carbonate units (Platteville, Decorah, and Galena) and later by organic-rich, graptolitic shale of the Maquoketa Group. Marine carbonate deposition was reestablished on the western shelf as well, and graptolite-rich deep-water limestone was deposited on the outer shelf. Outboard basinal successions also record the sea-level highstand. The Bigfork Chert–Polk Creek Shale contact records the shutoff of sediment supplied from the shelf. The uppermost Maravillas Chert in Texas is largely chert and graptolitic shale; debris-flow beds are absent. The same applies to the upper Vinini Formation in the Roberts Mountains allochthon.

The highest Cincinnatian either is missing at a disconformity that extends into the lower Silurian or includes a rapid shallowing-upward sequence. In the Roberts Mountains allochthon, the graptolitic black shale is replaced by deep-water limestone in the uppermost Vinini Formation (Finney and others, 1995). No evidence of shallowing is present in the Ouachita and Marathon successions; however, the highest Ordovician in these areas is missing at disconformities. On the outer western shelf, graptolite-rich limestone in the upper Hanson Creek Formation is replaced by shallow-water limestone, and in the central Midcontinent succession,

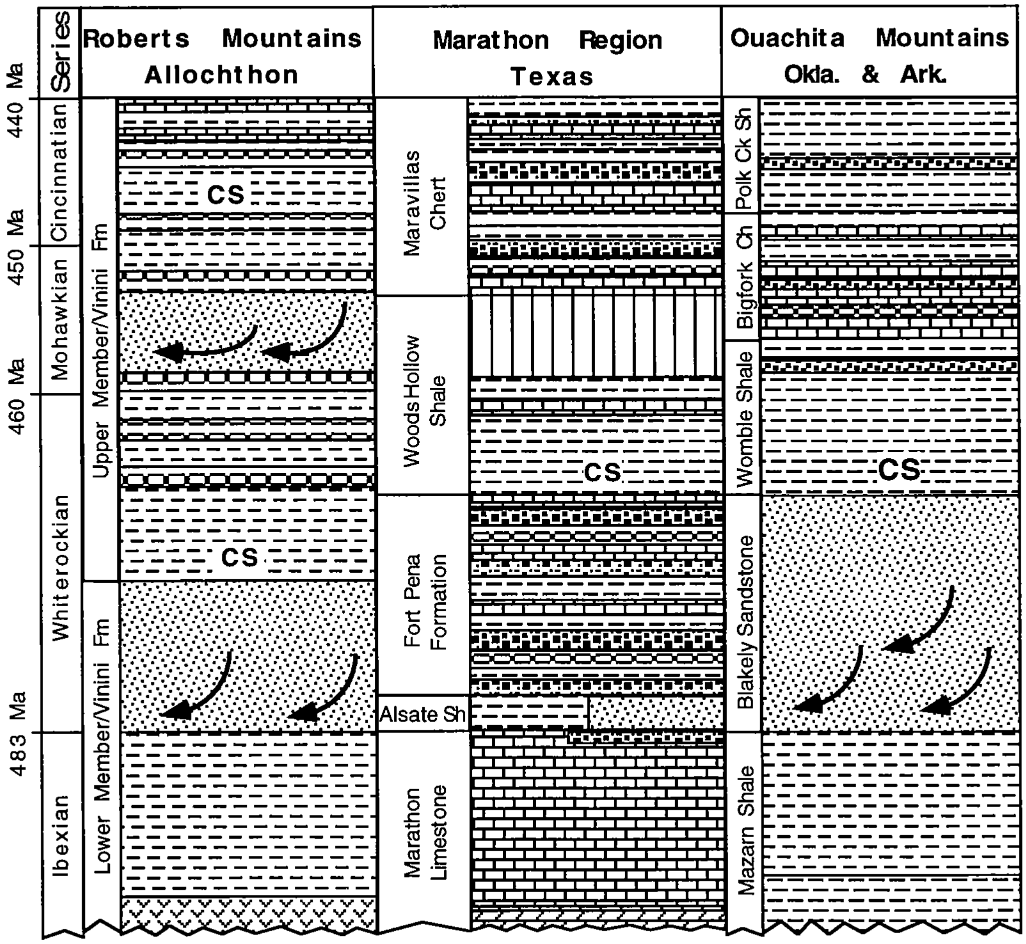


Figure 2. Simplified stratigraphic columns for key Ordovician successions. Roberts Mountains allochthon in central Nevada includes deep-basinal succession deposited off Cordilleran margin of Laurentia (Cordilleran eugeocline); stratigraphy and correlations are from Finney and Perry (1991) and Finney and others (1993). Marathon region of Texas includes Ordovician succession that represents shallower water, more inboard depositional setting such as outer shelf to upper slope. Stratigraphy and correlations are from Berry (1960) and Finney (1986). The succession in the Ouachita Mountains of Oklahoma and Arkansas is a deep-water continental-rise to basin-plain facies; stratigraphy and correlations are from Finney (1986), Ethington and others (1989), and Dworian (1990). Stratigraphy and biostratigraphy of Western shelf succession of central Nevada is from Ross and others (1982), Ross and others (1989), Ross and Ethington (1991, 1992), and Finney and Ethington (1995), and illustrates the inboard–outboard (east–west) facies change in the shelf succession. Information for the central Midcontinent is from Ross and others (1982) and is generalized for sections in Missouri, Iowa, and Illinois. The Appalachian column illustrates south-to-north stratigraphic variation from sections in Tennessee and Alabama to those in Pennsylvania to those in New York. Stratigraphy and correlations are from Finney (1986), Finney and others (1996), and Ross and others (1982).

the Maquoketa Group shallows upward and is replaced by oolitic skeletal limestone.

ORDOVICIAN EUSTATIC SEA-LEVEL CURVE

Three intervals of sea-level highstand and three intervals of lowstand are recognized from outboard, basinal Ordovician successions (Fig. 3). More than 25 sea-level cycles have been recognized in the upper Ibexian to topmost Cincinnatian in inboard, shallow-water shelf successions (Ross and Ross, 1992, 1995), but many of them cannot be correlated precisely into the basinal facies or even between various shelf successions. Furthermore, some of the better known shallow-shelf sections include substantial unconformities or were deposited in tectonically active basins, such as the southern Oklahoma aulacogen. The numerous sea-level cycles recognized by Ross and Ross (1992, 1995) are third-order cycles that had durations of 1 to 8 million years. Although few sea-level cycles have been recognized in basinal successions, those that have can be correlated with considerable precision into shelf successions and among various basinal successions. The basinal stratigraphic successions are largely complete, and sea-level changes are represented by conspicuous vertical facies changes. More sea-level cycles may be recognized with further detailed sedimentological studies of basinal successions. Among the sea-level cycles recognized, one is considered to be a second-order cycle with a duration of 40–50 million years, and the other two are considered to be third-order cycles.

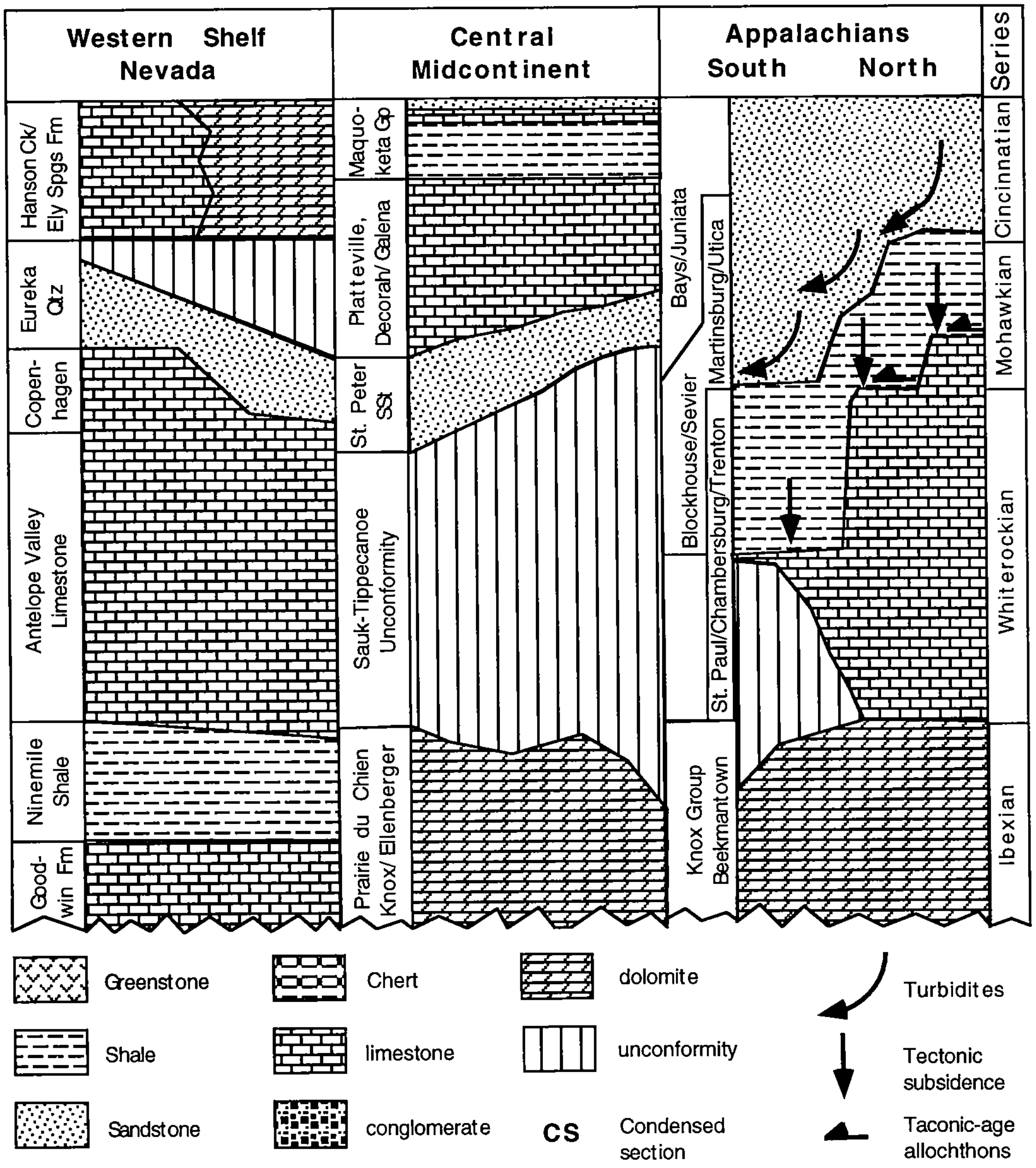


Figure 2 (continued).

The latest Ibexian was a time of sea-level highstand across all environments. Almost all the craton was flooded. The highstand was clearly eustatic. It represented the culmination of the Sauk transgression that began in the latest Precambrian. The Sauk–Tippecanoe Sequence boundary represents a eustatic lowstand that was followed, in turn, by the Tippecanoe transgression. The sea-level drop and regression at the Ibexian–Whiterockian boundary were rapid. The stratigraphic record is abrupt and nearly isochronous among both basinal and shelf successions. The lowstand lasted for at least the period required for deposition of one long conodont zone, approximately 3 to 5 million years, before the subsequent transgression began. This transgression initiated deposition of Sloss's (1963) Tippecanoe Sequence, which extends to the top of the Silurian. The stratigraphic change at the Ibexian–Whiterockian boundary is the most conspicuous record of sea-level change in Ordovician successions across North America. It was produced by a eustatic sea-level drop that separates two second-order depositional sequences. The sea-level rise in the later Whiterockian was gradual. Transgressive facies are diachronous onto the craton. The transgression appears to have been interrupted, however, by the early Mohawkian sea-level drop. Basinal successions indicate that this drop was eustatic. Its duration is hard to determine, but it may have been approximately 2 to 5 million years. Abrupt vertical facies changes suggest that both the sea-level drop and the subsequent rise were rapid. By the Cincinnatian, the Tippecanoe transgression inundated the craton to an extent unmatched since the late Ibexian. The supply of shelf sediment to the deep outboard basins was shut off, and graptolitic shale was deposited far into the interior of the craton. This relative sea-level rise was eustatic; it has been recognized in Upper Ordovician successions worldwide (Brenchley, 1988). It was followed in the latest Cincinnatian by a glacioeustatic sea-level drop and subsequent rise produced by the advance and retreat of Gondwanan glaciation. This was a time of severe global climatic change (Brenchley, 1989; Berry and others, 1995). Oceanic circulation, temperature, and water chemistry changed dramatically, and more than 50% of species went extinct, making it the second greatest extinction in Earth history. Sea level is considered to have dropped 50–100 m. The duration of the glacioeustatic lowstand was approximately 1 million years (Brenchley and others, 1995).

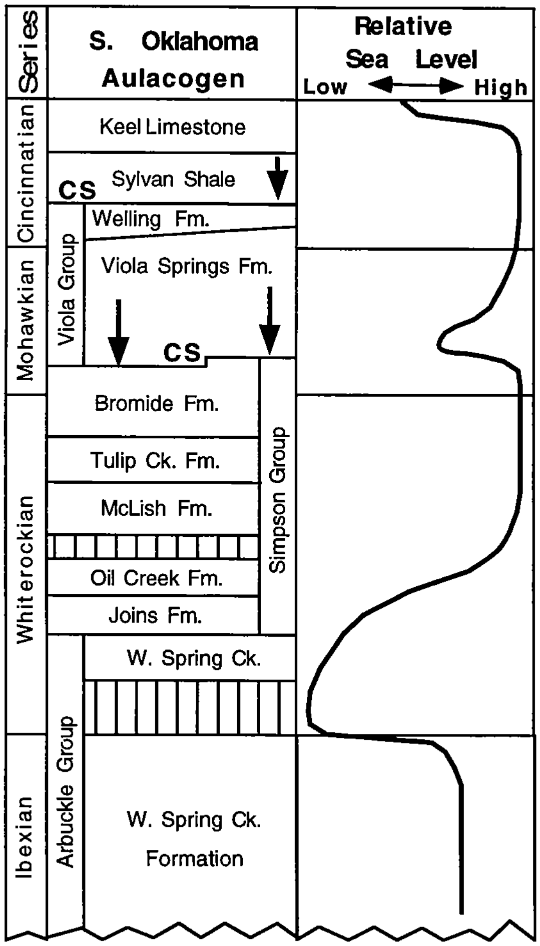


Figure 3. Stratigraphic section for the southern Oklahoma aulacogen and sea-level curve for Ordovician of North America. Stratigraphy and correlations from Finney (1986), Derby and others (1991), and Ross and others (1982).

Tectonically induced subsidence and sediment supply controlled stratigraphic records of relative sea-level changes along the Appalachian margin during the mid-Whiterockian to Cincinnatian. The Taconic tectonism was driven by an arc–continent collision. In three stages as the collision proceeded, from the central to the northern Appalachians, the carbonate shelf foundered and subsided as a result of lithospheric loading. Plate-tectonic motion that produced the orogeny may have altered ocean basins and, in turn, affected sea level. Emplacement of the Taconic allochthon in New York was contemporaneous with the early Mohawkian sea-level drop (Finney, 1986). However, the earlier emplacement of the Hamburg klippe in Pennsylvania and the mid-Whiterockian subsidence of the Sevier foredeep in the southern Appalachians were coincident with a sea-level highstand and a sea-level rise, respectively.

RELATIONSHIP OF ORDOVICIAN OF OKLAHOMA TO EUSTASY

The Ordovician succession in the Arbuckle Mountains of Oklahoma is largely complete. It was deposited in the southern Oklahoma aulacogen that experienced periodic subsidence, and the stratigraphy includes many abrupt vertical facies changes that reflect changes in relative sea level. The stratigraphic record of the most dramatic sea-level change in the Ordovician, the eustatic sea-level drop at the Ibexian–Whiterockian boundary, is remarkably subtle. It is a disconformity within the West Spring Creek Formation at the top of the Arbuckle Group and was recognized primarily on the basis of biostratigraphy (Ethington and Dresbach, 1990; Derby and others, 1991). The subsequent eustatic rise in the middle and late Whiterockian corresponds to deposition of the Simpson Group, the stratigraphic record of which includes several relative sea-level changes.

The base of the Viola Group represents a dramatic deepening event from a shallow-marine to peritidal environment represented by the uppermost Bromide Formation to the deep-water environment in which fine-grained, organic-rich, graptolite-bearing lime mudstone of the lower Viola Springs Formation was deposited (Finney, 1986). This relative sea-level rise in the southern Oklahoma aulacogen was contemporaneous with the early Mohawkian sea-level fall considered to be eustatic. If the sea-level fall was indeed eustatic, then the southern Oklahoma aulacogen must have subsided rapidly and much farther than the contemporaneous eustatic sea-level fall to have produced the deepening event recorded at the Simpson–Viola contact.

The base of the Sylvan Shale also represents a deepening event. The lower Sylvan is a graptolitic black shale; it rests directly on coarse-grained skeletal limestone of the Welling Formation. The contact correlates with the early Cincinnatian eustatic highstand. The relative sea-level rise may have been a third order sea-level fluctuation, or, if sea level did not change, this stratigraphic change must represent rapid subsidence in the aulacogen. The Sylvan is composed of a shallowing-upward sequence. Black shale is overlain by unfossiliferous blue-gray and green shale. The Sylvan is, in turn, succeeded by oolitic Keel Limestone that records the topmost Cincinnatian glacioeustatic sea-level fall.

Significant correspondence is lacking between the eustatic sea-level curve developed here and relative sea-level changes recorded in the succession of the southern Oklahoma aulacogen. Unrecognized third-order cycles may have produced many of the vertical facies changes in the succession. Furthermore, some of the more obvious relative sea-level rises may have been caused by rapid, substantial subsidence within the aulacogen.

REFERENCES CITED

Bergström, S. M., 1978, Middle and Upper Ordovician conodont and graptolite biostratigraphy of the Marathon, Texas, graptolite zone reference standard: Palaeontology, v. 21, p. 723–758.

Berry, W. B. N., 1960, Graptolite faunas of the Marathon region, West Texas: University of Texas Publication 6005, 179 p.

Berry, W. B. N.; Quinby-Hunt, M. S.; and Wilde, Pat, 1995, Impact of Late Ordovician glaciation–deglaciation on marine life, *in* Stanley, S. M.; and Kennett, J. (eds.), The effects of past global change on life: Studies in Geophysics, National Academy Press, Washington, D.C., p. 34–46.

Brenchley, P. J., 1988, Environmental changes close to the Ordovician–Silurian boundary: British Museum of Natural History (Geology) Bulletin, v. 43, p. 377–385.

______1989, The Late Ordovician extinction, *in* Donovan, S. K. (ed.), Mass extinctions: processes and evidence: Columbia University Press, New York, p. 104–132.

Brenchley, P. J.; Carden, G. A. F.; and Marshall, J. D., 1995, Environmental changes associated with the "First Strike" of the Late Ordovician mass extinction: Modern Geology, v. 20, p. 69–82.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle, and Simpson Groups, Cambrian and Ordovician, Oklahoma: a review of correlation tools and techniques available to the explorationist, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Dworian, P. R., 1990, The biostratigraphy and biogeography of Upper Ordovician graptolites from North America: California State University, Long Beach, unpublished M.S. thesis, 168 p.

Ethington, R. L.; and Dresbach, R. I., 1990, Ordovician conodonts in the Arbuckle Group, southern Arbuckle Mountains, Oklahoma, *in* Ritter, S. M. (ed.), Early to middle Paleozoic conodont biostratigraphy of the Arbuckle Mountains, southern Oklahoma: Oklahoma Geological Survey Guidebook 27, p. 33–37.

Ethington, R. L.; Finney, S. C.; and Repetski, J. E., 1989, Biostratigraphy of the Paleozoic rocks of the Ouachita orogen, Arkansas, Oklahoma, west Texas, *in* Hatcher, R. D., Jr.; Thomas, W. A.; and Viele, G. W. (eds.), The Appalachian–Ouachita orogen in the United States: Geological Society of America, The Geology of North America, v. F-2, p. 563–574.

Finney, S. C., 1986, Graptolite biofacies and correlation of eustatic, subsidence, and tectonic events in the Middle–Upper Ordovician of North America: Palaois, v. 1, p. 435–461.

______1988, Middle Ordovician strata of the Arbuckle and Ouachita Mountains, Oklahoma: contrasting lithofacies and biofacies deposited in southern Oklahoma aulacogen and Ouachita geosyncline, *in* Hayward, O. T. (ed.), Centennial Field Guide: Geological Society of America, South-Central Section, v. 4, p. 171–176.

Finney, S. C.; and Ethington, R. L., 1995, Base of Whiterock Series correlates with base of *Isograptus victoriae lunatus* Zone in Vinini Formation, Roberts Mountains, Nevada, *in* Cooper, J. D.; Droser, M. L.; and Finney, S. C. (eds.), Ordovician odyssey: short papers for the Seventh International Symposium on the Ordovician System: Society for Sedimentary Geology (SEPM), Pacific Section, Fullerton, California, p. 153–156.

Finney, S. C.; and Perry, B. D., 1991, Depositional setting and paleogeography of Ordovician Vinini Formation, central Nevada, *in* Cooper, J. D.; and Stevens, C. H. (eds.), Paleozoic paleogeography of the western U.S., II: Society for Sedimentary Geology (SEPM), Pacific Section, Book 67, p. 747–766.

Finney, S. C.; Perry, B. D.; Emsbo, Poul; and Madrid, R. J., 1993, Stratigraphy of the Roberts Mountains Allochthon, Roberts Mountains and Shoshone Range, Nevada, *in* Lahren, M. M.; Trexler, J. H., Jr.; and Spinosa, C. (eds.), Crustal evolution of the Great Basin and Sierra Nevada: Guidebook for Geological Society of America, Cordilleran/Rocky Mountain Sections, Department of Geological Sciences, University of Nevada, Reno, p. 197–230.

Finney, S. C.; Berry, W. B. N.; and Sweet, W. C., 1995, An important Ordovician/Silurian boundary interval section in Vinini Formation, Roberts Mountains, Nevada, *in* Cooper, J. D.; Droser, M. L.; and Finney, S. C. (eds.), Ordovician odyssey: short papers for the Seventh International Symposium on the Ordovician System: Society for Sedimentary Geology (SEPM), Pacific Section, Fullerton, California, p. 163–164.

Finney, S. C.; Grubb, B. J.; and Hatcher, R. D., Jr., 1996, Graphic correlation of Middle Ordovician graptolite shale, southern Appalachians: an approach for examining the subsidence and migration of a Taconic foreland basin: Geological Society of America Bulletin, v. 108, p. 355–371.

Goldman, Daniel; Bergström, S. M.; and Mitchell, C. E., 1995, Zone 13 graptolite biostratigraphy in the Marathon, Texas, standard succession and its bearing on Upper Ordovician graptolite biogeography: Lethaia, v. 28, p. 115–128.

Haq, B. U.; Hardenbol, J.; and Vail, P. R., 1988, Mesozoic and Cenozoic chronostratigraphy and cycles of sea-level change, *in* Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 71–108.

Loutit, T. S.; Hardenbol, J.; Vail, P. R.; and Baum, G. R., 1988, Condensed sections: the key to age determinations and correlation of continental margin sequences, *in* Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 183–213.

Posamentier H. W.; and Vail, P. R., 1988, Eustatic controls on clastic deposition II—sequence and systems tract models, *in* Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 125–154.

Ross, C. A.; and Ross, J. R. P., 1988, Late Paleozoic transgressive–regressive deposition, *in* Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 227–247.

______1992, Ordovician sea-level fluctuations, *in* Webby, B. D.; and Laurie, J. R. (eds.), Global perspectives on Ordovician geology: Balkema, Rotterdam, p. 327–335.

______1995, North American Ordovician depositional sequences and correlations, *in* Cooper, J. D.; Droser, M. L.; and Finney, S. C. (eds.), Ordovician odyssey: short papers for the Seventh International Symposium on the Ordovician System: Society for Sedimentary Geology (SEPM), Pacific Section, Fullerton, California, p. 309–313.

Ross, R. J., Jr.; and Ethington, R. L., 1991, Stratotype of Ordovician Whiterock Series, with an appendix on graptolite correlation of the topmost Ibexian by C. E. Mitchell: Palaois, v. 6, p. 156–173.

______1992, North American Whiterock Series suited for global correlation, *in* Webby, B. D.; and Laurie, J. R. (eds.), Global perspectives on Ordovician geology: Balkema, Rotterdam, p. 135–152.

Ross, R. J., Jr.; and 27 others, 1982, The Ordovician System in the United States, correlation chart and explanatory notes: International Union of Geological Sciences Publication 12, 73 p.

Ross, R. J., Jr.; James, N. P.; Hintze, L. F.; and Poole, F. G., 1989, Architecture and evolution of a Whiterockian (early Middle Ordovician) carbonate platform, Basin Ranges of western U.S.A., *in* Crevello, P. D.; Wilson, J. L.; Sarg, J. F.; and Read, J. F. (eds.), Controls on carbonate platform and basin development: Society of Economic Paleontologists and Mineralogists Special Publication 44, p. 167–185.

Scotese, C. R.; and McKerrow, W. S., 1990, Revised world maps and introduction, *in* McKerrow, W. S., and Scotese, C. R. (eds.), Palaeozoic palaeogeography and biogeography: Geological Society [London] Memoir 12, p. 1–21.

Sloss, L. L., 1963, Sequences in the cratonic interior of North America: Geological Society of America Bulletin, v. 74, p. 93–113.

Van Wagoner, J. C.; Posamentier, H. W.; Mitchum, R. M.; Vail, P. R.; Sarg, J. F.; Loutit, T. S.; and Hardenbol, J., 1988, An overview of the fundamentals of sequence stratigraphy and key definitions, *in* Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 39–45.

Wilgus, C. K.; Hastings, B. S.; Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), 1988, Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, 407 p.

Oklahoma Geological Survey Circular 99, 1997

Structural and Stratigraphic Factors That Influence Simpson Group Production in Central Oklahoma

Paul W. Smith
NOREX Corporation
Norman, Oklahoma

ABSTRACT.—The area of study includes Ts. 7–9 N., Rs. 1–3 W., Cleveland and McClain Counties, Oklahoma. Sandstones of the five Simpson Group formations have produced more than 65 million barrels of oil (65 MMBO) from this 324-mi^2 area. Production is from structural traps, generally small faulted anticlines ranging in size from 80 to 750 acres. Cumulative oil production per field ranges from 36,000 to 11.76 MMBO.

The distribution of oil production from the Simpson Group has been considered enigmatic, because all the sandstone members are present throughout the study area but some fields have attained production from all the sandstone members and others produce from only one zone. The Simpson shales are not capable of generating hydrocarbons, and the oil produced from the Simpson Group probably originated from the Devonian–Mississippian Woodford Shale. The McClain County fault juxtaposed the Woodford Shale with the Simpson Group, which enabled lateral oil migration from the Woodford into the Simpson sandstones. Also, tortuous migration pathways, which involve downthrown younger rocks adjacent to upthrown older rocks, allowed Woodford oil ultimately to accumulate in Simpson reservoirs.

Slight structural movements occurred contemporaneously with deposition of the Simpson Group, creating semi-parallel northeast–southwest-oriented thick and thin trends. Local structural movements were active during part or all of Simpson deposition. This created stratigraphic variations in the individual Simpson Group formations, which cause the apex of a field to migrate (or even vanish) with depth. Consequently, lower Simpson structures may not be reflected by upper Simpson structures, and conversely, upper Simpson structures may not continue with depth. Variations in Viola deposition enhanced the vertical discontinuity of structures within the study area, so that mapped Viola structures may not reflect underlying Simpson structures. Furthermore, a dramatic change in the orientation of the structural grain began to appear in Late Ordovician (Viola) time. Subsequent movements enhanced this later structural orientation, producing two acute structural trends that control the entrapment of oil. This study demonstrates that the dual structural imprint is probably the single most important factor in controlling the distribution and accumulation of hydrocarbons within the study area. This study also identified stratigraphic conditions within the Simpson Group sandstones that may affect their productivity.

INTRODUCTION

The study area includes Ts. 7–9 N., Rs. 1–3 W., Cleveland and McClain Counties, Oklahoma. Geographically, it includes the Norman, Noble, Goldsby, Slaughterville, and Washington areas and is positioned to include both sides of the McClain County fault approximately midway between the Pauls Valley uplift to the south, and the Oklahoma City uplift to the north. This 324-mi^2 area has produced approximately 65 million barrels of crude oil to date from sandstones of the Ordovician Simpson Group. The sandstones included in the study area are, in descending order: "First Bromide" sandstone, "Second Bromide" sandstone, Tulip Creek sandstone, McLish sandstones, and Oil Creek sandstone. The Joins sandstone is present in only one well near the southern edge of the study area; consequently, it was not included within the study. Production is from structural traps, generally small faulted anticlines. As shown by a Simpson Group production map (Fig. 1), the many fields within the study area range in size from 80 to 750 acres. Cumulative production per field ranges from 36,000 to 11.76 million barrels of oil (11.76 MMBO). Some of the fields have established production from all the Simpson sandstones; other fields produce from only one zone. This subsurface study includes the examination of over 1,100 well logs in the area to determine the factors that created the productive anomalies. Each of the Ordovician sandstones listed above is present within the entire study area. This area was selected on the basis of several criteria that include the following:

1. All Simpson Group reservoirs have proved productive within the area and generally are prolific producers.
2. All the reservoirs are present throughout the study area.
3. Well density is excellent, with the greatest percentage of deep penetrations to the Oil Creek sand and below.

Smith, P. W., 1997, Structural and stratigraphic factors that influence Simpson Group production in central Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 111–136.

4. Well logs, both new and old, are available.

5. Enigmatic production is the case from seemingly closed anticlinal structures: some fields are productive from all reservoirs, whereas nearby, seemingly similar, structures are not productive from every reservoir.

6. The structural geology is not overly complicated by numerous faults and high degrees of dip, which could prevent an accurate reconstruction of deposition, and the geologic history and mechanisms are not a topic of debate.

7. Dipmeter data are not required to correct thicknesses.

8. The study area is centrally located, to facilitate possible expansion.

REGIONAL GEOLOGY

The Middle Ordovician Simpson Group originally consisted of five formations, in ascending order, above the Arbuckle Group and below the Viola Group: Joins, Oil Creek, McLish, Tulip Creek, and Bromide (Decker and Merritt, 1931). Subsequently, Harris (1957) interpreted a hiatus separating the Bromide from the superjacent "Simpson Dense." Although the name *"Simpson Dense"* was used by geologists working the subsurface geology in this area, Harris established a new formation, the Corbin Ranch. However, this formation is overwhelmingly called *"Simpson Dense"* rather than *Corbin Ranch* in the subsurface of the study area. The original name *"Simpson*

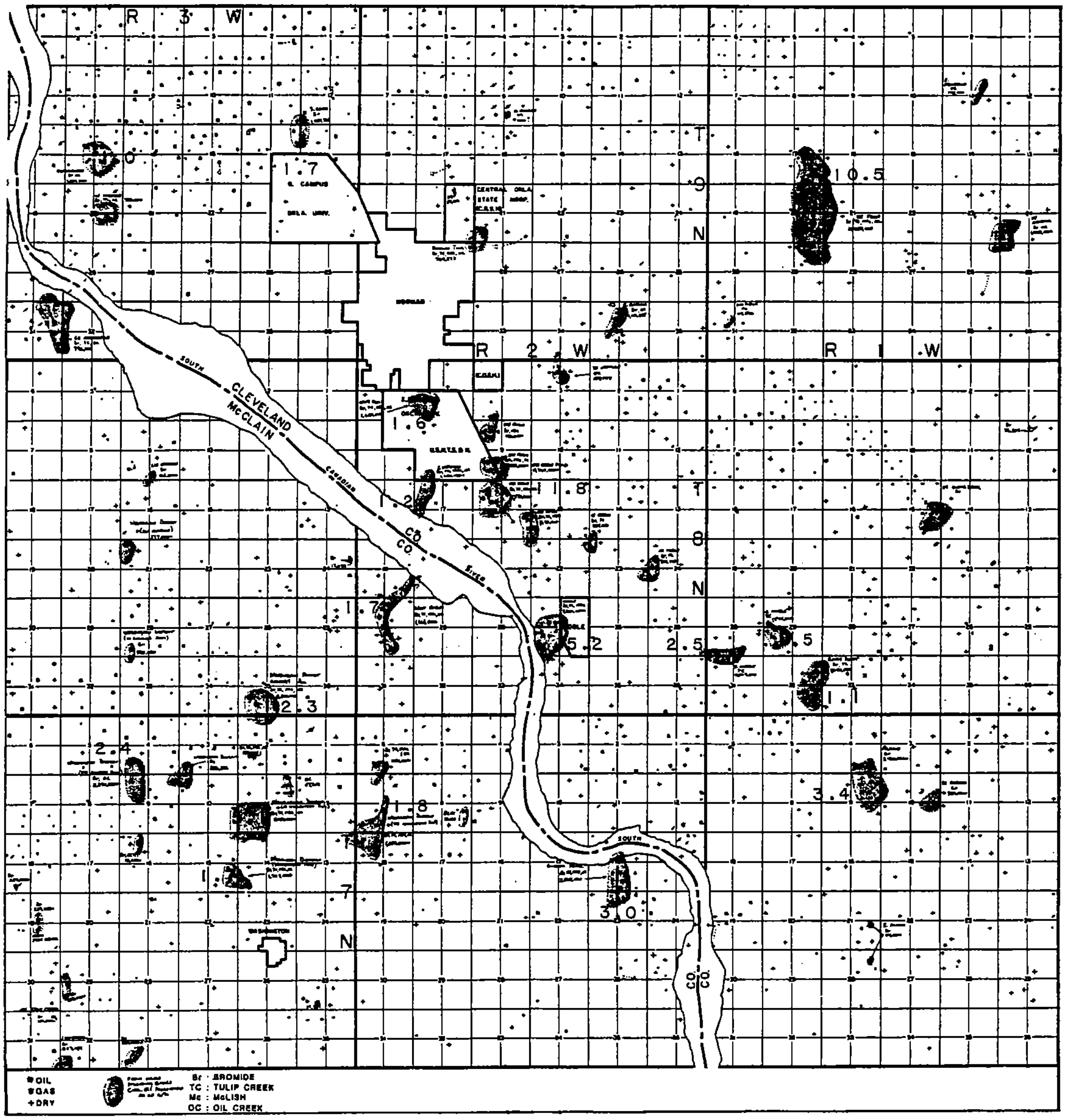


Figure 1. Simpson Group production map.

Dense" is used exclusively on scout tickets for wells drilled within the area. An excellent representative example of wireline logging responses and characteristics of the Simpson Group can be observed in the Cenco No. 1 Taylor Ranch well (NW$\frac{1}{4}$NW$\frac{1}{4}$NW$\frac{1}{4}$ sec. 23, T. 8 N., R. 2 W.). Figure 2 shows a set of logs for this well.

Schramm (1964) described the Middle Ordovician "Simpson Basin" and provided an excellent description of the Simpson Group. Johnson and others (1988) included the same region in the "Oklahoma Basin," which spanned Middle Ordovician to Early Mississippian time. Citing regional distribution of detritus, Johnson and others (1988) indicated that the clastic debris constituting the Simpson Group had an eastern source. Schramm (1964) referred to the earlier works of Dake (1921) and Dapples (1955), which suggested a source from the Canadian shield. The thickest intervals of the Simpson Group were deposited along a linear feature known as the southern Oklahoma aulacogen. The Simpson Group within the study area was deposited upon a relatively stable shelf of the Oklahoma basin (Fig. 3).

Following deposition of the Cambrian–Ordovician Arbuckle carbonates, a eustatic withdrawal of the Canadian sea exposed the Arbuckle to widespread erosion. This produced an irregular unconformity surface throughout the Midcontinent shelf region over which the early Chazyan Simpson sea advanced because of renewed subsidence of the basin. A significant unconformity separates Arbuckle rocks from the earliest Simpson sediments.

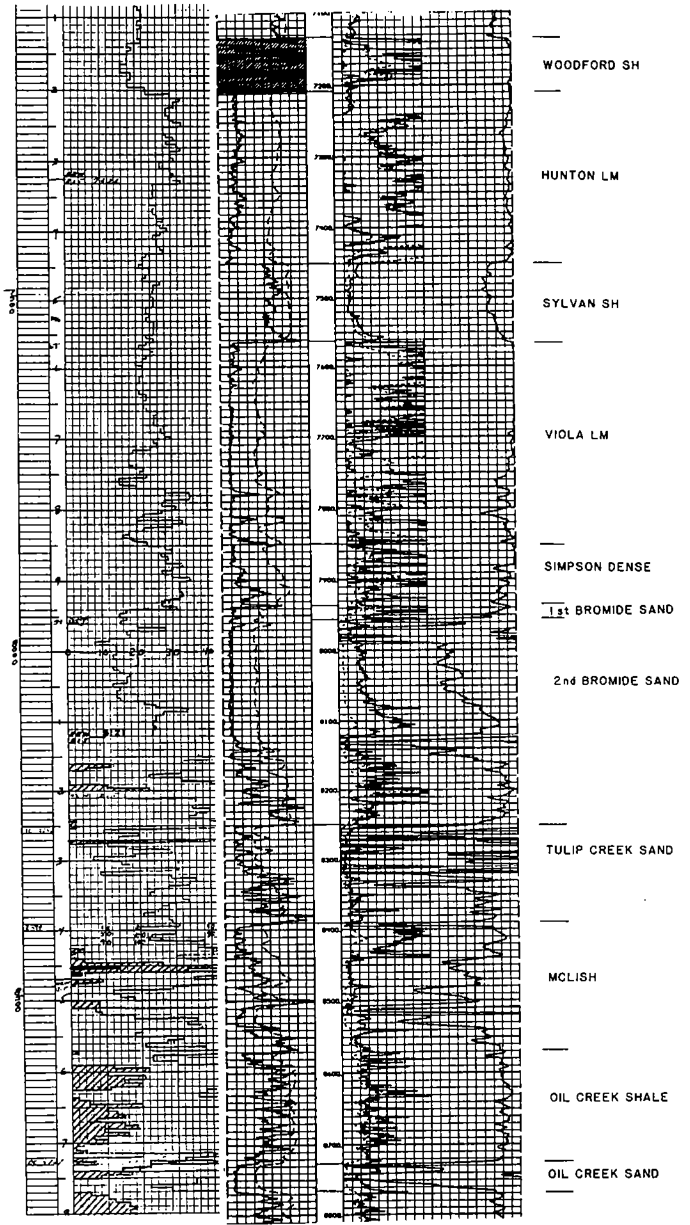


Figure 2. Type log.

Joins Formation

Conditions on the shallow shelf in the study area favored deposition of carbonates—the Joins Formation—which are difficult to distinguish from the Arbuckle carbonates. Within the study area only one well encountered sandstone of the Joins section (sec. 21, T. 7 N., R. 2 W.). Joins sandstone distribution within the study area is probably limited to the south half of T. 7 N., R. 2 W. Sandstones are present within the Joins south of the study area.

Joins carbonates (limestones and dolomites) are present throughout the study area but were not evaluated.

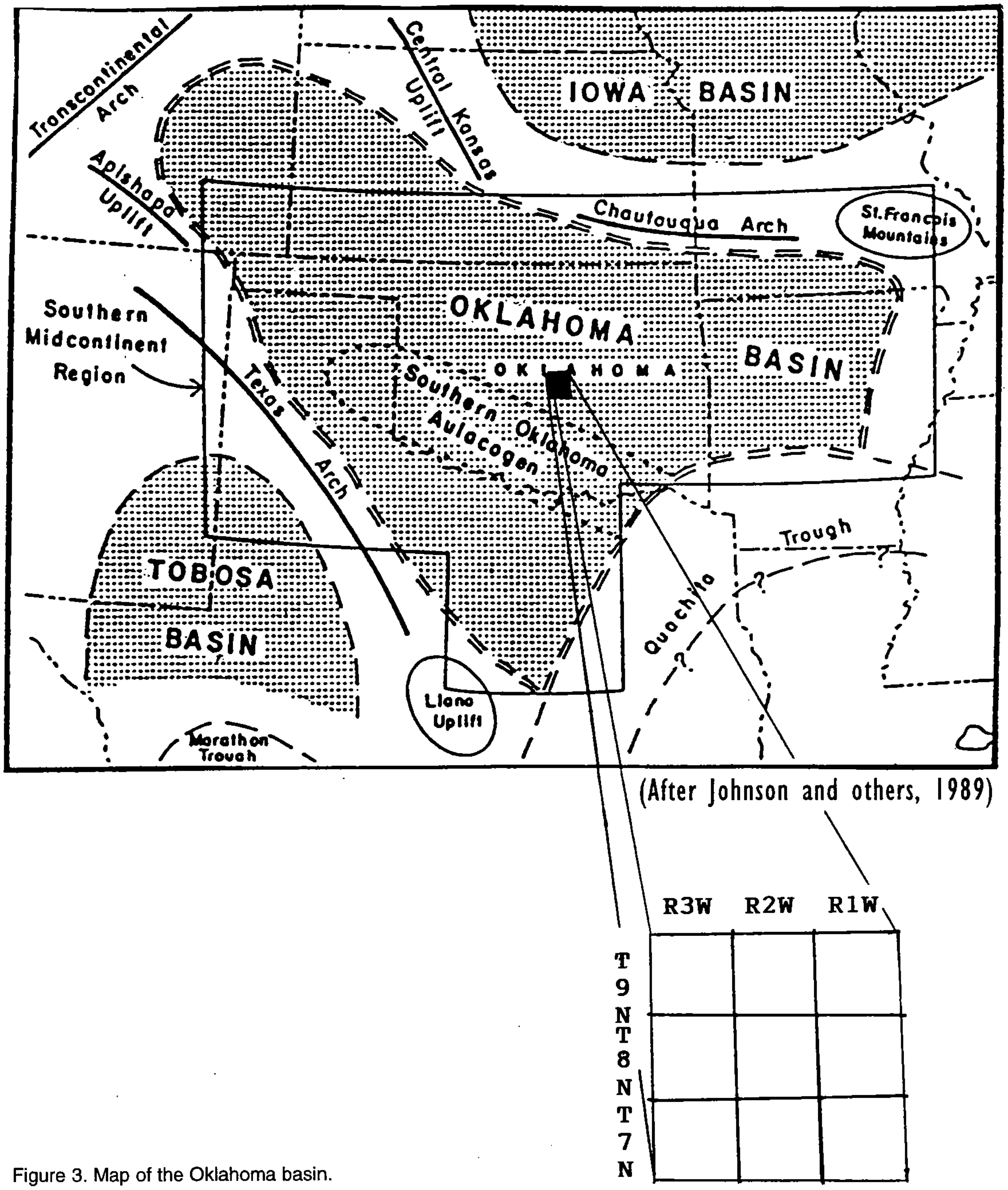
Oil Creek Formation

Increased subsidence of the Simpson basin and a rise in sea level during late Chazyan time allowed the influx of substantial quantities of terrigenous clastic material from a source in the northeast. Deposited throughout the study area, the Oil Creek sandstone consists of poorly to well-cemented, well-rounded, well-sorted, fine- to very fine-grained, bioturbated sandstone commonly mottled to banded with siltstone. Forgotson and others (1997) investigated the origins and influences on productivity of the "alternating hard and soft sandstones" first described by Smith (1992). Forgotson and others report that depositional and late diagenetic processes have had extreme effects on the productive characteristics of the Oil Creek sandstone.

The deposition of the Oil Creek shale can be characterized by sedimentation of fine detrital material with sporadic influxes of coarser terrigenous material. The high influx of clay prevented the accumulation of appreciable amounts of carbonates (Schramm, 1964). Within the study area, the Oil Creek shale can be described as dark gray to gray platy shale containing streaks of microcrystalline limestone, siltstone, and sandstone.

McLish Formation

Schramm (1964) recognized a discontinuity between the Oil Creek shale and the McLish Formation but did not believe it to be a major unconformity. This hiatus separates the Chazyan Oil Creek Formation from the Black Riveran McLish Formation (Harris, 1957). Studies by Schramm (1964) show that the regional isopach trends of the McLish Formation are similar to those described for the Oil Creek Formation. A transgression of the Simpson sea, coupled with another large influx of sand, resulted in deposition of the McLish Formation. Sandstone deposition was limited to the northeast rim of the Simpson Basin, possibly because the Central Oklahoma arch obstructed the longshore currents (Schramm, 1964). Fluctuations in sea level caused deposition of sandstones interbedded with limestones and shales. The sandstones consist of medium- to fine-grained, well-sorted, well-rounded to subrounded, clear to slightly frosted sand grains with varying amounts of green shale and/or varying degrees of cementation. Sand distribu-



(After Johnson and others, 1989)

Figure 3. Map of the Oklahoma basin.

tion within the McLish is noticeably erratic. Variations of more than 15 ft in the thickness of a single sandstone lens occur between wells drilled 500 ft apart. The water depth was probably fairly shallow, allowing tidal action or currents to control sediment distribution.

Tulip Creek Formation

The Tulip Creek Formation (Black Riveran) conformably overlies the McLish Formation. The deposition and distribution of the Tulip Creek are similar to those of the McLish; however, in the northern and northeastern areas of Oklahoma the Tulip Creek was truncated during deposition of the Bromide (Schramm, 1964). Within the study area, the Tulip Creek is divided into two parts: a lower member containing sandstone, shale, and some limestone (Tulip Creek sandstone) and an upper member composed of green shale (Tulip Creek shale). The lower member exhibits a funnel shape on electric logs, which indicates an upward-increasing sand content (versus shale). The Tulip Creek sandstone is composed of fine- to very fine-grained, well-rounded, well-sorted, bioturbated, nearly unconsolidated to cemented sand. It also contains laminations of green sandstone that are very poorly cemented. The laminations increase in number and thickness toward the top of the formation. In the study area, the top of the Tulip Creek sandstone is commonly composed of this nearly unconsolidated green sandstone, which displays very low resistivity on logs even when oil saturated (Smith, 1992, 1993). The Tulip Creek shale varies in thickness in the study area from about 20 to about 40 ft. The variability in thickness appears to be related to the maximum amount of sand buildup in the uppermost sandstone member of the Tulip Creek sandstone and the timing of the influx of coarser terrigenous material, which marks the base of the Bromide Formation.

Bromide Formation

The Bromide Formation was deposited conformably on the Tulip Creek shale within the study area. A major pulse in the Ozark uplift caused the Tulip Creek and McLish to be eroded in northern and eastern Oklahoma. This material, combined with clastics from source terrains in the north-central United States, formed the thick sandstones of the "Second Bromide." The "First" and "Second Bromide" sandstones are often called the "First" and "Second Wilcox" sandstones by subsurface geologists.

The "Second Bromide" sandstone is a fine-grained, well-rounded, well-sorted sand, which often was deposited with no discernible internal structures. The lowest part of this massive sandstone commonly exhibits laminar bedding with 0.25-in. shale laminations and small, 0.25-in. shale rip clasts. Within the study area, two zones of very poorly cemented, very low-resistivity green sandstones are present. Examination of cores revealed varying degrees of cementation as well as various types of cement (Smith, 1992). Furthermore, directly below the poorly consolidated green sandstone zones, the sandstone contains laminations grading upward into low-angle cross-beds that are covered by coarser (becoming medium-grained) highly trough-cross-bedded sandstone. Above the trough-cross-bedded sandstone is a medium- to coarse-grained, well-sorted, well-rounded, poorly consolidated, very friable green sand. The cross-bedded sandstone interval below the green sand is approximately 6–8 ft thick. The increased grain size and apparent cross-bedding suggest an episode of increased energy during deposition. The grain size in the green-sandstone zone and the transitional zone directly below is larger than the grain sizes observed in the Tulip Creek sandstone and the McLish sandstone. This implies that the sand composing these intervals was not derived from the reworked Tulip Creek or McLish sandstone. A similar or perhaps smaller grain size would be expected if the source were from a reworked sandstone. The lower green-sand zone can be correlated throughout the study area. The top of the upper green-sand zone was defined by Smith (1992) to be the top of the "Second Bromide" sandstone. Smith (1992, 1993) reports that the low-resistivity green sand interval in the "Second Bromide" sandstone creates severe log-analysis problems.

The "First Bromide" sandstone in the subsurface (see Fig. 2, type log) directly overlies the porous green sandstone of the "Second Bromide." Usually, a thin shale, a tight limestone, or a well-cemented sandstone separates the "Second Bromide" sandstone from the "First Bromide" zone. Where present, the "First Bromide" sandstone usually exhibits frosted, medium-grained, well-sorted, well-rounded sandstone that is usually highly bioturbated, giving the sandstone a white to gray to dark-gray mottled appearance. The "First Bromide" interval represents the last clastic pulse prior to a prolonged episode of predominantly carbonate and shale deposition. Smith (1992) reports that the thickness of the "First Bromide" sandstone varies; however, it does not appear to influence the overall interval from the top of the "Simpson Dense" to the top of the "Second Bromide" sandstone.

"Simpson Dense" (Corbin Ranch Formation)

The limestone content of the "First Bromide" sandstone increases upward as the unit becomes a hard, dense, low-porosity, gray limestone referred to by subsurface geologists as the "Simpson Dense." The uppermost interval of the Simpson Group ("Simpson Dense" to "Second Bromide" sandstone) represents a dramatic change from the older depositional conditions. Late Black Riveran to early Trenton sediments are primarily microcrystalline carbonates in contrast to the previously clastic-dominated deposition. Harris (1957) elevated the "Simpson Dense" to formational status and renamed it the Corbin Ranch Formation. Because it had been previously referred to by geologists working the subsurface as "Simpson Dense," subsequent well-site geologists still refer to the Corbin Ranch Formation as the "Simpson Dense." This writer prefers the term *"Simpson Dense"* over *Corbin Ranch* and shall refer to it as such.

Post-Simpson Units

The Upper Ordovician Viola lies disconformably above the "Simpson Dense" (Corbin Ranch Formation) as stated by Harris (1957, p. 100). Cronenwett (1956) identified a thin conglomerate separating the Viola from the Simpson Group. The Viola represents shallow-water carbonate deposition (Johnson and others, 1988). Late Ordovician carbonate deposition was interrupted by an influx of terrigenous material, which created the Sylvan Shale. Within the study area, carbonate deposition in warm, shallow water continued during the Silurian and into Late Devonian time (Johnson and others, 1988).

The Silurian–Devonian Hunton Group contains generally clean-washed skeletal limestones. Shaly intervals are restricted to areas promixal to the Ouachita province to the southeast. Evidence suggests that several episodes of uplift and erosion existed during deposition of the Hunton Group (Johnson and others, 1988). These depositional hiatuses and erosional events were not as extensive as the Early to Middle Devonian uplift and subsequent erosion (post-Hunton epeirogeny). Significant variations in thickness resulted from post-Hunton erosion. The entire erosional surface was buried under organic-rich dark-gray to black shale as the seas transgressed across the area during late Middle Devonian to early Late Devonian time. Subsequently, the Late Devonian to Early Mississippian Woodford Shale covered most of the Oklahoma basin.

During the Mississippian, epeirogenic movements continued throughout the Oklahoma basin in which shallow-marine limestones and shales were being deposited. Generally, most of the Mississippian sediments were deposited west of the study area in the Anadarko basin. However, some Late Mississippian rocks are present on the west side (downthrown side) of the McClain County fault. This fault has up to 2,500 ft of vertical displacement and extends along the western part of R. 2 W. and the eastern part of R. 3 W. The Nemaha uplift, which extended from Kansas southward to the Oklahoma City uplift, developed during Late Mississippian to Early Pennsylvanian time. The McClain fault is a southward extension of this large uplift. According to Smith (1992), the McClain County fault plays an important role in the migration of petroleum within this area. After the Oklahoma City uplift (Nemaha uplift) was formed, the eastern two-thirds of the study area was exposed to erosion. A significant unconformity exists within the Pennsylvanian in the eastern two ranges, where Desmoinesian strata rest unconformably on the Devonian–Mississippian Woodford Shale or the Silurian–Devonian Hunton limestone. West of the McClain County fault (R. 3 W.), sediments representing Lower Pennsylvanian (Atokan, Morrowan, and Springeran) and most Mississippian (Chesterian, Meramecian, and Osagean) formations thicken toward the west and southwest into the Anadarko basin. Pennsylvanian (Desmoinesian) to Permian (Leonardian) strata are present throughout the study area, gently dipping west toward the Anadarko basin.

DETAILED RECONSTRUCTION

Each formation was isolated and isopached to provide insight into cause(s) of observed variations in thickness of the Simpson Group. Wells with faulted or stretched intervals were omitted in the formations affected. Reconstruction of the Simpson Group began with detailed study of the Oil Creek sandstone.

Oil Creek Sandstone

The isopach map of the Oil Creek sandstone (Fig. 4) illustrates the range of thickness of this sand unit from less than 15 ft in the northern and northeastern parts of the study area to more than 100 ft in the southern and southwestern parts. Thicks (troughs) and thins (crests) are oriented perpendicular to strike in a northeast–southwest pattern. These variations are probably due to undulations in the underlying Arbuckle–Joins unconformity surface, or more likely may represent small structural movements during Oil Creek deposition. It is believed that the underlying Arbuckle–Joins surface was relatively flat lying and devoid of significant or sharply contrasting undulations within the study area. An excellent example of the variability of the sandstone thickness can be observed in the south half of T. 8 N., R. 1 W., where the sandstone thickens from less than 40 to more than 100 ft in less than 2 mi. The average thickening of the Oil Creek sandstone is approximately 5 ft/mi from northeast to southwest. The overall isopach trend probably results from thinning caused by the central Oklahoma uplift.

Oil Creek Shale

The Oil Creek shale thickens from north to south (with a slight east-to-west component) at about the same rate as the Oil Creek sandstone. Figure 5 illustrates the increase in shale thickness from about 110 to 225 ft across the study area. A thick section of both Oil Creek shale and sandstone is present in the southern part of T. 8 N., R. 1 W., suggesting that this thick wedge may represent deposition over an irregular surface or, more likely, that slight structural movements occurred during Oil Creek time.

It is important to note that, following deposition of approximately 125 to more than 325 ft of sand and shale, any effects of an irregular surface on the Arbuckle–Joins unconformity surface probably would have been obscured by the end of Oil Creek time.

McLish Formation

Within the study area the overall thickness of the McLish varies from 150 ft in the northeastern part of the area to about 225 ft in the southern part. The McLish isopach map (Fig. 6) shows the distribution of McLish sediments within the study area. As shown, noticeable departures in the northeast–southwest strike direction of thickness occur in this mapped interval. The thickness of the McLish interval may vary more than 50 ft/mi (about 25% of the interval) within these northeast–southwest thin and thick trends. These trends are likely the result of localized structural movements. The thickened intervals represent relatively low areas, and the thin intervals represent uplifted areas.

Tulip Creek Sandstone

Because the Tulip Creek sandstone is an excellent marker in this area, the top of the Tulip Creek sandstone to the top of the McLish was isopached (Fig. 7). This isopach interval shows northeast–southwest thick and thin trends similar to those of the lower formations. The Tulip Creek increases in thickness from about 125 ft in the northeastern part of the study area to 200 ft in the southwest corner of the study area. A pronounced northeast–southwest isopach thin trends from sec. 26, T. 8 N., R. 3 W., toward sec. 3, T. 9 N., R. 1 W. Another pronounced northeast–southwest isopach thin trends through T. 7 N., R. 1 W.

Tulip Creek to Oil Creek Interval

An isopach map from the top of the Tulip Creek sandstone to the top of the Oil Creek sandstone is shown in Figure 8. This interval thickens from 400 ft in the northeastern part of T. 9 N., R. 1 W., to more than 600 ft in the southwestern part (T. 7 N., R. 3 W.). Several anomalously thick and thin areas of sediment deposition, probably owing to small structural movements that occurred during deposition of this interval, are superimposed on the regional isopach pattern. The northeast–southwest patterns of structural movement (folding or faulting) produced variations in sediment thickness up to 100 ft in distances of less than 1 mi.

A comparison of the Oil Creek sandstone isopach map (Fig. 4) with Figure 8 shows remarkable similarities in thick and thin trends. Areas that had abnormal thin or thick intervals of sand deposition during Oil Creek sand "time" continued to have similar thick or thin depositional patterns from Oil Creek shale through Tulip Creek "time." Examination and comparison of each of the lower Simpson members (Tulip Creek sandstone and older) suggest that one mechanism uniformly controlled the deposition of each member.

An excellent example of an active structure can be examined for T. 7 N., R. 1 W., which is the structure on the southeast quarter of the transect on the stratigraphic cross section (Fig. 9). Figure 9 is a northwest-to-southeast-ori-

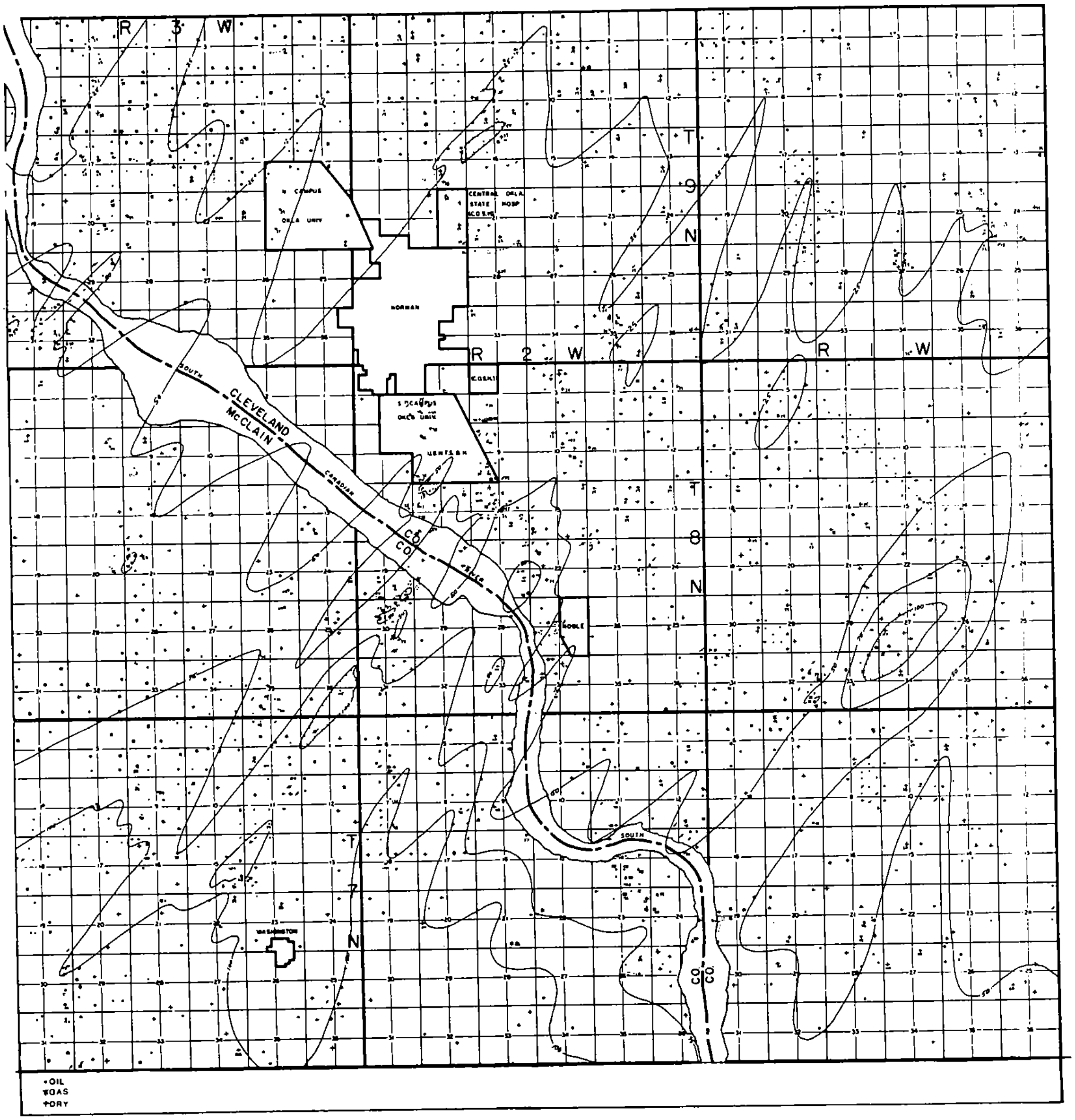


Figure 4. Oil Creek sandstone isopach map. Contour interval, 25 ft.

ented cross section of the lower Simpson Group members (stratigraphic cross section of the interval from the top of the Tulip Creek sandstone to the base of the Oil Creek sandstone). Figures 8 and 9 show the vertical and horizontal relationships of the thick and thin trends within the lower Simpson Group. The thick and thin trends are spatially coincidental, which also suggests a common cause that was actively controlling deposition throughout Oil Creek to Tulip Creek time. Localized structural movements during deposition are believed to have been that cause.

"Second Bromide" to Tulip Creek Interval

The distribution of sediments shown by the interval from the "Second Bromide" sand to the Tulip Creek sand (Fig. 10) reflects the same northeast-to-southwest trend; however, it shows more of an east-to-west component. Some of the fold/fault-created thick and thin trends observed in previous isopach maps do not continue into the "Second Bromide" formation. Similarly, some new isopach trends emerge for the first time in this interval. Therefore, it is concluded that some of the structural movements that were contemporaneous with early Simpson deposition did not continue during later Simpson deposition and that additional local structural movement began during deposition of the "Second Bromide" sandstone. It is important to note, however, that the structural movements are generally parallel.

The northwest–southeast isopach cross section of this interval (Fig. 11) depicts the significant variations in thickness. It appears that the concentration of structural

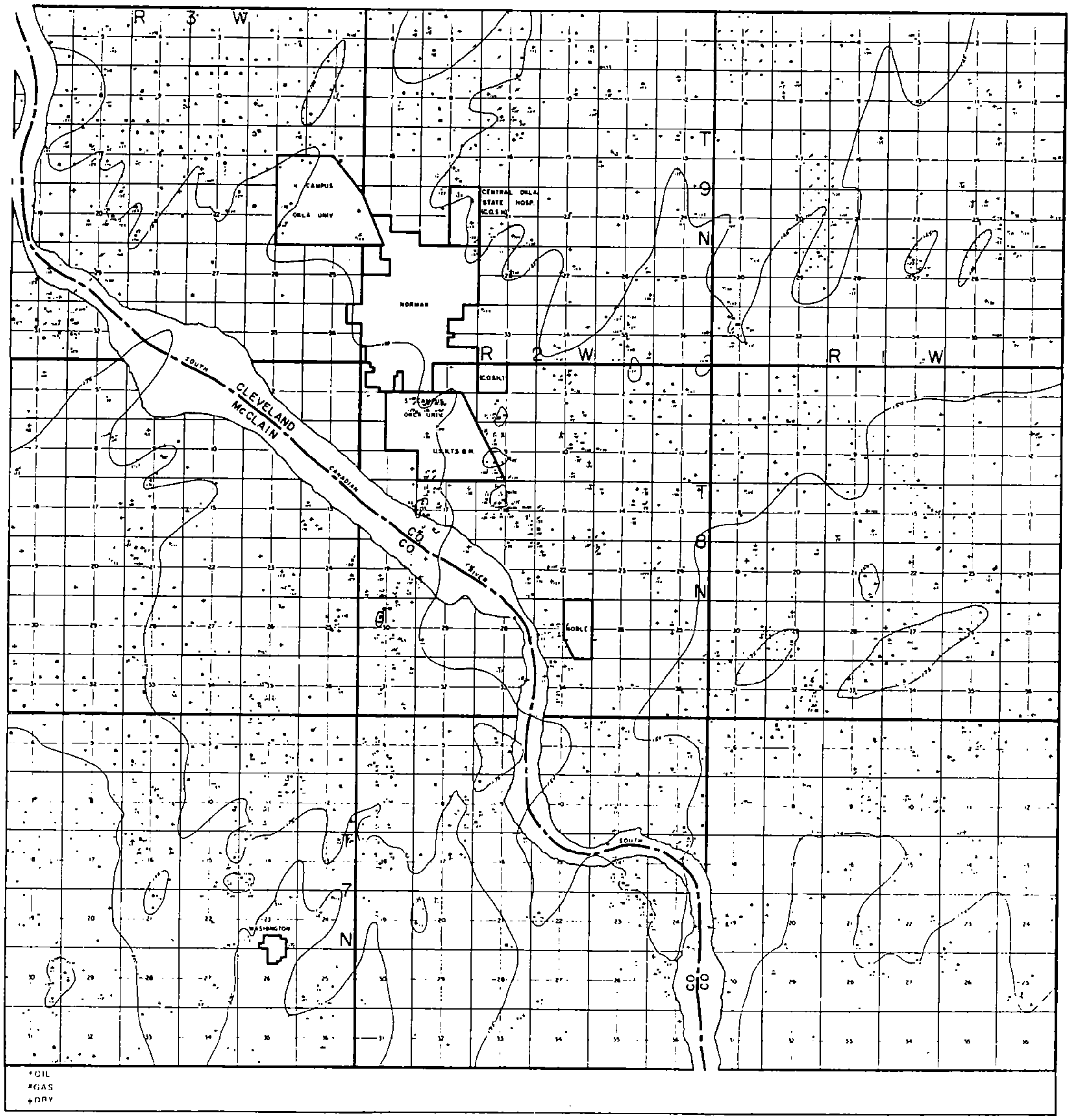


Figure 5. Oil Creek shale isopach map. Contour interval, 25 ft.

movements shifted northwestward from Bromide time as compared to pre-Bromide time. The pre-Bromide structural activity was concentrated from the Northwest Noble field southeastward (see Figs. 8,9). In contrast, post–Tulip Creek structural activity is more pronounced from the Northwest Noble field northwestward (see Figs. 10,11).

Oil Creek Through "Second Bromide" Interval

An isopach map of the interval from the "Second Bromide" to the Oil Creek sand (Fig. 12) indicates more than 300 ft of thickening from northeast to southwest. This suggests that the southwestern area was more basinward and that the study area was proximal to the shelf edge. Although two different episodes of structural movements are represented, parallel thick and thin trends are present on this map. Some of the thin trends apparently indicate structures that were active throughout Simpson time. The Northwest Noble field lies atop one of the more pronounced structural trends, which was active throughout Simpson time.

The Northwest Noble trend is also related to a noticeable thinning trend on a northwest–southeast stratigraphic cross section of the interval from the top of the "Second Bromide" to the base of the Oil Creek sandstone (Fig. 13). On this cross section there exists a significant difference in the configuration between the "Second Bromide"–Tulip Creek contact and that of the Oil Creek sandstone in the southeastern part of the section. This suggests that most of the variations were formed prior to "Second Bromide" deposition. In con-

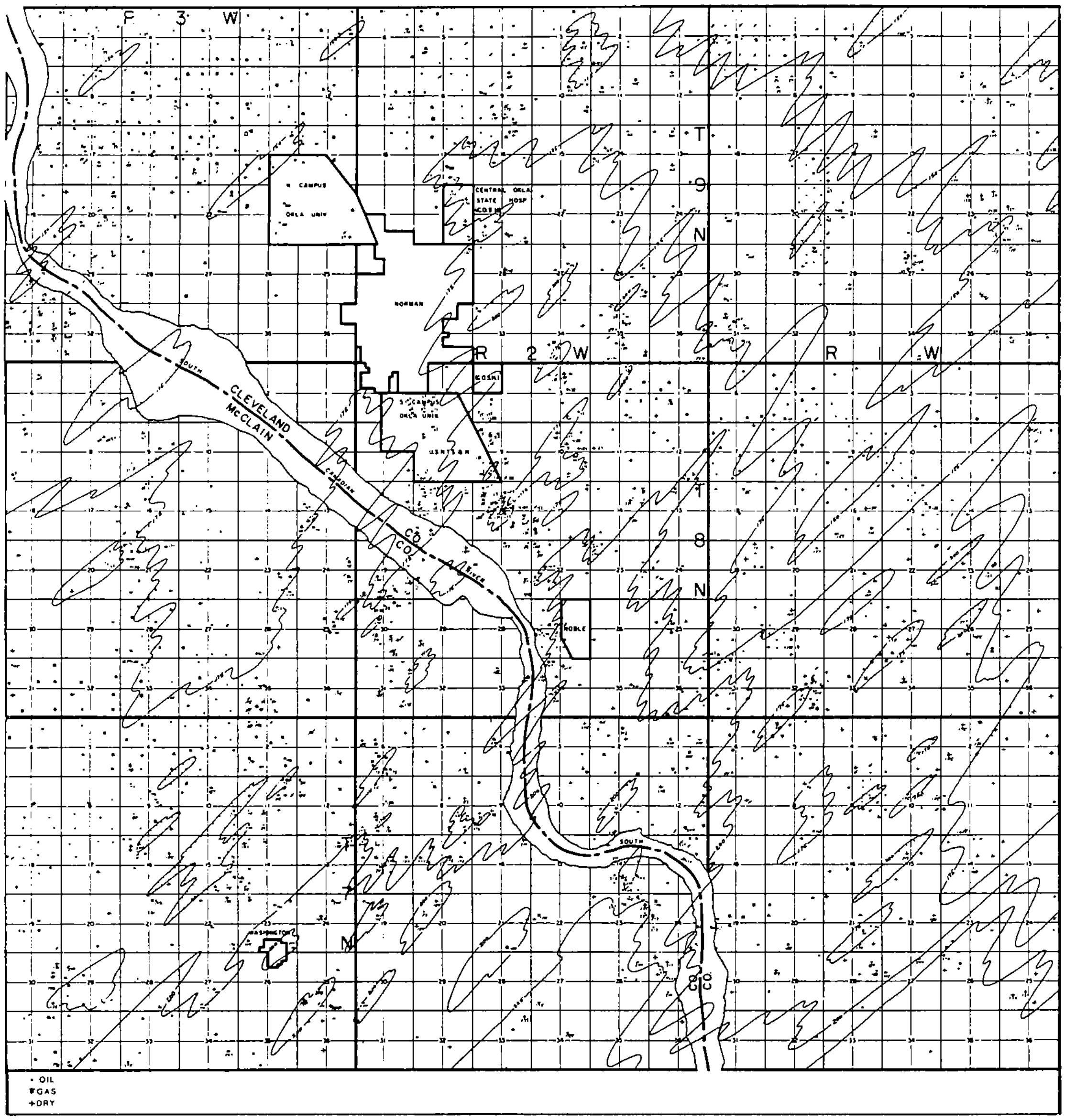


Figure 6. McLish isopach map. Contour interval, 25 ft.

trast, there exists a high degree of similarity in the configurations of the "Second Bromide"–Tulip Creek contact and that of the Oil Creek sandstone in the northwestern part of the study area. This suggests that most of the variations were formed after deposition of the Tulip Creek. The interpretation resulting in this correlation also may be partially due to the lack of well control under the Norman, Oklahoma, urbanized area.

The depositional genesis of the Simpson Group, illustrating contemporaneous structural movement, is provided in Figure 14. This series of northwest–southeast cross sections clearly allows the ages of the significant movements to be determined, which consequently affected the deposition and distribution of Simpson Group sediments. The cross sections are also designed to illustrate the Arbuckle–Joins surface at the end of deposition of each of the Simpson Group members from the Oil Creek through the "Second Bromide."

"Simpson Dense" to "Second Bromide" Interval

An isopach map of the interval from the "Simpson Dense" to the "Second Bromide" sand (Fig. 15) shows the same pattern of southwestward thickening, suggesting that the earlier structural trends were still dominant during deposition of this interval. However, in T. 8 N., R. 2 W., a north–south thinning pattern suggests that the stable shelf environment was experiencing the early subtle changes of a new structural orientation.

The northeast area is significantly thinner than the southwest area. Although northeast–southwest-oriented

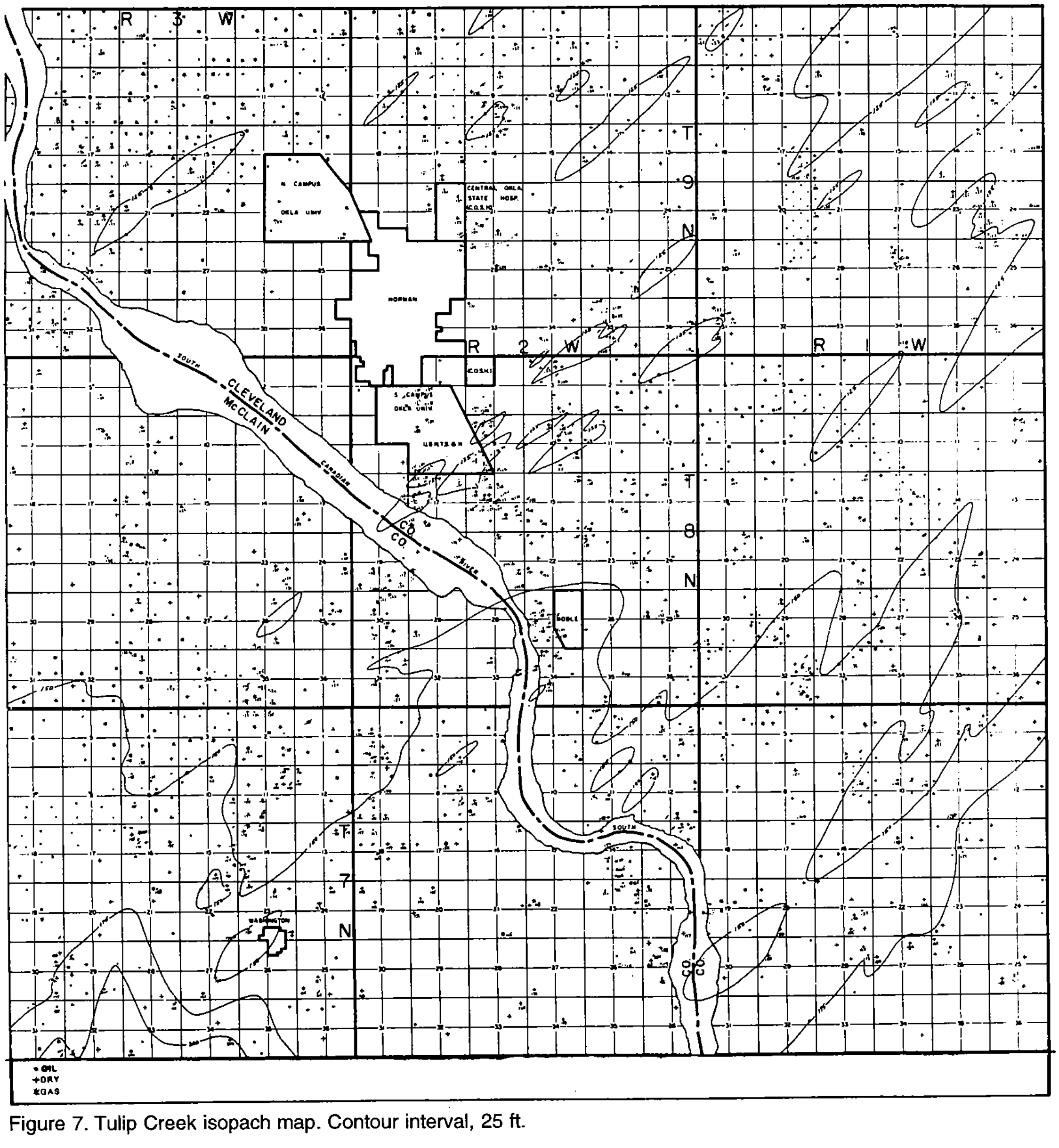


Figure 7. Tulip Creek isopach map. Contour interval, 25 ft.

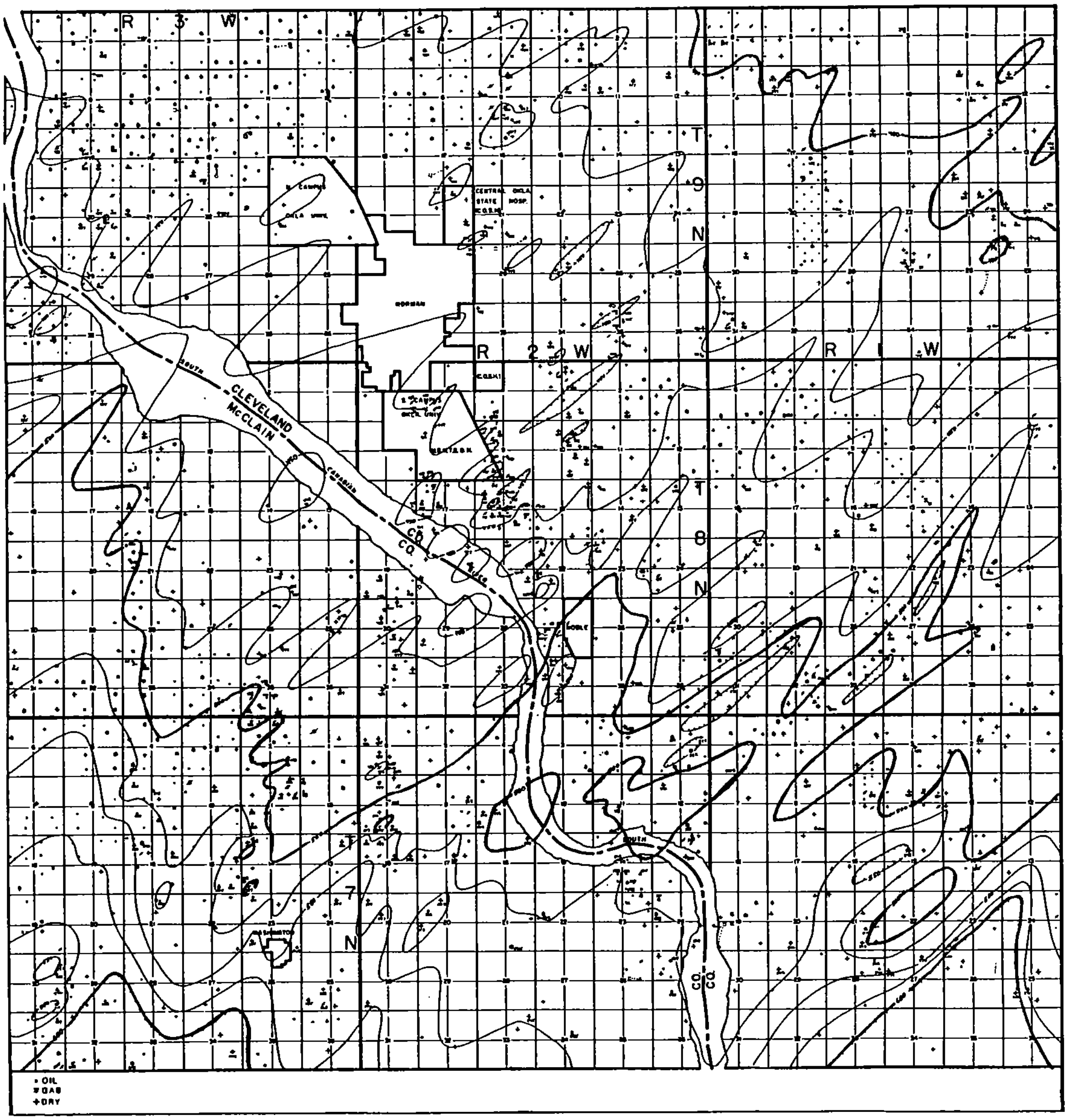


Figure 8. Isopach map of the interval from the top of the Tulip Creek sandstone to the top of the Oil Creek sandstone. Contour interval, 25 ft.

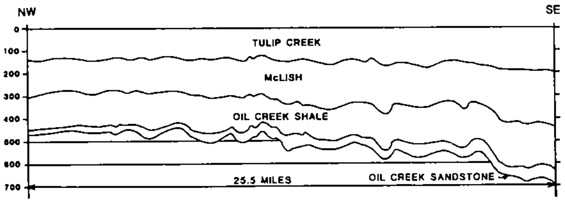


Figure 9. Stratigraphic cross section of the interval from the top of the Tulip Creek sandstone to the base of the Oil Creek sandstone.

thick and thin trends are evident, a north–south pattern is observable for the first time. Variations in thickness of the "First Bromide" sandstone are independent of the thickness of this interval (Smith, 1992).

Viola Interval

During deposition of the Viola, the northeast-to-southwest structural orientation observed for deposition of the Simpson Group changed to a north–south trend. An isopach map of the interval from the Viola to the "Second Bromide" sand clearly illustrates this change (Fig. 16).

Many of the north–south thinning trends display more than 50 ft of thinning. The subtle northeast–southwest thick and thin trends of the "Simpson Dense" to the "Second Bromide" sand are completely obliterated by the relative magnitude of the north–south thick and thin trends. There exists, however, a strong imprint, within the Viola, of the Simpson-age structural orientation. Viola deposition absorbed the northeast–southwest undulations present on the "Simpson Dense" surface. Thickness variations in these Viola-age north–south trends represent more than a 20% variation in the Viola thickness.

It is generally accepted that carbonate rocks are less prone to compaction over a structure than are clastic rocks. Thus, if the thinning observed in the Viola was caused by subsequent structural movements, the Simpson Group would have the same structural imprint—which it does not. Therefore, this movement is interpreted to have occurred during deposition of the Viola. Post-Viola structural movements generally enlarged or enhanced these structures.

This new structural orientation, one of the primary factors controlling Simpson Group production, can be traced back to Late Ordovician (Viola) time. The Simpson structural orientation (northeast–southwest) and the Viola-to-present structural orientation (north–south) create a dual structural imprint.

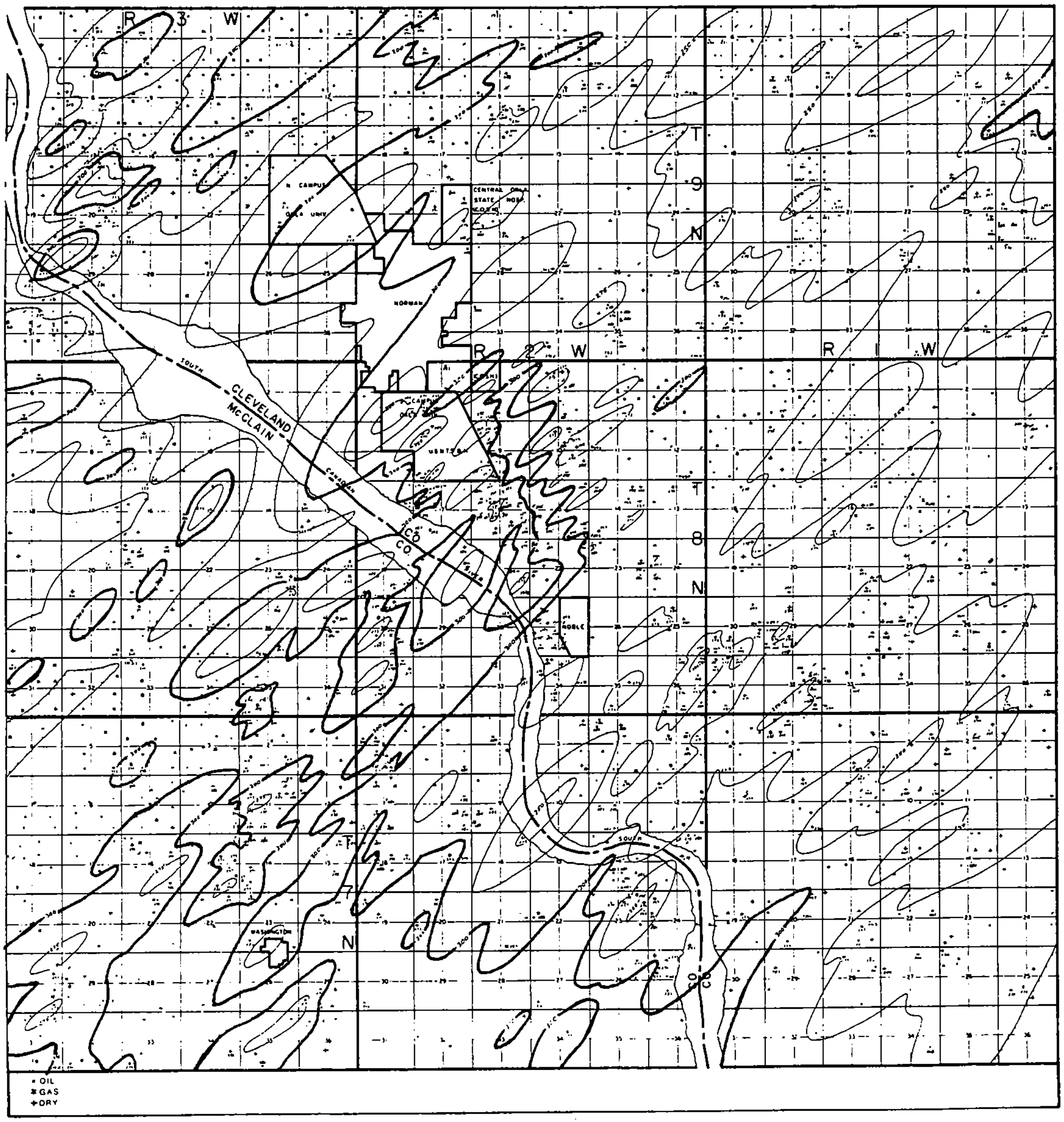


Figure 10. Isopach map of the interval from the "Second Bromide" to the Tulip Creek sandstone. Contour interval, 25 ft.

Silurian–Devonian and Lower Mississippian Interval

The north–south structural trends observed in the Viola continued to be active during an episode of uplift and erosion following Hunton deposition and prior to Woodford deposition. A fold or fault with down-to-the-west movement extended from sec. 6, T. 9 N., R. 2 W., southward toward sec. 34, T. 7 N., R. 3 W. Several hundred feet of Hunton was preserved on the downthrown side of this fault/fold, which is not present on the upthrown side. Subsequently, the Hunton surface was buried and covered by the Woodford Shale. Then, another episode of uplift and erosion occurred following deposition of the Woodford (Fig. 17).

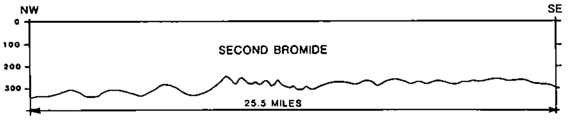


Figure 11. Isopach cross section of the interval from the "Second Bromide" sandstone to the Tulip Creek sandstone.

STRUCTURAL FACTORS

Structural movement occurring contemporaneously with the deposition of the Simpson Group dramatically influenced the stratigraphic and structural factors controlling production. Evidence suggests that structural movements during Simpson deposition had a northeast-to-southwest orientation. While the "Simpson Dense"

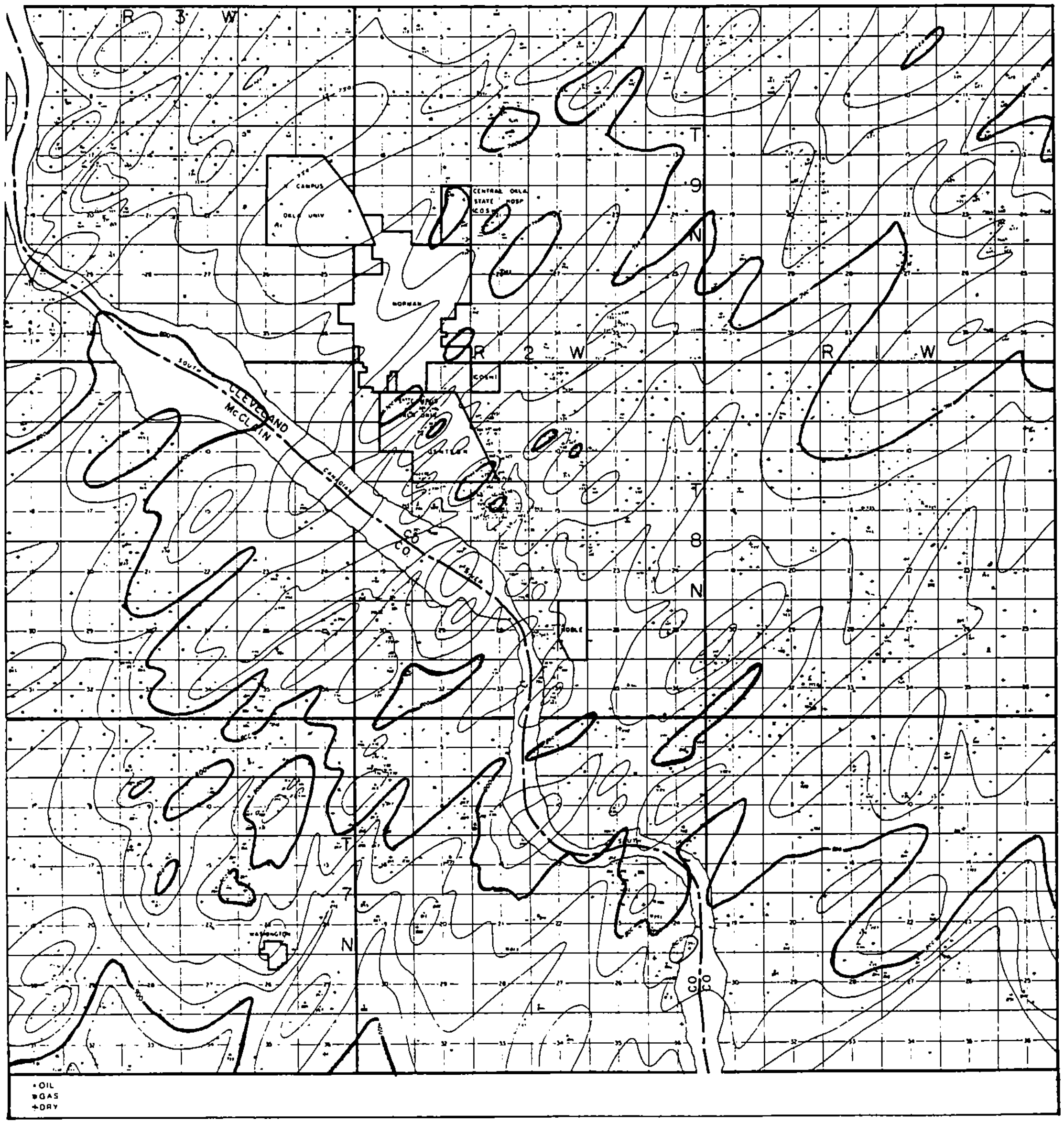


Figure 12. Isopach map of the interval from the "Second Bromide" to the Oil Creek sandstone. Contour interval, 25 ft.

(Corbin Ranch) was being deposited, this orientation began to change. By Viola time the structural pattern, and consequently the depositional pattern, had changed to a north–south orientation.

The Silurian through Early Mississippian structural orientation was north–south, similar to that which emerged during Viola deposition. The Hunton orogeny partially eroded the Hunton. Subsequently, the Woodford Shale was deposited, and the post-Woodford unconformity removed or partially eroded the Woodford within the study area. Subsequent Mississippian to Pennsylvanian structural movements were oriented north–south, with a westward regional dip.

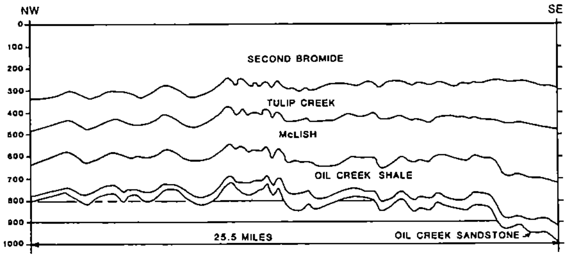


Figure 13. Stratigraphic cross section of the interval from the top of the "Second Bromide" to the base of the Oil Creek sandstone.

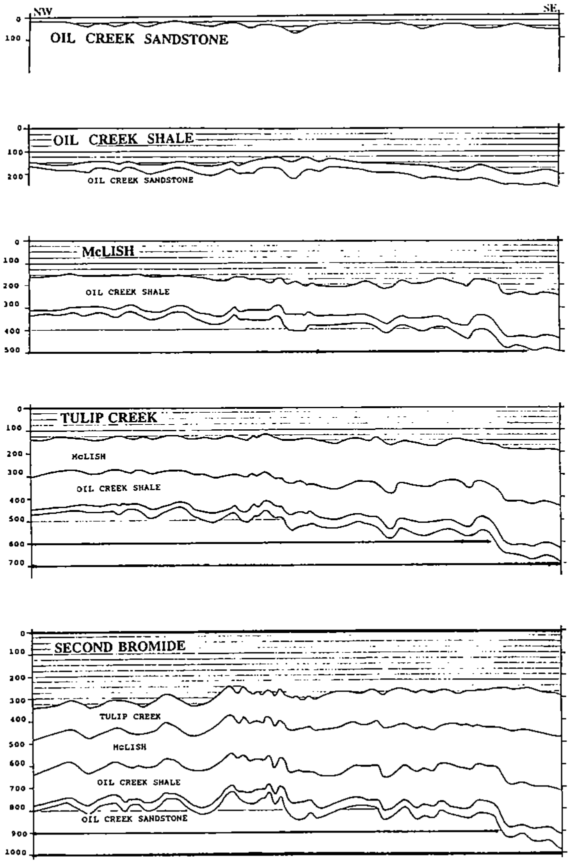


Figure 14. Series of cross sections showing the depositional genesis of the Simpson Group, illustrating contemporaneous structural movement.

The Pennsylvanian-to-present structural orientation is generally north–south. The present-day structural configuration of the "Second Bromide" sandstone is presented in Figure 18. Within the study area, this sandstone has more than 4,500 ft of structural relief (from less than –5,600 to more than –10,100 ft subsea). The McClain County fault displays up to 2,500 ft of down-to-the-west displacement. Excluding the McClain County fault, the average westerly dip is about 100 ft/mi. There is also a southerly dip component of about 25 ft/mi. The "Second Bromide" structure map also illustrates that post-Bromide structural orientation (north–south) is dominant.

The east–west structural closures created by the north–south (post-Bromide) structural orientation are larger in magnitude. Consequently, they are more pronounced and easier to identify with subsurface mapping and seismic modeling than are the north–south closures. However, the north–south dip creates the critical closure. This critical north–south dip results from the northeast–southwest structural orientation prevalent during Simpson deposition. The Viola integrated the last vestiges of the Simpson northeast–southwest orientation while incorporating the newly formed north–south structural orientation. Thus, Simpson Group rocks have a dual structural imprint, resulting from the two acutely diverse structural orientations.

Although pre-Viola (northeast–southwest) and post-Simpson (north–south) structural orientations reflect the greatest divergence, the two phases of the Simpson structural movements (pre-Bromide "Phase 1" and post–Tulip Creek "Phase 2") also dramatically affect structural position with depth. The Tulip Creek to Oil Creek interval (see Figs. 8,9) thickens from 400 ft in the northeastern part of T. 9 N., R. 1 W., to more than 600 ft in the southwestern part (T. 7 N., R. 3 W.) of the study area. Several anomalously thick and thin areas of sediment deposition, probably resulting from small structural movements that occurred during deposition of this interval, are superimposed on the regional isopach pattern. Overall thickness variations related to structural noses and fault/fold lineations are clearly visible on the isopach maps. One of the northeast–southwest patterns of folding or faulting produced variations in sediment thickness up to 100 ft in a distance of less than 1 mi.

This implies that a present-day closed structure on the Tulip Creek sandstone may not represent a closed structure in the underlying formations. Conversely, a closed structure on the Oil Creek sandstone may not have a closed structure above it in the Tulip Creek sandstone. The effect of a northeast–southwest thickening trend underlying a closed Tulip Creek structure would be to shift or completely remove the closure in the Oil Creek structure, depending on the degree of thickening. Figure 19 (closed Tulip Creek over an open Oil Creek) illustrates the "vanishing" effect on an Oil Creek structure from isopach thickening.

The effect of a northeast–southwest thinning trend underlying a closed Tulip Creek structure enhances the trapping capacity at the Oil Creek horizon. Additionally, a thinning trend can create the closure critical to entrap oil if no closure exists at the Tulip Creek level (Fig. 20).

During deposition of the Bromide interval, some of the earlier structural movements became dormant while others remained active. Furthermore, localized structural movement developed. All the movements were parallel to the earlier movements and caused similar northeast–southwest-oriented thick and thin trends. This creates a scenario in which, as with the lower Simpson members, the structural configuration of one horizon does not mean that other horizons are similar. The isopach of "Second Bromide" deposition suggests that the Tulip Creek sandstone could be found on a closed structure where the "Second Bromide" sandstone is not on a closed structure. Conversely, the "Second Bromide" sandstone could be found on a closed structure where the structure at the Tulip Creek sandstone horizon either does not close because of a thickened "Second Bromide" interval or the closure is not directly below the "Second Bromide" closure. A locally thick "Second Bromide" sandstone to Tulip Creek sandstone interval can remove the potential closure of the Tulip Creek sandstone or create a "saddle" in the Tulip Creek structure. Figure 21 illustrates a closed Bromide structure overlying an open Tulip Creek structure. A thin "Second Bromide" sandstone to Tulip Creek sandstone interval may result in closure on the Tulip Creek sandstone that was not present on the "Second Bromide" sandstone. Figure 22 represents a closed Tulip Creek structure below an open Bromide structure. Stratigraphic variations produced by small local structural movements significantly influence Simpson Group production.

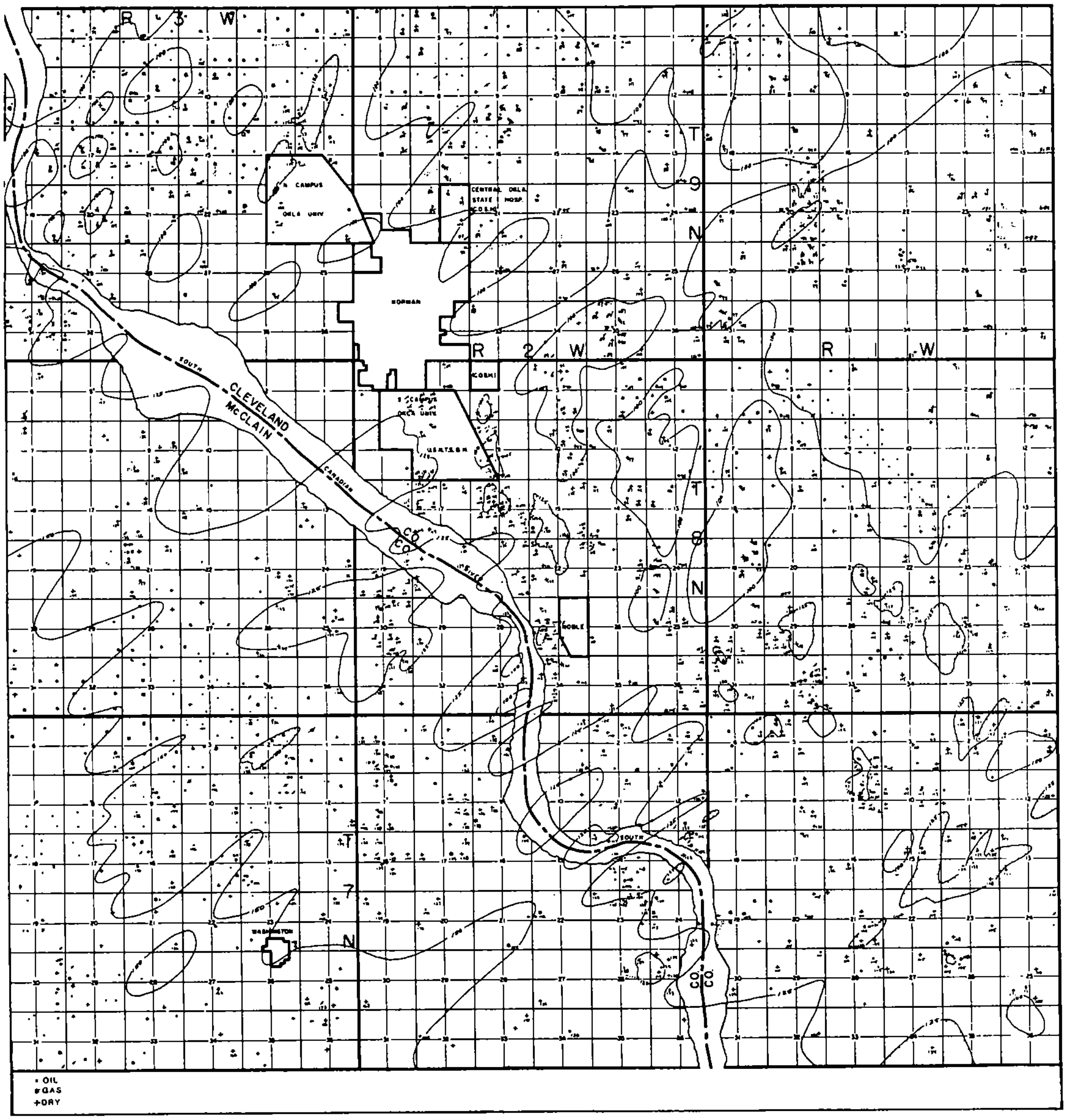


Figure 15. Isopach map of the interval from the "Simpson Dense" to the "Second Bromide" sandstone. Contour interval, 25 ft.

As shown in Figures 19–22, structural position at an upper horizon will likely shift with depth, depending on the relative position to a Simpson thick or thin trend. A 50-ft structural disadvantage at the "Second Bromide" sandstone horizon may transform into a 50-ft structural advantage with depth—or may transform into a 150-ft structural disadvantage.

Within a north–south-trending Viola structural "ridge," critical north and south closure is provided by the structures emplaced during Simpson time. This allowed oil to migrate into and ultimately accumulate within a north–south structure, where thickening or thinning zones within the Simpson section created the critical north and south closure. Conversely, the stratigraphic relationships within the Viola and Simpson may have caused the oil to migrate and to accumulate "off-structure" relative to the mapped Viola structure.

A stratigraphic cross section of the interval from the top of the Viola Limestone to the base of the Oil Creek sandstone (Fig. 23) illustrates how the last thickness variations resulting from the Simpson-age northeast–southwest structural movements combined with the Viola-age north–south thickness variations to create circumstances in which the Viola surface would not accurately reflect the underlying surfaces.

A closed structure mapped on the Viola may not overlie a closed Simpson structure (Fig. 24). After drilling a closed Viola structure and encountering a barren open "Second Bromide" structure, one might interpret the drilling results to be that an unproductive closed

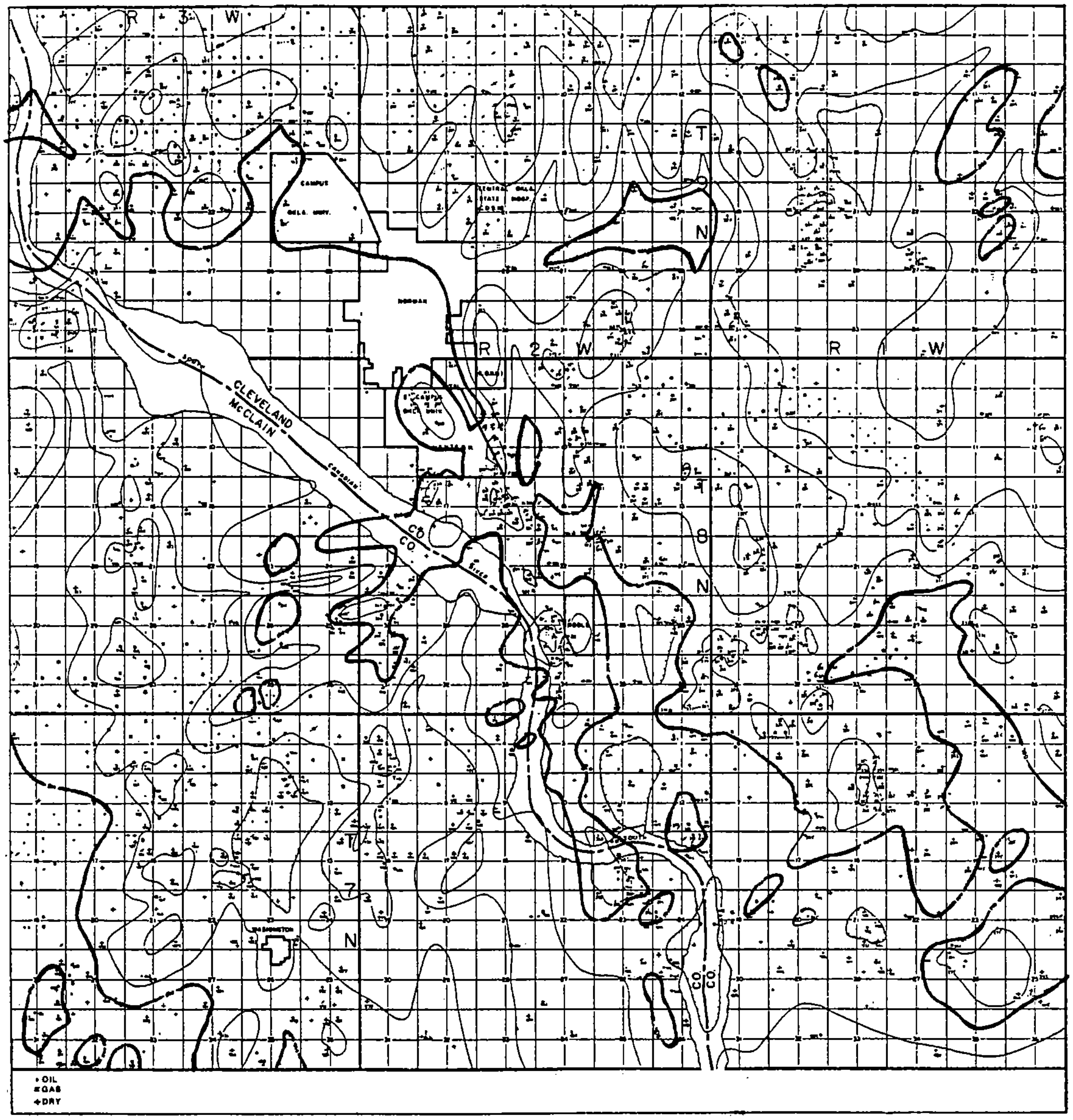


Figure 16. Isopach map of the interval from the top of the Viola to the "Second Bromide" sandstone. Contour interval, 25 ft.

structure was drilled. Figure 24 also depicts a closure on the "Second Bromide" sandstone that is not overlain by a closed Viola structure.

Similar conditions could exist for other Simpson sandstones where closure in lower Simpson sandstones is not reflected by closure in upper Simpson strata.

It is the opinion of this author that true "unproductive Bromide structures" are uncommon in this study area, and that an unproductive "structure" is most likely open to the north. Circumstances can be identified, however, in which a Bromide reservoir on a truly closed anticlinal structure is barren (Smith, 1992, 1993). In one example, the Bromide seal was breached, and the oil migrated vertically (and was trapped) into the overlying Viola.

Summary of Structural Control

The "Second Bromide" structure map (Fig. 18) illustrates the general structural geology of the study area. Although the area is dissected by numerous small faults, only the large faults were placed on the map to present a clear picture of the regional features, as reflected by a 100-ft contour interval. The structure map shows that the regional dip is westward, toward the Anadarko basin. The regional dip is interrupted by structural noses, and small closed structures. The western half of the area contains the most rugged structural relief with the largest closures. Post-Bromide structural movements created the east–west closures. East-dip closure required to entrap hydrocarbons along north–south trends was

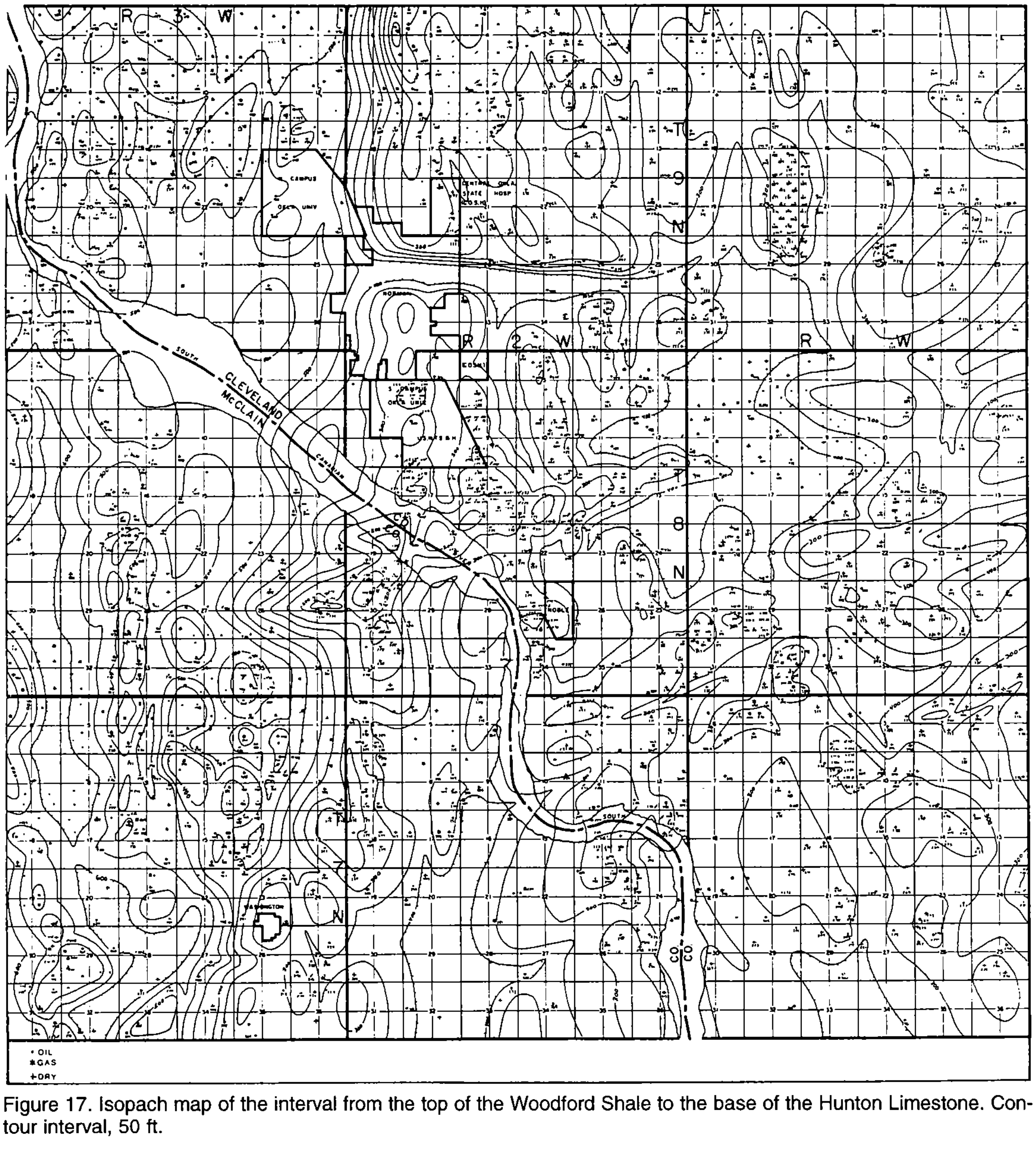


Figure 17. Isopach map of the interval from the top of the Woodford Shale to the base of the Hunton Limestone. Contour interval, 50 ft.

generally provided by structural rollover into small faults that are difficult to detect with seismic methods.

Within a Viola structure, stratigraphic variations in the Viola and in the Simpson Group, resulting from localized structural movements during deposition, provided critical north–south closure. These stratigraphic conditions control the internal structures that determine which zones are productive on a given structure. Commonly, the apex of a lower horizon is not directly below the apex of an upper horizon. Thus, a well drilled into a closed "Second Bromide" structure may or may not remain on a closed structure at the Oil Creek horizon. The internal structure of the Simpson Group may also allow a well penetrating an open structure at the "Second Bromide" level to encounter a closed structure at the Oil Creek sandstone level.

SOURCE TO TRAP

Information regarding the oil-source potential of the Simpson Group is scant. Although the Simpson Group contains several marine-shale intervals, little work has been published evaluating the source-rock potential of these shales. Twelve samples from a well drilled in sec. 34, T. 8 N., R. 2 W., were analyzed by Rock-Eval by Ted Daws (U.S. Geological Survey, Denver): nine from the Simpson shale, and for comparison, one sample of Desmoinesian (Red Fork to Bartlesville interval) Pennsylvanian shale and two Devonian–Mississippian Woodford Shale samples. Rock-Eval analysis is a pyrolysis method for evaluating kerogen type, total organic carbon (TOC), and maturity. (Waples, 1985, provides a

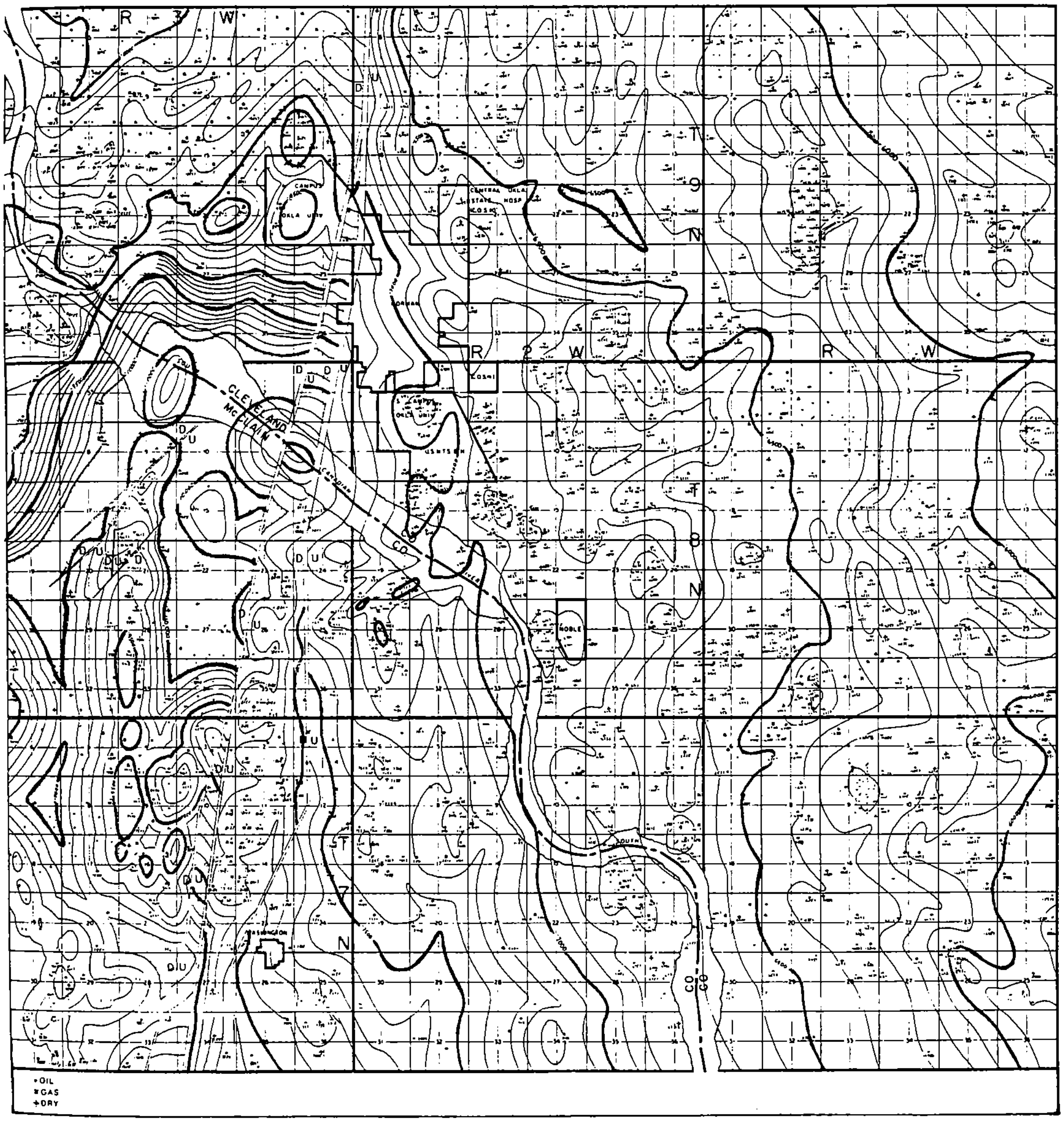


Figure 18. "Second Bromide" structure map. Contour interval, 100 ft.

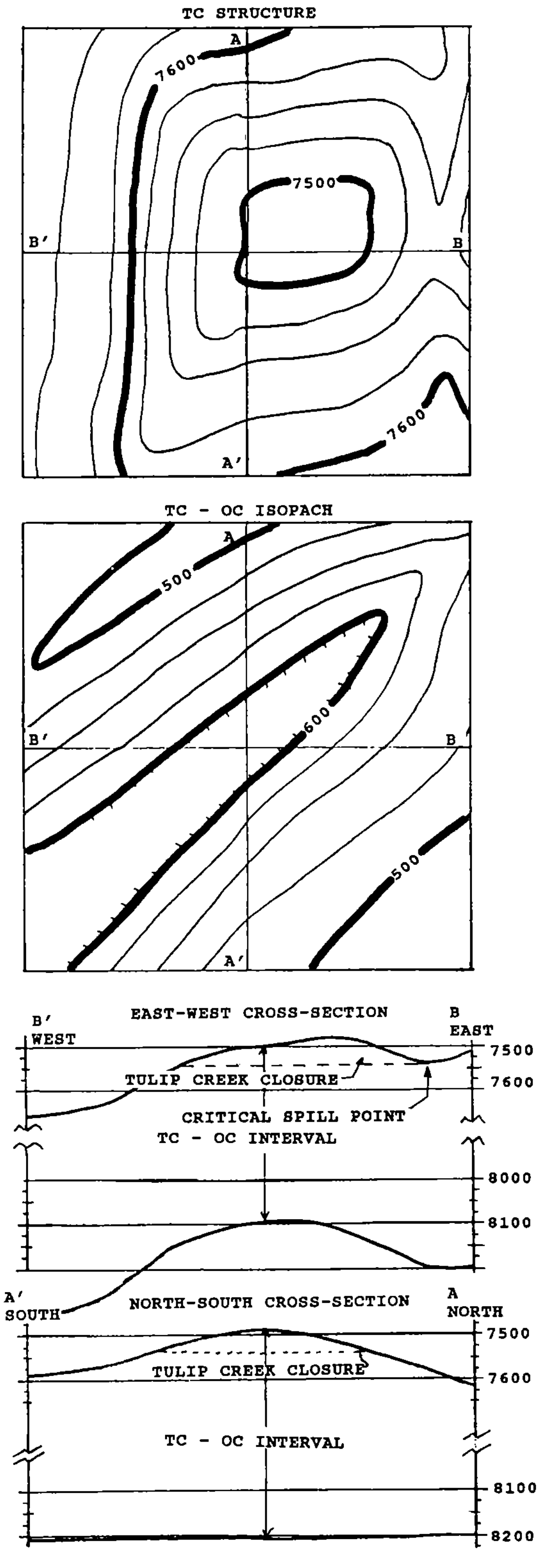


Figure 19. Closed Tulip Creek structure over an open Oil Creek structure.

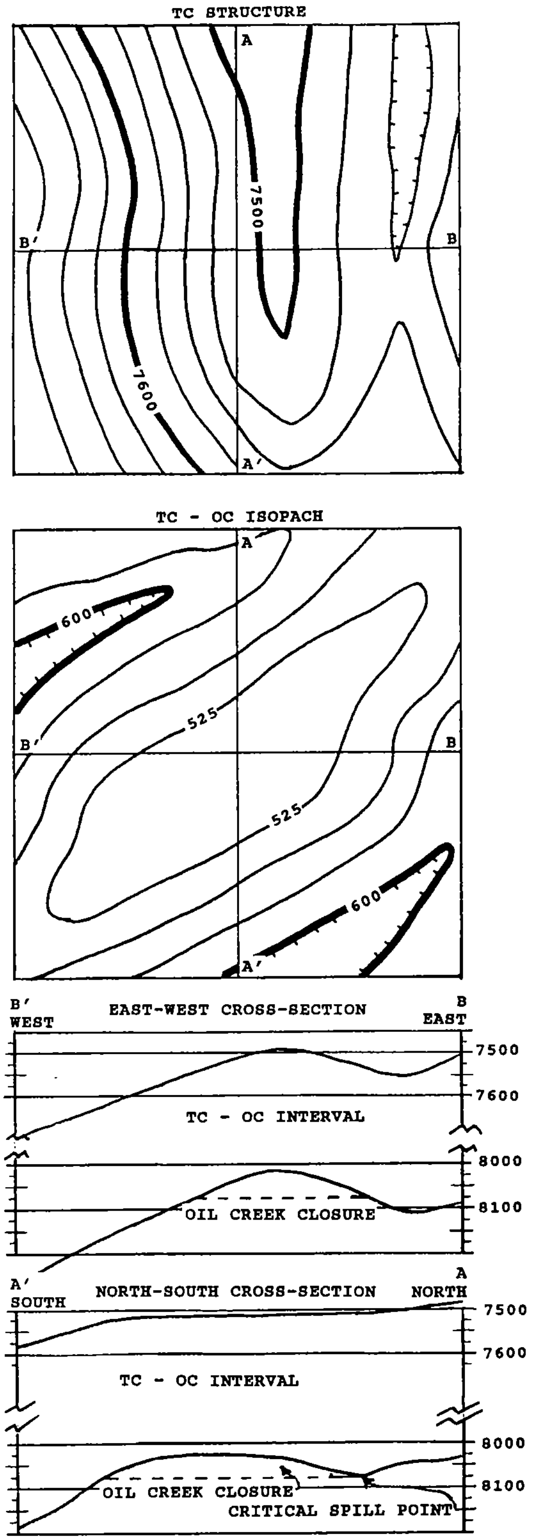


Figure 20. Open Tulip Creek structure over a closed Oil Creek structure.

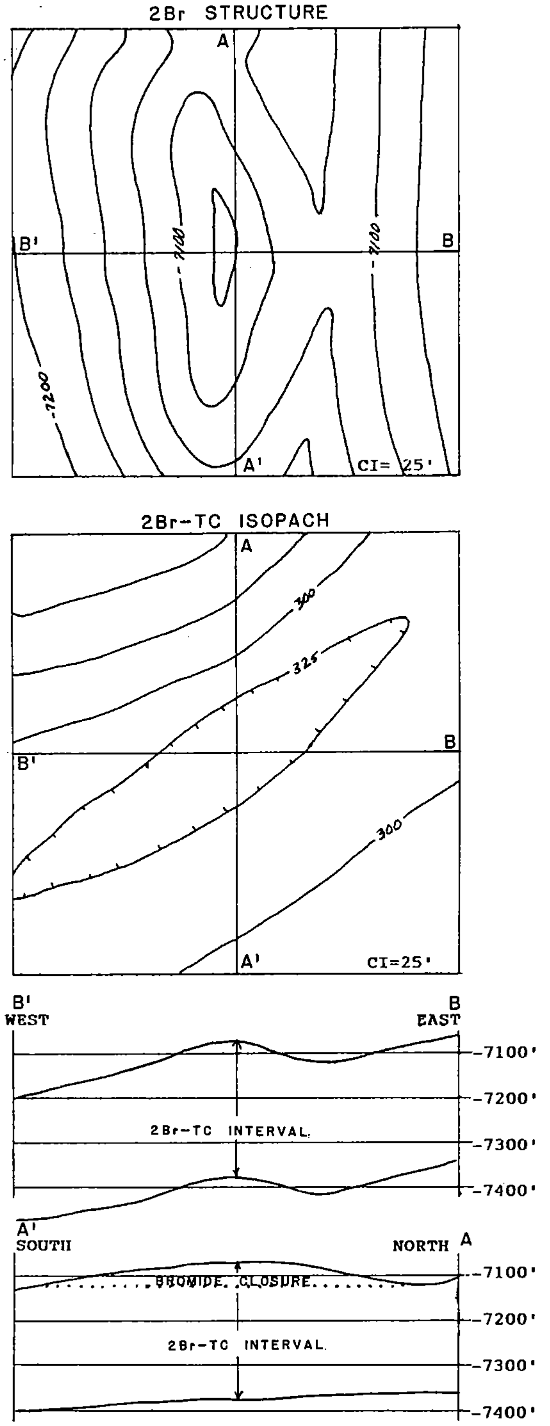


Figure 21. Closed Bromide structure over an open Tulip Creek structure.

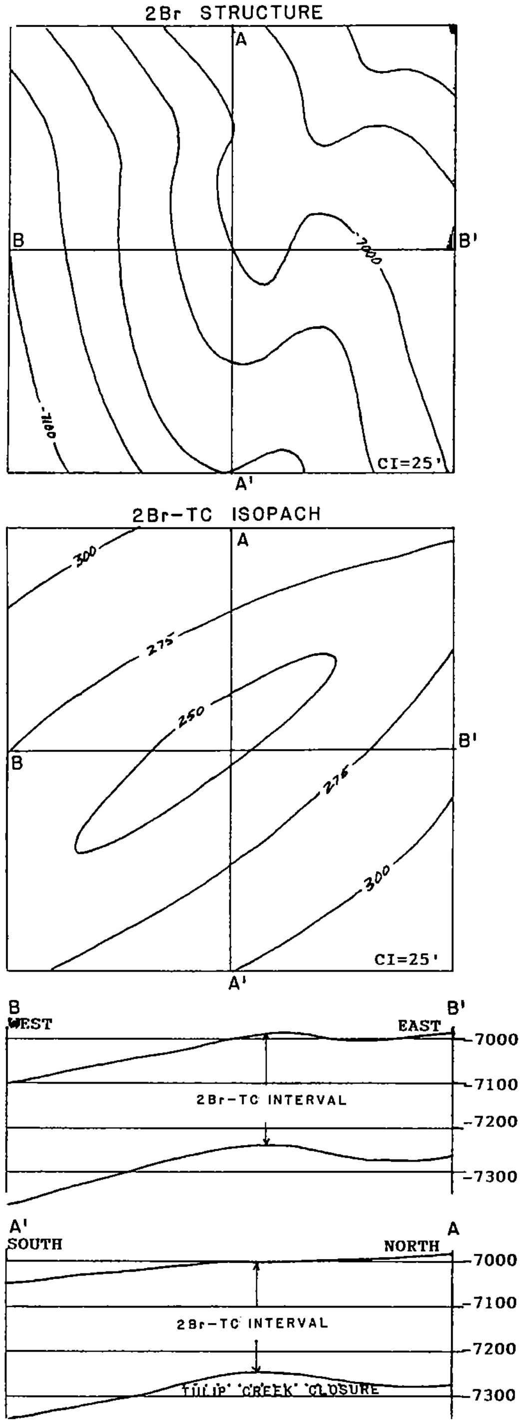


Figure 22. Open Bromide structure over a closed Tulip Creek structure.

TABLE 1.—SOURCE-ROCK EVALUATION RESULTS, CENCO, INC., NO. 2 BARBOUR BALLINGER[a]

Formation and depth (ft)		TOC (%)	T_{max} (°?)	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	PI	S_2/S_3	HI	OI
Lower Pennsylvanian 6,900–7,100		0.70	431	0.07	0.56	0.69	0.11	0.81	80	98
Woodford Shale		4.76	440	1.47	21.02	3.58	0.07	5.87	441	75
7,170–7,230		4.58	439	1.46	20.29	3.51	0.07	5.78	443	76
Tulip Creek	(o)	0.03	428	0.03	0.38	0.30	0.07	1.26	76	60
8,150–8,200	(g)	0.11	394	0.03	0.28	0.27	0.10	1.03	254	245
	(p)	0.60	430	0.06	0.50	0.65	0.11	0.76	83	108
McLish shale	(o)	0.38	431	0.02	0.32	0.31	0.06	1.03	84	81
8,450–8,550	(g)	0.11	394	0.02	0.20	0.25	0.09	0.80	181	227
	(p)	0.45	426	0.06	0.48	0.48	0.11	1.00	106	106
Oil Creek shale	(o)	0.31	431	0.06	0.50	0.25	0.11	2.17	161	74
8,650–8,700	(g)	0.10	428	0.03	0.32	0.36	0.09	0.88	320	360
	(p)	0.31	427	0.02	0.32	0.26	0.06	1.23	103	83

[a] Sec. 34, T. 8 N., R. 2 W.

Note: (g) = green-colored/tinted shale; (p) = picked sample; (o) = overall sample.

TOC = total organic carbon; T_{max} = maximum pyrolysis temperature; PI = production index (transformation ratio) = $SI/(S_1 + S_2)$; HI = hydrogen index; OI = oxygen index.

complete description of the process.) The results of the analyses are given in Table 1.

The potential of the Simpson shale to generate hydrocarbons is low. The samples evaluated generally contained less than 0.5% TOC; however, a maximum of 0.60% TOC was observed. According to Waples (1985, p. 106), rocks containing less than 0.5% TOC have a negligible source capacity, and 0.6% TOC indicates a slight source capacity. Therefore, on the basis of TOC analyses, the Oil Creek and McLish shales probably are incapable of generating liquid hydrocarbons. In considering hydrogen-index (HI) values, the Simpson shales realistically have no potential for generating oil, because they lack significant amounts of lipid materials that are necessary for such generation. The samples that do contain elevated HI values (the *g* samples) lack sufficient TOC to generate hydrocarbons for expulsion. Thus, the oil produced from the Simpson Group is not derived from local Simpson shales.

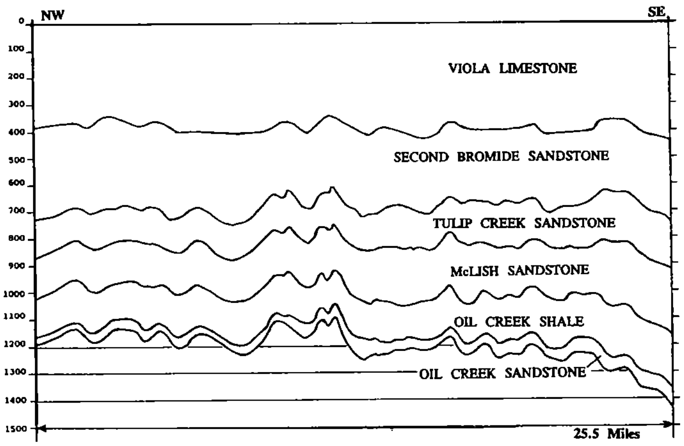


Figure 23. Stratigraphic cross section of the interval from the top of the Viola Limestone to the base of the Oil Creek sandstone.

The Lower Pennsylvanian (Desmoinesian) shale was also analyzed for source-rock potential. Similar to the Simpson shales, the Desmoinesian shale has low TOC and HI values. This implies that the oil found in the Simpson Group did not originate in the interval of dark-gray to black shales of the Desmoinesian section.

Two samples from the Devonian–Mississippian Woodford Shale, considered the source rock for most of the oil in central Oklahoma, were also analyzed. With a TOC averaging about 4.65% and an HI over 440, the Woodford is potentially an excellent oil-source rock. In fact, the Rock-Eval analysis of the Woodford Shale samples suggests that the Woodford has generated hydrocarbons and is capable of generating much more oil (Ted Daws, personal communication, 1992).

Wang (1993) reports that parts of the Viola contain enough organic material to be considered potential source rocks. He determined Viola kerogen as being Type II (oil prone). He also determined that the Springer and Morrow shales (Upper Mississippian and Pennsylvanian) are also potential source rocks but would be gas sources (Type III kerogen). He found that the Sylvan Shale has no source potential and that Chesterian shale has only a low potential as a gas source (low TOC and Type III kerogen).

Wavrek and others (1997) report that in southern Oklahoma the Viola Group contains sections that are potential source rocks. Wang and Philp (1997) report that produced oils from the Anadarko basin have been traced to a Viola source rock. While no data have been presented characterizing the Viola Group from within the study area, the Viola should be considered a possible source rock.

Kareem (1992) reports that hydrocarbon generation and expulsion from the Woodford Shale and organic-rich intervals within the Viola may have begun during Early Pennsylvanian time in the deepest regions of the Anadarko basin. Any Early Pennsylvanian hydrocarbons migrating out of the deep Anadarko basin could have been trapped by structures within the study area. As the Anadarko basin continued to subside during Pennsylvanian time, the basinal area capable of generating hydrocarbons expanded. It was not until Late Pennsylvanian to Permian time that the Woodford Shale was buried deep enough locally to generate hydrocarbons. By this time, however, most of the structural features observed today were in place. Thus, oil generated from the Woodford could be entrapped by local structures. The structures probably have not been breached by subsequent structural movements; therefore, the oil should still be entrapped. Thus, any trap formed along an oil-migration pathway prior to oil generation is capable of containing hydrocarbons.

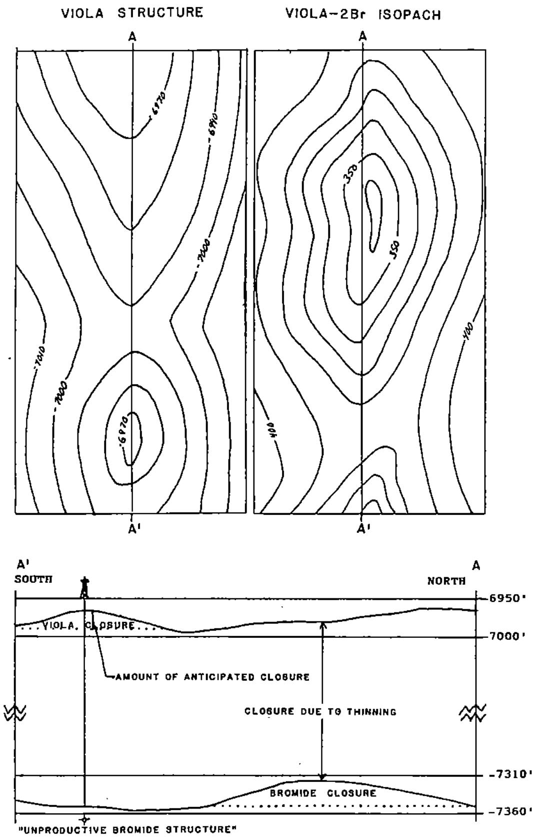


Figure 24. Open Bromide structure under a closed Viola structure, and a closed Bromide structure under an open Viola structure.

The top of the Simpson Group lies 750–1,250 ft below the Woodford Shale. Therefore, the ideal structural relationship for migration of Woodford oil into the Simpson reservoirs would be the Woodford downfaulted against Simpson sandstones. However, Woodford Shale abutted against Simpson sand is not required to allow oil to migrate into the Simpson section. As listed below, the Woodford Shale can be positioned in a wide range of relationships to allow migration into sands of the Simpson Group.

1. The Woodford Shale could be juxtaposed to the Simpson Group by faulting. This position could permit easy migration into the Simpson reservoirs.

2. The Woodford in fault contact with porous Arbuckle rocks could allow migration into the Simpson. If the Woodford is below the Simpson sandstones, it is easy to envision upward migration into the Simpson sands via the Arbuckle through faults and/or fractures.

3. If the Woodford is juxtaposed to the Viola, an updip lateral Viola–Simpson fault contact is required to enable the Viola to act as a conduit for oil migration into the Simpson.

4. The critical barrier separating Simpson reservoirs from Woodford source rocks is the Sylvan Shale. Oil from the Woodford could migrate laterally through Hunton limestones. A fault emplacing oil-saturated Hunton limestone against permeable strata below the Sylvan Shale could allow Woodford oil eventually to migrate into the Simpson across permeable fault boundaries.

The McClain County fault provides excellent opportunities to allow Woodford oil to enter older strata, and, most importantly, the fault provides contacts and/or direct pathways into rocks of the Simpson Group.

Accumulation patterns and production totals of the oil fields within the study area suggest that oil probably entered the Simpson Group along the McClain County fault. The Simpson Group production map (Fig. 1) illustrates the geographical distribution of the oil fields within the study area. Oil fields adjacent to the McClain County fault have the thickest net pay intervals (or are filled to the spill point) and consequently have produced the most oil per acre. The structures nearest the McClain County fault with production from all of the Simpson sands have produced considerably more oil per acre than have more distal "omni-productive" structures. This implies the existence of an oil-productivity relationship associated with the McClain County fault that is probably related to structural positioning of the Woodford Shale along the fault. Thus, oil generated from the Woodford Shale migrated into Simpson Group reservoirs through faults juxtaposing younger downthrown strata opposite upthrown older strata. Some structural traps contain only one oil-productive Simpson sandstone, and others contain several oil-saturated Simpson reservoirs. Local structural movements contemporaneous with deposition of the Simpson Group determined which reservoirs had sufficient structural closure to entrap hydrocarbons.

EXAMPLES OF SIMPSON-CONTROLLED PRODUCTION

Production from the Simpson Group is controlled by Viola to Late Pennsylvanian structures overprinting Simpson-age structures. Some traps have proved production from all the Simpson formations (Bromide, Tulip Creek, McLish, and Oil Creek), whereas other fields have production from only one, two, or three of the formations. Faulting allowed the migration of oil from the Woodford Shale (primary source) into the Simpson Group. The relationship of source to migration conduits ultimately determined which sands received and subsequently trapped oil over a given structure. As will be demonstrated, the apex of a field migrates with depth, depending on stratigraphic thinning and thickening from Simpson-age structural movements. Preexisting internal variations within the Simpson Group determined where oil was trapped in sands over a given structure. The productivity of a given field (barrels per acre) results from the net oil column in the sand reservoirs and is controlled by the amount of structural closure on each sand. The productivity of Simpson Group fields ranges from 8,000 BO/acre to more than 20,000 BO/acre (Smith, 1992, 1993). For more information, Smith compares the structure and production of six fields producing from the Simpson Group.

Navy Pool

The Navy pool lies in secs. 5 and 6, T. 8 N., R. 2 W. Production has been attained from all of the Simpson sands in this 200-acre field. As shown in Figure 25, the apex of the structure migrates with depth, owing to thinning of the Simpson formations. The southeasternmost productive well in the field discovered oil in all of the sands except the Oil Creek. The northernmost well, in contrast, produced oil only from the McLish and Oil Creek sandstones. A cross section of the field (Fig. 26) illustrates the migration of the structural apex and the initial production rates of the wells. The Navy pool is within 2 mi of the upthrown side of the McClain County fault, which enabled the Woodford to be the source of oil for all the Simpson sands. This field has produced a total of about 1.6 MMBO from 5 wells. A high leak point, causing a low net oil pay (or reduced structural closure) in this field, probably is responsible for the relatively low recovery factor per acre (8,000 BO/acre).

Northeast Falls Field

The Northeast Falls field has produced more than 10 MMBO from a structure covering approximately 750 acres. Production has been attained from the Bromide, McLish, and Oil Creek sandstones. The Tulip Creek sandstone has not been productive. Figure 27 shows the structures mapped on the Viola and Simpson formations. Figure 28 is a north–south cross section through the field. These diagrams illustrate the dramatic influence that variations of thickness within the Simpson have on the position of closure on various sandstones underlying a simple closed Viola structure. The apex of the Viola structure is south of the apex of the "Second Bromide" sandstone structure. The apex observed on the "Second Bromide" does not coincide with the apex of the Oil Creek sandstone, which has about 100 ft of oil column.

It is likely that the apex of the Tulip Creek was not drilled or tested. Thus, 10–20 ft of untested, potentially productive Tulip Creek sandstone may be undeveloped within the field. However, the oil columns within the other Simpson sands exceed 20 ft. A fault probably exists on the west side of the field. This fault could have interrupted the migration of oil to the Tulip Creek sandstone by allowing Tulip Creek oil to feed into lower zones. The position of this structure, 7 mi from the McClain County fault, combined with the magnitude of the oil production, 10 MMBO, suggests

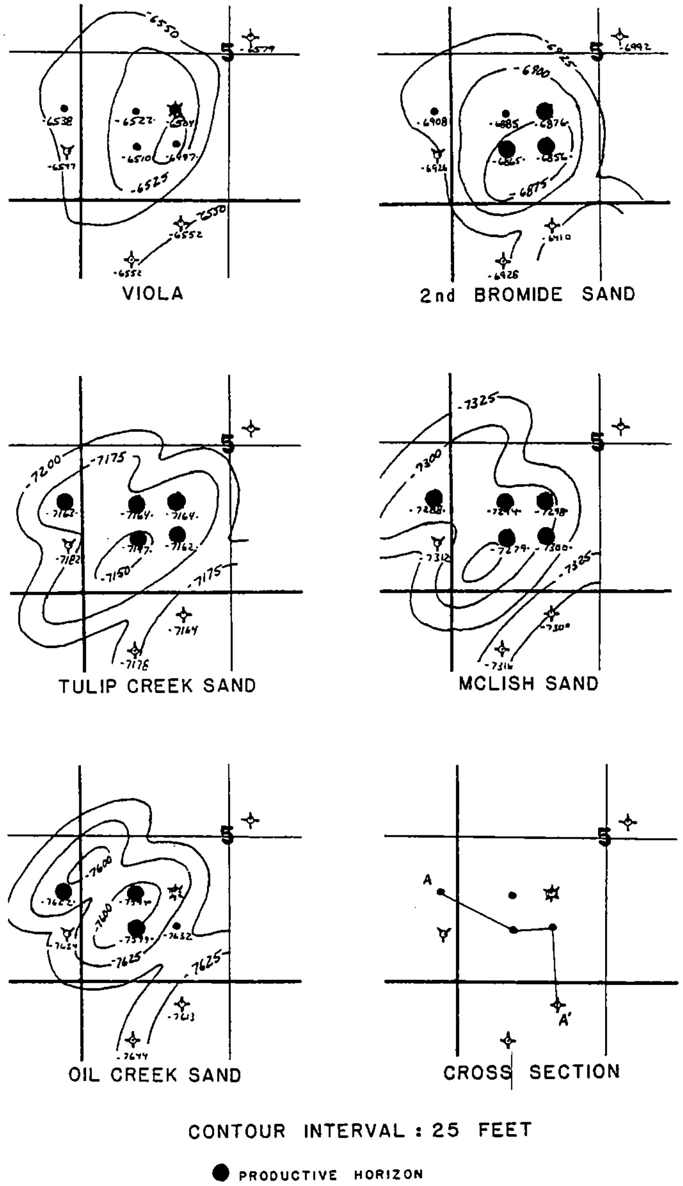


Figure 25. Structure of the Navy pool.

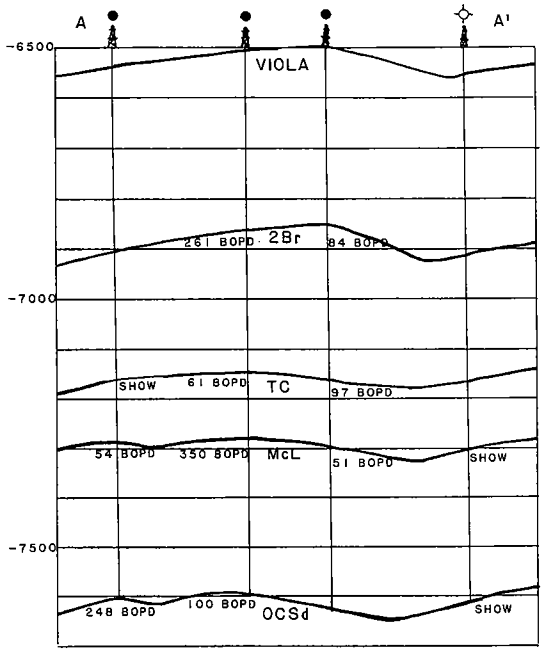


Figure 26. Cross section of the Navy pool. Line of section shown in Figure 25.

that Woodford oil either migrated a considerable distance, filling all the traps along the migration path to the spill points, or followed a more tortuous path, involving lateral migration through a series of faults, emplacing younger downthrown strata against older upthrown strata. The Northeast Falls field has produced approximately 13,800 BO/acre.

EXPLORATION PITFALLS

The Viola Limestone typically provides a strong seismic reflection within the study area. Often, features below the Viola are difficult to interpret or cannot be identified accurately on seismic records. Therefore, the Viola is usually chosen as a mapping horizon to portray the structure of a prospective area. Evidence suggests that Viola structures do not always represent Simpson structures, especially structures on the lower Simpson sandstones. A high structural position reflected by the top of the Viola may vanish at greater depths because of thickened Viola and Simpson intervals. A flat or even slightly low structural position on the Viola may gain structural position because of a thin Viola interval. Therefore, a seismic interpretation of the Viola may not accurately represent the structure of various sandstones within the Simpson Group. Most of the seismic energy has been lost by the time the signal penetrates the Simpson section; consequently, signals from within the Simpson tend to be erratic and weak. Obtaining a structural interpretation of the "Second Bromide" sandstone is stretching the limits of the seismic method (Roberto Feige, personal communication, 1992). This study has demonstrated that an upper Simpson structure may or may not continue with depth. Furthermore, a lower Simpson structure may not display closure in the upper strata.

Many prospects recently drilled and those presently under consideration for drilling result from seismic interpretations of the Viola. Consequently, many wildcat wells drilled on Viola closed structures were found to be nonproductive in the "First Bromide" and "Second Bromide" sections. These discouraging results often led to abandonment of the well without evaluating the deeper sandstones in the lower Simpson. Many exploration wells drilled for structural traps in the lower Simpson Group (Tulip Creek, McLish, and Oil Creek) on the basis of seismic interpretations of the Bromide section have terminated in the "Second Bromide" because the subsurface well data were different from the anticipated result from seismic interpretation. If recorded signals from within the Simpson Group can be accurately resolved, it is important to interpret seismic reflections of the Simpson sandstones independently of one another. Unfortunately, however, current seismic technology does not always permit definitive interpretations of individual Simpson sandstones.

SUMMARY AND CONCLUSIONS

Approximately 65 million barrels of oil (65 MMBO) have been produced from the Simpson Group in the study area. Faults control conditions that permit oil expelled from the Woodford Shale to migrate ultimately into Simpson Group sandstones. Faulting allows oil to enter formations that behave as conduits for migrating

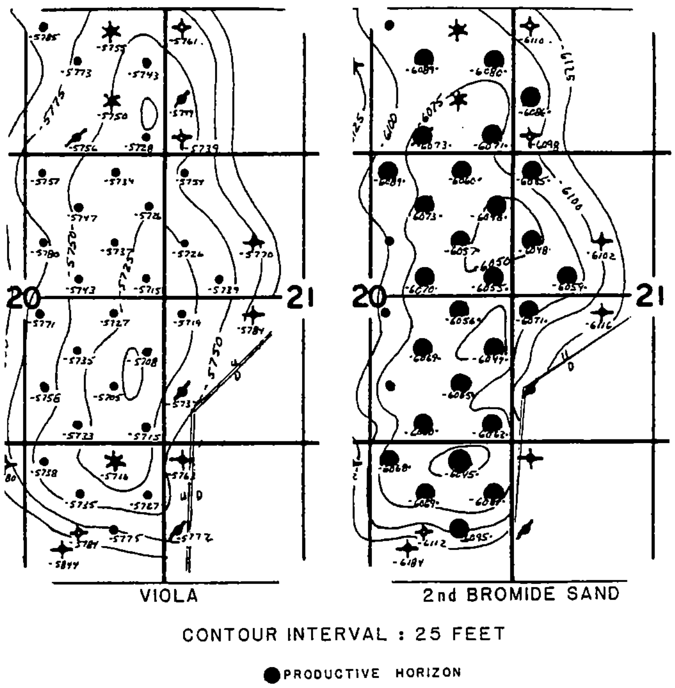


Figure 27. Structure of the Northeast Falls field (continued on page 135).

oil. Under proper conditions, these conduits trap the migrating oil over a specific structure. This study demonstrates that the presence of two acute structural trends (a northeast–southwest orientation imparted during Simpson deposition and a north–south orientation imparted during subsequent structural movements) within the Simpson Group affects the entrapment of oil. More than 60 MMBO of the 65 MMBO produced from the Simpson Group in the study area can be directly correlated to the intersections of these two trends. This dual imprint on the structures, therefore, is the single most influential factor that controls Simpson production.

Geochemical Controls

Geochemical evidence indicates that the Simpson shales are neither capable of generating nor expelling substantial quantities of oil and gas. Rock-Eval analysis suggests that the Woodford Shale and possibly the Viola Limestone and Springer shales are the source rocks for the oil in the Simpson Group. Initial oil generation began in Late Pennsylvanian to Permian time, when these formations were buried to a sufficient depth for source-rock maturation.

Migration Factors

Once oil generation had begun, the study area was relatively stable, and little structural deformation had occurred. Therefore, most of the structural traps and key oil-migration pathways existed prior to hydrocarbon generation. The McClain County fault and other normal faults are integral factors in ultimately juxtaposing the source rock (primarily Woodford Shale) and the reservoir rocks (Simpson Group), or providing avenues for accomplishing the same result.

Controls Resulting from Simpson Structures

While the Simpson Group was being deposited, slight structural movements occurred, creating thin and thick trends in the stratigraphic section. These semi-parallel trends have a northeast–southwest orientation, which is perpendicular to regional thickness trends. The thickness of a member within the Simpson Group may vary by 25–50 ft within 0.25 mi. Evidence of continuous structural movement in localized areas during Simpson deposition can be identified where depositionally thinned intervals of younger Simpson Group members can be shown to stack upon older thinned members. However, not all the structures were active throughout Simpson deposition, and differential movement of structures can be observed.

Factors Involving Post-Simpson Structures

A change in orientation of the structural grain from northeast–southwest to north–south began to appear during Late Ordovician (Viola) time. Subsequently, most major structural movements were oriented north–south. As these north–south-trending structural movements occurred, the previous northeast–southwest grain was incorporated into the newly forming structures. The older structures formed crests and saddles along these new

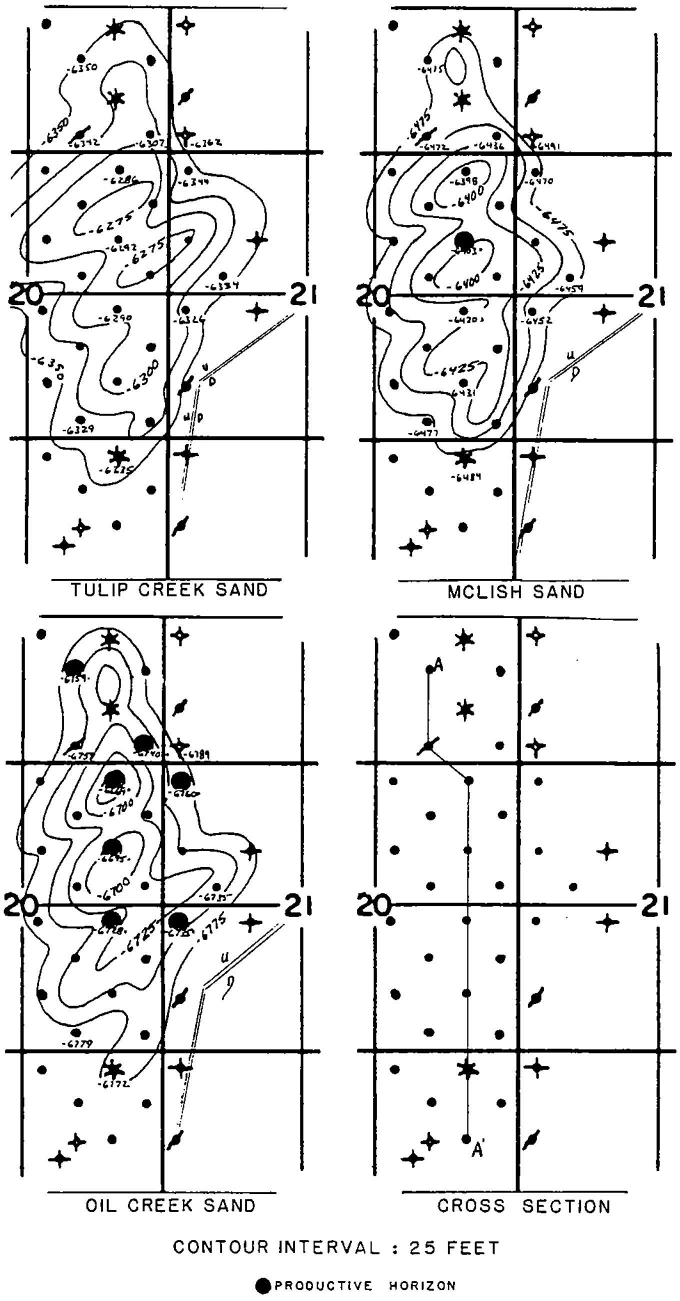


Figure 27 (continued).

north–south trends that created the critical north and south closures required to entrap hydrocarbons. This dual structural imprint (derived from Simpson and post-Simpson structural movements) is the most important factor that controlled the distribution of hydrocarbons within the study area.

REFERENCES CITED

Cronenwett, C. E., 1956, A subsurface study of the Simpson group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

Dake, C. L., 1921, The problem of the St. Peter sandstone: Missouri School of Mines and Metallurgy Bulletin, v. 6, 225 p.

Dapples, E. C., 1955, General lithofacies relationship of St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Decker, C. E.; and Merritt, C. A., 1931, The stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Forgotson, J. M.; Boyce, J. T.; Knapp, R. M.; Liu, Huaibo; and Smith, P. W., 1997, Influence of vertical permeability barriers on ultimate recovery from Oil Creek reservoirs, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 194–202.

Harris, R. W., 1957, Ostracoda of the Simpson group: Oklahoma Geological Survey Bulletin 75, 333 p.

Johnson, K. S.; Amsden, T. W.; Denison, R. E.; Dutton, S. P.; Goldstein, A. G.; Rascoe, Bailey, Jr.; Sutherland, P. K.; and Thompson, C. M., 1988, Geology of the 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. [Reprinted in 1989 as Oklahoma Geological Survey Special Publication 89-2, 53 p.]

Kareem, M. R., 1992, Geologically constrained modeling of the temporal and spatial evolution of hydrocarbon generation in the Anadarko Basin: University of Oklahoma unpublished M.S. thesis, 191 p.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

Smith, P. W., 1992, Factors controlling Simpson Group production in central Oklahoma: University of Oklahoma unpublished M.S. thesis, 78 p.

______1993, Factors controlling Simpson Group production in central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 43, nos. 2, p. 12–26, and 3, p. 30–39.

Wang, H. D., 1993, A geochemical study of potential source rocks and crude oils in the Anadarko Basin, Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 296 p.

Wang, H. D.; and Philp, R. P., 1997, Geochemical study of Viola source rocks and associated crude oils in the Anadarko basin, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 87–101.

Waples, D. W., 1985, Geochemistry in petroleum exploration: International Human Resources Development Corp., Boston, 217 p.

Wavrek, D. A.; Garcia, M. A.; and Ferebee, C. D., 1997, The Viola Group as a petroleum system: implications for horizontal-drilling prospects, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent: Oklahoma Geological Survey Circular 99 [this volume], p. 78–86.

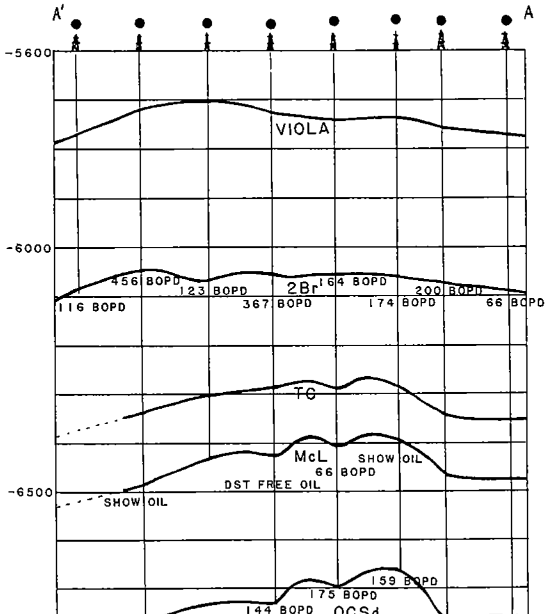


Figure 28. Cross section of the Northeast Falls field. Line of section shown in Figure 27.

Stratigraphy, Paleogeomorphology, and Structure of Simpson, Viola, and Mississippian Strata, and Their Integral Relationships to "Second Wilcox" Production in Lincoln and Logan Counties, Oklahoma

Kurt Rottmann
Consultant Geologist
Oklahoma City, Oklahoma

ABSTRACT.—The Bromide Formation, locally referred to as the "Second Wilcox," is the principal producing formation of the Simpson Group on the central Oklahoma shelf. The following observations and conclusions result from a detailed regional subsurface study of the Lincoln and Logan County area of Oklahoma.

Based on limited well penetrations below the Simpson Group, the "Second Wilcox" apparently resulted from deposition on a relatively stable shelf environment. An isopach map of the interval from the top of the Viola Formation to the top of the "Second Wilcox" represents a cast of the "Second Wilcox" paleotopographic surface. This isopach pattern suggests northwest-trending regional sand buildups in the southern and central parts of the study area. In the northern part of the study area, uplift and subsequent partial erosion of the "Second Wilcox" resulted in geomorphic-relief features capped and preserved by deposits of the "Bromide Dense" or "Marshall Zone." Local geomorphic features can become ideal stratigraphic traps where overlain by the impermeable cap rock of the "Marshall Zone." Because of the geometry and relief of these erosional features, subsequent structural uplift, as mapped, for example, at the Viola horizon, is not a prerequisite or reliable predictor for oil entrapment. Oil production from the "Second Wilcox" coincides with isopach thins of the Viola to "Second Wilcox" interval. Oil production, in fact, is confined to those areas where the above isopach interval is a thin, regardless of the presence or absence of later structure.

The Mississippian isopach, even though removed in age and in vertical proximity, is an important mapping horizon when considering "Second Wilcox" oil possibilities. On the basis of the isopach of the top of the Mississippian unconformity to the first persistent limestone within the Cherokee Group, the pre-Pennsylvanian erosion surface was a very low-relief, featureless surface. However, the underlying Mississippian strata are dissected into fault blocks of markedly varying thicknesses. Known oil fields of the "Second Wilcox" are confined only to those fault blocks that have a thin Mississippian section. Blocks with thick Mississippian units probably represent low areas at the time of oil migration within the "Second Wilcox."

INTRODUCTION

The Bromide Formation, locally referred to as the "Second Wilcox," is the principal producing formation of the Simpson Group within Lincoln and Logan Counties, Oklahoma. Because of its prolific producing characteristics and relatively shallow depth, the "Second Wilcox" was a major target of the oil pioneers in north-central Oklahoma.

In this area, only a few wells extend below the "Second Wilcox." Owing to a general lack of production in any zone below the "Second Wilcox," the normal historic procedure was simply to drill and complete only in the uppermost part of the "Second Wilcox." As a result of this procedure, two interpretational pitfalls can develop from this drilling practice: (1) the lack of data from well control in those areas devoid of apparent structures inhibited interpretation and thus a complete understanding of the relationship of "Second Wilcox" stratigraphy to production; and (2) the concept developed that Viola structural closure was a prerequisite for "Second Wilcox" production.

This paper is a compilation of findings and ideas of the author in his research of the "Second Wilcox" and an attempt to shed some light on the stratigraphy, paleogeomorphology, and structure of the "Second Wilcox" and its relationship to other formations. The regional maps presented within have been simplified to protect potential prospects developed by the author. However, they should be detailed enough to demonstrate the concepts presented in this paper.

METHOD OF STUDY

Figure 1 is a location map defining the area of study for this paper. Approximately 1,200 "Second Wilcox"

Rottmann, Kurt, 1997, Stratigraphy, paleogeomorphology, and structure of Simpson, Viola, and Mississippian strata, and their integral relationships to "Second Wilcox" production in Lincoln and Logan Counties, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 137–154.

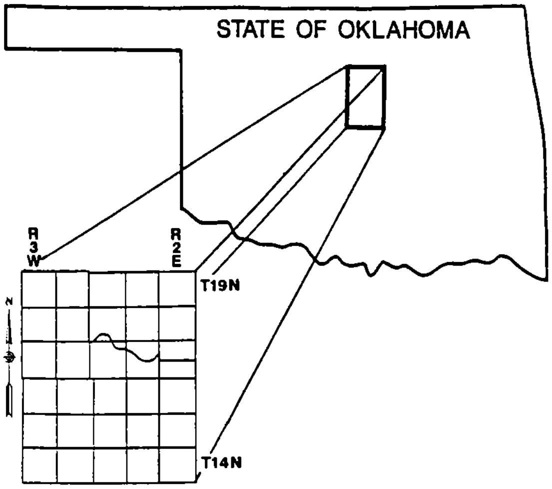


Figure 1. Location of the study area in central Oklahoma.

penetrations were incorporated into the study. Every effort was made to include those wells that penetrated the entire "Second Wilcox" interval.

Figure 2 is a photograph of an example of the fence-diagram technique the author employed when he detailed the Simpson section for this paper. This technique allows geologists to analyze and correlate a large number of wells at a time. The method involves subdividing a large surface into map divisions whereby the electric logs, which have been annotated and trimmed, are secured to the fence diagram using a datum, common to all logs, as a well spot. The results of the correlations were then compiled and calculated and used to derive the various interpretations and maps for this paper.

GEOLOGIC SETTING

Figure 3 is a stratigraphic column taken from Cronenwett (1956). The portion of the column labeled *Northeastern Oklahoma* probably represents the stratigraphic section found within most of this study area. An analysis of the stratigraphy and geologic setting of the Simpson Group also can be found in the paper by Cronenwett (1956) and is discussed in further detail in this paper.

Figure 4 is a north-to-south stratigraphic cross section that shows the general correlations within the study area of those formations from the top of the Viola to the top of the McLish. The Viola Limestone–"Simpson Dense" isopach is generally uniform in thickness within the study area, except for scattered areas where minor thicks or thins may occur. The "First Wilcox" interval also remains generally consistent on a regional basis; however, this interval is complex internally, with abrupt facies changes. The "Marshall Zone" is of importance to the explorationist seeking "Second Wilcox" production. It is a zone of intercalated shales and tight limestones and dolomites that can thicken and thin abruptly. The "Second Wilcox" sandstone was deposited throughout the study area. In the southern part it exceeds 200 ft in total thickness at some localities and thins to the north. This thinning is in response to uplift and erosion of the "Second Wilcox" prior to "Marshall Zone" deposition. There appears to be a facies within the lower part of the "Second Wilcox" that is prevalent in almost all "Second Wilcox" penetrations. This facies is characterized by a very low resistivity reading on wireline logs relative to the "Second Wilcox" as a whole and by a slight positive increase in spontaneous-potential (SP) deflection. The facies seems to be in about the same stratigraphic position relative to the base of the "Second Wilcox." It has been identified on the cross section in Figure 4 as the *Regional Low Resistivity Marker* and is discussed later in this paper.

The "Second Wilcox" lies unconformably on the McLish Formation, as the Tulip Creek Formation is present only in the extreme southwestern part of the study area (Cronenwett, 1956).

DISCUSSION OF FIGURE 5

Figure 5 is an isopach map of the interval from the top of the Viola Limestone to the top of the "Second Wilcox" sandstone. Several assumptions specific to this isopach must be addressed prior to any interpretation. First, it appears that the Viola, "Simpson Dense," and "First Wilcox" intervals are fairly uniform in thickness regionally; therefore, their thicknesses can be treated as a constant within this isopach interval. Most of the abrupt isopach changes generally occur in the "Marshall Zone" interval. Secondly, gradual regional thickening basinward must be considered. For instance, a 200-ft isopach thickness in the northeastern part of the study area is considered a thick for the isopach interval, whereas it would be considered a thin in the southwestern part.

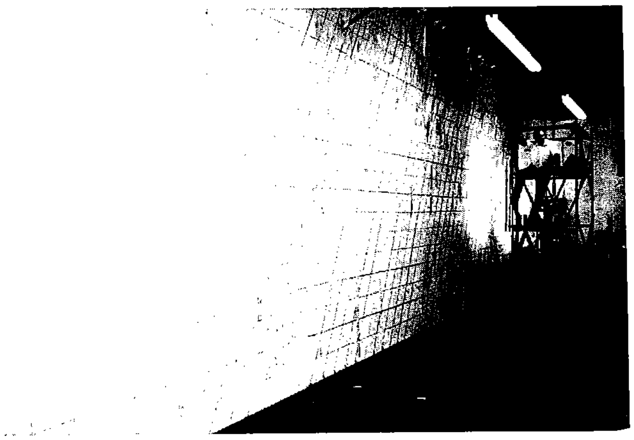


Figure 2. Photograph of the fence-diagram technique.

By assuming that the thickening and thinning of this isopach interval are primarily contained within the "Marshall Zone," this isopach interval represents a cast of the surface of the "Second Wilcox" at the time of deposition. The question now arises: is the undulating surface of the "Second Wilcox," which causes the thickness changes in the "Marshall Zone" inter-

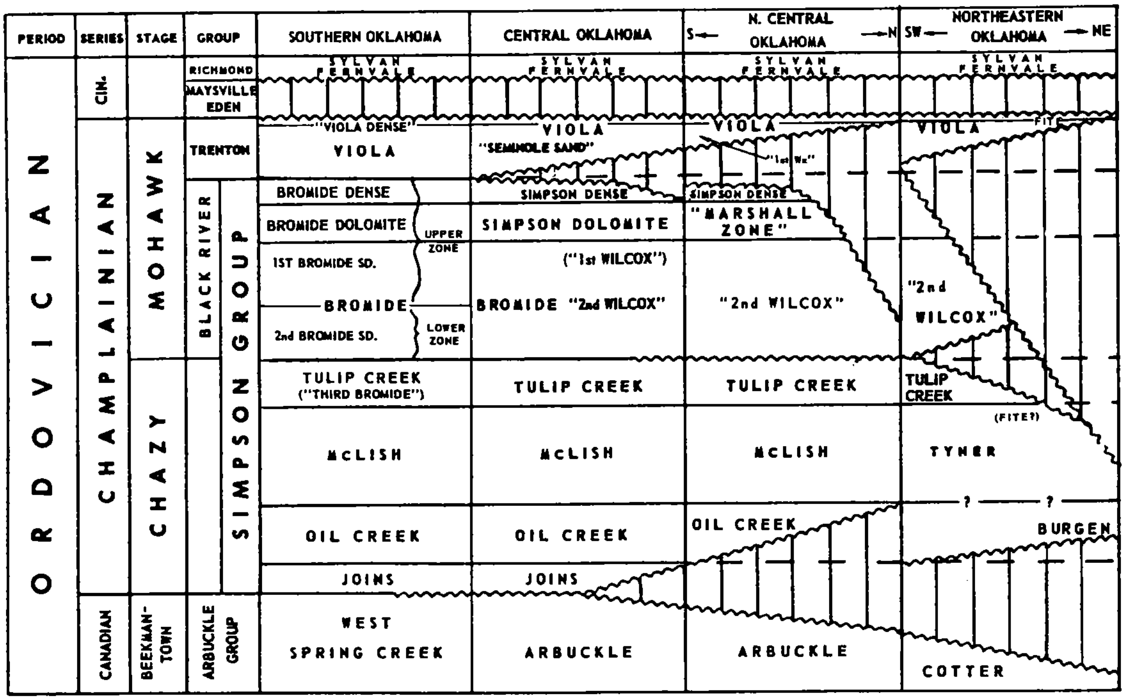


Figure 3. Geologic column of the Ordovician in central and eastern Oklahoma (from Cronenwett, 1956).

val, a result of structural movement prior to "Marshall Zone" deposition or a sedimentary buildup of sand with such possible sand structures as regional dunes or bar structures that were preserved by deposition of the "Marshall Zone"? Figure 6 depicts these two hypotheses. The lack of total "Second Wilcox" penetrations hinders any verification of either hypothesis A or B. It is the author's view, based on close control of the total "Second Wilcox" penetrations where there is significant thickening and thinning of the "Marshall Zone," that the upper part of the "Second Wilcox" sandstone changes in thickness and that the lower part is fairly consistent in thickness. Therefore, it is the author's feeling that hypothesis A generally represents the stratigraphic relationships between the McLish, "Second Wilcox," and "Marshall Zone" intervals over the study area.

"SECOND WILCOX" DEPOSITION AND MODIFICATION

Figure 7 comprises a series of block diagrams drawn to recreate the author's interpretations of various stages of "Second Wilcox" and post–"Second Wilcox" deposition and modification. If hypothesis A of Figure 6 is correct, the "Second Wilcox," as drawn in Figure 7A, was probably deposited on a relatively stable shelf environment. This conclusion is based on the observation that the regional low-resistivity marker within the lower part of the "Second Wilcox," as seen on cross section *A–A′*, remains at about the same vertical stratigraphic interval from the top of the McLish Formation regionally. The thickening and thinning of the "Second Wilcox" appear to be confined only to the upper part of the "Second Wilcox."

Figure 7B illustrates a probable uplift of the northeastern part of the study area, with the hinge line being from T. 14 N., R. 2 E., northwestward to T. 19 N., R. 3 W.

On the northeastern side of the hinge line, the "Second Wilcox" was modified by erosion (Fig. 7C). An examination of the northern part of the isopach in Figure 5 indicates geomorphic-relief features such as channeling types of geometries associated with possible isolated errosional sand remnants.

Deposition of the "Marshall Zone" as seen in Figure 7D probably occurred as a fill deposit that preserved those geomorphic-relief features of the northern part of the study area and the thick and thin sand-body buildups of the southern part. Owing to the geometry and relief of these features, they can become ideal stratigraphic traps where encased by the impermeable "Marshall Zone." Notice that most of the oil fields shown in Figure 5 are in proximity to those areas identified as thins on the isopach map. The thicks on this map do not include "Second Wilcox" production.

Figure 7E illustrates deposition of the "First Wilcox," "Simpson Dense," and Viola intervals. As mentioned earlier, these intervals are considered to be constant in thickness locally and generally do not affect the thickening and thinning of the isopachs of Figure 5.

This then brings into question the role of Viola structure to "Second Wilcox" production. Figure 8 is a generalized structure map of the top of the Viola. Any migrating oil that has become concentrated within these localized thin isopach areas, as seen in Figure 5, will be affected by any post-Viola structure that also occurs within these thins. A later example will be given of how a post-Viola structure occurred in an isopach thick, resulting in barren "Second Wilcox" production. In the early days of industry development of this region, most explorationists probably relied on surface data or seismic methods to explore for "Second Wilcox" production. Since the oil can be trapped by the geometry of the surface of the "Second Wilcox," stratigraphic trends and geometries of the top of the "Second Wilcox" surface play just as important a role in searching for production as structure. Therefore, the idealized method of exploring for "Second Wilcox" production, as seen in Figure 9, is to incorporate the contours of the top of the Viola structure, as seen in Figure 8, with the top of the Viola to the top of the "Second Wilcox" isopach interval, as seen in Figure 5. Adding the contours of the structure map to the contours of the isopach map produces an extrapolated "Second Wilcox" structure map. This structure map is advantageous not only because it is controlled by structure at the Viola horizon but also because it utilizes and honors the stratigraphic trends and geometries of the "Second Wilcox" surface. The following three examples will serve as a general reflection of the results of the author's interpretations of the "Second Wilcox" isopach and the Viola structural interrelationships over the study area and to underscore the need for geologists to understand the role of "Second Wilcox" depositional trends for predicting producible fields.

ANALYSIS OF NORTH WELLSTON FIELD

North Wellston field lies in secs. 34, 35, and 36, T. 15 N., R. 2 E., and secs. 1, 2, and 3, T. 14 N., R. 2 E., Lincoln County, Oklahoma. The field was discovered in 1936 by the Stanolind Oil and Gas No. 1 D. W. Crawford well in the NE¼NE¼SE¼ sec. 35, T. 15 N., R. 2 E. Figure 10 is a Viola structure map overlain by an isopach map of the interval from the top of the Viola to the top of the

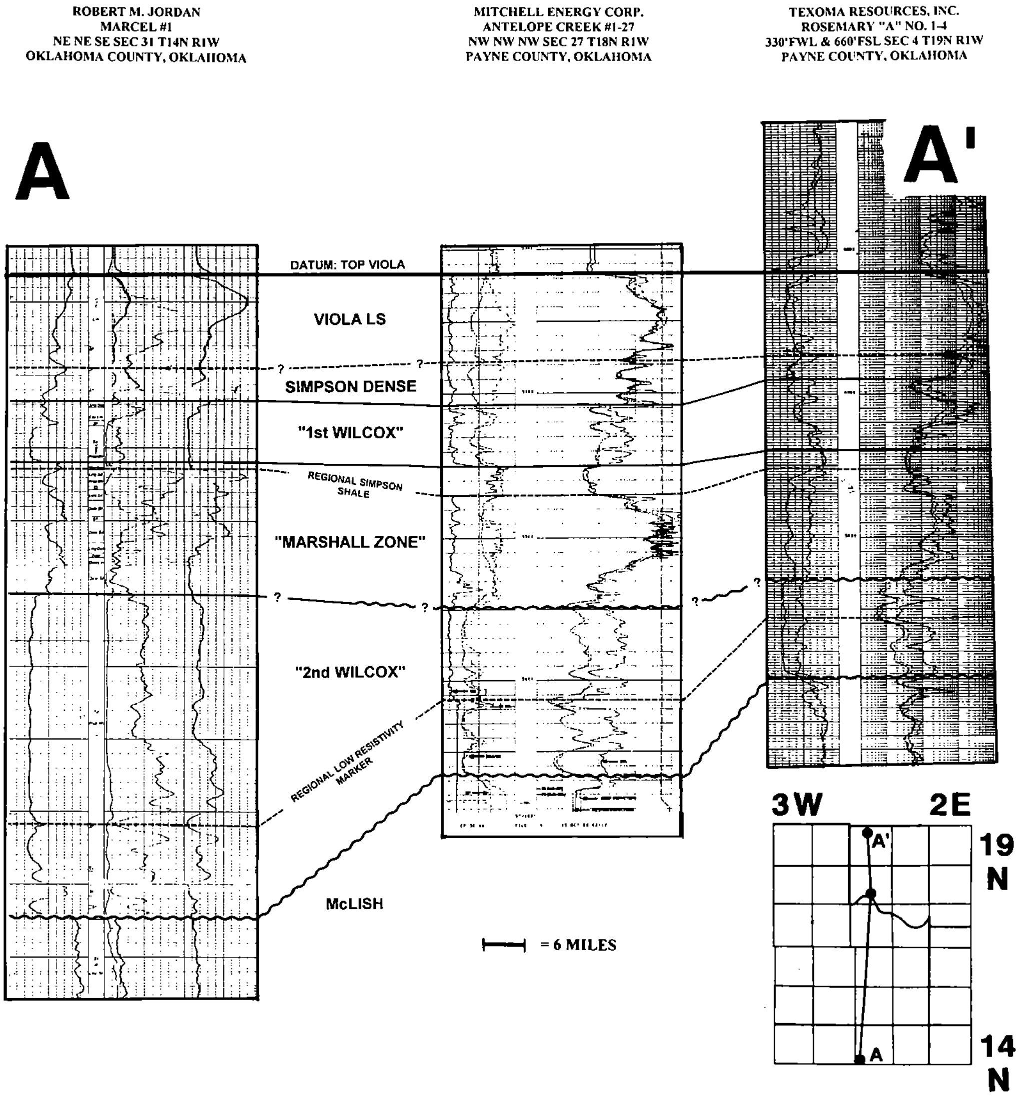


Figure 4. Stratigraphic cross section *A–A′*.

"Second Wilcox." The solid-gray area is that portion of the isopach that exceeds 200 ft in thickness. The stippled area is that portion of the isopach that is less than 160 ft thick. Notice that the apex of the Viola structure occurs in the W½ sec. 36 and the E½ sec. 35, T. 15 N., R. 2 E., and that this is also where the isopach interval exceeds 200 ft in thickness. The Stanolind No. 1 Crawford was drilled on the apex of this structure and established production from the "First Wilcox" interval and encountered water production with oil shows from the "Second Wilcox." Subsequent drilling confirmed "First Wilcox" production, but, as the field enlarged, shows from the "Second Wilcox" on the southwest flank of the Viola structure became more and more discouraging until, finally, the "Second Wilcox" was not even considered a potential pay zone and was seldom penetrated. In 1955, 19 years after discovery of the field, Frankfort Oil Co. completed the No. 1 Erwin in the SW¼SW¼ sec. 35 for an open-flow potential of 314 barrels of oil per day (BOPD) from the "Second Wilcox." With this discovery, subsequent drilling to the south in secs. 2 and 3 confirmed production from the "Second Wilcox" interval.

The contours of the Simpson isopach thin, in secs. 2 and 3, superimposed on and added to the contours of the Viola structure, create closure at the "Second Wilcox" interval, as shown in Figure 11. The Viola structural uplift, greatest in the E½ sec. 35 and the W½ sec. 36, raised the top of the Viola and the top of the "Second Wilcox" isopach thick, which resulted in uplifted "Second Wilcox" water at the apex of the Viola structure.

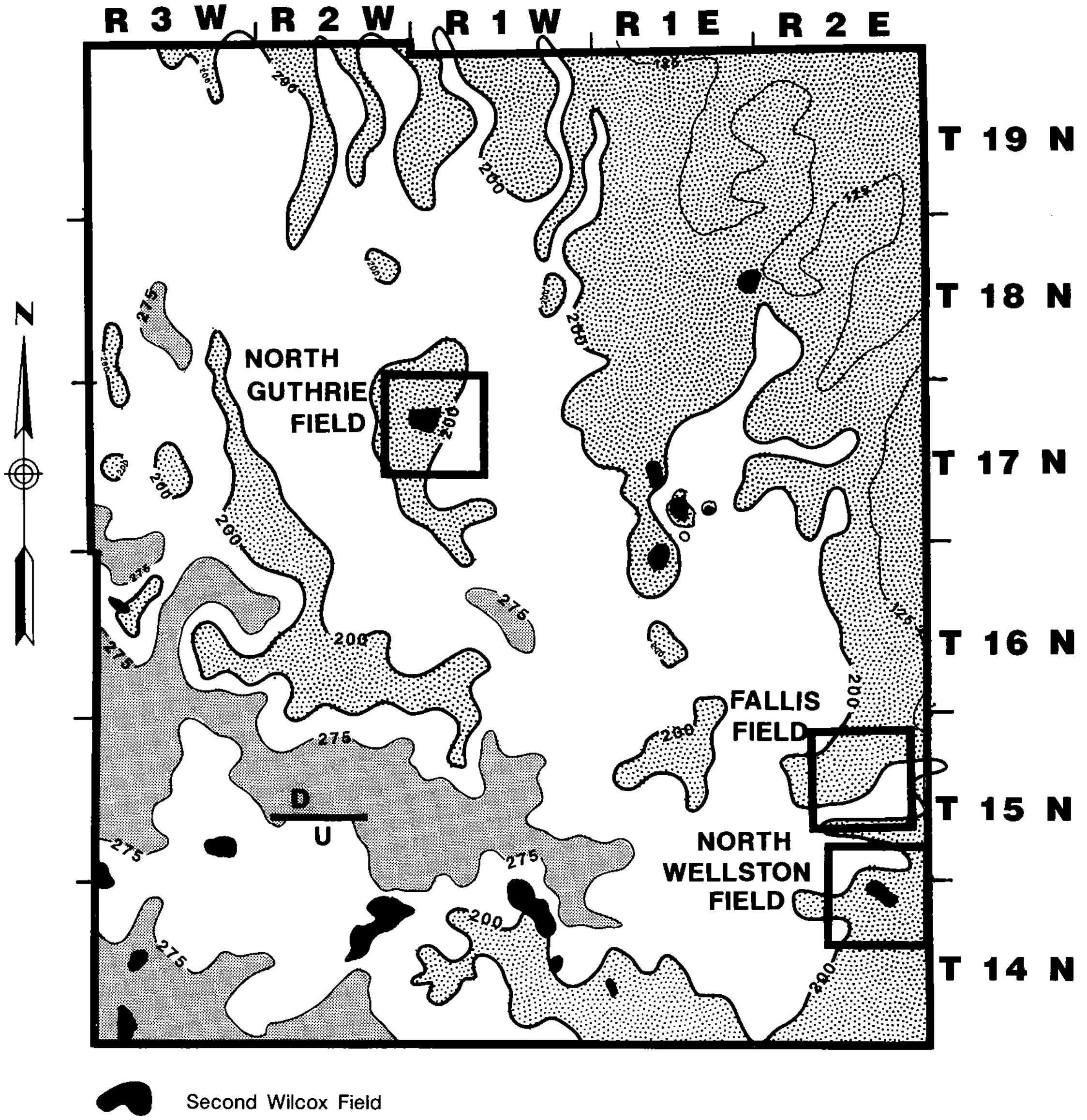


Figure 5. Isopach map of the interval from the top of the Viola to the top of the "Second Wilcox." Contour interval, 75 ft.

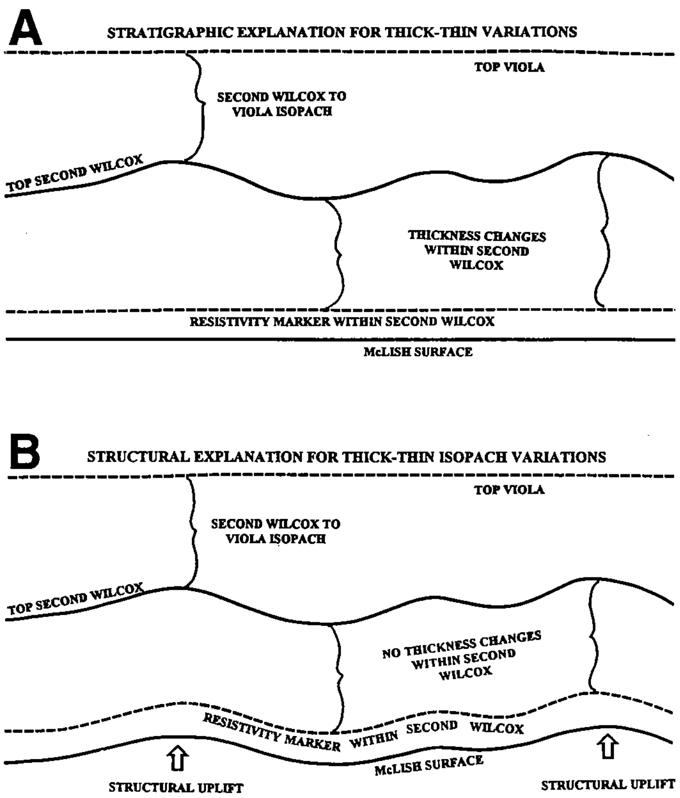


Figure 6. "Second Wilcox" to Viola isopach thick and thin hypotheses.

ANALYSIS OF NORTH GUTHRIE FIELD

North Guthrie field lies in secs. 7, 8, and 18, T. 17 N., R. 1 W., and sec. 12, T. 17 N., R. 2 W., Logan County, Oklahoma. The gray area of Figure 12 is that portion of the top of the Viola to the top of the "Second Wilcox" isopach interval greater than 200 ft in thickness. Starting from the center of sec. 7 and moving in an eastward direction, the isopach interval thickens rather dramatically. This thickening occurs primarily within the "Marshall Zone" interval. An east–west normal fault seals the field on the north side. The throw on the fault is sufficient to allow the "Second Wilcox" to be offset by the Sylvan Shale, thereby creating a seal. The structure at the top of Viola is generally a homocline that dips to the southwest at approximately 100 ft/mi. Drag from the fault creates an apparent west-dipping nose that extends into sec. 7. The structure at the top of the Viola horizon is not sufficient to be the primary trapping mechanism within the "Second Wilcox." This field is an example of how oil that has accumulated in a regional isopach thin, as seen in Figure 5, has migrated to the highest structural point of the isopach thin. Figure 13 is an extrapolated "Second Wilcox" structure map, derived from the addition of the contours of the top of the Viola structure map and the top of the Viola to the top of the "Second Wilcox" isopach interval. This field is an excellent example of how a stratigraphic closure occurs at the "Second Wilcox" horizon with little or no closure at the Viola horizon.

ANALYSIS OF FALLIS FIELD

Fallis Field lies in secs. 14 and 15, T. 15 N., R. 2 E., Lincoln County, Oklahoma. The gray area in Figure 14 represents that portion of the top of the Viola to the top of the "Second Wilcox" isopach interval thicker than 200 ft, and the stippled area represents the isopach interval thinner than 160 ft. A northeast–southwest-trending normal fault is present through secs. 14 and 15, with a throw of up to 125 ft. A Viola closure is present in the NE$\frac{1}{4}$ sec. 15. According to the interpretations presented thus far in this paper, the NE$\frac{1}{4}$ sec. 15 should be a prime example of where "Second Wilcox" oil should be concentrated. Indeed, the addition of the contours of the Viola structure map and the isopach map from Figure 5 suggests sufficient closure at the "Second Wilcox" horizon, as depicted in Figure 15. However, drill-stem tests of the "Second Wilcox" in the wells drilled on the apex of the "Second Wilcox" structure recovered water. The following two paragraphs offer probable causes as to why this area is devoid of oil from the "Second Wilcox" and why these considerations should be part of the basis for the reader's evaluation of the structural and stratigraphic potential of "Second Wilcox" prospects within this study area.

The isopach interval at the apex of the Viola structure in the NE$\frac{1}{4}$ sec. 15 is approximately 140 ft thick; however, the throw on the fault adjacent to the structure approaches 110 ft. The "Second Wilcox" on the upthrown side would be offset against the Viola on the downthrown side. This fault may not be a sealing fault.

Figure 16 is an isopach map of the interval from the Mississippian unconformity surface to the first major onlapping Cherokeean persistent limestone marker such as the "Brown Limestone," the Inola Limestone, or the "Pink Limestone." The isopach contour interval suggests that the post-Mississippian erosional surface was very low in relief and featureless. Even at this contour interval, no indication of channeling or marked isopach irregularities in the unconformity surface is evident. Figure 17 is an isopach map of the Mississippian strata within the study area. This isopach demonstrates that even though the unconformity surface is essentially flat and featureless, the underlying Mississippian strata are dissected into fault blocks of markedly varying thicknesses. Cross section *B–B′*, as seen in Figure 18, demonstrates the onlap of the Pennsylvanian over the featureless post-Mississippian surface. Notice the varying thicknesses of Mississippian strata. Of note is the proximity of the "Second Wilcox" oil fields to these fault blocks and isopach areas as seen in Figure 17. Known oil fields of the "Second Wilcox" are confined only to

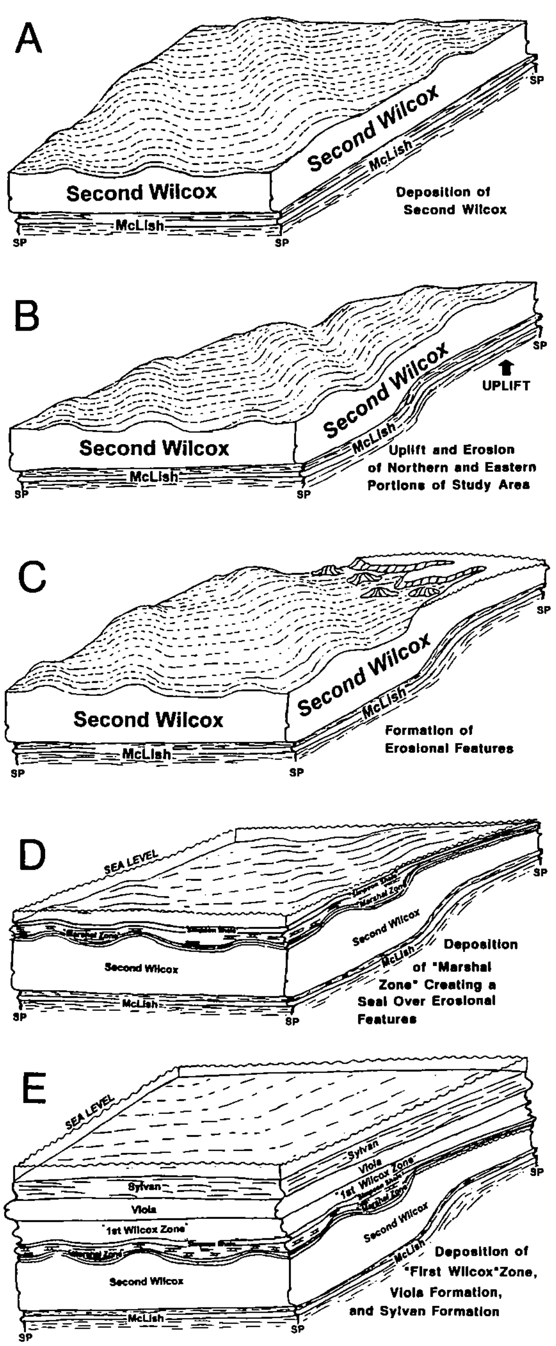


Figure 7. (A) Deposition of "Second Wilcox" on a flat, featureless surface. (B) Partial uplift of "Second Wilcox." (C) Erosion of exposed "Second Wilcox." (D) Deposition of "Marshall Zone." (E) Deposition of "First Wilcox" through Sylvan formations.

those fault blocks or isopach areas that have a thin Mississippian section. The fault blocks with relatively thick Mississippian sections apparently do not contain oil fields producing from the "Second Wilcox." The Fallis area is situated in a Mississippian thick. Perhaps this is an indication of the age of oil migration within the "Second Wilcox." With the top of the Mississippian being flat and featureless, the blocks with thick Mississippian strata may represent low areas at the time of oil migration in the "Second Wilcox."

CONCLUSIONS

The following conclusions may serve as a guide for exploring for "Second Wilcox" production.

- Uplift and erosion locally of "Second Wilcox" strata resulted in geomorphic-relief features preserved by impermeable deposits of the "Marshall Zone," creating ideal stratigraphic traps.
- "Second Wilcox" oil does not seem to be present in those areas identified as thicks on the Viola to "Second Wilcox" isopach interval.
- The structure at the top of the Viola horizon is not a prerequisite for oil entrapment within the "Second Wilcox."
- The contours of a regional isopach map of the Viola to the top of the "Second Wilcox" interval, superimposed and added to a regional Viola structure map, may suggest potential "Second Wilcox" prospective areas.
- Regional isopach mapping of Mississippian strata may determine relative low and high areas of "Second Wilcox" strata at the time of oil migration.
- "Second Wilcox" permeable strata need to be upthrown against impermeable strata for a fault seal to occur.

ACKNOWLEDGMENTS

Sincere appreciation is extended to several people who have contributed to this paper: to Steve Cody, for his cooperation in drafting the figures, and to Martin Pruatt and Walter Parrish of Sensor Oil and Gas, Inc., for their insight and review of the paper.

REFERENCE CITED

Cronenwett, C. E., 1956, A subsurface study of the Simpson group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

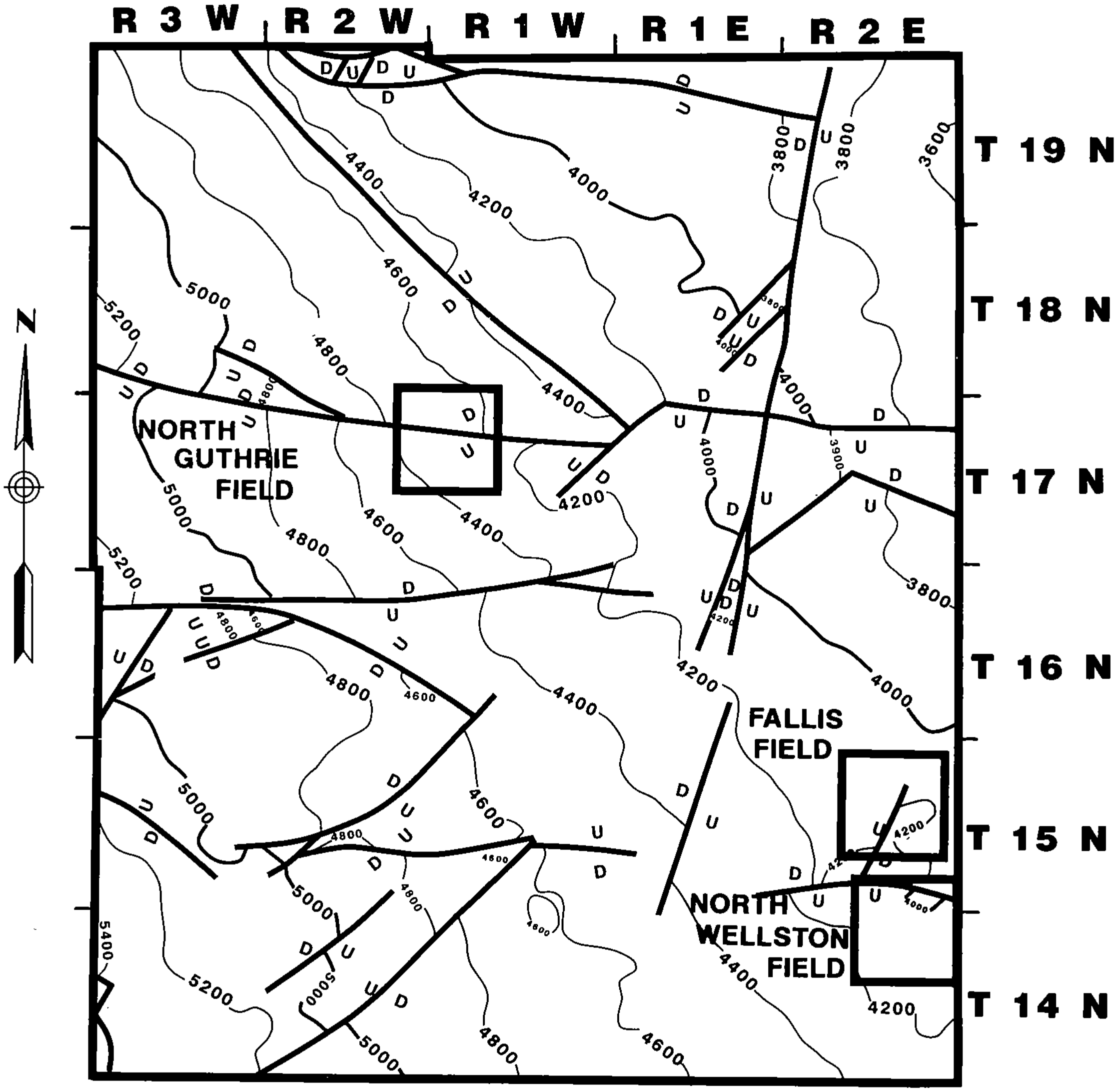


Figure 8. Structure map of the top of the Viola for the study area. Contour interval, 200 ft.

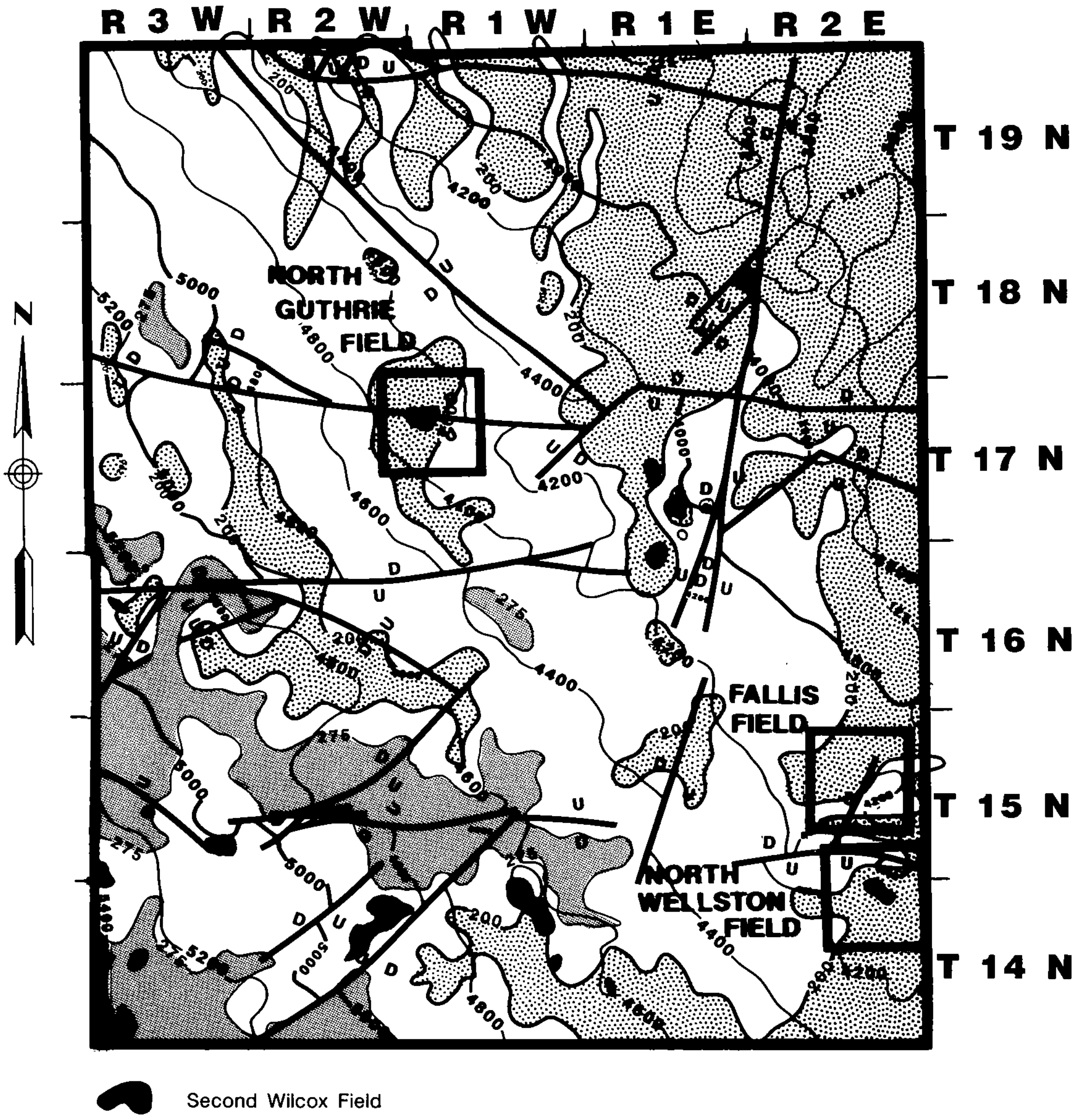


Figure 9. Isopach map of the top of the Viola to the top of the "Second Wilcox" interval, superimposed on the structure map of the top of the Viola.

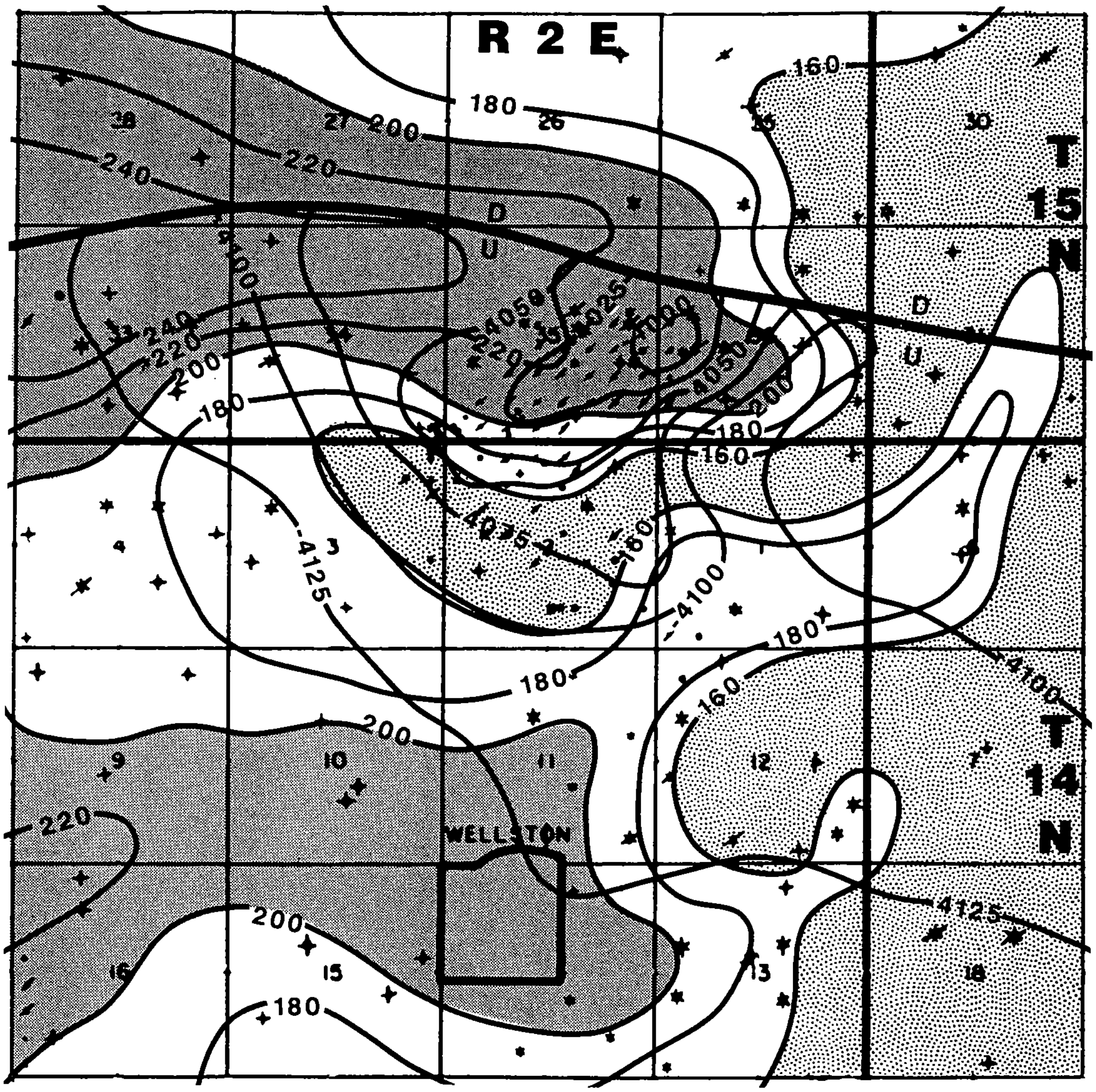


Figure 10. Isopach map of the top of the Viola to the top of the "Second Wilcox" interval, superimposed on the structure map of the top of the Viola; North Wellston field, Lincoln County. Contour interval for isopach map, 20 ft; contour interval for structure map, 25 ft.

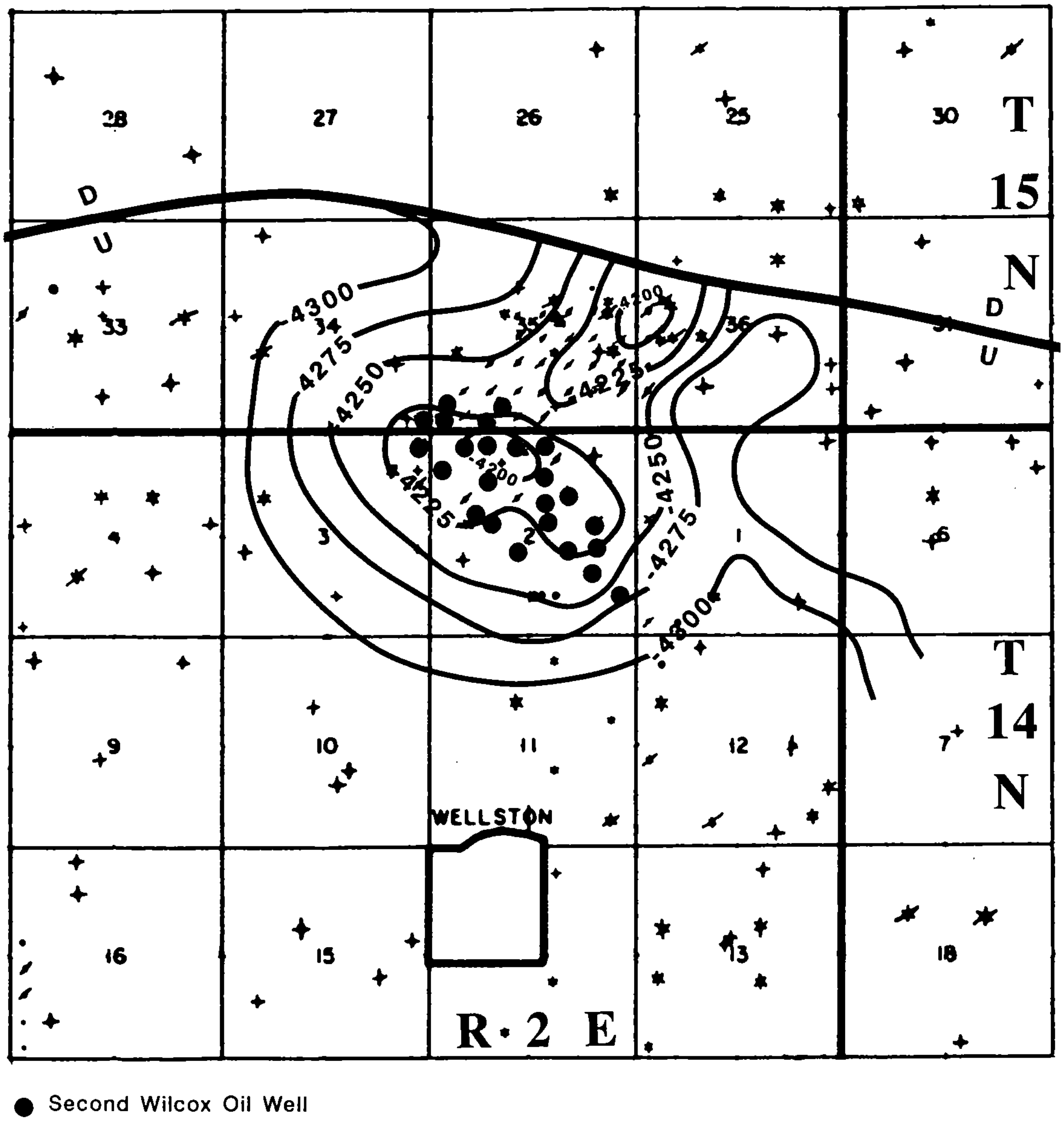


Figure 11. Extrapolated "Second Wilcox" structure map, derived from well control and the addition of contours as seen in Figure 10; North Wellston field, Lincoln County. Contour interval, 25 ft.

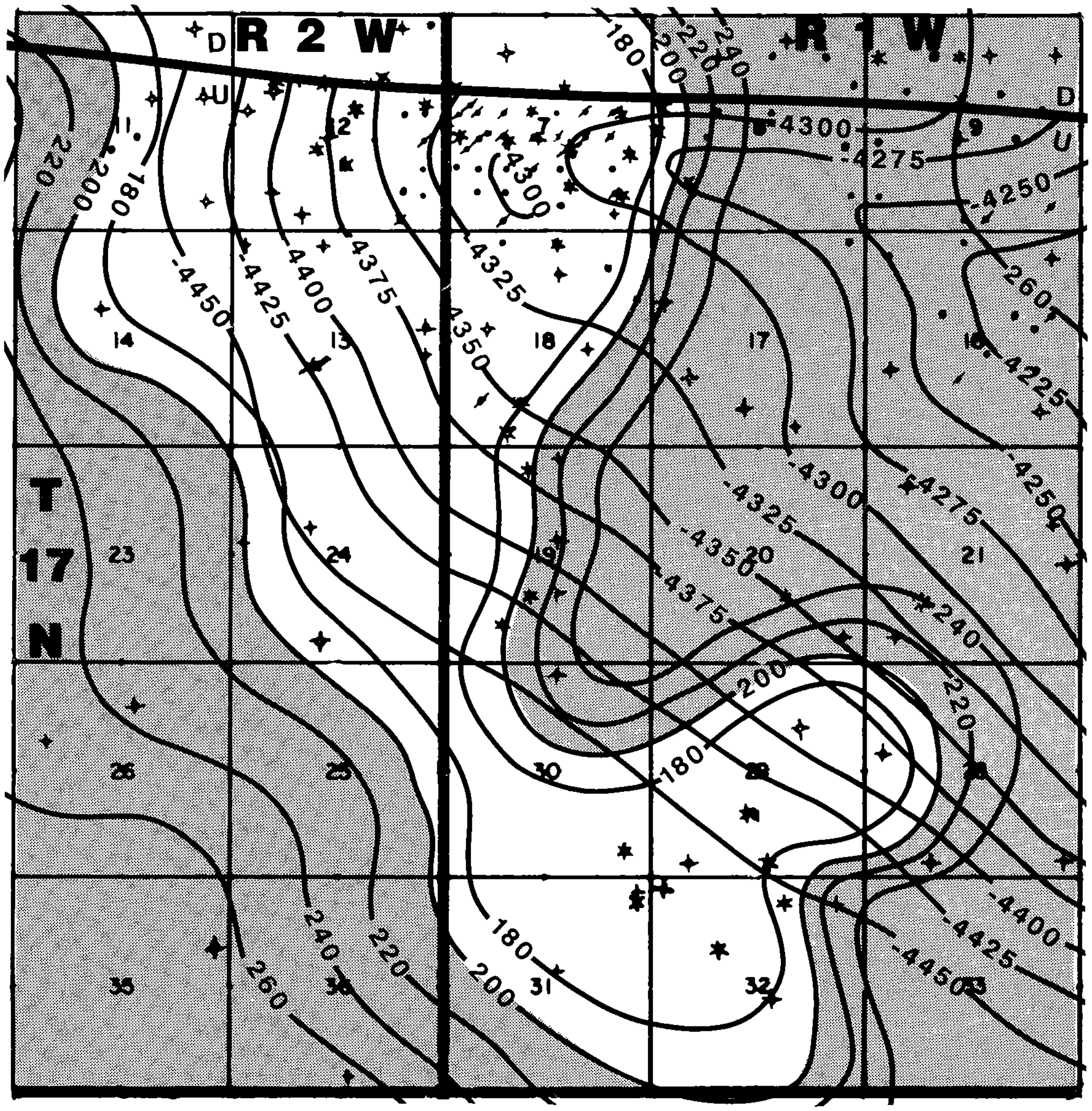
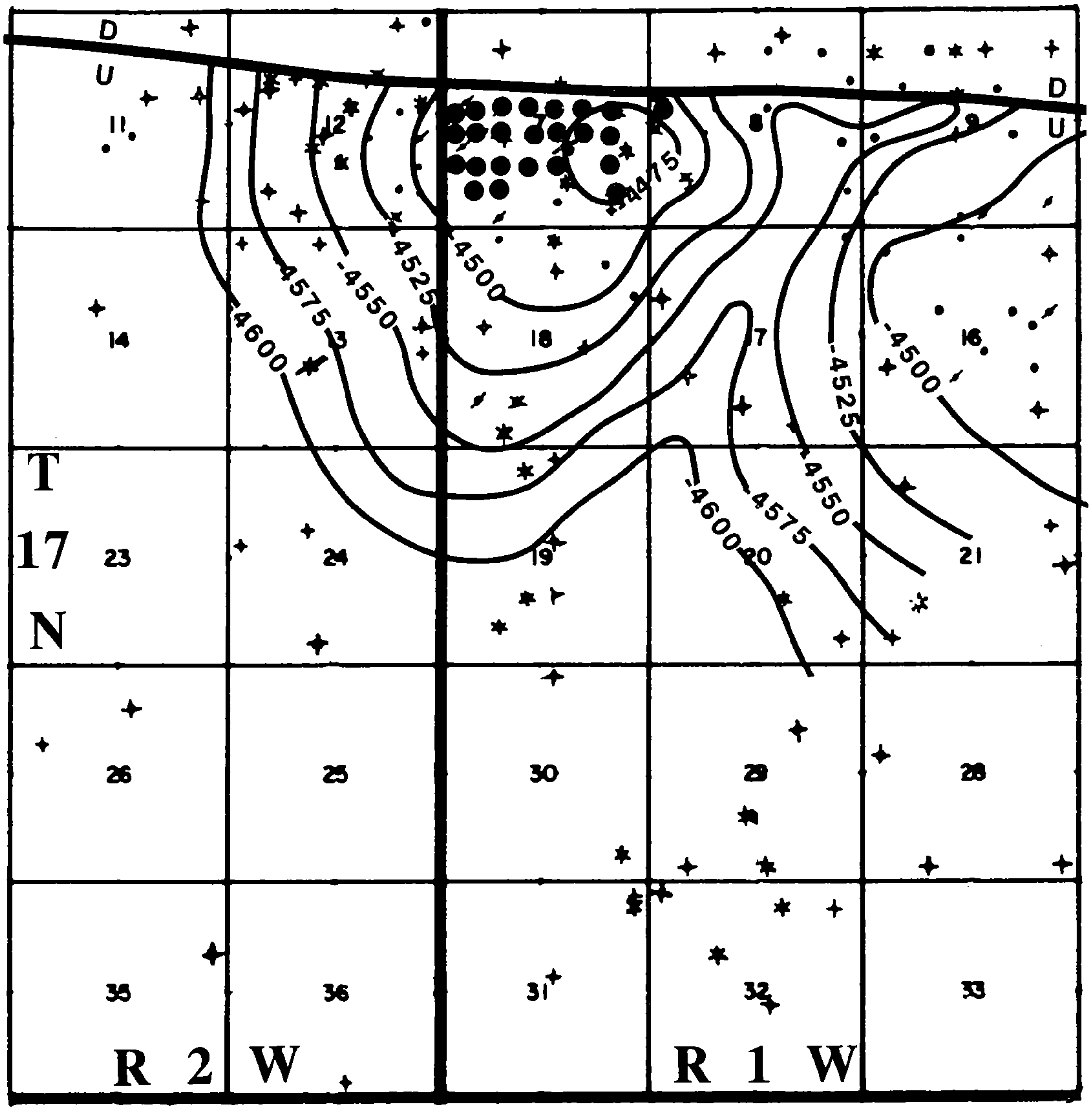


Figure 12. Isopach map of the top of the Viola to the top of the "Second Wilcox" interval, superimposed on the structure map of the top of the Viola; North Guthrie field, Logan County. Contour interval for isopach map, 20 ft; contour interval for structure map, 25 ft.



● Second Wilcox Oil Well

Figure 13. Extrapolated "Second Wilcox" structure map, derived from well control and the addition of contours as seen in Figure 12; North Guthrie field, Logan County. Contour interval, 25 ft.

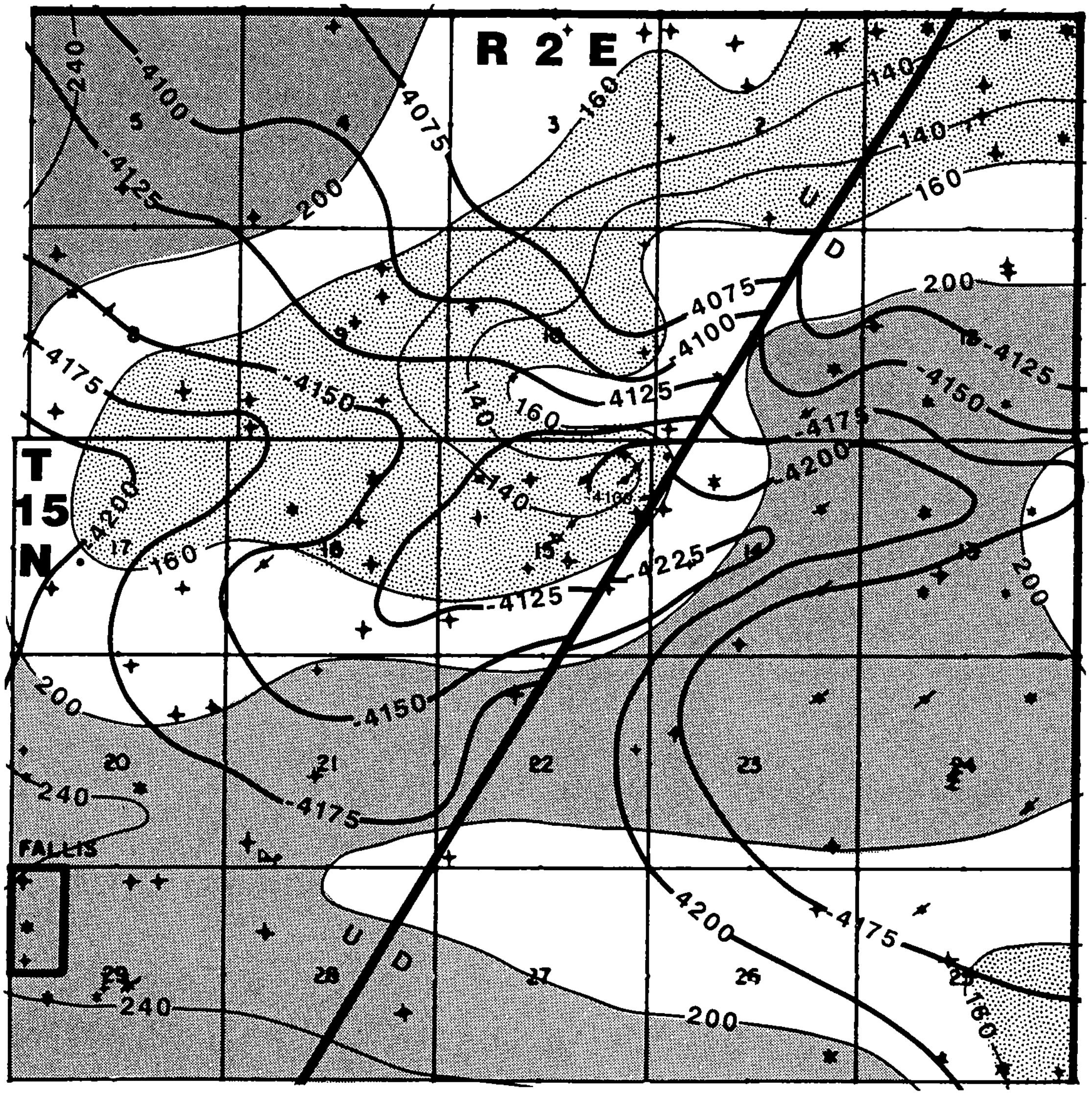


Figure 14. Isopach map of the top of the Viola to the top of the "Second Wilcox" interval, superimposed on the structure map of the top of the Viola; Fallis field, Lincoln County. Contour interval for isopach map, 20 and 40 ft; contour interval for structure map, 25 ft.

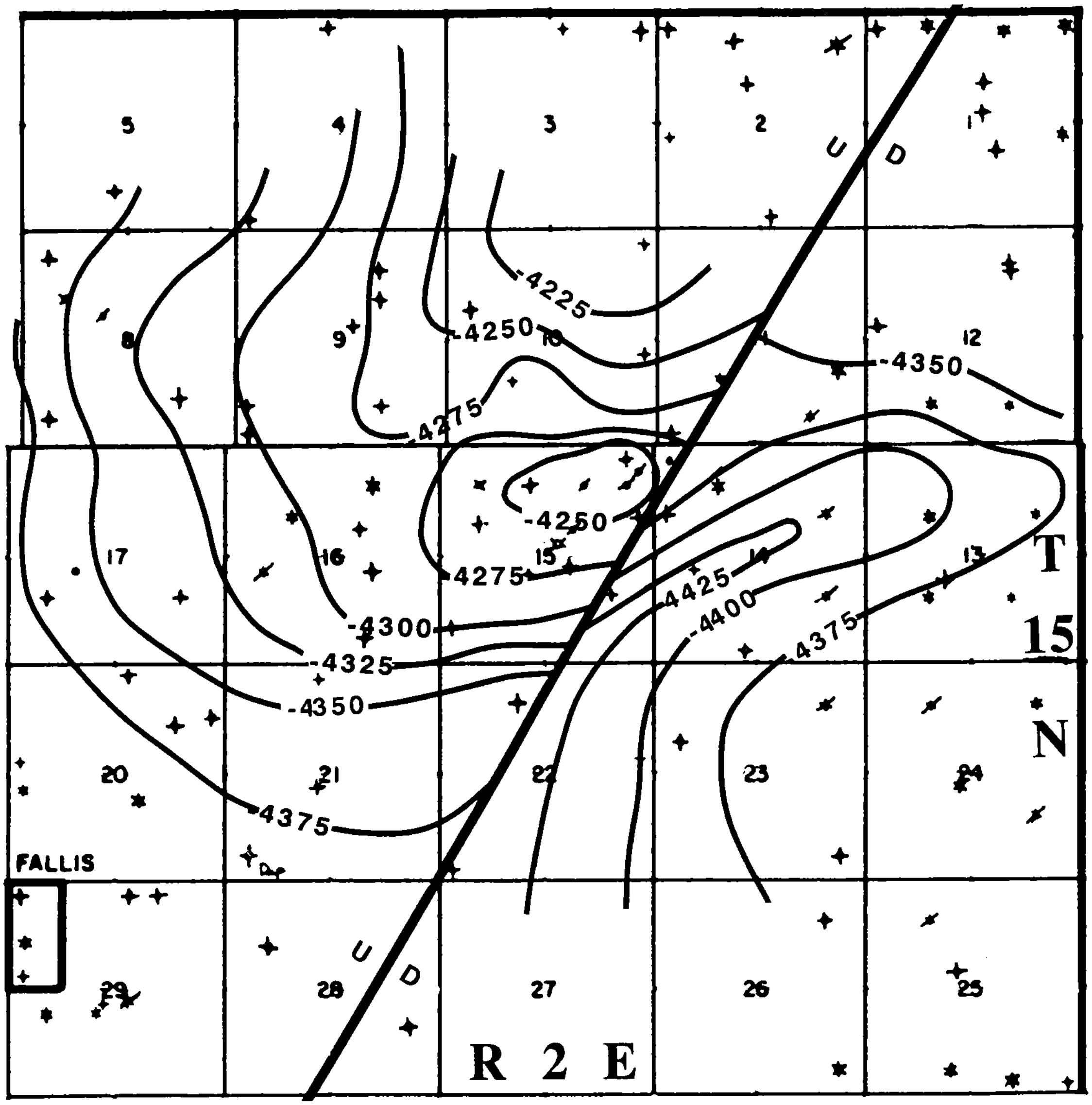


Figure 15. Extrapolated "Second Wilcox" structure map, derived from well control and the addition of contours as seen in Figure 14; Fallis field, Lincoln County. Contour interval, 25 ft.

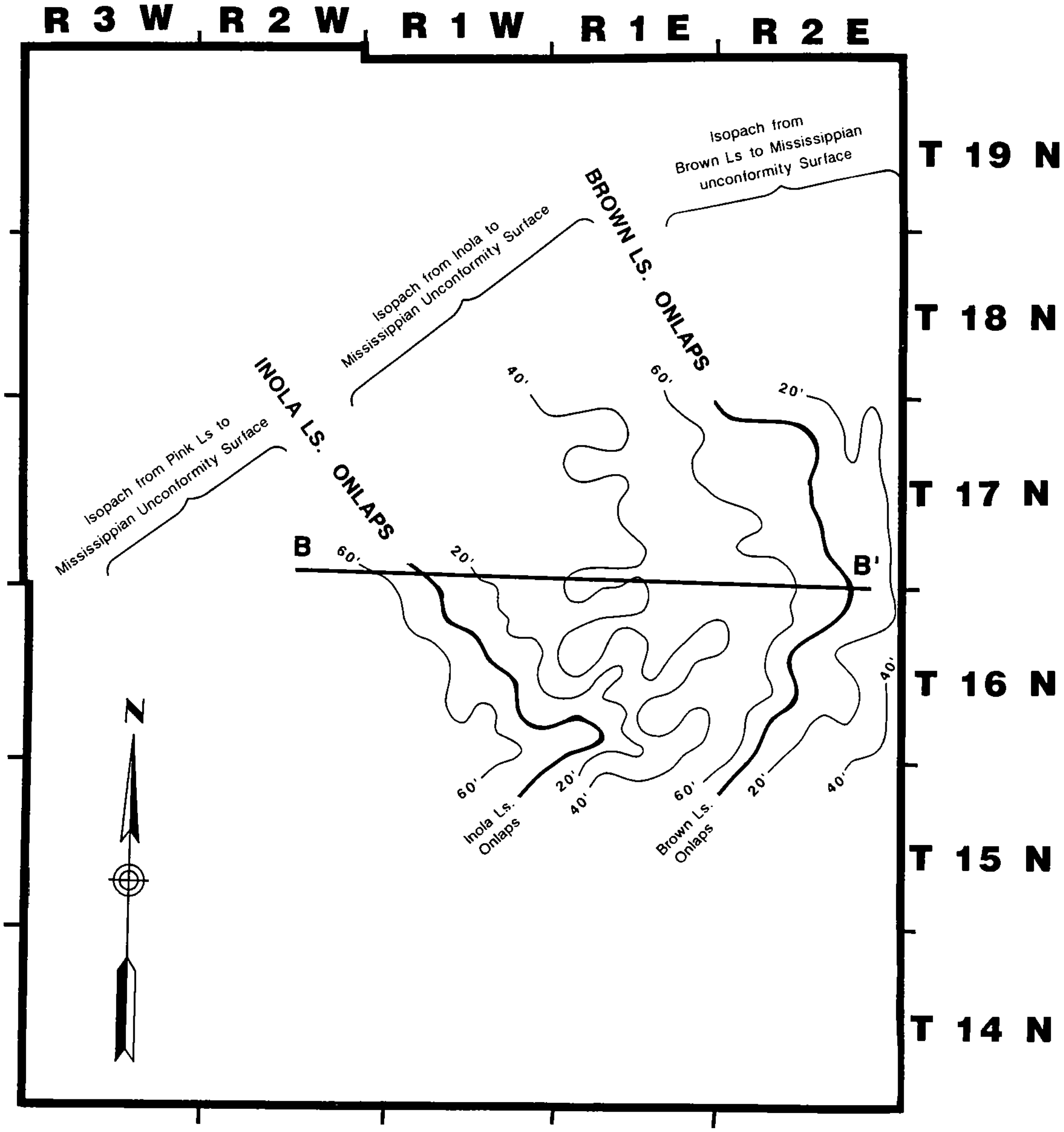


Figure 16. Isopach map of the interval from the Mississippian unconformity to the first persistent regional limestone marker in the Pennsylvanian Cherokeean over a part of the study area.

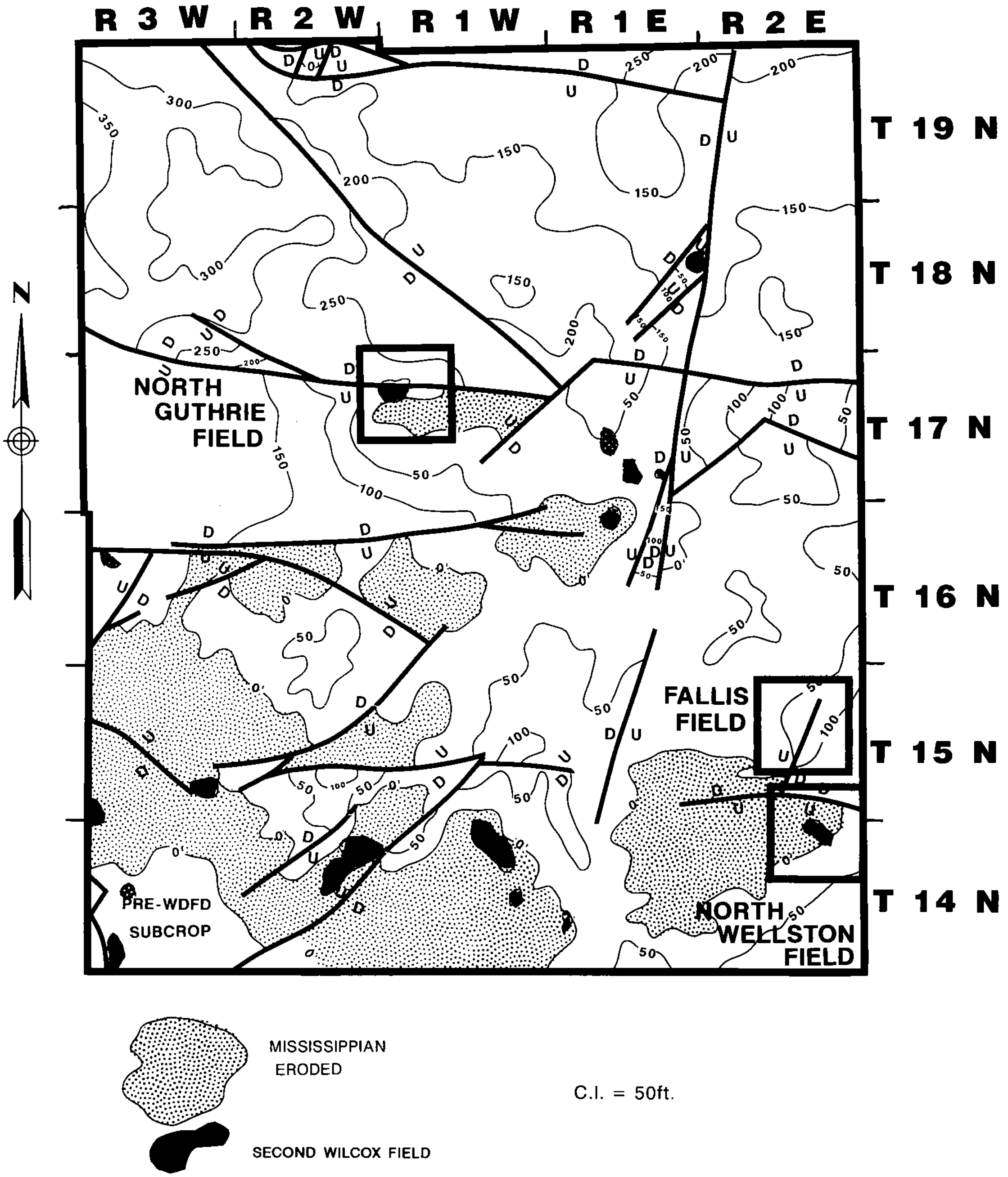


Figure 17. Mississippian isopach map for the study area.

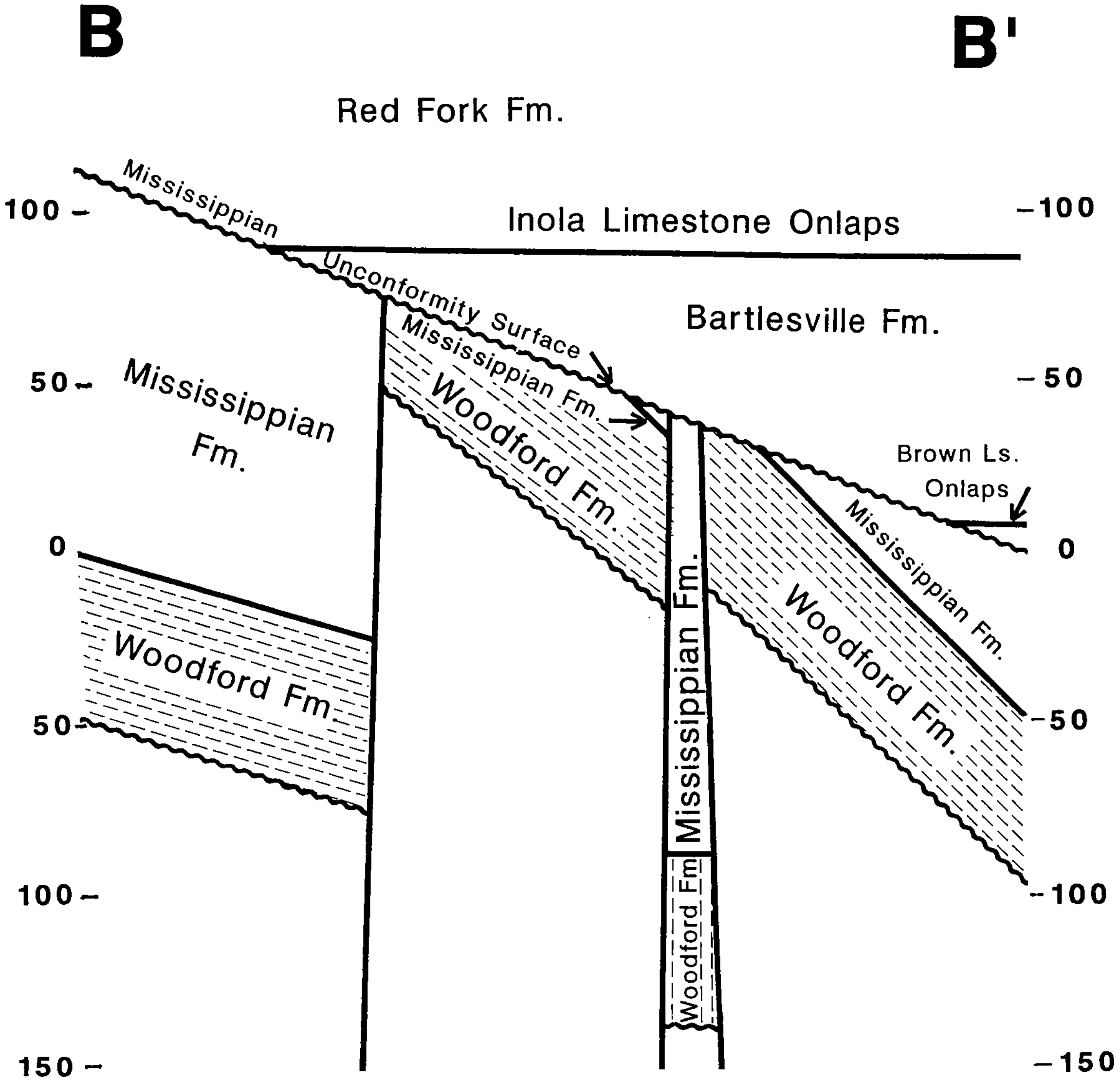


Figure 18. Sratigraphic cross section *B–B′*. Line of section is shown in Figure 16.

Oklahoma Geological Survey Circular 99, 1997

Facies and Depositional Environments of the Simpson Group (Middle Ordovician) in the Salina Basin of Kansas

Jim Mazzullo and Martha McRae
Texas A&M University
College Station, Texas

ABSTRACT.—The depositional origin of the Simpson Group (Middle Ordovician) in the Salina basin of Kansas was determined by a study of cores and well logs from Scully field in Marion County. The results of the study indicate that the group was deposited largely in a prograding coastal tidal flat similar to those tidal flats of the German North Sea coast. Six clastic facies are distinguished in the Simpson Group: Facies A and B, which are interpreted as intertidal-flat deposits; Facies C, D, and E, which are interpreted as tidal-creek and tide-dominated stream-channel deposits; and Facies F, which is interpreted as a transgressive inner-shelf deposit.

INTRODUCTION

The lower Paleozoic sedimentary rocks in the cratonic interior of North America consist largely of thick sections of carbonate rocks separated by thin intervals of quartzose sandstones. The carbonate rocks in this orthoquartzite–carbonate suite were deposited in shallow seas that flooded the interior of the continent during a sea-level highstand (Wilson, 1975), but there is less known about the depositional environments of the sandstones other than that they are thought to be largely coastal and shallow marine in origin (Dake, 1924; Dapples, 1955; Dott and Byers, 1981). This paper addresses this problem of the depositional origins of the lower Paleozoic sandstones in the cratonic interior of North America with an examination of the facies and depositional environments of the Middle Ordovician Simpson Group in the Salina basin of Kansas.

The Simpson Group is a thin (18-m) sequence of interbedded sandstones and mudstones that forms the base of the Tippecanoe Sequence in the cratonic interior of North America (Sloss, 1963). The group is unconformably underlain by carbonate rocks of the Arbuckle Group (Cambro–Ordovician), which is the uppermost stratigraphic unit in the Sauk Sequence, and it is unconformably overlain by the carbonates of the Viola Formation (Middle–Upper Ordovician) (Fig. 1). This study examined two cores, those from the Walker No. 6–10 (WS-6) W. Scully well and the Walker No. 1–10 (WPD-1) P. Dudeck well, and several dozen logs of the Simpson Group (and its underlying and overlying carbonate) from Scully field in Marion County, Kansas (Figs. 2,3), where the sandstones of the group are petroliferous. The facies and depositional environments of the Simpson and the bounding carbonates were determined by core, thin-section, and SEM analysis of their lithology and stratification, and the logs were used to construct cross sections and isopachs of the Simpson Group and its sandstones.

RESULTS

General Lithology and Stratigraphy

The Simpson Group of Scully field consists of 12 to 14 m of interbedded sandstone, sandy mudstone, and mudstone (Fig. 1). It contains three thick sandstones (Sands 1, 2, and 3) that range in thickness from 0 to 4.3 m and which are petroliferous. The sandstones are composed primarily (>90%) of well-rounded to subrounded fine to medium quartz sand, and minor amounts of glauconite, feldspar, mud, and mudstone clasts, and they are cemented largely by quartz and to a lesser extent by calcite and dolomite. The detrital cores of the quartz grains are generally either well rounded or subrounded, but they are usually overlain by angular quartz overgrowths. The Simpson sandstones are typically stained moderate to dark brown to dark black by hydrocarbons, and they are less commonly tan, buff, and greenish gray. The mudstones are largely composed of quartz silt and sand and illitic clay, as well as of traces of hematite (indicated by a dark reddish-brown color). Lastly, the Simpson rocks contain numerous trace fossils but no body fossils.

Facies of the Simpson Group

Six facies can be distinguished in the Simpson Group on the basis of lithology and sedimentary structures.

Facies A is composed of blackish-brown mudstones with thin sandstone stringers (Fig. 4). The mudstone is thick to very thick bedded and contains very thin planar and slightly wavy laminae. The sandstone stringers are

Mazzullo, Jim; and McRae, Martha, 1997, Facies and depositional environments of the Simpson Group (Middle Ordovician) in the Salina basin of Kansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 155–163.

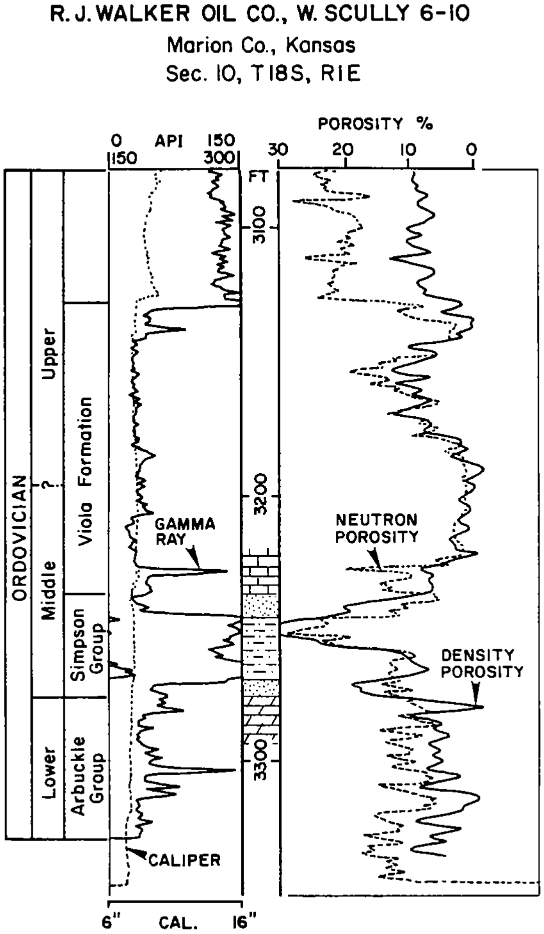


Figure 1. Stratigraphy of the Ordovician section in the study area. Sandstones of the Simpson Group are recorded by the three gamma-ray low peaks.

tan and thickly laminated (0.1–0.5 cm) and commonly appear as cross-laminated starved ripples; they are composed of quartz sand and mudstone clasts. This facies also contains a few narrow (0.5–1 cm), isolated tubular horizontal burrows filled with fine- to medium-grained sandstone and mudstone clasts.

Facies B consists of grayish-green and grayish-brown, slightly glauconitic sandy mudstones with minor amounts of fine sandstone. The mudstones are thick bedded, and the sandstones occur in planar, wavy, and lenticular laminae and very thin beds. The facies is usually moderately to highly bioturbated and contains many narrow (0.3–2 cm) tubular *Spreite* and *Condrite* burrow traces, which are filled with quartz sand and mudstone clasts. Wherever bioturbation is slight, the mudstones appear laminated and the sandstones appear laminated and cross-laminated.

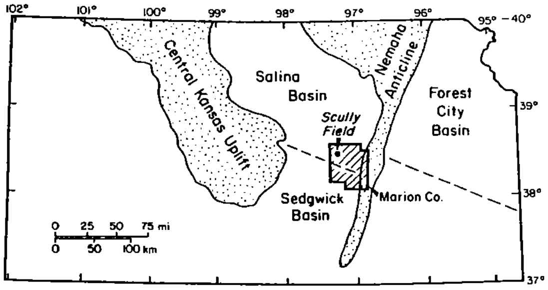


Figure 2. Location of the study area.

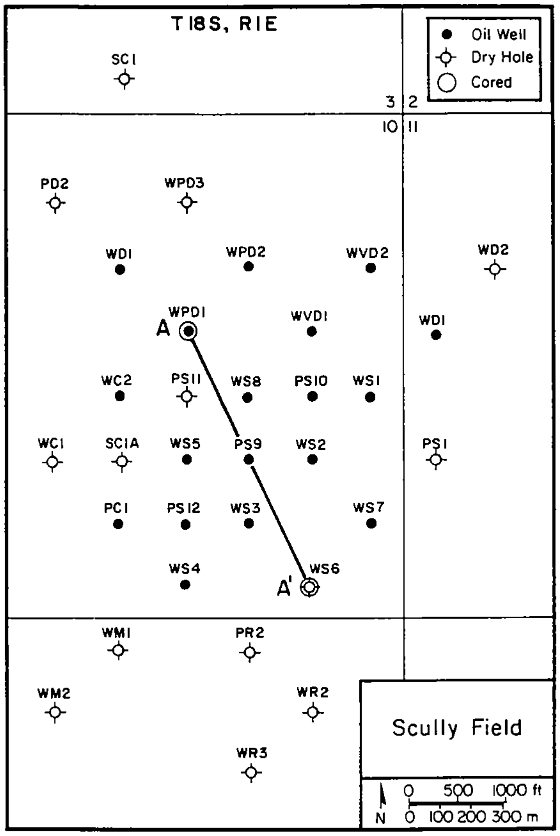


Figure 3. Map of Scully field, showing the locations of the wells and cross section *A–A'*. The study uses electric logs from all the wells, as well as cores from the WPD–1 and WS–6 wells.

Facies C consists of thin and very thin beds of sandstone separated by thin (0.1–0.3 cm), wavy mudstone laminae (Fig. 5). The sandstone is well sorted, fine to medium grained and quartzose, and commonly contains the casts of broken shell clasts. The sandstone beds contain some thin wavy laminae, ripple cross-laminations, and very thin cross-beds (1–3 cm thick), but they are more typically moderately to highly bioturbated, mottled in appearance, and rich in vertical and horizontal burrows.

Facies D consists of thin to thick beds of sandstone separated by either very thin (0.5–2 mm) mudstone drapes or trunctation surfaces (Fig. 5). The lower parts of the sandstone beds are usually massive and laminated, but the upper parts are intensely bioturbated and burrow-mottled.

Facies E is represented by a single distinctive thin (20 cm) bed of poorly stratified sandstone and compressed mudstone clasts (Fig. 6), which always underlies Facies D. The sandstone clasts are 1 to 3 cm in size, and they are separated by deformed clumps and partings of mudstone and sandy mudstone. There are no obvious burrow or root traces in this bed.

Facies F consists of slightly glauconitic, well-sorted sandstone (Fig. 7). It is thick to very thick bedded and greenish gray, and it consists largely of fine- to medium-grained quartz-sand grains and glauconite. The sandstone is usually massive and highly bioturbated, and less commonly contains thin, wavy and horizontal mudstone laminae.

Facies in the Bounding Beds

The Simpson Group is directly underlain and overlain by the carbonates of the Arbuckle Group and the Viola Formation, respectively. The two cores from Scully field captured several feet of these two stratigraphic units (Figs. 6,7).

The Arbuckle cores are composed of thickly bedded, light-olive-gray dolomitic mudstones and wackestones with numerous stylolites, chert, and slightly inclined (5°–10°), very thin (1–2 mm) clay laminae. A single large stromatolite (36 cm), surrounded by carbonate mud and broken shell fragments, is also present in the Arbuckle cores, as are several small vugs (0.5–3 cm) and long (3–10 cm), thin (0.5–3 mm) calcite- and chert-filled fractures and chert nodules. Bioturbation is generally slight, with both horizontal and vertical burrows giving a mottled appearance to a few beds.

The Viola cores consist of thin- to thick-bedded dolomitic and calcareous mudstones that are interbedded with thin-bedded silty mudstones. The carbonate mudstones are olive gray and highly bioturbated, and they

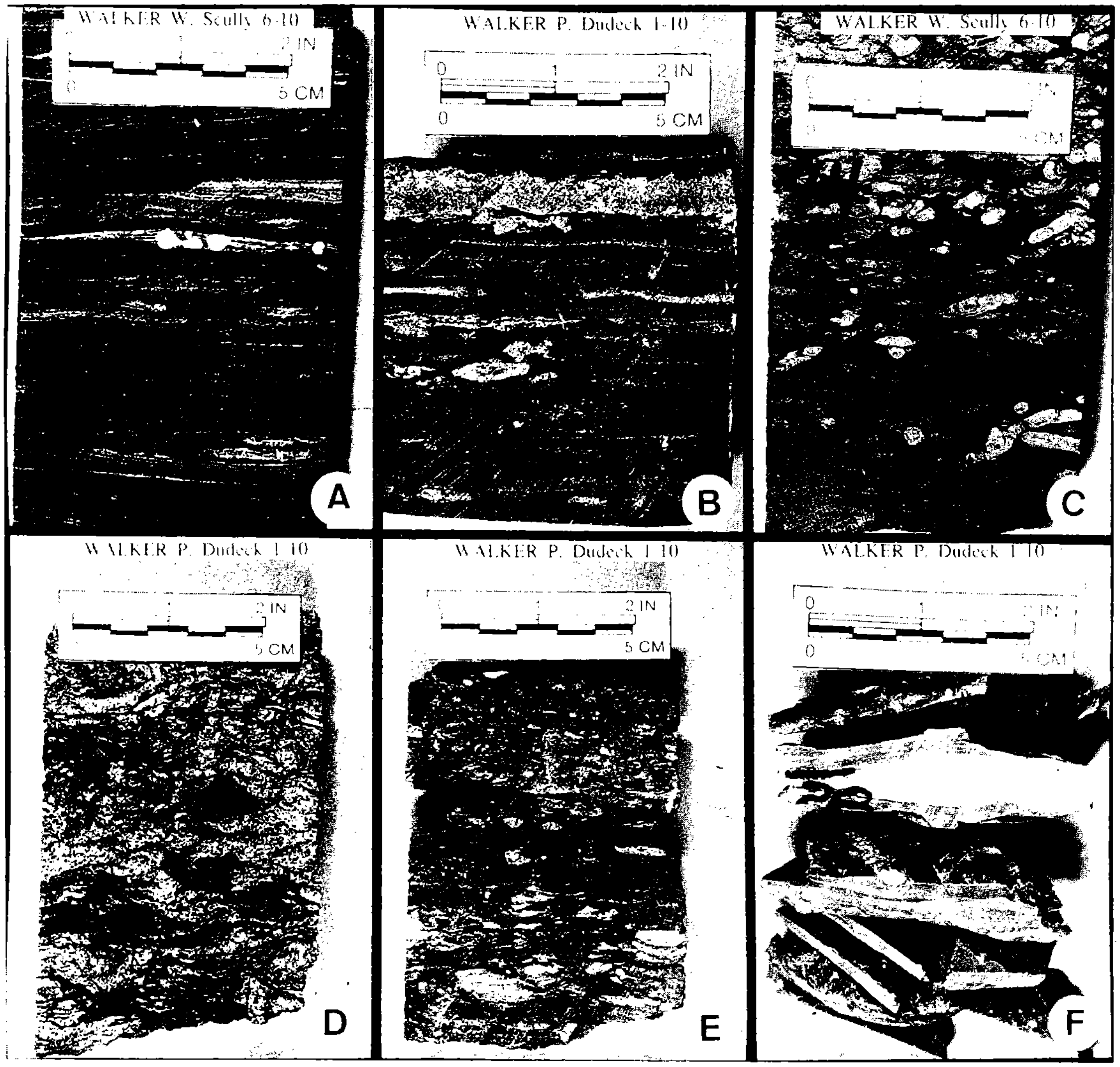


Figure 4. Core photographs of Facies A and B. (A) Laminated mudstones of Facies A with sandstone stringers. (B) Sand-filled burrows and sandstone stringers in mudstones of Facies A. (C) Highly burrowed mudstones of Facies A, with some remnant primary laminae. (D) Highly burrowed sandy mudstones of Facies B. (E) Sand-filled horizontal burrows in sandy mudstones of Facies B; note the remnant primary laminae. (F) Sandy mudstone of Facies B with sandstone lens and sand-filled *Spreite* burrows.

have a mottled appearance owing to the presence of many thin (0.3–1 cm), tubular burrows. They also contain a few small (1–4 cm) calcite-filled vugs (1–4 cm), stylolites, and fine, wavy laminae (where not bioturbated). The silty mudstone beds are olive black and contain wavy laminae, ripple cross-laminae, tubular horizontal burrows, and many inclusions of quartz sand and mudstone.

Stratigraphic Sequence

The following description refers to five figures: Figure 8, which illustrates the stratigraphy of the Simpson Group in the Walker No. 1–10 P. Dudeck core (the more complete of the two cores); Figure 9, which shows a cross section of the Simpson along line *A–A′*; and Figures 10, 11, and 12, which show the geometry of the three sandstone members of the Simpson Group.

The Arbuckle Group is abruptly overlain in both cores by the massive bioturbated sandstones of Facies F, which constitutes the entirety of Sand 3. The sandstone forms a thin (1.5–2.4 m) sheet that extends across the entire field, and it grades abruptly (within 4 cm) into the overlying sandy mudstones of Facies B.

The middle Simpson in the No. 1–10 Dudeck core consists of two sandstones that are bounded above and below by the mudstones and sandy mudstones of Facies A and B. The two sandstones are entirely composed of the thin-bedded sandstones of Facies C, and their contacts with the mudstones are always sharp. The lower and thicker of the two sandstones is Sand 2 of the Simpson Group, which forms a thin shoestring body that runs northeast to southwest through the field and pinches out to the northwest and southeast. The second sandstone (which we refer to hereafter as Sand 2a) pinches out abruptly, and it is absent at the Walker No. 6–10 W. Scully well.

Sand 1, which forms the top of the Simpson Group, consists of the sandstones of Facies D and E in both

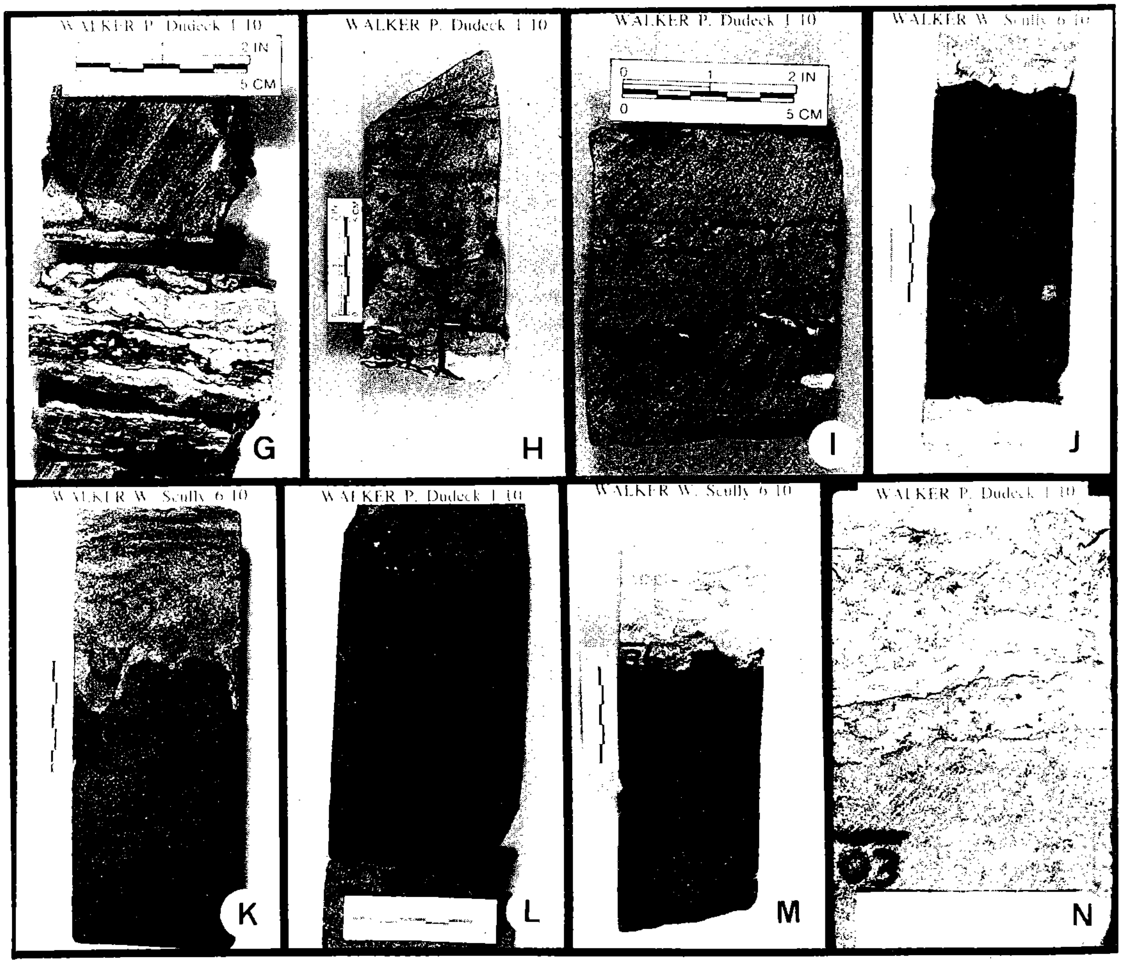


Figure 5. Core photographs of Facies C and D. (G) Top part of core is the base of Facies C; note the shell fragments and large mudstone clasts. (H) Stratification and bioturbation of Facies C sandstone; note the mudstone partings between the sand beds. (I) Thin-bedded sandstone with mudstone partings of Facies C. (J) Highly bioturbated sandstone of Facies D. (K) Sandstone bed in Facies D, showing the contact between its lower stratified part and upper bioturbated part. (L) Massive bioturbated sandstone of Facies D. (M) Contact between Facies D sandstone and carbonates of overlying Viola Formation. (N) Close-up of same contact, showing abrupt gradation from sandy carbonates or calcareous sandstone at the base to pure carbonate at the top.

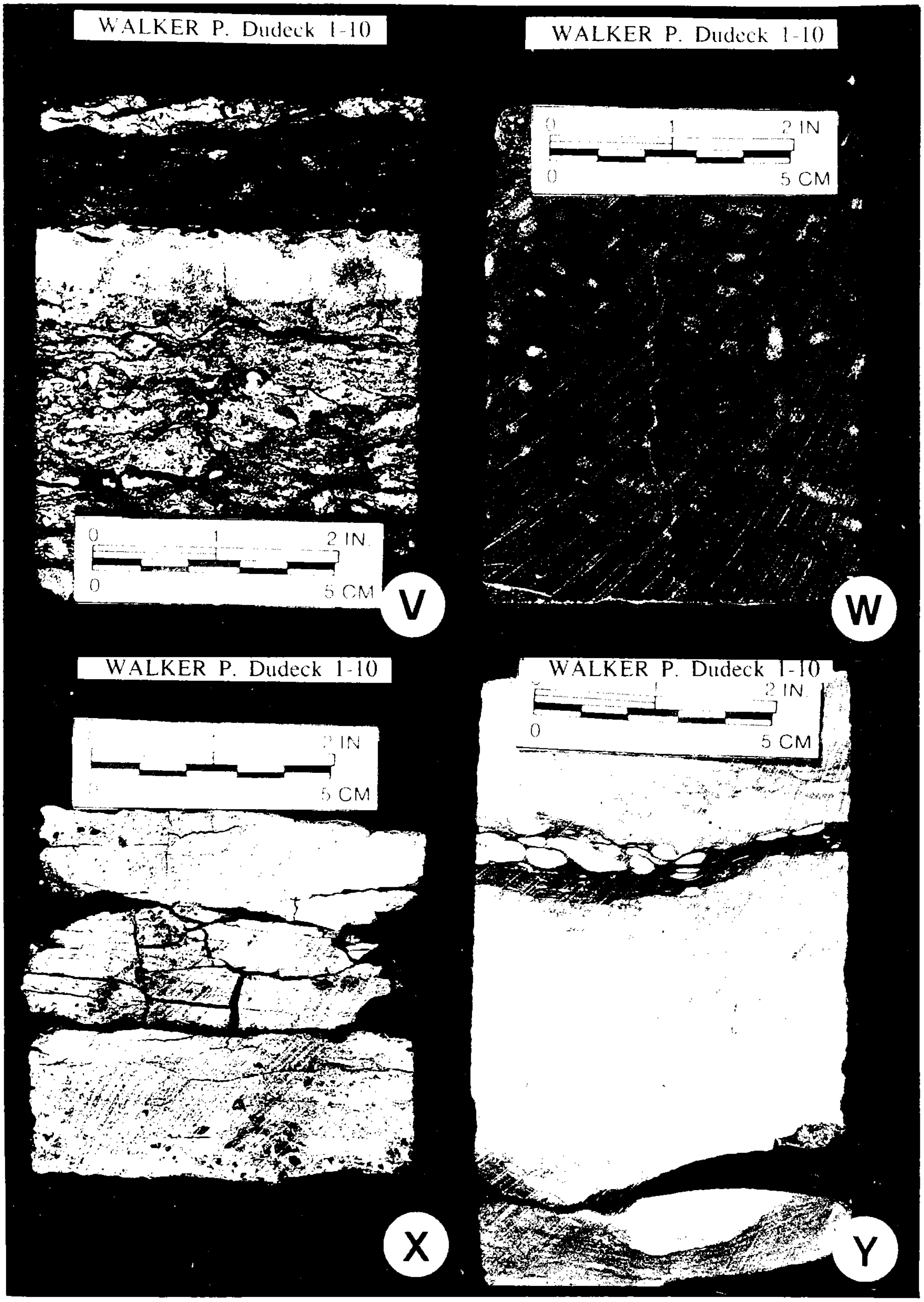


Figure 6. Facies E of the Simpson Group and the Viola carbonates. (V) Poorly stratified sandstones and mudstones of Facies E. (W) Highly bioturbated carbonate mudstone of the Viola. (X) Silty mudstones of the Viola, with small, angular mudstone clasts and thin, wavy laminae. (Y) Interbedded bioturbated carbonate mudstone and brown silty mudstone in the Viola.

cores. It is a wedge-shaped body that is thickest (2.4–4.3 m) along the northeast side of the field and thins to the south. The lower part of this sand, which has a sharp basal contact with the mudstones of the middle Simpson, consists of a thin (20–25 cm) bed of the poorly stratified sandstones and mudstones of Facies E. This facies is next abruptly overlain by 2 to 3 m of the thin-bedded sandstones of Facies D, which is next overlain by the carbonates of the Viola Formation. The contact between the Simpson and Viola is absent in both cores from the field, but it appears to be abrupt in the logs.

DISCUSSION

Dapples (1955) postulated that the Simpson Group (and its northern equivalent, the St. Peter Sandstone) was deposited in coastal and inner-shelf environments during a regional transgression of the North American craton in the Middle Ordovician. This transgression is recorded in the lower sand (Sand 3 or Facies F) of the Simpson Group, which is similar in its massive, bioturbated appearance to the inner-shelf facies of the St. Peter Sandstone of Minnesota, Wisconsin, and Iowa (e.g., Dake, 1924; Mazzullo and Ehrlich, 1983), and in the upper sand (Sand 1), which passes abruptly upward into the carbonates of the Viola. However, this study has also shown that this regional transgression was interrupted in Scully field by the progradation of a coastal tidal flat similar to the modern tidal flats along the German North Sea (Reinick, 1972; Figs. 13,14), and that the greater thickness of the Simpson Group (specifically Facies A through E) was deposited in this environment.

The sand-starved laminated mudstones of Facies A are attributed to the mud flats of the upper intertidal zone. Such flats are characterized by low current velocities (even during the peaks of tidal cycles) and the deposition of suspended mud from slack tidal waters. Sand is present only in minor amounts on such mud flats owing to the low velocities, and it occurs as starved ripples and lamina-thin sheets. The sandy mudstones and sandstones of Facies B are attributed to the mixed sand

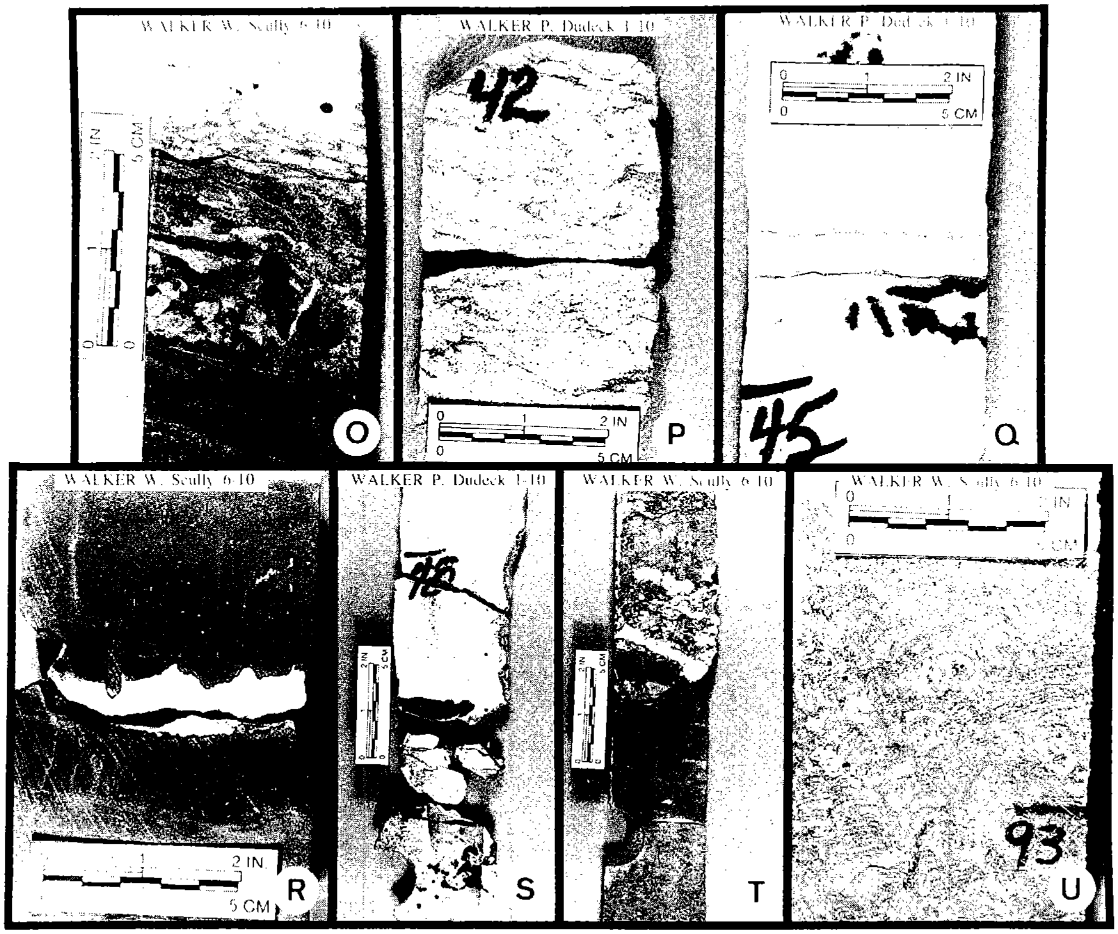


Figure 7. Facies F of the Simpson and the Arbuckle carbonates. (O) Sharp contact between the glauconitic sandstone of Facies F and the underlying bioturbated dolomitic mudstone of the Arbuckle Group. (P) Highly bioturbated glauconitic sandstone of Facies F. (Q) Fine, wavy laminae in Facies F sandstone. (R) Large stylolite and chert nodule in the massive mudstone of the Arbuckle. (S) Sharp contact between Facies F of the Simpson and the underlying Arbuckle. (T) Chert-filled vugs in the mudstones of the Arbuckle. (U) Algal stromatolite in the Arbuckle.

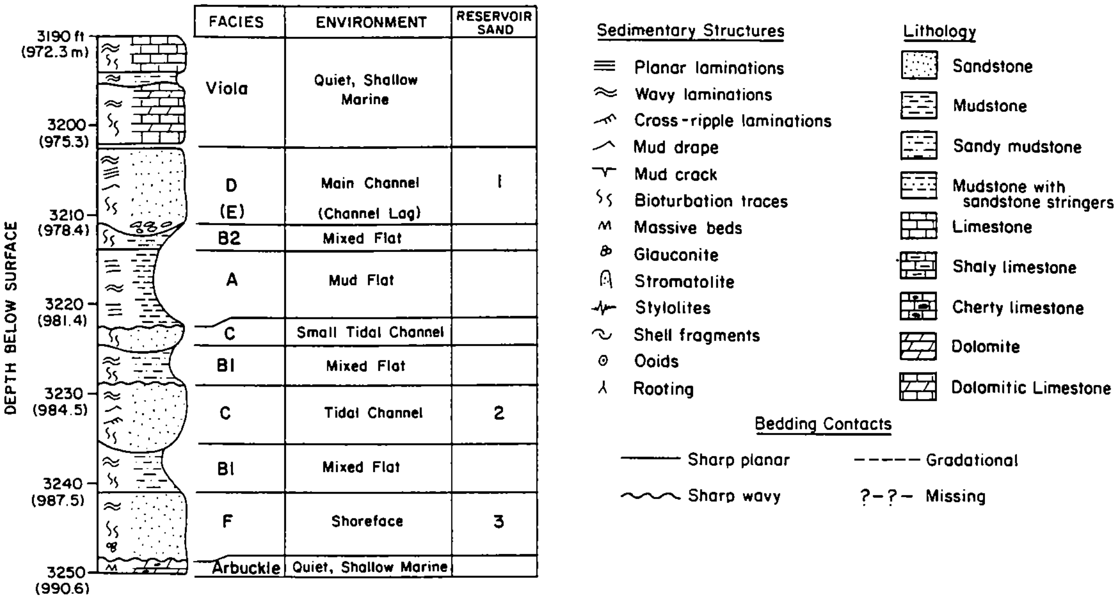


Figure 8. Stratigraphy of the Simpson Group and the overlying and underlying formations in the Walker No. 1–10 P. Dudeck core.

flats of the middle and lower intertidal zones. Such flats are characterized by the alternating bedload transport of sands (during the peaks of tidal phases) and suspension deposition of muds (in slack-water phases) (Stevenson and Emery, 1958; Reinick and Singh, 1967; Reinick, 1972). The greater density of bioturbation in Facies B (compared to Facies A) is also typical of the progression from the upper to the lower part of an intertidal flat (Howard and Frey, 1973).

The thin and laterally continuous sandstones of Facies C, which constitute the two sandstones (Sand 2 and Sand 2a) in the middle Simpson and which are interbedded with intertidal flat deposits, are attributed to small tidal creeks that dissected these tidal flats. On the other hand, Facies D and E, which together constitute the thick, wedge-shaped sandstone (Sand 1) at the top of the Simpson, are interpreted as bar and thalweg deposits (respectively) of the main channel of the coastal tidal flat. This channel was presumably the lower tide-dominated reaches of a fluvial system that funneled sediment into this field area from the north and northeast (in light of the geometry of Sand 1). The alternation of sandstone beds and mudstone drapes in Facies C and D is typical of tide-dominated channels, wherein current velocities rise and fall through individual tidal cycles (Van Straaten, 1964; Reinick, 1972; Reinick and Singh, 1967; Ginsburg and Hardie, 1975; Greer, 1975).

The bioturbated and glauconitic sandstones of Facies F are interpreted to have been deposited in lower-shoreface and inner-shelf environs by storm- and wave-driven currents (e.g., Swift, 1976) during a period of shoreline retreat and erosion. Finally, the lithology and stratification of the carbonate rocks of the Viola and Arbuckle indicate that they were both deposited in low-energy and shallow subtidal shelf waters (Wilson, 1975; Bathurst, 1976).

The following scenario for deposition of the Simpson Group in Scully field can be postulated from the stratigraphic sequences in the two cores. Deposition of the Simpson Group was preceded by a major fall in sea level, which exposed the underlying carbonate rocks of the Arbuckle Group and led to the formation of the karst surface that now separates the Sauk and Tippecanoe Sequences in the cratonic interior (Merriam and Atkinson, 1956). Clastic deposition began with a eustatic rise in sea level, which resulted in the transgression of this karst surface and deposition of the massive subtidal sands of Facies F (Sand 3 of the lower Simpson). This transgression was locally interrupted, however, by the influx of clastic

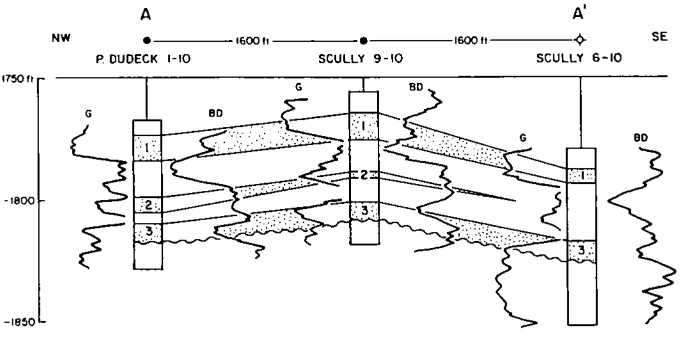


Figure 9. Cross section of the Simpson Group along line *A–A'* (see Fig. 3 for line of section), showing the log response for the sandstones and the intervening mudstones.

sediment and the progradation of a coastal tidal flat into the field area, wherein the remainder of the Simpson Group was deposited. Transgression resumed with the cessation of sediment input, and the field area was swiftly flooded by a shallow, carbonate-dominated sea.

One of the perplexing problems with all the cratonic sandstones in North America has been their thickness. This problem has been discussed for the St. Peter Sandstone, which is far thicker on average (30 m) than Pleistocene or Holocene transgressive sheet sands on the continental shelves of the world, which are usually only a few inches to a few feet thick (see Mazzullo and Ehrlich, 1983). This paper reconciles this problem for the Simpson Group, because it shows that the Simpson was largely deposited during a progradational episode that interrupted the regional transgression of the study area.

Lastly, the depositional model for the Simpson Group is consistent with the models for cratonic sedimentation that were proposed by Klein (1977). It is also consistent with the tidal-flat models for the St. Peter Sandstone of St. Paul, Minnesota (Mazzullo and Ehrlich, 1987), and the Mt. Simon (Upper Cambrian) of Wisconsin (Driese and others, 1981), among other formations.

REFERENCES CITED

Bathurst, R., 1976, Carbonate sediments and their diagenesis: Elsevier, New York, 658 p.

Dake, C. L., 1924, The problem of the St. Peter sandstone: Missouri School of Mines and Metallurgy unpublished Ph.D. dissertation, 356 p.

Dapples, E. C., 1955, General lithofacies relationship of St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Dott, R. H., Jr.; and Byers, C. W., 1981, SEPM Research Conference on Modern Shelf and Ancient Cratonic Sedimentation—the orthoquartzite–carbonate suite revisited: Journal of Sedimentary Petrology, v. 51, p. 330–347.

Driese, S.; Byers, C. W.; and Dott, R. H., Jr., 1981, Tidal deposition in the basal Upper Cambrian Mt. Simon Formation in Wisconsin: Journal of Sedimentary Petrology, v. 51, p. 367–381.

Ginsburg R. N.; and Hardie, L. A., 1975, Tidal and storm deposits, northeastern Andros Island, Bahamas, *in* Ginsburg, R. N. (ed.), Tidal deposits: a casebook of recent examples and fossil counterparts: Springer–Verlag, Berlin, p. 201–208.

Greer, S. A., 1975, Sandbody geometry and sedimentary facies at the estuary–marine transition zone, Ossabaw Sound, Georgia: a stratigraphic model: Senckenberg. Mar., v. 7, p. 105–135.

Howard, J. D.; and Frey, R. W., 1973, Characteristic physical and biogenic sedimentary structures in Georgia estuaries: American Association of Petroleum Geologists Bulletin, v. 57, p. 1169–1184.

Klein, G. deV., 1977, Tidal circulation model for deposition of clastic sediment in epeiric and monoclinal shelf seas: Sedimentary Geology, v. 18, p. 1–12.

Mazzullo, Jim; and Ehrlich, Robert, 1983, Grain shape variation in the St. Peter Sandstone: a record of eolian and flu-

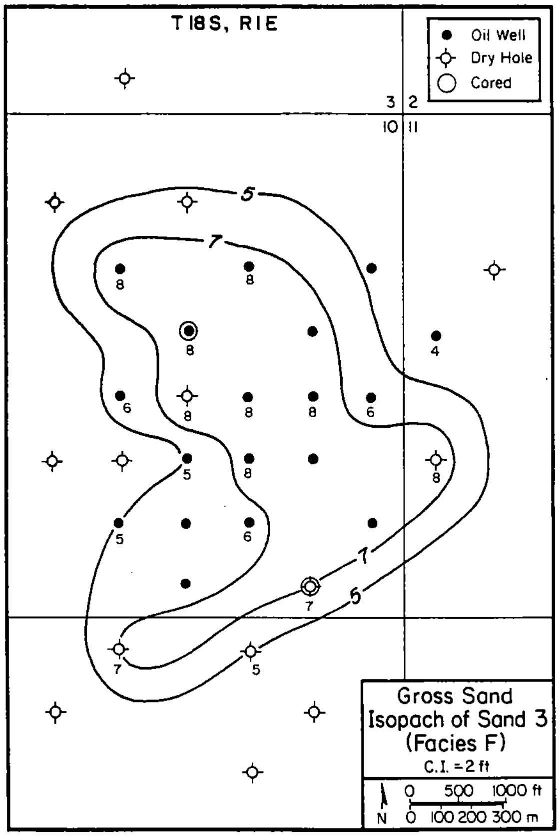


Figure 10. Geometry of basal Sand 3 in the Simpson Group.

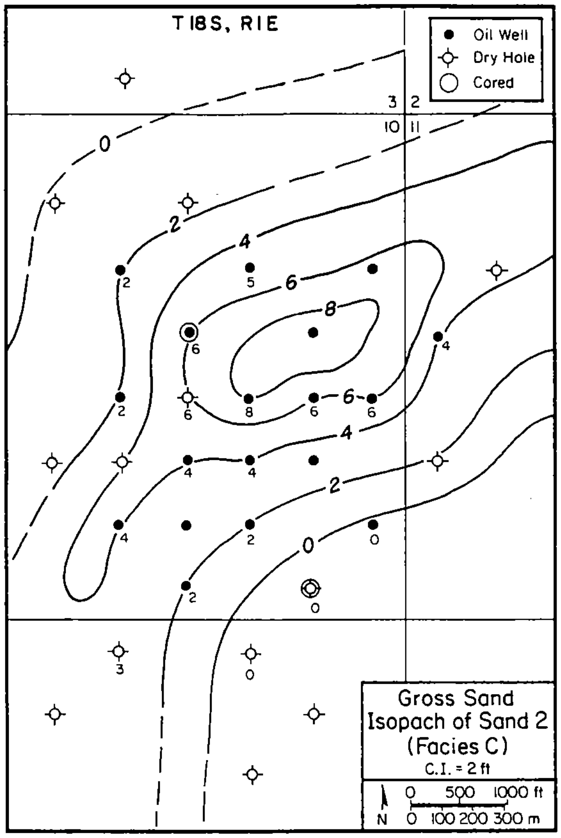


Figure 11. Geometry of middle Sand 2 in the Simpson Group.

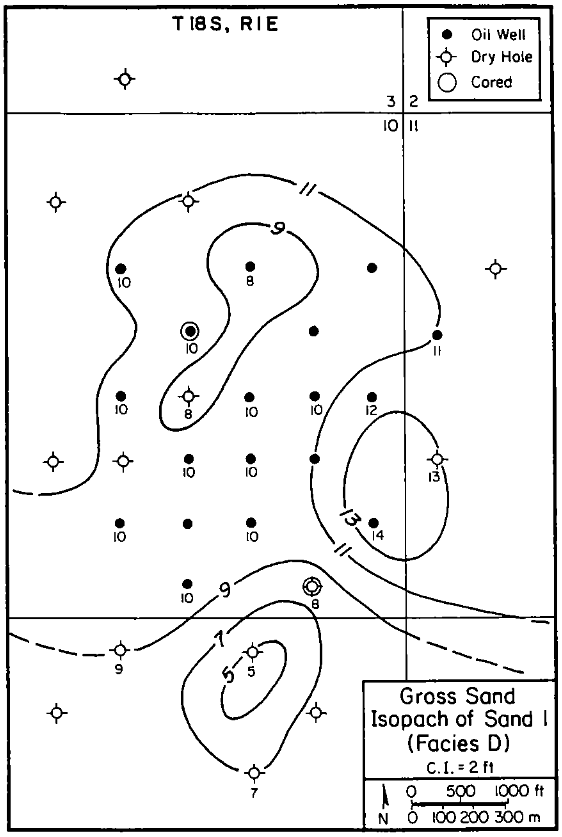


Figure 12. Geometry of upper Sand 1 in the Simpson Group.

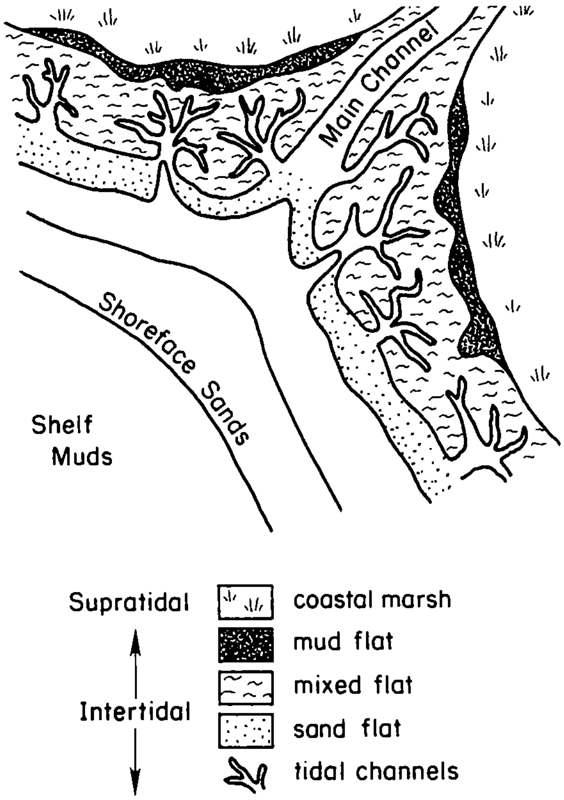


Figure 13. Depositional model for the coastal tidal flats of the Simpson Group.

vial sedimentation of an early Paleozoic cratonic sheet sand: Journal of Sedimentary Petrology, v. 53, p. 105–120.

______1987, The St. Peter Sandstone of southeastern Minnesota: Minnesota Geological Survey Report of Investigations 35, p. 44–50.

Merriam, D. F.; and Atkinson, W. R., 1956, Simpson-filled sinkholes in eastern Kansas: Kansas Geological Survey Bulletin 119, Part 2, p. 61–80.

Reineck, H. E., 1972, Tidal flats, *in* Rigby, T. K.; and Hamblin, W. K. (eds.), Recognition of ancient sedimentary environments: Society of Economic Paleontologists and Mineralogists Special Publication 16, p. 146–159.

Reineck, H. E.; and Singh, I. B., 1967, Primary sedimentary structures in the Recent sediments of the Jade, North Sea: Marine Geology, v. 5, p. 227–235.

Sloss, L. L., 1963, Sequences in the cratonic interior of North America: Geological Society of America Bulletin, no. 74, p. 93–113.

Stevenson, R. E.; and Emery, K. O., 1958, Marshlands at Newport Bay, California: Allan Hancock Foundation Publication 20, p. 1–109.

Swift, D. J. P., 1976, Continental shelf sedimentation, *in* Stanley, D. J.; and Swift, D. J. P. (eds.), Marine sediment transport and environmental management: Wiley, New York, p. 311–350.

Van Straaten, L. M. J. U., 1964, De bodem der Waddenzee: Het Waddenboek, Nederlands Geol. Ver., p. 75–151.

Wilson, J. L., 1975, Carbonate facies in geologic history: Springer–Verlag, New York, 471 p.

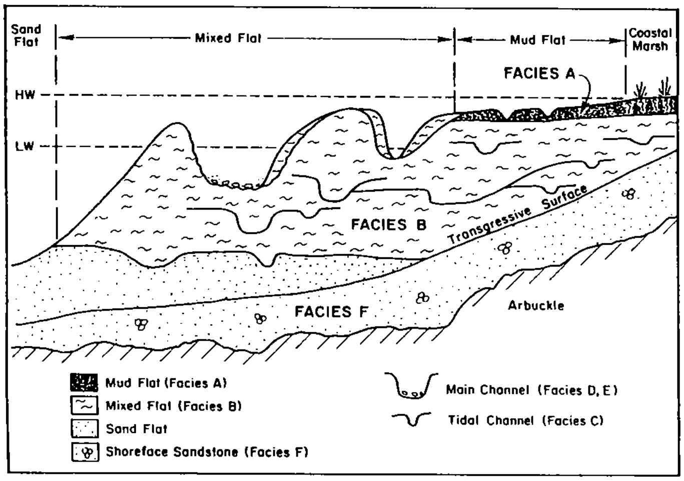


Figure 14. Stratigraphic model for the Simpson Group of Scully field.

Oklahoma Geological Survey Circular 99, 1997

Middle Ordovician Ironstones in Kansas: Subsurface Markers of Paleoshorelines for the Midcontinent

Pieter Berendsen and John H. Doveton
Kansas Geological Survey
Lawrence, Kansas

ABSTRACT.—Throughout the Midcontinent, Middle Ordovician ironstones occurred at low latitudes around the margins of Laurentia. Oolitic ironstones in siliciclastic rocks of the St. Peter Sandstone in Kansas record important new data on the paleogeomorphology of the area and the geochemical environment of ooid formation. The goethite ooids that make up the ironstones are of primary, syndiagenetic origin and occurred seaward from a string of islands created by the northward-advancing Ordovician seas. The islands consisted mostly of granitic rocks and lay along the crest of the ancestral Nemaha uplift. The Nemaha uplift is a major tectonic element, parts of which were reactivated periodically throughout Paleozoic time. Ooids formed in the shallow, warm, marine waters adjacent to the islands. Deep lateritic weathering of the granitic rocks on the islands probably provided the iron necessary for ooid formation. The petrophysical properties of goethite, together with limited amounts of drill cuttings and cores, make it possible to map the distribution and concentration of ironstones.

INTRODUCTION

Ordovician ironstones occur at widespread localities on several continents, notably in Africa and Europe (Petranek, 1964) and North America (Van Houten, 1990). Ironstone formation took place around the fringes of Gondwana at both high southern latitudes (Young, 1989a), close to the South Pole, as well as at low latitudes in a more tropical setting typical of Laurasia.

The geographic and temporal distribution of Paleozoic oolitic ironstones on the North American craton was summarized by Van Houten (1990), even though he included minor occurrences that, by definition, are not true ironstones.

The occurrence and distribution of Middle Ordovician ironstones in Kansas and elsewhere in the Midcontinent are not well documented, because they are present only in the subsurface. Witzke (1980) discussed the distribution of Middle Ordovician ironstones associated with the St. Peter Sandstone, and the overlying Glenwood Shale, Platteville, and Decorah Formations. They occur both to the north and south of the Transcontinental arch (Dapples, 1955), which occupied a position just south of the equator (Fig. 1).

Ironstones in Kansas are encountered in many wells drilled for hydrocarbons and mineral resources. Generally, when ironstones are penetrated by the drill, the drilling mud turns a blood-red color characteristic of the presence of accessory hematite. Even if ooids are not recognized in the well cuttings, the existence of an ironstone bed is detected easily on wireline logs. While wireline logs are universally used in subsurface mapping, the distinctive petrophysical properties of ironstones not only make it possible to map ironstones in the subsurface but also allow for a semi-quantitative evaluation of their compositional aspects (Berendsen and others, 1992). In this paper the occurrence, distribution, and environment of deposition of ironstones in Kansas are discussed and briefly compared with similar, but less prominent, occurrences in the Mississippian Hannibal Shale (formerly called Boice Shale) (Maples, 1994).

OCCURRENCE OF IRONSTONES IN KANSAS

The first reported occurrence of oolitic ironstones was by Leatherock (1945), who correlated rocks of Simpson age in north-central Kansas with the St. Peter Sandstone in northwestern Missouri. Leatherock (1945) noted pseudo-oolitic ironstone pellets in the cuttings of two drill holes in the middle zone of the St. Peter Sandstone. This zone consists of shale and shaly sandstone and is bracketed between an upper and a lower zone of sandstone characterized by frosted and rounded quartz grains. Ironstones in cores obtained from drill holes in northeastern Kansas occur in the lower part of the St. Peter Sandstone in a transition from a generally more shaly and silty unit below to a clean quartz sandstone above the ironstone interval. The ironstone is unconformably underlain by either Precambrian granitic basement rocks (1.6–1.8 Ga; Sims and Peterman, 1986) or

---

Berendsen, Pieter; and Doveton, J. H., 1997, Middle Ordovician ironstones in Kansas: subsurface markers of Paleoshorelines for the Midcontinent, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 164–171.

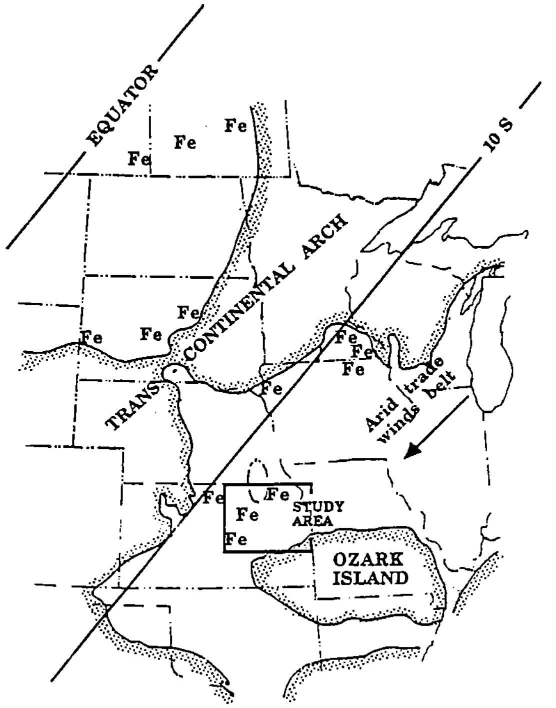


Figure 1. Generalized paleogeographic map of U.S. Midcontinent during the Middle Ordovician, indexed with locations of ironstone occurrences and Kansas study area. Modified from Witzke (1980).

by Cambro–Ordovician carbonate rocks belonging to the Arbuckle Group. Most of the St. Peter Sandstone is considered to be Chazyan (Witzke, 1980), and thus the ironstones are either late Llanvirnian or Llandeilian in age (Sloan, 1987). The ironstones definitely are older than the Glenwood ironstones, because they occur at the base of the transgressive sandstone.

Ironstones also occur as localized lithofacies in the Lower Mississippian Hannibal Shale and in the upper part of the Chattanooga Shale. No core and few well cuttings are available for examination.

The Kansas ironstones in Middle Ordovician and Lower Mississippian shales and siltstones can be traced for a distance of approximately 240 km along the trend of the Nemaha uplift rather than the Transcontinental arch, as shown by Witzke (1980). The north-northeast-trending Nemaha uplift is a tectonic element closely linked with the 1.1-Ga Central North American rift system (Berendsen and others, 1989).

The ironstone occurrences are linked closely to a string of positive elements associated with the Nemaha uplift. Nearshore, shallow-water formation of iron oolites in a transgressive, eustatically controlled marine environment is a generally accepted model for these occurrences (Lamoalle and Dupont, 1976; Hallam and Bradshaw, 1979; Kimberley, 1980; Gygi, 1981; Van Houten and Purucker, 1984; Cotter, 1988; Young, 1989a). The source of the iron is postulated to be the deeply weathered lateritic soils that formed on top of the granitic islands associated with the Nemaha uplift. Petranek (1991) suggested that iron was released during early diagenesis from black shales that were deposited basinward contemporaneously from the ironstones associated with Gondwana. A hydrothermal origin, possibly related to young intrusives, was suggested by Kimberley (1994) for modern iron oolites that form along the coast of Venezuela.

Petrographic and chemical data were obtained by examination of thin sections and analysis and X-ray-diffraction studies of drill cuttings from 30 wells and 4 cores. Neutron-density measurements of wireline logs from 156 wells provided additional data to map the distribution and concentration of ironstones that ringed the islands in the Middle Ordovician seas. Spectral gamma-ray logs provide useful indications on the geochemistry of ironstone derivation and deposition. The absence of the St. Peter Sandstone in certain parts of Kansas and on the Southeast Nebraska arch in southeastern Nebraska has been interpreted as nondeposition rather than from later erosion (Lee and others, 1948; Merriam, 1963). This view conforms with Witzke's view (1980) that Cambrian and Lower Ordovician rocks were erosionally truncated around the Southeast Nebraska arch.

DESCRIPTION OF OOLITIC IRONSTONES

One or two ironstone zones occur in the lower part of the St. Peter Sandstone at the transition from a shaly or silty unit below to a clean sandstone above (Fig. 2) in which the quartz grains are well rounded and frosted. The total thickness of the unit in which the iron ooids occur generally ranges from 2 to 3 m. Where two ironstone zones are present, the upper zone is always thicker (up to 1.6 m) than the lower zone (up to 1 m). Macroscopic and microscopic observations on the nature of the ooids are briefly summarized; additional details are given in Berendsen and others (1992).

The upper boundaries of both ironstone beds are gradational. In contrast, the lower boundaries are sharp and well defined. Individual ooids in the upper zone are smaller in size (0.3–0.4 mm) than those in the lower zone (0.7–1.1 mm). Chemical analyses show the ooids to consist almost entirely of goethite, with locally minor amounts of siderite. The ooids are made up of thin, successive cortices that separate relatively easy and have a smooth appearance and iridescent luster.

In the drill holes for which core is available, differences exist between the upper and the lower ironstone zones. In the lower zone, ooids occur in a medium- to dark-gray shale–siltstone matrix of wavy, mechanically disrupted, and biologically reworked laminae that also contain large intraclasts of the same oolitic ironstone. Individual ooids make up from 25% to 60% of the rock in the interval. Small amounts of detrital material consisting of fine-grained, angular quartz, feldspar, mica, glauconite, and phosphatic debris may also be present. Most (about 75%) ooids are eccentric in shape and mimic the irregular shapes of the nuclei around which they form. Concentric, distorted, and mechanically broken ooids account for the rest. Ooids may also show outward-radiating syneresis cracks that are filled with secondary dolomite or siderite. Nuclei in the lower zone are larger than in the upper zone and consist of quartz, minor phosphatic debris, and rarely chamosite or pyrite.

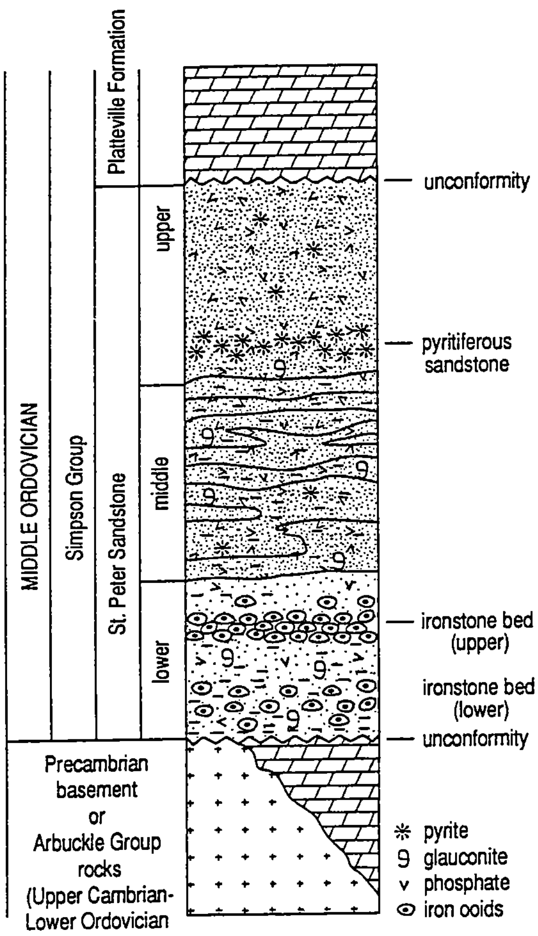


Figure 2. Generalized lithologic profile of Middle Ordovician rocks in northeastern Kansas.

The shale–siltstone matrix is composed of clay minerals of illite and the hydro-muscovite group that are impregnated with carbonates and hydroxyl iron oxides.

In the upper zone, ooids make up to 85% of the volume of the rock. Their smaller nuclei consist of quartz grains, fragments of other ooids, phosphatic debris, and locally glauconite or feldspar. The matrix consists mainly of finely crystalline dolomite and ankerite impregnated with iron oxides and minor clay minerals of the illite and illite–montmorillonite group. Abundant faunal debris replaced by phosphorite occurs throughout the matrix.

By comparison, the mineralogical composition of the Mississippian ironstones is similar to those occurring in the Ordovician. The ooids consist of goethite with minor amounts of siderite and hematite, and their nuclei are mainly detrital grains and phosphatic particles. The matrix of the ironstones is made up of fine-grained quartz, feldspar, iron carbonates, and clay minerals (illite, illite–smectite mixed layer, glauconite, kaolinite). In some of the shales surrounding the ironstone zones, granitic clasts occur, indicating renewed uplift and weathering along parts of the Nemaha uplift.

PETROPHYSICAL CHARACTERISTICS OF IRONSTONES

The petrophysical properties of both goethite and hematite are highly distinctive. Small amounts of these minerals can be detected easily and semi-quantitatively evaluated on several types of wireline logs. Theoretical expectations of log responses for goethite are an apparent density of 4.34 g/cm^3, a compensated equivalent neutron porosity greater than 60%, and a photoelectric absorption of 19.02 barns per electron (Schlumberger, 1991). The elevated neutron porosity of goethite is caused by its hydroxyl component and differs markedly from hematite, whose neutron response is only 11%. The high atomic number of iron results in a high value for photoelectric absorption.

The total amount of iron in a simple clastic succession of rocks can be estimated, because the aggregate atomic numbers of silica and aluminosilicates are similar (Ellis, 1987). This property is useful, because ironstones are defined as having greater than 15% iron (Kimberley, 1978). The direct link between photoelectric factor and atomic number means that 6.48 barns per electron can be used as the log equivalent of this criterion in simple sandstone–shale sequences. The oolitic zones in our study area show responses that clearly exceed this value and thus can be classified exclusively as ironstones (Fig. 3). Oolites in Middle Ordovician rocks are concentrated alongside the trend of the Nemaha uplift. Farther to the west and east, away from the uplift, the concentration and thickness of the ironstone units decrease. The equivalent zone becomes a black shale having a density ranging from 2.5 to 2.6 g/cm^3 and a compensated neutron response of about 25 porosity units. The ironstone zone itself has a maximum density of 3.21 g/cm^3 and a compensated neutron reading of 57 porosity units.

Thus, wireline logs are useful for determining the presence of ironstones in the subsurface and for accurately mapping their vertical and lateral distribution patterns. The occurrences of ironstone along the trend of the Nemaha uplift were mapped by using a computer contouring program (Fig. 4).

Spectral gamma-ray logs of potassium, thorium, and uranium were recorded in ironstone sections in a few wells in the area. An example of such a log, together with the density, neutron, and photoelectric factor, is shown in Figure 3. The total gamma radiation of ironstones is generally lower than that of the surrounding shales, even though the uranium content may be higher. The reason is that the thorium, and especially the potassium content of the illite clay in the surrounding shales more than negates the uranium anomaly in the ironstones.

The shales and siltstones have an average Th/K ratio of 2.7, consistent with the illitic composition of the rock (Hassan and others, 1976). Glauconite, which may be seen in core samples, also accounts for a somewhat higher potassium content. The decrease in thorium in the ironstone zone is simply a reflection of the reduction in volumetric proportion of clay minerals. The decrease of potassium in the ironstone zone gives rise to an increase in the Th/K ratio to an average of about 4.3. Higher ratios are reported by Myers (1989), who attributed

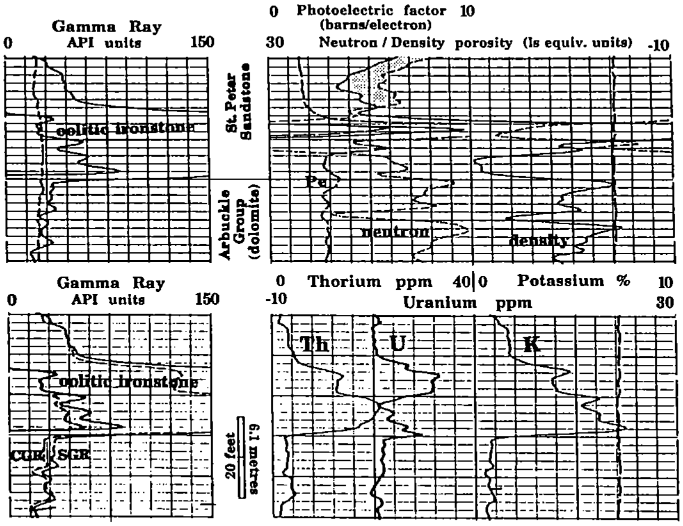


Figure 3. Spectral gamma-ray and lithodensity–neutron logs of the ironstone sequence in the Conoco No. 1–11 Frey well, northeastern Kansas.

them to deep weathering and leaching of potassium in the lateritic source area.

The minor but distinctive enrichment in uranium causes an average Th/U ratio of 3.1 within the ironstones, which, according to Adams and Weaver (1958), may be indicative of neutral redox potential conditions. The simultaneous depletion of potassium and enrichment of uranium are indicative of the overprint of two separate processes: lateritic weathering under oxidizing conditions, with enrichment of immobile thorium and removal of potassium and uranium, followed by the introduction of uranium at the shallow-marine depositional site. Uranium likely is associated with the abundant phosphatic material present with the ironstone. Phosphate was derived from phosphate-rich anoxic waters welling up in the shallow epicontinental sea during high sea-level stand (Brongersma-Sanders, 1971; Heckel, 1977). Even though ferric oxides, such as goethite, may be indicative of an oxic environment, Berner (1981) points out that they can persist stably in relatively anoxic conditions. Undoubtedly, these ironstones record a complex geochemical history with successive overprints of source weathering, depositional environment, and early diagenesis.

DISCUSSION

The Middle Ordovician transgression of the sea into the North American interior over areas of low relief resulted in a rapid increase of the area covered by the continental sea (up to 30%). In east-central Kansas, the seas advanced from the south and east over a landscape whose paleomorphology was influenced strongly by the north-northeast-trending rib of the Nemaha uplift, situated about 450 km south and east of the Transcontinental arch.

The Nemaha uplift was recognized first as a major post-Mississippian–pre-mid-Pennsylvanian tectonic element crossing the state of Kansas (Fig. 1) by Moore and Haynes (1917) and Jewett (1951). The uplift is a complex, basement-cored set of westward-tilting, southward-plunging, fault-bounded blocks that have been active throughout geologic time. The Humboldt fault on the east side of the uplift is a tectonic zone consisting of a series of anastomosing faults separating individual blocks stepped down to the east (Dubois, 1978; Berendsen and Blair, 1986). The maximum recorded post-Mississippian vertical displacement on the Humboldt fault is on the order of 400 m in northern Kansas. Major northwest-trending faults intersect and offset north-northeast-trending structures. Absolute movement is difficult or impossible to document because of repeated reactivation of structures. The basement rocks in the northern half of the State are predominantly 1.63–1.80-Ga granitic rocks (Bickford and Van Schmus, 1986) of the Central Plains orogen (Sims and Peterman, 1986). Rhyolitic to dacitic volcanic rocks and epizonal plutons, ranging in age from 1.34 to 1.48 Ga (Bickford and Van Schmus, 1986), are the major rock types in the southern half of the State. Some of the granite plutons contain up to 2% magnetite that show up as positive magnetic anomalies on aeromagnetic maps.

We propose that during Middle Ordovician time a string of islands existed along the crest of the ancestral Nemaha uplift (Fig. 4). These islands, the largest of which measured approximately 80 km in a north–south and 40 km in an east–west direction, are visualized as having been situated on a shallow-marine shelf. The area was situated at a low southerly latitude (about 10°) in the humid equatorial belt (Witzke, 1980). The climate was conducive for the igneous rocks exposed on the islands to undergo deep lateritic weathering. Depending on the climate, the climatic history, the nature of the parent rock, and the regional tectonic history, the depth of weathering may extend to 150 m or more (Nahon and Tardy, 1992). Many elements, including Al, Fe, Mn, Co, V, P, Cr, Ni, Cu, and Au, may be concentrated to ore grade in lateritic soils (Nahon and Tardy, 1992). The logical source of iron is a lateritic soil, which has been suggested by a number of authors for the European Jurassic ironstone deposits (Hallam and Bradshaw, 1979; Gygi, 1981; Van Houten, 1985). One of the mechanisms by which iron can be effectively transported by water is in the colloidal form by a sol, $Fe(OH)_3$. Upon entering the sea, the iron may be flocculated by reaction with electrolytes in the sea water and precipitated (Krauskopf and Bird, 1995). The reduction of iron to Fe^{2+} is probably the result of a later diagenetic process involving organic matter associated with the bottom sediments.

Another model for ooid formation was reviewed by Young (1989b), who postulated an environment of low sediment influx, ample iron supply, and physical reworking of the materials, giving rise to an authigenic mineral assemblage characteristic of the oxic to post-oxic regime. The depositional environment varies between oxidizing and weakly reducing conditions (Berner, 1981). These conditions resemble the environment in which the ooids formed in the Middle Ordovi-

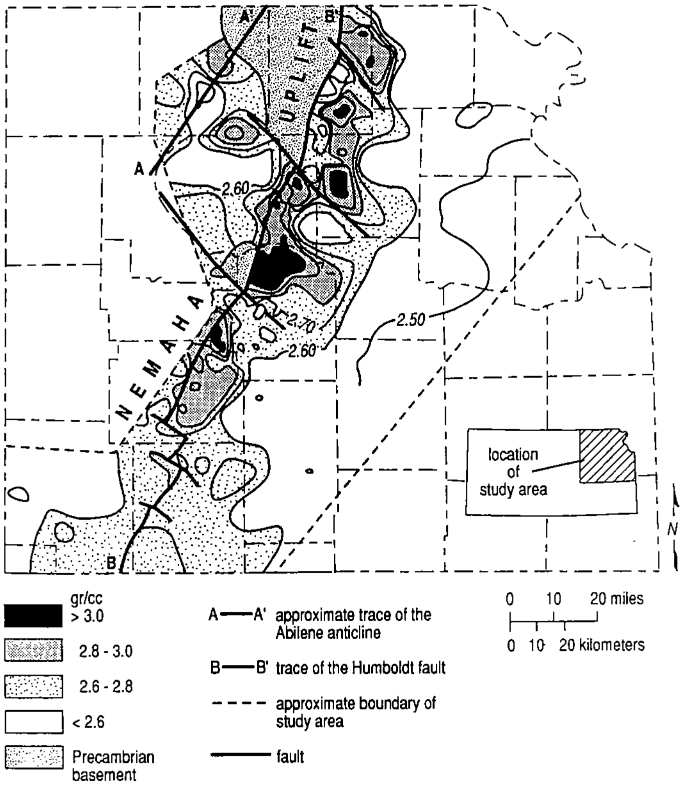


Figure 4. Computer-generated log-density map of ironstone in the St. Peter Sandstone of northeastern Kansas.

cian in Kansas. Goethite may be precipitated directly, and the ooids formed primarily, but not exclusively, by intrasedimentary growth (Young, 1989b).

Glauconite is an abundant mineral constituent of the sandy parts of the St. Peter Sandstone, even where sandstone makes up some of the matrix within the ironstone zones. Glauconite contains both ferric and ferrous iron in its structure, and where present in larger concentrations it imparts a greenish tint to the rock.

The occurrence of two ironstone beds separated by up to 2.5 m of shaly siltstone/silty sandstone indicates that the environment favoring ooid formation changed. However, phosphatic debris and glauconite do occur in the interval between the two ironstone zones. Figure 4 shows the distribution of the ironstones in close proximity and mostly parallel to the proposed island chain. The paucity of core, the uneven distribution of useful wireline logs, and the relative coarse vertical resolution of the logging tools (a little less than 1 m) have prevented us from mapping the areal distribution and extent of the two individual ironstone zones, but there seems to have been a tendency for two zones to develop closer to the shore. Two ironstone zones are not present everywhere, and the resolution of this problem requires further work, particularly as it relates to the proposition that the ironstone is the product of eustatic sea-level changes.

The two ironstone zones may have formed in a slowly transgressing sea, and the interval from which the iron ooids are missing may record a temporary slowdown in the rate of advance of the sea. It also is possible that a minor drop in sea level occurred after formation of the lower ironstone zone. In this situation we envision a scenario by which the matrix, because of its lower density, was removed preferentially, first from areas closer to the coast, followed by removal of the denser ooids, which then formed the stratigraphically higher ironstone unit. The advantage of the latter hypothesis is that the higher concentration of ooids in the upper bed can be explained readily as a mechanical separation based upon the density of the material. It may also help explain the absence of ooids from some areas near the island chain.

Two ironstone zones also may have developed as the result of synsedimentary tectonism. Bayer (1989) observed patterns of distribution in the Lower Jurassic in Germany that are best explained as local traps formed by movement on active faults along the northern flank of the Rhenic Island (Thienhaus, 1969).

The Humboldt fault along the east side of the Nemaha uplift is a tectonic zone defined by a series of curved, anastomosing, high-angle normal or reverse faults that define a series of fault blocks stepped down to the east (Berendsen and Blair, 1995). Repeated movement on these faults occurred periodically throughout geologic time up to the present (Berendsen and Blair, 1995; Berendsen, 1995); thus the position of the islands basically was tectonically controlled. The amount of uplift influenced the depth of weathering and the amount of lateritic soil development and thus the supply of iron. Granitic clasts occur in shale bounding the Lower Mississippian ironstones of the Hannibal Shale, indicating nearby tectonic activity. Thus the association of ironstone distribution and mapped faults suggests that synsedimentary tectonic activity may have been an influencing factor.

It is interesting to note that whatever conditions prevailed at the time the iron ooids formed in Middle Ordovician seas, similar conditions seem to have persisted throughout geologic time to the present (Kimberley, 1994). Iron ooids appeared again in Kansas in Early Mississippian time with about the same geographic distribution (Doveton and others, 1994) in shale and siltstone of the Hannibal Shale. At that time the area lay once more in low southerly latitudes (Witzke and Heckel, 1988). Lambert (1992) also mentions hematite ooids (probably goethite) and red and purple shale in the Chattanooga Shale as evidence of subaerial exposure or at least extremely shallow-water conditions at the end of Chattanooga time. The wireline-log responses are similar in character to those of the St. Peter Sandstone, except for the high thorium content recorded on spectral logs. Unfortunately, few spectral logs are available, but the high radioactivity can be traced laterally, using conventional gamma-ray logs. The thorium content of ooids from a drill hole for which samples were available measured 71 parts per million. The Th/U ratio (24) is typical of bauxites from a number of localities, including Arkansas, Surinam, French Guinea, and the Gold Coast in Africa. Preliminary analysis comparing the chemical composition of St. Peter Sandstone and Hannibal Shale ooids indicates that the latter are noticeably enriched in the rare-earth elements La, Ce, Sm, Eu, and Tb, and in other elements such as Cr, Sc, and Cs (Fig. 5). Additional studies to document this apparent enrichment may help us to better interpret the geochemical environment in which the ooids formed.

SUMMARY AND CONCLUSIONS

Interpretation of neutron and density logs, together with examination of drill cuttings and core enabled us to map the distribution and relative concentration of iron ooids in the Middle Ordovician St. Peter Sandstone in Kansas. By comparing the distribution pattern with structure (Berendsen and Blair, 1986; Merriam, 1963), it is evident that the ironstones occurred seaward from a string of islands in a shallow epicontinental sea. The concentration of ironstones decreases away from the islands with increasing water depths. The islands themselves are centered over the trace of the Nemaha uplift. This uplift has been interpreted as a zone of complex faulting and folding, and is considered to be an integral part of the Keweenawan-age Midcontinent rift system (Berendsen and Blair, 1995). As a result of tectonic activity throughout the Paleozoic, parts of the Nemaha uplift were raised periodically above sea level and formed the string of fault-controlled islands.

Ooids formed in an oxygen-poor to slightly reducing environment off the coast of the islands in the shallow warm sea water, as also was suggested previously by Berner (1981), Van Houten and Purucker (1984), Odin (1988), and Young (1989b). At the time of ooid formation, sediment accumulation was low, and shale, silt, and minor amounts of sand made up most of the material, possibly indicating a slowdown or stillstand in the advancing sea. Phosphate was supplied continuously to this environment by a mechanism described by Brongersma-Sanders (1971) and cited by Heckel (1977) as typical of this setting. Phosphatic debris occurs throughout the ironstone and may form the nuclei of individual ooids. An upwelling of oxygen-poor, relatively phosphate-rich water in the trade-wind belt around the barrier islands of the Nemaha uplift is a reasonable mechanism for deposition of phosphate. In a tropical environment, iron can be leached easily from land masses without significant mechanical erosion (Odin and others, 1988). The sedimentary rocks in which the ooids occur indicate that higher energy events took place periodically. The delicate balance between oxidizing and reducing conditions under which the ooids formed may be reversed temporarily (Brongersma-Sanders, 1971).

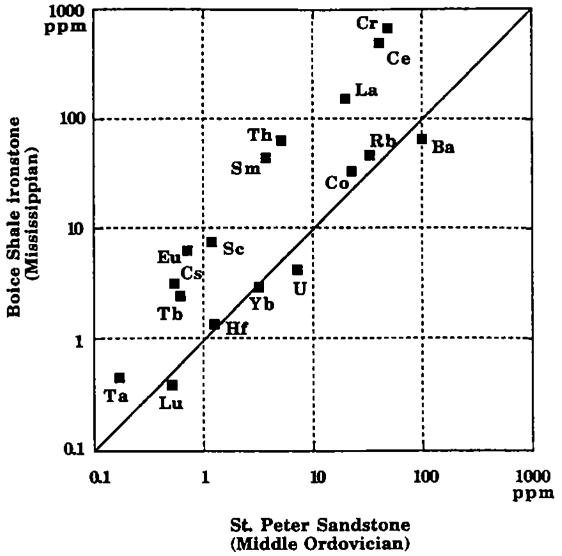


Figure 5. Trace-element distribution in ooids in parts per million (ppm) from the St. Peter Sandstone and Hannibal Shale (Boice Shale).

Glauconite, up to several percent, occurs in the more sandy units above and below the ironstone, and sporadically within thin sandy intervals in the ironstone. Glauconite formation associated with sand-sized substrates in the Gulf of Guinea (Odin, 1988) occurs in a comparable environment. Heckel (1977) estimated that the sediments associated with the ironstone accumulated in water on the order of 100 m deep. Ooids formed when sediment supply was low during a temporary stillstand in the advancing sea (Van Houten and Purucker, 1984), followed by renewed transgression. This, coupled with a gradual southward tilt of the continent (Adkinson, 1972), significantly increased the sediment supply.

No evidence of replacement has been noted, and chemical and X-ray-diffraction analysis showed the goethite ooids to contain few impurities, which Maynard (1986) cites as possible evidence of the primary origin of goethite. We believe that the ooids are of primary–syndiagenetic origin, and that the rate of transgression of the Ordovician sea exercised a primary control over the formation and distribution of the ironstones.

In conclusion, stratigraphic evidence shows that Middle Ordovician ironstones in the Midcontinent become progressively younger to the north, reflecting advancement of the encroaching sea. At this time no correlation is possible with ironstones of similar age in Gondwana because of uncertain stratigraphic correlations based on European and American graptolite and conodont zones (Sweet and Bergstrom, 1976). However, Midcontinent ironstone zones probably should have equivalents in Gondwana.

ACKNOWLEDGMENT

We would like to thank Daniel F. Merriam for his critical review of and thoughtful suggestions about the original manuscript.

REFERENCES CITED

Adams, J. A. S.; and Weaver, C. E., 1958, Thorium to uranium ratios as indicators of sedimentary processes: example of the concept of geochemical facies: American Association of Petroleum Geologists Bulletin, v. 42, p. 387–430.

Adkison, W. L., 1972, Stratigraphy and structure of Middle and Upper Ordovician rocks in the Sedgwick basin and adjacent areas, south-central Kansas: U.S. Geological Survey Professional Paper 702, 33 p.

Bayer, U., 1989, Stratigraphic and environmental patterns of ironstone deposits, *in* Young, T. P.; and Taylor, W. E. G. (eds.), Phanerozoic ironstones: Geological Society [London] Special Publication 46, p. 105–117.

Berendsen, Pieter, 1995, Consequences of neotectonic recurrent movement along Precambrian structures on the stratigraphic record, Midcontinent U.S.A. [abstract]: Geological Society of America Abstracts with Programs, New Orleans, v. 27, no. 6, p. A-229.

Berendsen, Pieter; and Blair, K. P., 1986, Subsurface structural maps over the Central North American rift system (CNARS), central Kansas, with discussion: Kansas Geological Survey Subsurface Geology Series 8.

______1995, Structural development of the Nemaha tectonic zone in Kansas, *in* Johnson, K. S. (ed.), Structural styles in the southern Midcontinent, 1992 symposium: Oklahoma Geological Survey Circular 97, p. 208–214.

Berendsen, Pieter; Blair, K. P.; and Newell, K. D., 1989, Structural aspects of the Midcontinent rift in Kansas: Oklahoma City Geological Society, Transactions Volume of 1989 American Association of Petroleum Geologists, Midcontinent Section, Meeting, 26 p.

Berendsen, Pieter; Doveton, J. H.; and Speczik, S., 1992, Distribution and characteristics of a Middle Ordovician oolitic ironstone in northeastern Kansas based on petrographic and petrophysical properties: a Laurasian ironstone case study: Sedimentary Geology, v. 76, p. 207–219.

Berner, R. A., 1981, A new geochemical classification of sedimentary environments: Journal of Sedimentary Petrology, v. 51, p. 359–365.

Bickford, M. E.; and Van Schmus, W. R., 1986, Proterozoic history of the Midcontinent region of North America: Geology, v. 14, p. 492–496.

Brongersma-Sanders, M., 1971, Origin of major cyclicity of evaporites and bituminous rocks: an actualistic model: Marine Geology, v. 11, p. 123–144.

Cotter, E., 1988, Hierarchy of sea-level cycles in the medial Silurian siliciclastic succession of Pennsylvania: Geology, v. 16, p. 242–245.

Dapples, E. C., 1955, General lithofacies relationship of St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Doveton, J. H.; Berendsen, Pieter; Hoth, P.; and Haug, D., 1994, Log analysis of Paleozoic ironstones in the U.S. Mid-Continent: key to paleogeographic mapping: Transactions of Society of Professional Well Log Analysts, 35th Annual Logging Symposium, Paper ZZ, 17 p.

Dubois, S. M., 1978, The origin of surface lineaments in Nemaha County, Kansas: University of Kansas unpublished M.S. thesis, 37 p.

Ellis, D. V., 1987, Well logging for earth scientists: Elsevier, New York, 532 p.

Gygi, R. A., 1981, Oolitic iron formations: marine or not marine?: Eclogae Geologicae Helvetiae, v. 74, p. 233–254.

Hallam, A.; and Bradshaw, M. J., 1979, Bituminous shales and oolitic ironstones as indicators of transgressions and regressions: Geological Society [London] Journal, v. 136, p. 157–164.

Hassan, M.; Hossin, A.; and Combaz, A., 1976, Fundamentals of the differential gamma ray log: Transactions of Society of Professional Well Log Analysts, 17th Annual Logging Symposium, Paper H, 18 p.

Heckel, P. H., 1977, Origin of phosphatic black shale facies in Pennsylvanian cyclothems of Mid-Continent North America: American Association of Petroleum Geologists Bulletin, v. 61, p. 1045–1068.

Jewett, J. M., 1951, Geologic structures in Kansas: Kansas Geological Survey Bulletin 90, pt. 6, p. 105–172.

Kimberley, M. M., 1978, Palaeoenvironmental classification of iron formations: Economic Geology, v. 73, p. 215–229.

______1980, Origin of oolitic iron formations: Journal of Sedimentary Petrology, v. 50, p. 299–307.

______1994, Debate about ironstone: has solute supply been surficial weathering, hydrothermal convection, or exhalation of deep fluids?: Terra Nova, v. 6, p. 116–132.

Krauskopf, K. B.; and Bird, D. K., 1995, Introduction to geochemistry [3d edition]: McGraw-Hill, New York, p. 158–160.

Lambert, M. W., 1992, Lithology and geochemistry of shale members within the Devonian–Mississippian Chattanooga (Woodford) Shale, Midcontinent U.S.A.: University of Kansas unpublished Ph.D. dissertation, 163 p.

Lamoalle, J.; and Dupont, B., 1976, Iron-bearing oolites and the present conditions of iron sedimentation in Lake Chad (Africa), *in* Amstutz, G. C.; and Bernard, A. J. (eds.), Ores in sediments: Springer–Verlag, Berlin, p. 167–178.

Leatherock, C., 1945, The correlation of rocks of Simpson age in north-central Kansas with the St. Peter sandstone and associated rocks in northwestern Missouri: Kansas Geological Survey Bulletin 60, pt. 1, p. 1–16.

Lee, W.; Leatherock, C.; and Botinelly, T., 1948, The stratigraphy and structural development of the Salina basin of Kansas: Kansas Geological Survey Bulletin 74, 155 p.

Maples, C. G., 1994, Revision of Mississippian stratigraphic nomenclature in Kansas, *in* Baars, D. (compiler), Revision of stratigraphic nomenclature in Kansas: Kansas Geological Survey Bulletin 230, p. 67–74.

Maynard, J. B., 1986, Geochemistry of oolitic iron ores, an electron microprobe study: Economic Geology, v. 81, p. 1473–1483.

Merriam, D. F., 1963, The geologic history of Kansas: Kansas Geological Survey Bulletin 162, 317 p.

Moore, R. C.; and Haynes, W. P., 1917, Oil and gas resources of Kansas: Kansas Geological Survey Bulletin 3, 391 p.

Myers, K. J., 1989, The origin of the Lower Jurassic Cleveland Ironstone Formation of north-east England: evidence from portable gamma-ray spectrometry, *in* Young, T. P.; and Taylor, W. E. G. (eds.), Phanerozoic ironstones: Geological Society [London] Special Publication 46, p. 221–228.

Nahon, D.; and Tardy, Y., 1992, The ferruginous laterites, *in* Butt, C. R. M.; and Zeegers, H. (eds.), Regolith exploration geochemistry in tropical and subtropical terrains, *v. 4 of* Govett, G. J. S. (ed.), Handbook of exploration geochemistry: Elsevier, Amsterdam, p. 41–50.

Odin, G. S., 1988, Glaucony from the Gulf of Guinea, *in* Odin, G. S. (ed.), Green marine clays: Elsevier, Amsterdam, p. 225–246.

Odin, G. S.; Knox, R. W. O'B.; Gygi, R. A.; and Guerrak, S., 1988, Green marine clays from the oolitic ironstone facies: habit, mineralogy, environment, *in* Odin, G. S. (ed.), Green marine clays: Elsevier, Amsterdam, p. 29–51.

Petranek, J., 1964, Ordovician—a major epoch in ironstone deposition: 22d International Geological Congress, Delhi, Report 15, p. 51–57.

______1991, Ordovician oolitic ironstones and their source of iron: Geological Survey Bulletin, Prague, v. 66, p. 321–328.

Schlumberger, 1991, Log interpretation charts: Schlumberger, Houston, 172 p.

Sims, P. K.; and Peterman, Z. E., 1986, Early Proterozoic Central Plains orogen: a major buried structure in the north-central United States: Geology, v. 14, p. 488–491.

Sloan, R. E., 1987, An Ordovician time scale, in Sloan, R. E. (ed.), Middle and Late Ordovician lithostratigraphy and biostratigraphy of the Upper Mississippi Valley: Minnesota Geological Survey Report 35, 232 p.

Sweet, W. C.; and Bergstrom, S. M., 1976, Conodont biostratigraphy of the Middle and Upper Ordovician of the United States Midcontinent, *in* Basset, M. G. (ed.), The Ordovician System: Proceedings of Palaeontological Association symposium, Birmingham, p. 121–151.

Thienhaus, R., 1969, Übersicht über die Dogger-eisenerze Nordwestdeutschlands, *in* Sammelwerk Deutscher Eisenerzlagerstatten: Beiheft Geologisches Jahrbuch 79, 124 p.

Van Houten, F. B., 1985, Oolitic ironstones and contrasting Ordovician and Jurassic paleogeography: Geology, v. 13, p. 722–724.

______1990, Palaeozoic oolitic ironstones on the North American craton: Palaeogeography, Palaeoclimatology, Palaeoecology, v. 80, p. 245–254.

Van Houten, F. B.; and Purucker, M. E., 1984, Glauconitic peloids and chamositic ooids—favorable factors, constraints, and problems: Earth-Science Reviews, v. 20, p. 211–243.

Witzke, B. J., 1980, Middle and Upper Ordovician paleogeography of the region bordering the Transcontinental arch, *in* Fouch, T. D.; and Magathan, E. R. (eds.), Paleozoic paleogeography of the west-central United States: Society of Economic Paleontologists and Mineralogists, Rocky Mountain Section, Paleogeography Symposium 1, p. 1–18.

Witzke, B. J.; and Heckel, P., 1988, Paleoclimatic indicators and inferred Devonian paleolatitudes of Euramerica, *in* McMillan, N.; Embry, A.; and Glass, D. (eds.), Devonian of the world: Proceedings of Second International Symposium on the Devonian System: Canadian Society of Petroleum Geologists, v. 3, p. 49–63.

Young, T. P., 1989a, Eustatically controlled ooidal ironstone deposition: facies relationships of the Ordovician open-shelf ironstones of Western Europe, *in* Young, T. P.; and Taylor, W. E. G. (eds.), Phanerozoic ironstones: Geological Society [London] Special Publication 46, p. 51–63.

______1989b, Phanerozoic ironstones: an introduction and review, *in* Young, T. P.; and Taylor, W. E. G. (eds.), Phanerozoic ironstones: Geological Society [London] Special Publication 46, p. ix–xxv.

Simpson–Arbuckle Contact Revisited in Northwestern Oklahoma County, Oklahoma

Michael D. Allison
Consulting Geologist
Gainesville, Texas

R. W. (Bob) Allen
Kabodi, Inc.
Ardmore, Oklahoma

ABSTRACT.—The Joins Formation, the lowermost formation of the Simpson Group, is traditionally the least studied or understood of the Simpson formations. The Joins, not known to produce hydrocarbons in central Oklahoma, is frequently overlooked by those more interested in the productive Simpson formations, above, and the Arbuckle Group carbonates, below.

In a study of the lower Simpson to upper Arbuckle interval in northwestern Oklahoma County, Oklahoma, the Joins Formation was found to be present. The formation in this area varies from 65 to 195 ft thick, which is considerably thicker than most published data for the area; some publications state that the formation is absent.

Lithologically, the Joins Formation in central Oklahoma closely resembles that in the Arbuckle Mountain type section. The central Oklahoma section consists of interbedded gray, olive-gray and green, splintery, moderately waxy shale; cream to light-gray, homogeneous, microcrystalline dolomite; and microcrystalline to fine-crystalline, fossiliferous, slightly glauconitic limestone. In the lower half of the formation, fine- to medium-grained, slightly conglomeratic and glauconitic, well-cemented sandstones are also noted. The entire Joins Formation is moderately to highly fossiliferous, primarily consisting of crinoids, ostracodes, brachiopods, and trilobites. The ostracode fauna closely resembles and correlates with that of the Arbuckle Mountain section, which has been extensively studied over the years by such authors as Taff, Ulrich, and Harris. Beneath the Joins in this area is a normal section of Arbuckle dolomites.

Owing to the absence of a basal sand in the Joins, differentiating the Joins from the Arbuckle, utilizing electric logs only, is frequently tenuous. In comparison with the Arbuckle, the Joins tends to have higher gamma-ray and spontaneous-potential values. Other tools, such as resistivity, bulk-density, and photoelectric methods, are frequently inconclusive. The newest of the above tools, the photoelectric (primarily designed as a lithology-identification tool), is particularly ineffective, owing to the very thin-bedded nature of the Joins and the 2-ft-minimum resolution limits of this tool during normal logging.

For geologists studying the Simpson–Arbuckle contact in central Oklahoma, the presence or absence of the Joins Formation is best determined through conventional lithologic and paleontologic sample-identification techniques. Once this has been done, correlation of electric logs with this type log is possible for the local area. Care must be taken not to extend these correlations too far from the type well, primarily because of the commonly inconclusive nature of electric logs recorded through the Joins interval.

INTRODUCTION

During the past 15 years, the petroleum industry has shown increased interest in the Late Cambrian and Early Ordovician Arbuckle Group as an objective for oil and gas exploration in Oklahoma. Owing to these efforts, significant discoveries have been made, two of the most recent being the gas discovery at the Wilburton Deep field in the Arkoma basin and the oil discovery at Cottonwood Creek field in Carter County. Reserve estimates from Arbuckle reservoirs in the Midcontinent have proved to be sufficiently large to attract the interest of both major and independent oil companies.

Prior to this most recent interest in the Arbuckle Group as a reservoir, many oil operators and drillers considered the Arbuckle, unless it produced from the uppermost zones, to be "basement." The thinking at the time was that if one drilled 50–100 ft of Arbuckle strata without oil or gas shows, the entire stratigraphic column had been "tested" and there was no need to drill further. In like manner, the Joins Formation of the Simpson Group (deposited above the Arbuckle disconformity), not known to produce oil anywhere in Oklahoma, also received little interest. For these reasons and others, petroleum-industry interest in the Arbuckle and Joins

Allison, M. D.; and Allen, R. W., 1997, Simpson–Arbuckle contact revisited in northwestern Oklahoma County, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 172–182.

was limited. During the 1950s, many writers chose not to expend time on a subject of such limited interest as the Simpson–Arbuckle contact, and for convenience they included the Joins with the Arbuckle. As a result, the Joins Formation was largely ignored as a distinct lithologic or biostratigraphic entity. This trend was noted, with apparent dismay, by Harris (1957) in his outstanding monograph on the Simpson Group and its Ostracoda.

Because of recent interest in the Arbuckle Group, a number of geologists have expanded our knowledge of this unit, particularly as it relates to reservoirs, source beds, and diagenesis. Gatewood (1992) discussed the heterogeneous nature and self-sourcing potential of the Arbuckle. Amthor and Friedman (1991) discussed secondary-porosity development in the Ellenburger Group (equivalent to the Arbuckle). Amthor and Friedman (1992) discussed early-to-late dolomitization in the Ellenburger. Also, the Oklahoma Geological Survey sponsored a special symposium in 1989 on the Arbuckle Group (Johnson, 1991).

During this period of heightened interest in the Arbuckle, both geologic and economic, the past habit of including the Joins with the Arbuckle, unless scientifically warranted, is not acceptable.

Study Area, Scope, and Purpose

This study was undertaken to evaluate the lower Simpson and upper Arbuckle formations in northwestern Oklahoma County, Oklahoma. The study area is the western part of T. 14 N., R. 3 W. (Fig. 1). The study of this area is useful because of its proximity to the reported depositional edge of the Joins (Statler, 1965). Also, if the Joins is lithologically distinct at this distal subsurface location, then it should also be distinct at other places in the State.

The primary focus of this study is on the Joins and West Spring Creek (uppermost Arbuckle) Formations. The purposes are to recognize and identify the Joins and West Spring Creek in the subsurface by comparing their lithologies to those of the type sections in the Arbuckle Mountains, and to establish clear lithologic and electric-log criteria, if possible, which will allow the separation of the Joins from the underlying West Spring Creek in the study area.

Previous Investigations

No comprehensive studies of the Simpson or Arbuckle Group within the study area have been published, although several published articles discuss very generally the Joins and Joins–Arbuckle contact in central Oklahoma. Decker (1952) recognized a Joins graptolite in samples along the southern margin of the study area. Ford (1954), in a study of southern Logan County, made no reference to the Joins just north of the study area. Dietrich (1955), in primarily an electric-log study, briefly described the Simpson Group along the northern flank of the Anadarko basin and north to the Kansas state line. In this study, he determined that the Joins and Arbuckle were not lithologically or electrically distinct in the subsurface, and that the Joins should be included within the Arbuckle. Cronenwett (1956), in a sample and electric-log study, described the Simpson in east-central Oklahoma. In this study, he found the Joins in the subsurface to consist of light- to dark-gray, sucrosic, sandy dolomites, thin partings of dark-green to black shales, and coarse-crystalline, fossiliferous limestones. In his study area, the Joins is 0–140 ft thick. Jones (1960), in an electric-log, drillers-log, and well-record study, provided an overview of the pre-Desmoinesian units in north-central Oklahoma. Schramm (1964), in an electric-log and lithofacies study of the Simpson in Oklahoma, found that the Joins, in the subsurface, generally retained its lithologic character. Statler (1965) conducted a stratigraphic study of the Simpson in Oklahoma. Other studies with relevance to the study area were performed by Gatewood (1970, 1978a,b).

Methods of Study

The Joins Formation, the lowermost unit of the Simpson Group (Decker and Merritt, 1931), consists of interbedded thin shales and limestones, with a thin basal conglomerate, in its type section northwest of Woodford, Oklahoma. The Joins is disconformably overlain by the Oil Creek Formation, the basal unit of which is the Oil Creek sandstone (Harris, 1957).

In the Oklahoma County study area, the basal Oil Creek sandstone is well developed. Utilizing this well-recognized unit for stratigraphic control, a structure map was constructed that depicts the base of the Oil Creek, with the aid of electric logs from the area (Fig. 2).

After an electric-log study of the wells that penetrated the basal Oil Creek sandstone, samples from five wells were acquired. These wells were the Marjo Oil Co. No. 2–31 Ziegelgruber, sec. 31, T. 15 N., R. 3 W.; Marjo Oil Co. No. 1–5 Candy, sec. 5, T. 14 N., R. 3 W.; Marjo Oil Co. No. 3–8 Samara, sec. 8, T. 14 N., R. 3 W.; Imperial No. 1 Monk, sec. 15, T. 14 N., R. 3 W.; and Mid-Continent No. 2 Young, sec. 31, T. 14 N., R. 3 W. The well cuttings or core chips from these five wells were analyzed from above the basal Oil Creek sandstone to total depth. The study techniques consisted of a binocular-microscope examination of the rocks to determine the lithology. During this phase of study, fossils were identified as to phylum, genus, and species, where possible. Following this phase, thin sections were prepared for petrographic analysis. Through thin-section analysis, properties such as grain or crystal size, texture, mineralogy, rock type, fossil assemblages, diagenesis, and reservoir properties were determined. All thin sections in this study were treated with a solution of Alizarin Red-S for the purpose of distinguishing calcite from dolomite.

DISCUSSION

As in any study of this type, where the presence or absence of a formation is in question, knowledge must be acquired of the lithologic properties for that formation at its type section, as well as the formations in vertical succession above and below. Also, any lateral lithologic gradation that may exist between the type section and the study area should be known, if possible.

Type Sections

The Arbuckle and Simpson "formations" were first named and described by Taff (1904) in a study of the southern Oklahoma Arbuckle and Wichita Mountains. In this work he found the Arbuckle to be composed entirely of limestone and dolomite, except for a few thin shaly, cherty, or sandy strata. In contrast to the lithologic uniformity of the Arbuckle, Taff found the Simpson to consist of thin-bedded, interstratified greenish shale, crystalline shaly limestone, and sandstone. He also found the Simpson to contain an abundant fauna throughout.

Decker and Merritt (1931) elevated the Simpson to group status and divided it into the five formations of more-or-less current usage; in ascending order, they are the Joins, Oil Creek, McLish, Tulip Creek, and Bromide Formations. Harris (1957) modified the formation listing by adding the Corbin Ranch Formation above the Bromide.

Oil Creek Formation

In its type section, the Oil Creek Formation is divided into a basal sandstone member and an upper member

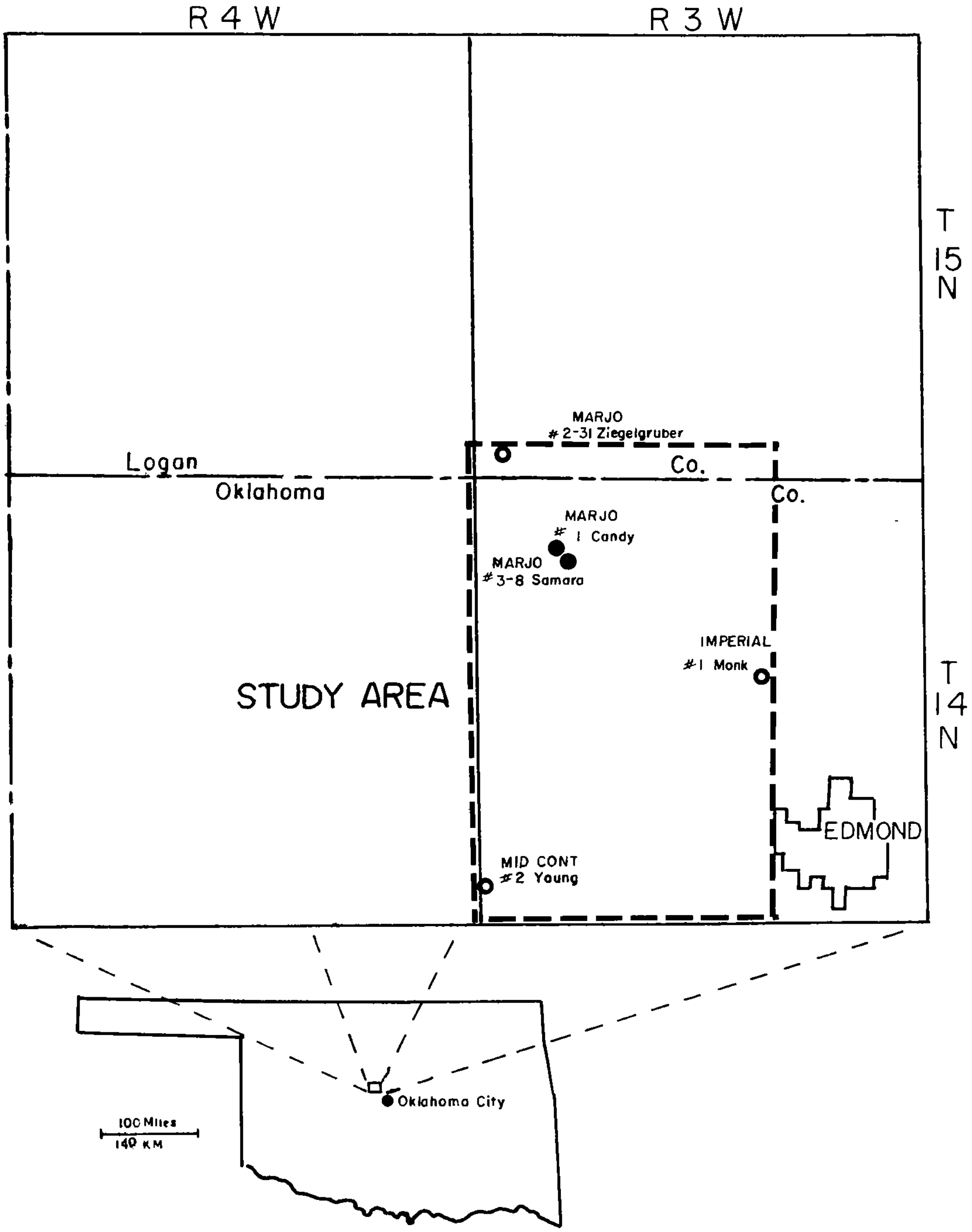


Figure 1. Index map showing the location of the study area (dashed outline) in northwestern Oklahoma County.

of thin-bedded, fossiliferous crystalline limestones and shales (Decker and Merritt, 1931; Harris, 1957). The basal sandstone consists of fine- to medium-grained, subrounded to rounded, frosted quartz sand. The primary cement, if any, is dolomite. Limestones within the formation are medium to coarse crystalline, fossiliferous, slightly cherty, and glauconitic. Shales are green to gray, waxy, splintery, and generally nonfossiliferous. The primary fossils are ostracodes, with a lesser abundance of crinoids, trilobites, brachiopods, and bryozoans. Within the Oil Creek, minor amounts of dolomite are observed.

Joins Formation

Beneath the Oil Creek is the Joins Formation. In the Arbuckle Mountains outcrop area, the Joins consists of interbedded thin limestones and shales with thin conglomerates near the base. Joins limestones are fine to coarse crystalline, fossiliferous, slightly cherty, and glauconitic. As in the Oil Creek Formation, some of these limestones are slightly to moderately dolomitic. The lower Joins limestones are oolitic at some localities. Joins shales, less abundant than in the Oil Creek, are thin bedded, dark green to gray, splintery, and waxy. Fossils within the Joins are primarily confined to the limestone fractions. Within the Joins, the primary fossils are ostracodes, brachiopods, bryozoans, trilobites, and crinoids.

Arbuckle Group

In contrast to the highly diverse stratified lithologies and abundant fauna of the Simpson formations, the formations of the Arbuckle Group consist of a uniform lithology of limestone, dolomite, or a combination of the two. Sandstones and shales are rare, and where present only exist as very thin partings, which rarely, if ever, exceed 10 ft thick. In the Ordovician part of the Arbuckle, the primary accessories are silt and sand grains, chert nodules, finely disseminated clay particles (normally not visible), and anhydrite (normally confined to the upper Arbuckle). These accessories are rarely more than minor constituents. Glauconite, observed in the Cambrian part of the Arbuckle, is absent throughout the Ordovician Arbuckle (West Spring Creek to McKenzie Hill Formations). Fossils within the Arbuckle are algae, trilobites, sponges, ostracodes, mollusks, pelmatozoans, and graptolites (Ham, 1973). None of these fossils, however, are considered to be prevalent and are only rarely seen, particularly when compared with the profusion of fossils in the overlying Simpson.

In the Arbuckle Mountain outcrop area, Harris (1957) found the contact between the Arbuckle and Joins to be an unconformity of "first magnitude." In addition to the distinctly different lithologies observed, during the hiatus between Arbuckle and Joins deposition the ostracode fauna of Arbuckle Beekmantown time died out and a completely different Chazyan fauna developed.

Lateral Lithologic Gradation

Joins Formation

Between the type section in the Arbuckle Mountains and the Oklahoma County study area, no detailed subsurface study of the Joins Formation has been conducted. It is known, however, that the Joins rocks in west Texas and southeastern New Mexico are lithologically and paleontologically similar to the type section of southern Oklahoma. This similarity is evidence of the uniformity of the formation over great distances.

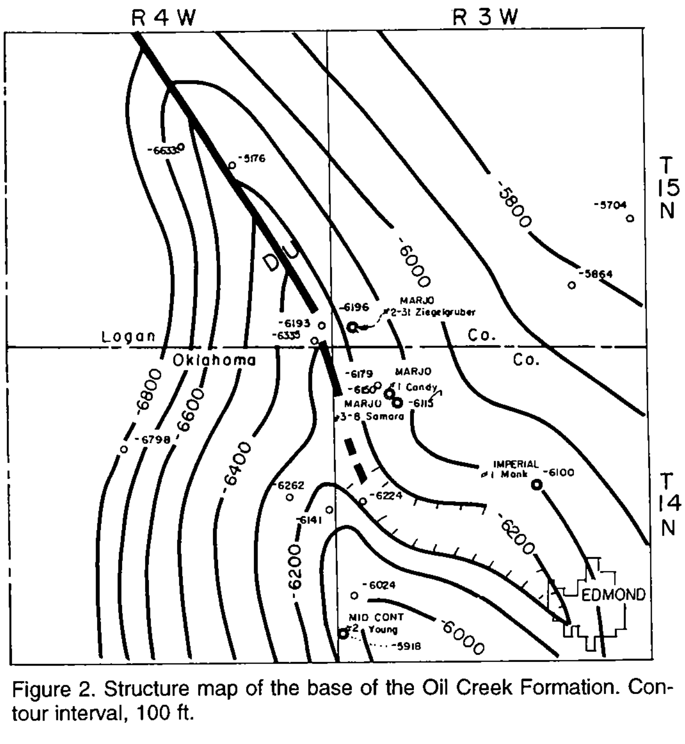


Figure 2. Structure map of the base of the Oil Creek Formation. Contour interval, 100 ft.

Arbuckle Group

In the southern Oklahoma Ardmore basin–Arbuckle Mountains area, the Ordovician Arbuckle formations are predominantly limestones. North or south of this geosynclinal area, on either the Oklahoma or Texas cratonic element, the Arbuckle becomes more dolomitic (Ham, 1973). At the Oklahoma City oil field, approximately 18 mi south of the study area, the Arbuckle is totally composed of dolomite (Gatewood, 1970, 1978b). In the study area, the Arbuckle should consist of dolomite, as was observed at the Oklahoma City field.

Northwestern Oklahoma County Area

Sample description began at a drilling depth of 7,170 ft in the Mid-Continent No. 2 Young well, and at 7,190 ft in the other four wells studied in detail. In all these wells, the beginning depths are 30–45 ft above the basal Oil Creek sandstone.

Oil Creek Formation

In the five study wells, the Oil Creek strata above the basal sand consist of dark-olive-gray (with a trace of green), splintery, waxy, slightly to moderately silty to sandy shale, interbedded with white, gray, tan, mottled, chalky to crystalline, fossiliferous, sandy, dolomitic, and slightly glauconitic limestone (Fig. 3). Sand grains within the shale and limestone are fine to coarse and are well rounded. Fossils are ostracodes, crinoids, and bryozoans. Diagnostic Oil Creek ostracodes observed in this interval are *Cryptophyllus magnum, Leperditella bulbosa, Paraschmidtella pauciperforata, Eoprimitia moorei,* and *Hilsweckella rugulosa.*

Beneath this lower Oil Creek interval is the 35–40-ft-thick basal Oil Creek sandstone. The Oil Creek sandstone is a coarsening-downward deposit, being very fine to medium grained at the top, and grading downward to fine to very coarse grained at the base. The sand is best developed at the base of the unit. Sedimentologically, the sand is friable to unconsolidated; it contains well-rounded quartz and traces of rock fragments, and has minor quartz overgrowths. Cementation, if any, is primarily dolomite. The upper two-thirds of the basal sand contains partings of green waxy shale, crystalline fossiliferous limestone, and microcrystalline to very finely crystalline sandy dolomite (Fig. 4).

Joins Formation

Beneath the basal Oil Creek sandstone is the Joins Formation. The upper 40 ft of the Joins consists of nearly equal amounts of dark-gray to dark-olive-green, splintery, waxy, nonfossiliferous shale, and cream to white, sucrosic, homogeneous microcrystalline dolomite that is slightly sandy and glauconitic (Fig. 5). Also present are lesser percentages of tan to gray, crystalline, fossiliferous, slightly sandy and glauconitic limestone, and dolomitic, very fine-grained sandstone. The remainder of the Joins consists of shales as above; approximately equal percentages of fossiliferous crystalline limestone (Fig. 6) and sucrosic microcrystalline, homogeneous dolomite (Figs. 7,8); and traces of calcareous, dolomitic, slightly arkosic conglomeratic sandstone (Fig. 9). The conglomeratic sandstones are most prevalent in the lower 70 ft of the formation. The limestones, dolomites, and conglomeratic sandstones are all glauconitic. Limestones in the lower Joins are slightly oolitic.

Within the Joins, the primary fossils are ostracodes and crinoids, with lesser amounts of bryozoans, brachiopods, gastropods, and colonial corals. Diagnostic Joins ostracodes are *Leperditella valida, L. cooperi, Paraschmidtella trifoveolata,* and *Eoleperditia mediumbonata.*

In the No. 2–31 Ziegelgruber and No. 1–5 Candy wells, the Joins is 160 and 170 ft thick, respectively. The No. 3–8 Samara well bottomed in the Joins, after

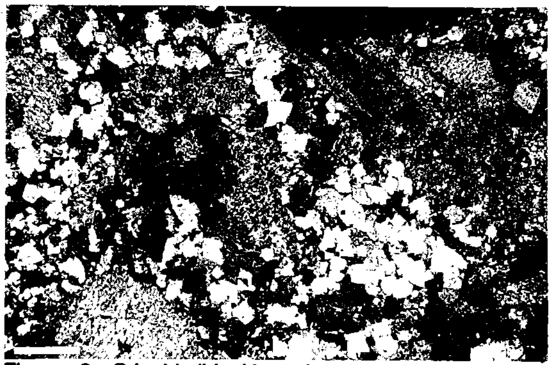


Figure 3. Crinoid (black) and ostracode grainstone, exhibiting considerable dolomite replacement; Oil Creek Formation. Imperial No. 1 Monk, 7,200–7,210 ft. Crossed nicols; bar represents 0.25 mm.

Figure 4. Very fine- to fine-grained sandstone, cemented by dolomite; Oil Creek sandstone. Marjo No. 3–8 Samara, 7,260–7,270 ft. Crossed nicols; bar represents 0.25 mm.

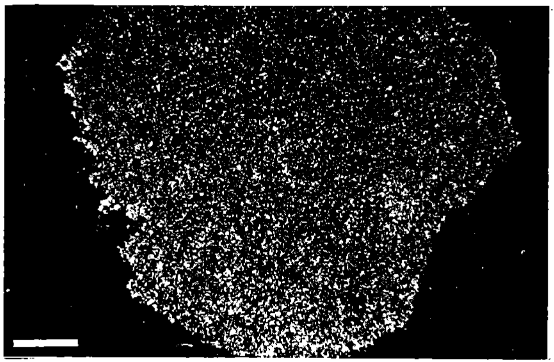


Figure 5. Microcrystalline dolomite; note uniform texture; Joins Formation. Marjo No. 3–8 Samara, 7,280–7,290 ft. Crossed nicols; bar represents 0.25 mm.

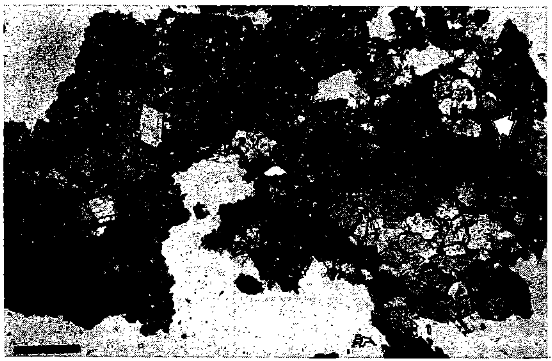


Figure 6. Crinoid–ostracode glauconite (arrow in upper right) and dolomitic (rhombs) grainstone; pyrite is black; Joins Formation. Imperial No. 1 Monk, 7,290–7,300 ft. Crossed nicols; bar represents 0.25 mm.

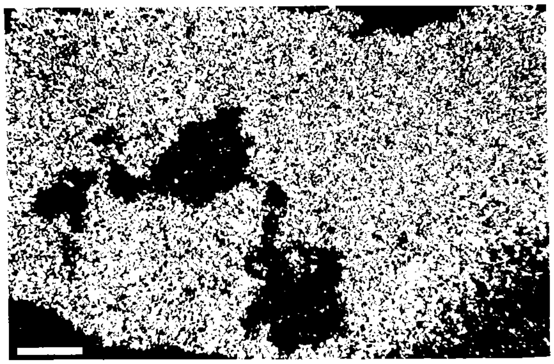


Figure 7. Uniform microcrystalline dolomite; pore spaces are black; Joins Formation. Marjo No. 1–5 Candy, 7,340–7,350 ft. Crossed nicols; bar represents 0.25 mm.

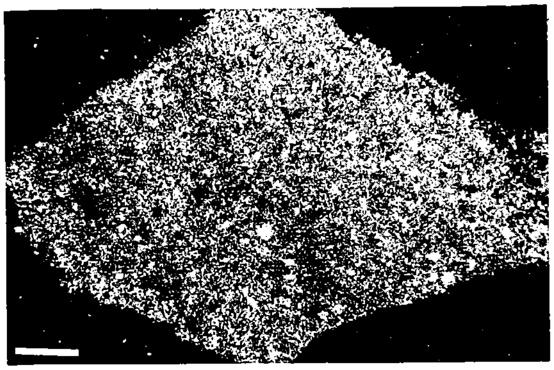


Figure 8. Uniform microcrystalline silty dolomite, with minor amounts of pyrite (black); Joins Formation. Marjo No. 1–5 Candy, 7,410–7,420 ft. Crossed nicols; bar represents 0.25 mm.

Figure 9. Slightly arkosic (arrow in center) and calcareous sandstone, with extensive dolomite cement; Joins Formation. Marjo No. 1–5 Candy, 7,410–7,420 ft. Crossed nicols; bar represents 0.25 mm.

drilling 95 ft of the formation. In the Imperial No. 1 Monk and Mid-Continent No. 2 Young wells, the Joins is 195 and 96 ft thick, respectively. The thickness of the Joins in the local area, except for the study wells, is based on well-log data (Fig. 10).

Arbuckle Group
(West Spring Creek Formation)

Beneath the Joins is the West Spring Creek Formation of the Arbuckle Group. The West Spring Creek consists of cream, tan to light-gray (with a trace of brown), nonhomogeneous, medium- to microcrystalline dolomite (Figs. 11,12). The formation is slightly silty to sandy and contains trace amounts of white to cream chert. Thin gray-green shale partings are scattered randomly throughout the formation. The Mid-Continent No. 2 Young contains one thin, very fine- to fine-grained dolomitic sandstone.

In contrast to the Joins above, the West Spring Creek contains no limestone and only trace amounts of shale or sandstone. The dolomites are crystalline rather than sucrosic (Archie, 1952), and are of a nonhomogeneous texture. The West Spring Creek contains no glauconite, a rather common constituent in the Joins.

Electric-Log-Correlation Potential

Identification and evaluation of the Joins, and determination of the Joins–Arbuckle contact, are readily achieved through sample-identification procedures (Fig. 13). These same determinations, solely through the use of electric logs, have for many years been problematic at best. Statler (1965), in a series of 13 cross sections, presented a number of examples of the variations in electrical responses observed in the Joins and upper Arbuckle (Fig. 14). He found that log correlations, with respect to the Joins, can be relied on only locally and frequently are not accurate. It was this sort of electric-log-correlation problem that the North American Commission on Stratigraphic Nomenclature (1983) was concerned with when they determined that rock units (formations) were to be defined solely from descriptions of actual rock material rather than their geophysical characteristics.

For the Joins Formation, even in an area as small as the study area, uniform electric-log responses do not exist. The primary reasons for the diversity of log responses are the very thinly interstratified nature of the Joins, the minimum resolution limits of the various tools, and the mechanical-presentation limits of log-recording devices. Normal bed thicknesses in the Joins are on the order of 2–12 in. and rarely exceed 3–4 ft. Under normal logging procedures, most logging tools, including the photoelectric (PE) lithology-identification tool, cannot resolve thicknesses of less than 1–2 ft. These logging tools, therefore, of necessity, present averaged responses, owing to their inability to resolve such thin-bedded, mixed-lithology units as the Joins. Mechanical presentation limits of log-recording devices also are affected by thin-bedded units. At a presentation scale of 5 in. per 100 ft, a 4-in.-thick bed would require a response capability on the log of 1/60th in. At 1 in. per 100 ft, this presentation requirement on the log would be 1/300th in.

One new technology that is showing some success in identifying the Joins Formation and the Joins–Arbuckle contact on electric logs is the log-analysis programs being written for computer analysis. George B. Asquith (personal communication, 1994), utilizing the CBA Carbonate Advisor Program (The Logic Group, 1994), analyzed logs from the Marjo No. 2–31 Ziegelgruber well; the results are presented in Figure 15. In this analysis,

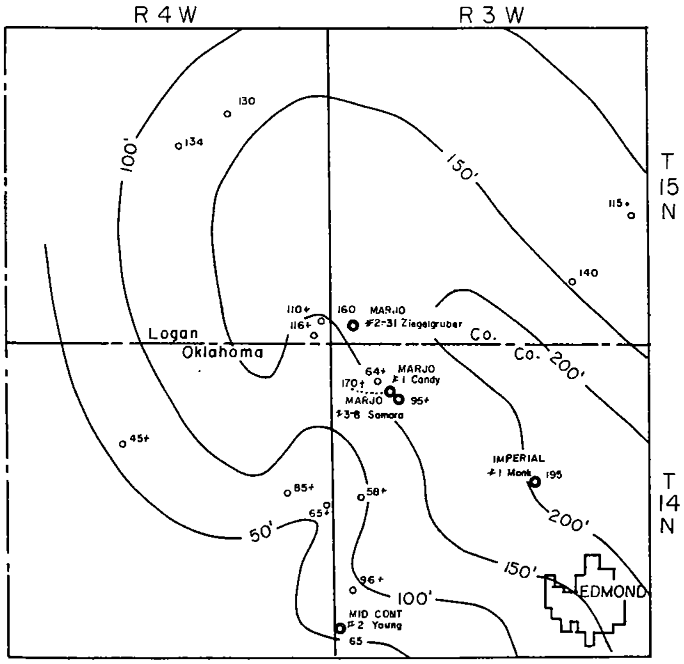


Figure 10. Isopach map of Joins Formation. Contour interval, 50 ft.

the Joins interval (7,270–7,430 ft) is recognized as the shaly interval beneath the basal Oil Creek sand in the Vcl and summary plots. From the computer log analysis, it is obvious that this interval does not represent the Arbuckle Group, owing to the high shale content.

Although this computer-analysis program is a distinct advantage over manual techniques, it still doesn't resolve all the problems generated by the thin-bedded, mixed lithologies of the Joins. These shortcomings are seen in the higher percentages of dolomite and sand reported in the summary versus what exist in the Joins. These problems are interpreted as being a factor of the similarity of PE values for shale and dolomite, and the artificially low spontaneous-potential (SP) and gamma-ray values that are a factor of the averaging of lithologies owing to the thin-bed effect.

ARBUCKLE PRODUCTION POTENTIAL

Although the primary purposes of this study are the identification of the Joins Formation in the study area and recognition of its lithologic uniquenesses with respect to the Arbuckle, the larger goal is, through use of this information, to increase precision in identifying the top of the Arbuckle Group. With this increased precision, one can make more accurate estimates of depths to potential porosity/permeability zones within the Arbuckle.

Within the study area, the uppermost formation of the Arbuckle Group is the West Spring Creek. In the Imperial No. 1 Monk well, the West Spring Creek is at a depth of 7,430–7,870 ft, a thickness of 440 ft. Beneath the West Spring Creek, in descending order, are the Kindblade Formation from 7,870 to 8,050 ft, a thickness of 180 ft, and the Cool Creek Formation from 8,050 to 8,425 ft, a thickness of 375 ft. In the No. 1 Monk, 995 ft of Arbuckle was drilled, and the well bottomed in the Cool Creek. From the well data, multiple porosity intervals were noted within the Arbuckle. The primary porosity intervals are the "Brown" zone, the lower 90 ft of the Kindblade, and the lower 265 ft of the Cool Creek.

The "Brown" zone, the lowermost unit of the West Spring Creek, is at a depth of 7,710–7,870 ft, a thickness of 160 ft. It occurs 280 ft below the top of Arbuckle. This interval consists of very fine- to medium-crystalline dolomite with coarse to very coarse, late-diagenetic, nonplanar dolomite crystals associated with fracture and vuggy porosity. In addition to fracture and vuggy porosity, intercrystalline porosity was present. Within the "Brown" zone, a slight to fair showing of oil was noted. The "Brown" zone was also recognized in the Mid-Continent No. 2 Young well; the "Brown" zone, approximately 280 ft below the top of the Arbuckle, has a porosity similar to that noted in the No. 1 Monk well.

In the No. 1 Monk well, the lower 90 ft of the Kindblade consists of medium-crystalline, coarsely pelletal (oolitic?) dolomite. This interval exhibited minor fractures and vuggy porosity with a slight to fair show of oil.

The third prospective reservoir in the No. 1 Monk well is the Cool Creek Formation. Fracture, vuggy, and intercrystalline porosity starts 80 ft below the top of the formation. Porosity increases with depth and is best developed in the lower 135 ft drilled. Within the Cool Creek, only a questionable show of oil was observed.

In the study area, porosity development in the top of the Arbuckle was only sporadically developed. In the Marjo No. 2–31 Ziegelgruber well, porosity is present in the top of the Arbuckle, mainly because of an increase in crystal size. This porosity interval was not noted in the Marjo No. 1–5 Candy well, 1.5 mi to the southeast, or in the Mid-Continent No. 2 Young well, approximately 6 mi to the south.

Within the study area, major porosity intervals should be expected approximately 280, 530, and 730 ft below the top of the Arbuckle. Porosity development within the upper 250 ft of the Arbuckle, though potential, is not considered to be prospective. A similar situation was observed at the Oklahoma City field, where the first significant porosity development within the Arbuckle is stratigraphically 200–250 ft below the top (Gatewood, 1970).

Porosity development within the Arbuckle is due primarily to fractures, solution-enlarged fractures, and vugs; intercrystalline porosity is less well developed. According to Nelson (1985), fractured reservoirs are very complicated and difficult to evaluate. For this reason, he felt that simplistic generalizations about fractured reservoirs are never appropriate, and may be scientifically unethical. Some examples of simplistic generalizations about the Arbuckle are (1) approximately 99% of cumulative production comes from the top 200–300 ft (Cardwell, 1977); (2) if oil is not found in the

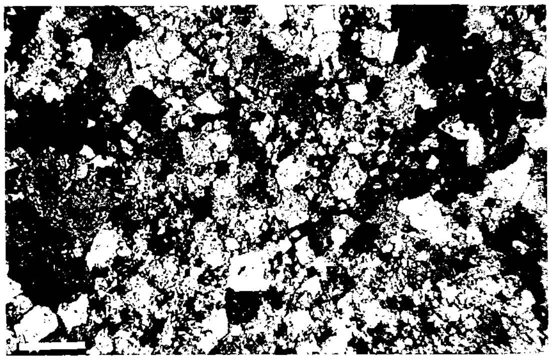


Figure 11. Extra-fine- to fine-crystalline, slightly cherty dolomite; note the intercrystalline and vuggy porosity; West Spring Creek Dolomite. Imperial No. 1 Monk, 7,640–7,650 ft. Crossed nicols; bar represents 0.25 mm.

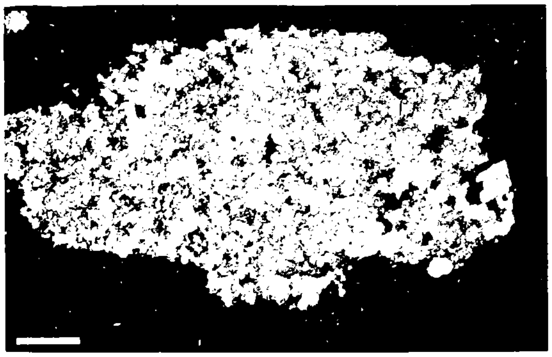


Figure 12. Extra-fine- to fine-crystalline dolomite; West Spring Creek Dolomite. Marjo No. 2–31 Ziegelgruber, 7,470–7,480 ft. Crossed nicols; bar represents 0.25 mm.

top few feet of the Arbuckle, the rest of the unit will be dry; (3) once water is noted in the Arbuckle, it will be "wet" the rest of the way down; and (4) the Arbuckle/Ellenburger Groups contain no source rock. Such statements have all been shown to be inaccurate (Gatewood, 1978a, 1992).

Owing to the complexity of the Arbuckle reservoirs, a reliance solely on sample identification and electric-log evaluation to determine the potential for hydrocarbon production is frequently inadequate. This observation can even be applied to core evaluation. The best and most highly recommended technique for evaluation of Arbuckle reservoirs is actual production testing, either drill-stem testing or production testing through or below pipe. Also, because of the heterogeneous, multiple-reservoir nature of the Arbuckle, unless one drills to a sufficient depth to at least evaluate the major porosity/permeability intervals in the Arbuckle, it can be stated that the unit was not thoroughly tested.

SUMMARY AND CONCLUSIONS

In the type section of southern Oklahoma, the Joins consists of thin-bedded, interstratified intervals of dark, waxy, fissile shale; crystalline, fossiliferous limestone; homogeneous, sucrosic dolomite; and trace amounts of conglomeratic sandstone. The limestones, dolomites, and sandstones all contain moderate amounts of glauconite. The Joins contains crinoids, bryozoans, brachiopods, and trilobites, as well as a rich collection of ostracodes. Several diagnostic Joins index ostracodes are present in the section. In the study area, the Joins is approximately 50–200 ft thick.

Beneath the Joins is a typical Arbuckle dolomite section. The Arbuckle consists of a monotonously uniform lithology of microcrystalline to medium-crystalline, slightly sandy and cherty dolomite with traces of greenish-gray splintery shale. The upper Arbuckle is nonglauconitic and virtually devoid of visible fossils.

Within the study area of central Oklahoma, the lower Simpson and upper Arbuckle have retained their strong lithologic and paleontological uniqueness, the same as in the type sections of southern Oklahoma. In contrast, there is a lack of consistent electric-log responses through the Joins-to-Arbuckle interval. Through the use of computer-based log-analysis techniques, some success has been achieved in the differentiation of the Joins and the Arbuckle.

Porosity development within the Arbuckle is common in discrete zones that can be estimated. For this reason, an accurate determination of the top of Arbuckle is imperative. As the Arbuckle becomes more and more important as a potential oil and gas reservoir, ignoring the presence of the Joins, or including it in the Arbuckle, is scientifically and economically reckless, particularly when the two units can be separated successfully and confidently through standard lithologic- and paleontologic-identification techniques.

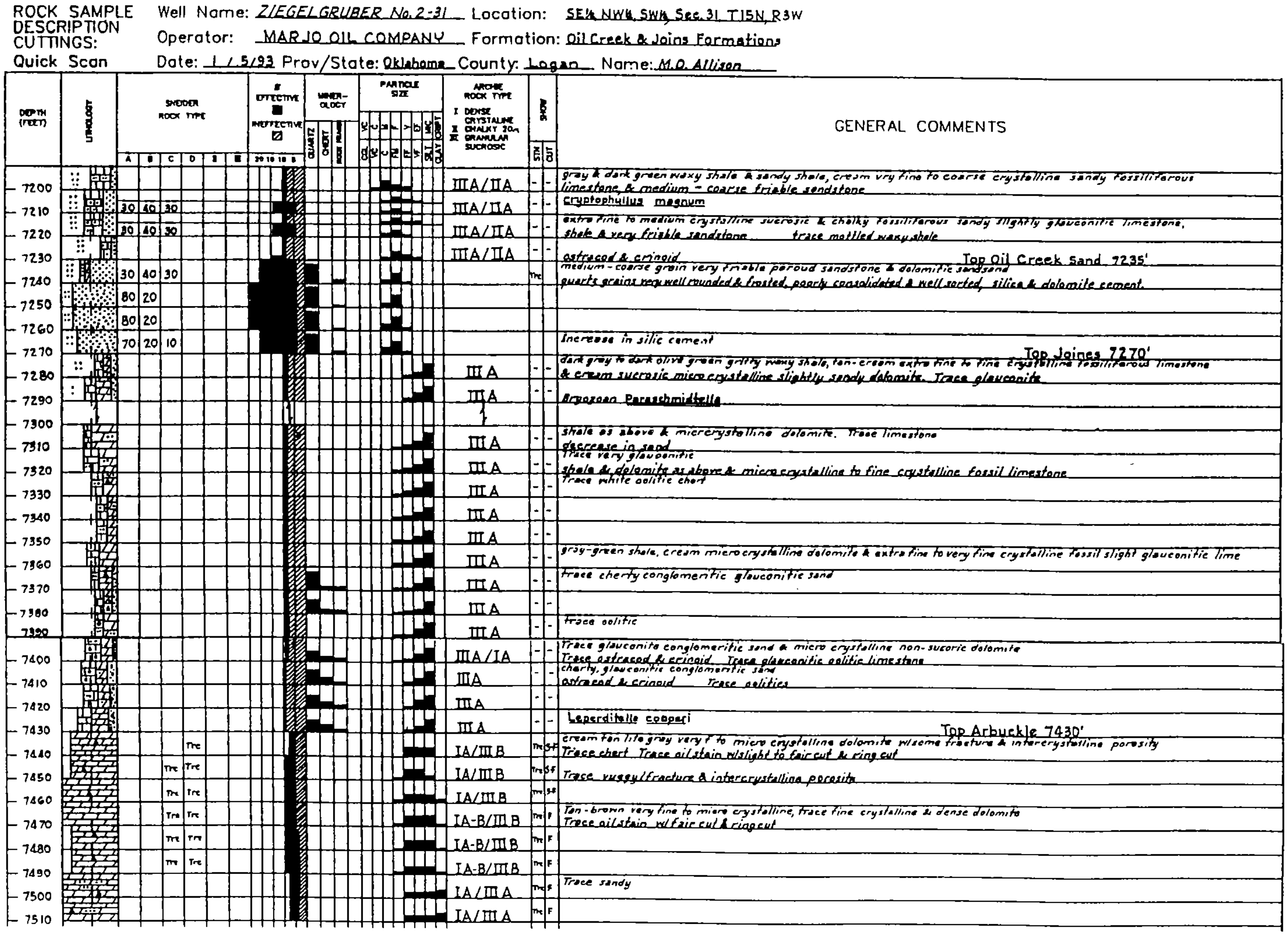
ACKNOWLEDGMENTS

First and foremost, the authors would like to express their unwavering gratitude to Stephen P. Friot and Robert G. Gum for their trust and confidence in the authors' abilities to perform this study. Their single-minded total support, enthusiasm, cordiality, and dedication toward this study was without peer. The authors also treasure the trust and support of J. T. Hoke and Chris Hoke of Baron Exploration Co., and Steve Agee and Clayton Lee of XAE Corp. Special recognition is given to Clayton Lee for his geological knowledge and wisdom, which were so useful during this study.

Special recognition is given to the following: George B. Asquith, with the Texas Tech University School of Geology, for performing the computer log analysis; The Logic Group of Austin, Texas, for allowing use of their log-analysis software; Charles R. Price, Jr., for assisting with sample identification; Bryan Sralla, for assisting with mapping and critically reading the manuscript; and Charles Clarke and L. A. Brown, for providing the drafting services. Lastly, the authors wish to express their sincerest appreciation to Mary S. Allison for critically reading, typing, and editing the manuscript.

REFERENCES CITED

Amthor, J. E.; and Friedman, G. M., 1991, Dolomite-rock textures and secondary porosity development in Ellenburger Group carbonates (Lower Ordovician), west Texas and southeastern New Mexico: Sedimentology, v. 38, p. 343–362.



ROCK SAMPLE DESCRIPTION CUTTINGS:
Quick Scan

Well Name: ZIEGELGRUBER No. 2-31 Location: SE¼ NW¼ SW¼ Sec. 31 T15N R3W
Operator: MARJO OIL COMPANY Formation: Oil Creek & Joins Formations
Date: 1 / 5/93 Prov/State: Oklahoma County: Logan Name: M.D. Allison

GENERAL COMMENTS

gray & dark green waxy shale & sandy shale, cream vry fine to coarse crystalline sandy fossiliferous limestone & medium - coarse friable sandstone

Cryptophullus magnum

extra fine to medium crystalline sucrosic & chalky fossiliferous sandy slightly glauconitic limestone, shale & very friable sandstone trace mottled waxy shale

ostracod & crinoid

Top Oil Creek Sand 7235'

medium - coarse grain very friable poroud sandstone & dolomitic sandsand

quartz grains very well rounded & frosted, poorly consolidated & well sorted, silica & dolomite cement.

Increase in silic cement

Top Joines 7270'

dark gray to dark olive green gritty waxy shale, tan-cream extra fine to fine crystalline fossiliferous limestone & cream sucrosic micro crystalline slightly sandy dolomite. Trace glauconite

Bryozoan Paraschmidtella

shale as above & micrcrystalline dolomite. Trace limestone

decrease in sand

Trace very glauconitic

shale & dolomite as above & micro crystalline to fine crystalline fossil limestone

Trace white oolitic chert

gray-green shale, cream microcrystalline dolomite & extra fine to very fine crystalline fossil slight glauconitic lime

trace cherty conglomeritic glauconitic sand

trace oolitic

Trace glauconite conglomeritic sand & micro crystalline non-sucoric dolomite

Trace ostracod & crinoid. Trace glauconitic oolitic limestone

cherty, glauconitic conglomeritic sand

ostracod & crinoid Trace oolitics

Leperditella cooperi

Top Arbuckle 7430'

cream tan lite gray very f to micro crystalline dolomite w/some fracture & intercrystalline porosity

Trace chert Trace oil stain w/slight to fair cut & ring cut

Trace vuggy/fracture & intercrystalline porosity

Tan-brown very fine to micro crystalline, trace fine crystalline & dense dolomite

Trace oil stain w/fair cut & ring cut

Trace sandy

Figure 13. Sample log for the Marjo No. 2–31 Ziegelgruber well; sec. 31, T. 15 N., R. 3 W.

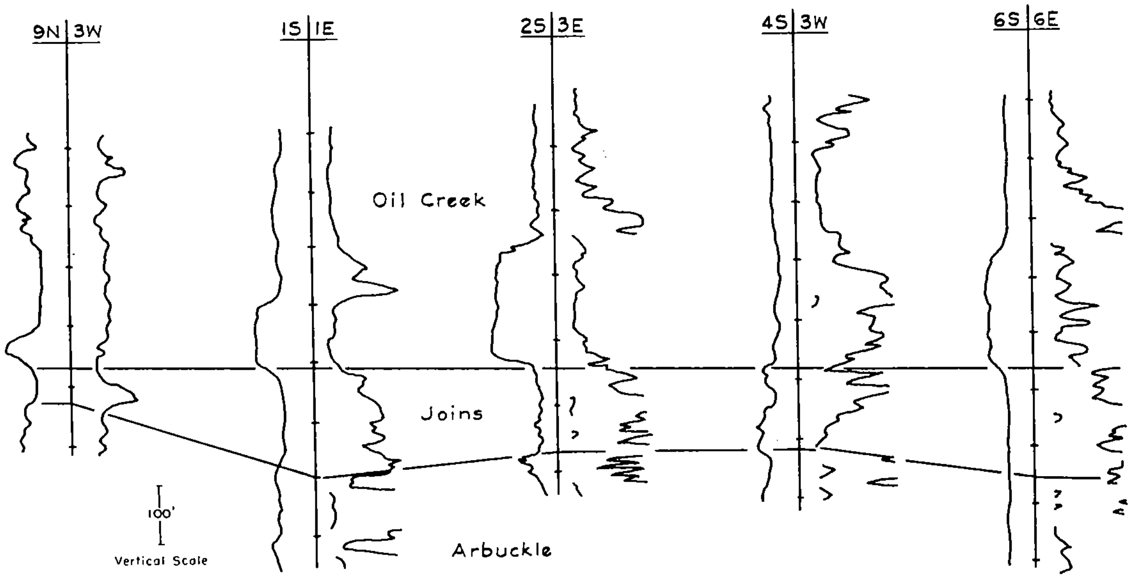
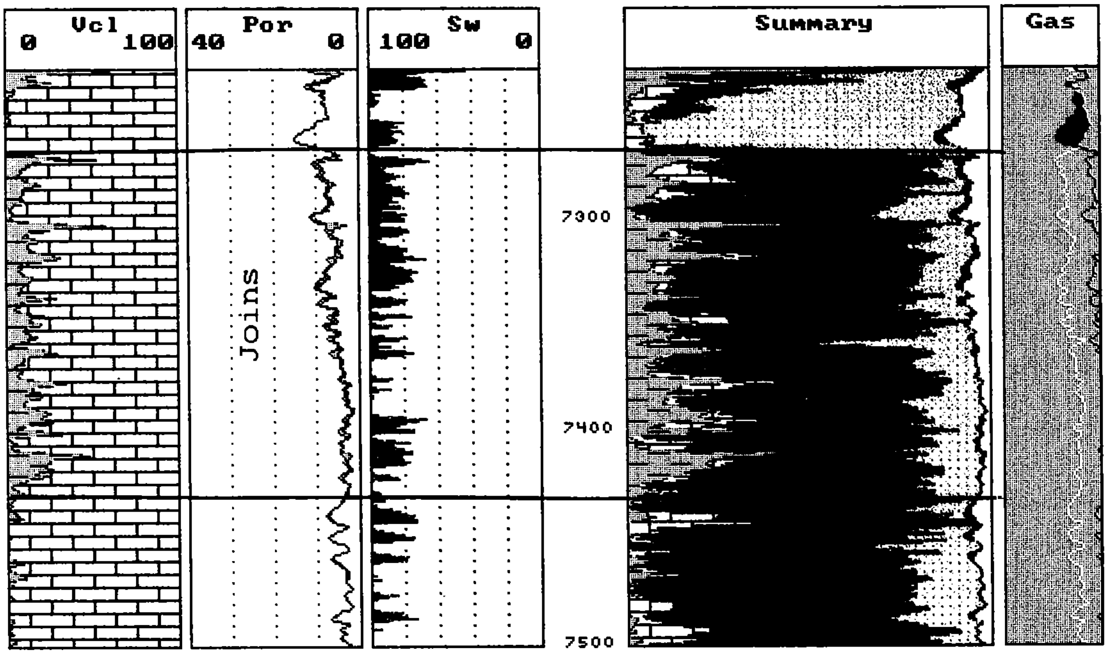


Figure 14. Various electric-log responses observed in the upper Arbuckle–Joins–lower Oil Creek interval in central and southern Oklahoma (modified from Statler, 1965). The cross section extends from T. 9 N., R. 3 W. (left), to T. 6 S., R. 6 E. (right).



No depths meet net pay requirements

Figure 15. Computer-generated log analysis of the upper Arbuckle–Joins–lower Oil Creek interval in the Marjo No. 2–31 Ziegelgruber. The tops of the Joins and Arbuckle are 7,270 and 7,430 ft, respectively (The Logic Group, 1994).

______1992, Early-to-late diagenetic dolomitization of platform carbonates: Lower Ordovician Ellenburger Group, Permian Basin, west Texas: Journal of Sedimentary Petrology, v. 62, p. 131–144.

Archie, G. E., 1952, Classification of carbonate reservoir rocks and petrophysical considerations: American Association of Petroleum Geologists Bulletin, v. 36, p. 278–298.

Cardwell, A. L., 1977, Petroleum source-rock potential of Arbuckle and Ellenburger Groups, southern Mid-Continent, United States: Colorado School of Mines Quarterly, v. 72, no. 3, 134 p.

Cronenwett, C. E., 1956, A subsurface study of the Simpson group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

Decker, C. E., 1952, Faulted graptolite shows Joins Formation deep near Edmond, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 36, p. 409–411.

Decker, C. E.; and Merritt, C. A., 1931, The stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Dietrich, R. F., Jr., 1955, The Simpson group along the north flank of the Anadarko basin: Oklahoma City Geological Society, Shale Shaker, v. 5, no. 7, p. 5–21.

Ford, W. J., 1954, The subsurface geology of southwest Logan County, Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 5, no. 2, p. 5–19, 24, 26–28.

Gatewood, L. E., 1970, Oklahoma City field—anatomy of a giant, *in* Halbouty, M. T. (ed.), Geology of giant petroleum fields—a symposium: American Association of Petroleum Geologists Memoir 14, p. 223–254.

______1978a, Stratigraphic trap possibilities in the Arbuckle Group: general relationships: Oklahoma City Geological Society, Shale Shaker, v. 28, no. 10, p. 219–227.

______1978b, Some Oklahoma Arbuckle production and thoughts on fracturing: Oklahoma City Geological Society, Shale Shaker, v. 29, no. 1, p. 4–11.

______1992, Can carbonates be source rocks for commercial petroleum deposits?, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 270–282.

Ham, W. E. (ed.), 1973, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, 61 p.

Harris, R. W., 1957, Ostracoda of the Simpson group: Oklahoma Geological Survey Bulletin 75, 333 p.

Johnson, K. S. (ed.), 1991, Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, 227 p.

Jones, C. L., Jr., 1960, An isopach, structural, and paleogeologic study of pre-Desmoinesian units in north central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 10, no. 5, p. 2–20.

Logic Group, The, 1994, CBA carbonate advisor [pamphlet]: Austin, Texas, 4 p.

Nelson, R. A., 1985, Geologic analysis of naturally fractured reservoirs (Contributions in petroleum geology and engineering, v. 1): Gulf Publishing, Houston, London, Paris, Tokyo, 320 p.

North American Commission on Stratigraphic Nomenclature, 1983, North American stratigraphic code: American Association of Petroleum Geologists Bulletin, v. 67, p. 841–871.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

Statler, A. T., 1965, Stratigraphy of the Simpson Group in Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 162–211.

Taff, J. A., 1904, Preliminary report on the geology of the Arbuckle and Wichita Mountains in Indian Territory and Oklahoma: U.S. Geological Survey Professional Paper 31, 97 p.

Reservoir Analysis of a Horizontal-Well Completion in the Viola Limestone "Chocolate Brown Zone," Marietta Basin, Oklahoma

Magell P. Candelaria[1]
Consulting Geologist
Midland, Texas

Brian P. Roux[1]
Parker & Parsley Petroleum Company
Midland, Texas

ABSTRACT.—Analysis of Viola well production in the Marietta basin of Jefferson and Carter Counties, Oklahoma, indicates that natural fractures exert a strong control on reservoir performance. A horizontal well was drilled to test fracture susceptibility and productive capacity from the lowermost 100–150 ft of the Viola Limestone, the "chocolate brown zone" (CBZ), in the Marietta basin. The Viola Limestone in the study area is a low-porosity reservoir (2%–3%) with extremely low matrix permeability ($k \cong 0.0001$ md, measured at overburden stress). The reservoir potential of the CBZ is fracture dependent. The structural model developed for southern Oklahoma predicts the existence of regional extension fractures aligned parallel with the maximum-principal-stress orientation. Regional extension fractures originated from far-field regional compressive forces emplaced during regional Late Mississippian to Pennsylvanian tectonism. High secondary-silica content in the CBZ, ranging from 35% to 70%, was conducive to brittle deformation within the largely compressive structural regime. The fractured CBZ is predicted to have significantly enhanced permeability relative to the less well-fractured, nonsiliceous, limestone-matrix lithologies higher in the Viola stratigraphic section.

A horizontal well was drilled at nearly hydrostatic balance and was completed open hole with approximately 1,000 ft of the 3,900 ft of lateral borehole within the fractured CBZ reservoir. The well initially flowed more than 1,200 barrels of oil per day (BOPD) before artificial lift was employed. After the well was placed on the pump, production remained constant at 450 BOPD with no associated water, until the fracture system was depleted. At this time, matrix permeability within inter-fracture regions was inadequate to feed the fracture network and sustain that production rate. Oil production rapidly declined to an uneconomic rate.

Production data from the horizontal test were matched reasonably accurately with a dual-porosity-reservoir simulator, using the specific reservoir properties of the CBZ. Drawdown/buildup test data and bottom-hole flowing pressure versus cumulative oil production were used to calibrate the model to actual well performance. The model was used to predict future performance, gain a better understanding of reservoir performance, and identify reservoir characteristics that are necessary for a successful horizontal Viola play.

The results of the reservoir modeling indicate that the reservoir properties fundamental to a successful Viola horizontal well are fracture spacing, fracture aperture, vertical and lateral fracture extent, and sufficient matrix permeability to sustain fluid flow to the fracture network. Simulator results and production forecasts indicate that the majority of recoverable reserves will be recovered very early in the productive life of a fractured Viola reservoir. Critical elements for making a successful horizontal completion are (1) minimizing pre-drilling expenses, (2) optimizing drilling efficiency while minimizing associated costs, and (3) identifying areas of intensely fractured CBZ reservoir that have both matrix permeability and storage capacity that can be economically exploited by a horizontal well. It is essential to maximize production rate in the first 6–12 months by way of appropriate drilling and completion techniques. Beyond this time frame, the daily rate will likely decline sufficiently to deny attainment of payout or preclude an acceptable economic return.

---

[1] Formerly with ARCO Oil and Gas Company, Midland, Texas. Current addresses: Candelaria—Cross Timbers Oil Company, Fort Worth, Texas; Roux—Citation Oil and Gas Corporation, Houston, Texas.

Candelaria, M. P.; and Roux, B. P., 1997, Reservoir analysis of a horizontal-well completion in the Viola Limestone "chocolate brown zone," Marietta basin, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 183–193.

INTRODUCTION

Stratigraphy and Geologic Setting

The Viola Limestone (Viola Group) of Late Ordovician age (Mankin, 1987; Derby and others, 1991) was deposited in the southern Oklahoma aulacogen (Schatski, 1946; Wickham, 1978) and on the cratonic shelf of the southern Midcontinent. Pennsylvanian tectonism, largely compressional in origin (Dott, 1934; Ham, 1951; Brown, 1984), subdivided the aulacogen into the present-day Marietta basin, Criner uplift, and Ardmore basin, from southwest to northeast, respectively (Fig. 1). The Viola Limestone attains a maximum thickness of approximately 900 ft in the subsurface of the Marietta Basin, though it is slightly thicker (1,070 ft) in the depocenter of the aulacogen (Glaser, 1965). In the Marietta basin, the Viola Limestone unconformably overlies the Bromide Limestone of the upper Simpson Group (Fig. 2) and is conformable(?) with the overlying Upper Ordovician Sylvan Shale (Ham, 1973).

Lithotypes and Depositional Environment

The Viola Limestone crops out in the Arbuckle Mountains and Criner uplift areas of southern Oklahoma. In outcrop, the lower Viola Limestone is described as dense, laminated, cherty lime mudstone/wackestone that locally is argillaceous with a limited biotic assemblage. The Viola Limestone is particularly siliceous in the basal 150–180 ft. Galvin (1983) assigned the lower Viola to a lower carbonate-ramp depositional environment. Lower Viola strata grade progressively upward to more grain-dominated lithotypes characterized by skeletal wackestone, packstone, and grainstone lithologies. The middle and upper Viola contain a more diverse biota and evidence of higher energy depositional processes, reflecting an overall shallowing-upward succession (Ham, 1973). The upper Viola Limestone represents shallow-shelf or upper carbonate-ramp deposition and culminates the upward-shallowing Viola succession from lower- to upper-ramp environments (Galvin, 1983).

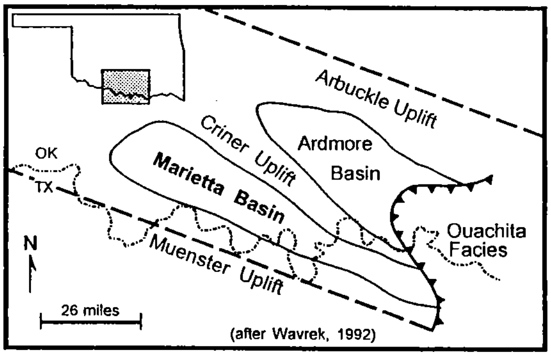


Figure 1. The Marietta basin is a Pennsylvanian-age structural basin in southern Oklahoma between the Muenster and Criner uplifts. The heavy dashed lines indicate the approximate boundary of the southern Oklahoma aulacogen.

Lower Viola "Chocolate Brown Zone"

The basal siliceous unit of the Viola is informally referred to as the "chocolate brown zone" (CBZ), owing to the medium- to dark-brown coloration of this interval, particularly as seen in core samples. In open-hole logs, the CBZ commonly exhibits slightly higher porosity-log response than the overlying Viola section (Fig. 3). The CBZ is also characterized by a high silica content. Silica-rich intervals in outcrop exhibit brittle-deformation tendencies where flexed or folded (Allen, 1983). Microscopic and X-ray-diffraction studies of cuttings from selected wells in the Marietta basin indicate that the CBZ consists of up to 70% secondary silica, occurring in the form of nodules and as disseminated silica replacing primary limestone matrix. The silica is likely derived from the abundant spicules of siliceous sponges endemic to the lower Viola depositional environment (Ham, 1973; Brown and Grayson, 1985). Silica cements occur in at least two generations—as cryptocrystalline and very finely to finely crystalline chalcedony. Both morphologies occur as pore-occluding cements and, as a result, reduce CBZ permeability.

Viola Production

Production from the Viola Limestone is widespread in southern Oklahoma. Viola reservoirs make up a substantial proportion of all Cambro–Ordovician reservoir

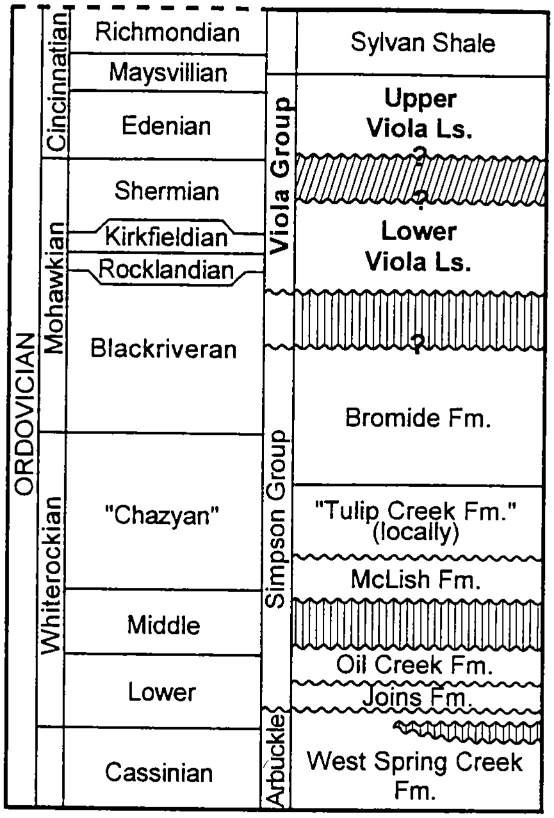


Figure 2. Ordovician stratigraphic chart for the Marietta basin, Oklahoma (modified from Derby and others, 1991).

oil and natural gas in the region. Through the mid to late 1980s, Viola production amounted to roughly 25% of all Cambro–Ordovician oil and gas production in Oklahoma. Cumulative Viola production was second only to cumulative Simpson production during the same period (Johnson, 1991).

Viola production (Fig. 4) peripheral to and within the Marietta basin has been established in numerous fault-bounded and fold structures in Carter and Jefferson Counties. Additionally, karst-enhanced reservoirs below the pre-Pennsylvanian (Springer) unconformity in eastern Jefferson County (Al-Shaieb and others, 1994) have contributed minor production. The average cumulative production is 40,000–60,000 BO from many wells producing longer than 10 years in the Criner uplift and Marietta basin areas. Typical open-hole well-log porosity from the Viola ranges from 2% to 8%, with average values closer to 3% (Fig. 3). Whole-core and plug permeability is low, and unfractured matrix permeability is seldom more than 1.0 md. Commonly, matrix permeability determined from whole core and core plugs is less than 0.01 md (Table 1). Despite these regionally low values of porosity and permeability, several Viola wells in the Marietta basin have cumulative production exceeding 300,000 BO each, and many Viola wells report initial potentials of 500–1,000 BOPD. It is noteworthy, however, that these prolific initial rates are seldom maintained for more than a few days or weeks at most, before production declines significantly and rapidly to a few tens of barrels of oil per day, after which production declines further at a slower but steady rate.

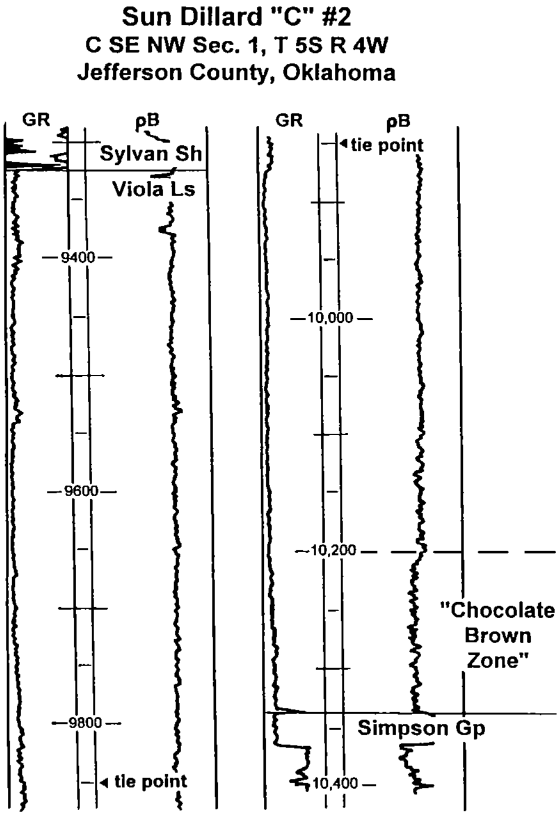


Figure 3. Type log for the Viola Limestone in the vicinity of the Seagull No. 1–12 Bigbie horizontal exploratory well drilled in the Marietta basin. Note the subtle density-log-character change in the "chocolate brown zone" relative to the younger Viola section.

Fracture-Enhanced Production

A common observation in outcrops and cores is evidence of fracturing related to epeirogenic uplift and regional tectonism, beginning perhaps as early as pre-Sylvan time (Al-Shaieb and others, 1994). Brittle lithologies fracture in response to induced stress more readily than do ductile lithologies. Fold-related fractures, readily observed in outcrop within the Arbuckle Mountains, occur in various lithologies and formations (Arbuckle Group, Viola Group limestone, Hunton Group limestone, Woodford Shale, and Sycamore Limestone). Regional and local origination of natural fractures in brittle lithologies enhances the poor reservoir-fluid conductivity of otherwise low-permeability strata (Elkins and Skov, 1960; Lorenz and Finley, 1989). Many occurrences of fractured reservoirs on anticlinal structures were described by Stearns and Friedman (1972) and Nelson (1985).

Well peformance and significant oil recovery from a number of Viola completions in the Marietta basin suggest fracture influence in regionally low-porosity–low-permeability lithologies. Fracture-influenced production from low-permeability reservoirs in Arbuckle, Hunton, and Sycamore limestones has long been recognized by the industry in Oklahoma. These low-permeability reservoirs serve as analogs for similar reservoir properties and behavior in the Viola and other formations in the southern Oklahoma region.

REGIONAL GEOLOGIC MODEL

General

The regional geologic model for southern Oklahoma incorporated in this study is one based on a largely compressional structural regime initially emplaced in Late Mississippian time (Brown and Grayson, 1985). Southern Oklahoma experienced southwest- to northeast-directed compression (Dott, 1934; Ham, 1951; Brown, 1984) related to the tectonic suturing of Gondwana to Laurasia at this time. Regional compression persisted and was episodically active throughout the Pennsylvanian Period, reactivating and inverting older structural elements of the southern Oklahoma aulacogen (Ham, 1951, 1973). The regional compressive regime set up the northwest-trending positive structural elements and intervening basins of the southern Oklahoma region (Fig. 1).

Fracture Model

The regional structural model predicts establishment of a far-field regional compressive regime capable of inducing regional extension fractures (Lorenz and others, 1991). In this model, regional extension fractures arising from far-field regional compression would be unidirectional and oriented southwest to northeast, parallel to the maximum principal horizontal stress, σ_1.

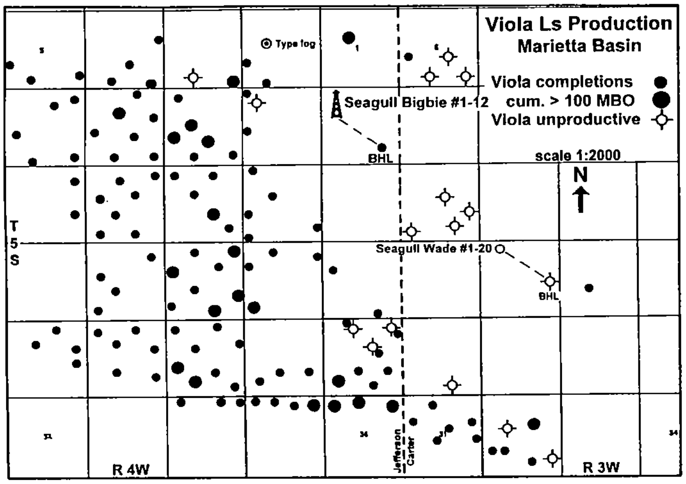


Figure 4. Viola production map for a part of the Marietta basin in Jefferson and Carter Counties, Oklahoma. The type-log well and the No. 1–12 Bigbie well locations are shown.

Regional extension-fracture systems may persist in orientation and lateral continuity across areas of up to hundreds of square miles (Stearns and Friedman, 1972). Regional extension fractures form very early in the compressional event and exhibit very little offset, as they are not load bearing (Lorenz and others, 1991). Moreover, regional extension fractures form at stress levels lower than those required for formation of conjugate shear-fracture pairs (Gramberg, 1965). Thus, a lack of visible offset of strata cannot be used as negative evidence against regional extension-fracture development.

Rock-mechanics studies demonstrate that extension fractures propagate parallel to σ_1 (Gramberg, 1965, 1989; Holzhausen and Johnson, 1979) and, as a result, display a fracture aperture normal to σ_1, or parallel to σ_3 (least principal stress) (Fig. 5). If largely unmineralized and therefore permeable, a fracture system can introduce significant permeability anisotropy to reservoir fluids. Permeability anisotropy as great as 1,000:1 has been documented from the fracture system in the Spraberry reservoir trend in the Midland basin of west Texas (Elkins and Skov, 1960). Extension fractures should remain open and permeable as long as the following two conditions are met: (1) that unidirectional, regional compressive stress is maintained parallel to the regional-extension fracture system; and (2) that fractures do not become completely occluded by mineralization through the course of burial history. If these criteria are met, then reservoir-permeability enhancement by fracturing can establish commercially exploitable permeability in otherwise nonproductive lithologies (Lorenz and Finley, 1989).

Implications for Fractured-Reservoir Development

As previously discussed, the CBZ is silica rich, bearing up to 70% combined primary-biogenic and secondary-replacement silica. Silica enrichment has rendered the CBZ more susceptible to brittle deformation where stressed beyond the mineralogy's elastic limit. The above-described regional structural model for the Marietta basin suggests that the CBZ may be a favorable interval for fracture enhancement of very low matrix permeability. It was reasoned that if fracture development is sufficient to interconnect a substantial reservoir volume that is charged with hydrocarbons, the fracture network could be economically exploited with suitably placed horizontal wells.

TABLE 1.—RESERVOIR PROPERTIES OF THE VIOLA LIMESTONE "CHOCOLATE BROWN ZONE" IN THE MARIETTA BASIN

Fracture porosity	0.0010 – 0.0043%
Matrix porosity	0.022%
Fracture permeability, *X* direction	0.24 – 2232 md
Fracture permeability, *Y* direction	0.24 – 2232 md
Fracture permeability, *Z* direction	0.48 – 4464 md
Matrix permeability, *X* direction	0.0001 md
Matrix permeability, *Y* direction	0.0001 md
Matrix permeability, *Z* direction	0.0000 md
Shape factor	0.120 – 2.191 1/ft
Initial pressure	4195 psia
Bubblepoint pressure	951 psia
Matrix water saturation	0.40
Matrix irreducible water saturation	0.40
Matrix critical gas saturation	0.006
Formation thickness	150 ft
Effective well-bore length	1000 ft
Fracture swarm height	150 ft
Fracture swarm half-length	660 – 1490 ft

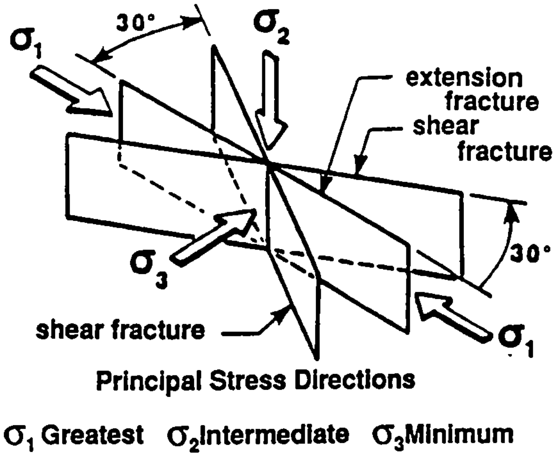


Figure 5. Orthogonal stress fracture model for the origin of regional extension fractures arising from far-field regional compression as described by Lorenz and others (1991).

Fractured-Reservoir Properties

Critical to successful exploitation of a fractured reservoir is knowledge of the elements necessary to the formation of a producible fracture system. Several recent studies have discussed these issues (Lorenz and others, 1991; Teufel and Lorenz, 1992; Weber and Freyer, 1992; Cadenhead and others, 1994; Hurley and others, 1994; Candelaria and Roux, 1994). The more significant elements relevant to the Viola CBZ include the following: (1) a compressional tectonic-stress regime established a regional extensional-fracture system; (2) fractures propagate parallel to maximum compressive horizontal stress (σ_1) and form early during deformation; they do not relieve significant stress, and therefore are typically regional in extent; (3) fractures commonly terminate at interfaces with more ductile lithologies, such as shale interbeds; (4) fractures are more common in brittle or semi-brittle lithologies and have greater frequency of occurrence (more closely spaced) in thinner bedded intervals; (5) fractures can provide substantial sustained fluid-flow rates; (6) fracture permeability increases as a function of the cube of fracture aperture; and (7) microfractures may induce significant local permeability.

Rationale for a Horizontal Exploration Well

The rationale used to justify drilling a horizontal exploratory well to evaluate reservoir potential of the Viola CBZ includes the following:

- The Viola Limestone contains an average 2.4% total organic carbon (TOC; oil-prone kerogen) and is potentially a self-sourcing reservoir characterized by low porosity and very low permeability.
- Regional compression-induced extension fractures are present parallel to the maximum principal stress direction, σ_1; such a Viola fracture play may be regional in extent.
- The CBZ contains up to 70% silica, and thus is brittle and more fracture prone than "clean" limestone elsewhere in the stratigraphic section.
- Viola production from numerous nearby fields is strongly influenced by natural fractures; several wells have cumulative production exceeding 300,000 BO.
- The CBZ reservoir is at moderate drill depths (7,000–10,000 ft); one horizontal well with a 4,000-ft lateral borehole could potentially drain 640 acres (1 mi^2).

Using the above rationale as part of the justification for drilling an exploratory horizontal well, the Seagull No. 1–12 Bigbie was drilled by Seagull Exploration, ARCO Oil and Gas, and other partners late in 1992.

Exploration Well

The Seagull No. 1–12 Bigbie well was drilled in the SW¼NW¼ sec. 12, T. 5 S., R. 3 W., Jefferson County, Oklahoma. The location is on the synclinal axis of the Marietta basin, as shown in Figure 6. The Bigbie well was drilled to the top of the Viola, where intermediate casing was set. The well entered the CBZ with a borehole azimuth of N. 130° E. after a medium radius turn. A lateral borehole of 3,900 ft was then drilled to a bottom-hole location in the SE¼SE¼ sec. 12. The well encountered numerous open fractures in the first 1,000 ft of the lateral, as identified on the micro-resistivity imaging log. Fewer, more widely spaced fractures were identified on the imaging log in the remaining portion of the lateral. The well was completed open hole for a flowing initial potential of over 1,200 BOPD, with no associated water.

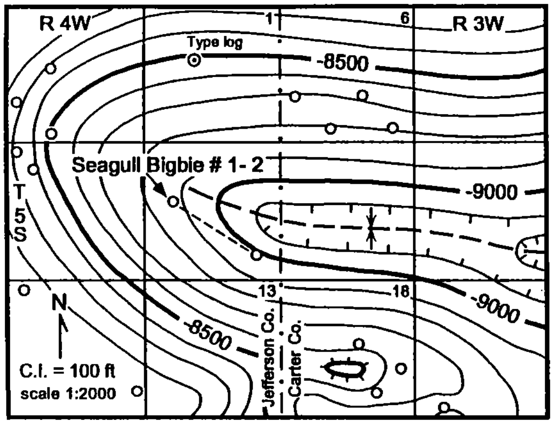


Figure 6. Top of Viola structure map for a part of the Marietta basin in Jefferson and Carter Counties, Oklahoma. The Seagull No. 1–12 Bigbie horizontal well is located along the synclinal axis of the basin in sec. 12, T. 5 S., R. 4 W.

Well Performance

The early production history of the No. 1–12 Bigbie horizontal completion, spanning the first 5 months of production is summarized in Figure 7. The high initial-potential-flow rate is attributable to "flush" production from the fracture system, which rapidly declined over a period of nearly 2 months until it ceased to flow. Production during the first 2 months was erratic, because of numerous short-term fluctuations in the ability of the reservoir to flow consistently at a high sustained rate. After the well ceased to flow, it was placed on high-capacity artificial lift. Production increased immediately to 700 BOPD for several days before declining. Production decline continued until it stabilized at roughly 450 BOPD after 7 weeks on pump (Fig. 7). The well continued to produce on pump at a constant 450 BOPD, water free, for nearly 2 months before production declined significantly. Cumulative production

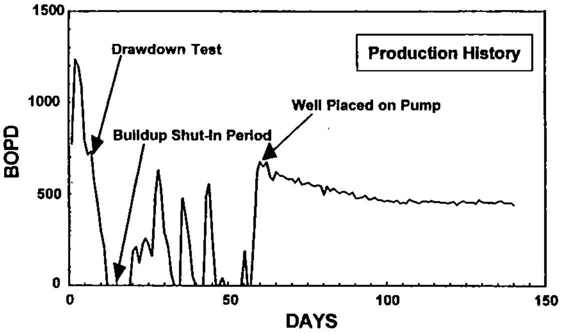


Figure 7. Early production history of the Seagull No. 1–12 Bigbie horizontal-well open-hole completion. Note the high initial rate of flow and subsequent rapid decline, typical of most completions in fractured Viola reservoirs.

at this time was approximately 90,000 BO, recovered in less than 5 months' time.

RESERVOIR MODELING

Introduction

During the first 2 months of production, various production-test data were acquired for input to a reservoir simulator to assist with modeling, reservoir-performance analysis, and production forecasts. These interpretations were used to assist determination of play viability, future development plans, and well and project economics. In addition, reservoir-performance analysis was used to guide stepout direction and timing, given existing lease considerations.

Reservoir and fracture characteristics for the Viola CBZ are listed in Table 1. Core-derived measurements for CBZ matrix porosity and permeability are from an offset horizontal well, the Seagull No. 1–20 Wade, drilled soon after the Bigbie completion in sec. 20, T. 5 S., R. 3 W., Carter County. The Wade well is less than 3 mi southeast of the Bigbie surface location (Fig. 4). The Bigbie well fracture porosity and apertures, and calculated fracture permeabilities, were derived from the micro-resistivity imaging log, the only open-hole log run in the lateral borehole of the Bigbie well.

Production-Test Results

Various production tests were conducted to assist reservoir modeling of the CBZ. Essential reservoir performance and production data were derived from a drawdown/buildup test run within days after open-hole completion. These data were used to determine the extent of the fracture system. Values for fracture porosity, permeability, and shape factor were obtained from interpretation of the micro-resistivity imaging log. These data, integrated with early production performance and physical properties of the reservoir as measured in the CBZ core from the No. 1–20 Wade well, provided the data necessary to evaluate future well performance and to project expected ultimate recovery through reservoir modeling.

Spinner/Temperature-Survey Results

Production data collected include spinner and temperature surveys to determine the spatial distribution of fractures contributing to production. Accurate reservoir characterization depends on determination of the distribution of fractured-reservoir permeability (Belfield, 1988). Moreover, determination of reservoir volume for reserves and drawdown calculations is highly dependent on fracture distribution. Results of the spinner and temperature surveys indicate that only the first 1,000 ft of the lateral borehole was contributing fluid to the well bore. The balance of the borehole had no permeability and was devoid of moveable hydrocarbons. The micro-resistivity imaging log indicated that fractures are present in this section of the borehole; however, these fractures apparently were annealed with various cements, as they produced no reservoir fluid and were essentially impermeable. These data indicate that nearly three-fourths of the lateral well bore penetrated unproductive Viola Limestone.

Examination of formation dips derived from the micro-resistivity imaging log revealed that beyond the first 1,000 ft of the lateral well bore, the well began to climb up-section relative to stratigraphic dip. Since the well bore was drilled at a constant angle relative to the horizon, this was interpreted to reflect an unexpected increase in reservoir dip angle. Hence, after roughly 1,000 ft of lateral drilling, the borehole drifted out of the CBZ and continued drilling into the overlying Viola Limestone, which is mineralogically different from the CBZ (silica poor) and contains fewer fractures. Also, with increasing lateral distance, the trace of the well bore deviated farther from the synclinal axis of the basin and away from flexure-related fractures that may be present along the synclinal axis. Thus, fewer fold-related fractures were encountered, and the fractures present were pervasively mineralized and impermeable, as revealed by the spinner surveys, which indicated no fluid entry from these fractures. Cadenhead and others (1994) recently reported this occurrence as commonplace in horizontal wells drilled along inferred fracture trends and fold axes. Deviation from the actual fracture-prone region results in drilling unfractured, unproductive rock and leads to many dry holes, or to poorer horizontal-well results than anticipated (Cadenhead and others, 1994; Hurley and others, 1994).

Fractured-Reservoir Model

The reservoir-modeling description that follows (Candelaria and Roux, 1994) is based on reservoir performance through only the first 5 months of production. No production data, pressure data, or other well-performance information has been incorporated into this analysis beyond the initial 5-month period in the productive life of the No. 1–20 Bigbie well.

A dual-porosity reservoir simulator was used to model reservoir characteristics and performance. The simulator was used in the mixed mode, in which the dual-porosity features of the simulator were used to account for flow in the fracture swarms consisting of both fracture and matrix porosity. Nonfractured regions of the CBZ were treated in the model as a single (matrix) porosity system characterized by very low permeability. The reservoir was modeled by using the various data shown in Table 1. The modeled reservoir volume in X, Y, and Z space had dimensions of 2,640 × 1,000 × 150 ft, respectively. A fundamental assumption in the model was that fracture swarms identified on the micro-resistivity log were interpreted to propagate through the entire height of the CBZ reservoir but not into the overlying Viola section. Thus, vertical fractures were input as having 150 ft of extent. The Y direction in the model was oriented parallel to the horizontal well bore (normal to σ_1 and normal to the anticipated extensional-fracture orientation). The X dimension was oriented normal to Y (parallel to σ_1, and the Z direction was oriented vertically, normal to bedding. The reservoir volume that was modeled represents 50% of a symmetrical well reservoir volume; the results were doubled to determine ultimate recovery for the complete reservoir volume drained by the well.

Model Calibration

Early production-history data at the time of modeling are shown in Figure 7. These data were used as input for the model. A reasonable match was obtained when calibrating the model against actual drawdown/buildup test results (Fig. 8). While the match is not ideal, it does capture the essential characteristics of the pressure-test data. Two model cases were run, model A and model B. Model B differs from model A only in that oil viscosity was reduced approximately 40% relative to model A, and model A yields a slightly better match to actual drawdown/buildup test data.

Also matched during early model calibration was bottom-hole flowing pressure versus cumulative production (Fig. 9). This comparison demonstrates a reasonable match between the model and the characteristics observed from production data. For the production forecast, it was assumed that the well would continue to produce on pump at a steady 450 BOPD until a bottom-hole flowing pressure limit of approximately 200 PSIG (pounds per square in., gauge) is attained. At this limit, the production rate will begin to decline, analogous to observed offset production declines for wells with similar reservoir properties and fracture characteristics. The production rate will decline until a limit is reached that is constrained by reservoir properties, principally the capacity of matrix permeability to supply oil to the fracture system and then to the borehole.

Production Forecasts

Actual well production, along with 20-year production forecasts for both models A and B, is shown in Figure 10. These forecasts were created with the understanding that all the input data for the model were accurate. This aspect of the modeling involves basic assumptions regarding inferred fracture continuity in three dimensions that are difficut to quantify but are particularly critical to model results. The production forecasts of Figure 10 indicate that the well should maintain a production rate of 450 BOPD for roughly 9 months after it has been placed on artificial lift. After this period, the model predicts that reservoir performance will decline rapidly to a rate sustainable by reservoir-matrix permeability, as mentioned previously. This rate may not be economic; thus, the value of predicting future performance by means of reservoir modeling becomes obvious for evaluation of fractured reservoirs. Moreover, reservoir modeling before exploratory drilling commences can be of great value and can be influential in the decision whether or not to proceed with the fractured-reservoir play. This decision may rely heavily upon results of pre-drilling reservoir modeling, which utilizes all the available production and fractured-reservoir-properties data.

Production-performance analysis can be a critical aspect of play evaluation for fractured reservoirs. A significant percentage of current Viola producers exhibits a flat production rate for a period of time, followed by precipitous declines, as shown in Figure 10. However, many Viola completions exhibit a production history that makes it appear as if the production rate is limited

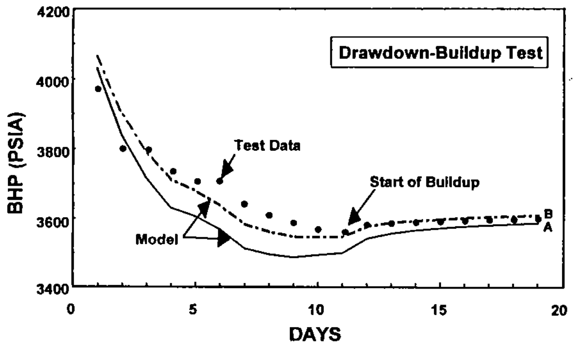


Figure 8. Calibration of a dual-porosity simulator with drawdown/buildup bottom-hole-pressure data. The use of two different equations of state (EOS), generated from oil-viscosity tables, produced models A and B. EOS oil viscosity is 40% less in model B than in model A, which yielded a slightly better match to the pressure data at this time. The calibration resulted in a reasonable match between the model and actual production data.

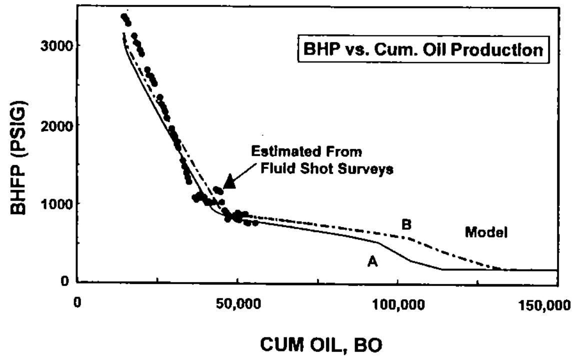


Figure 9. History match of the model with bottom-hole flowing-pressure data estimated from fluid-shot surveys as a function of cumulative oil. Though not perfect, the match captures all the salient characteristics of the production data and substantiates the validity of the model.

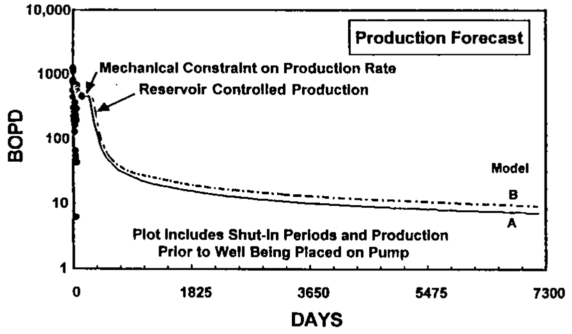


Figure 10. Semi-log plot showing actual and forecast production data over a projected 20-year life. Typical Viola reservoir behavior is shown in this plot by rapid decline after a short period of a relatively constant production rate. This behavior indicates that 50%–70% of recoverable reserves will be produced very early in the life of a fractured Viola reservoir completion.

by mechanical constraints, as opposed to being limited purely by reservoir properties. Mechanical constraints may include tubing-size, pump-capacity, or surface-facilities limitations (Gilman and Jargon, 1992). In rate-constrained wells, production history demonstrates a nearly flat-rate production for an extended period (up to 2–3 years in some cases) before experiencing a typical rapid decline. Flat-rate production for an extended period is atypical for Viola completions in the Marietta basin. Viola wells in this region normally exhibit a rapid decline within a few weeks or, at most, within a month or two after original completion. In some cases, wells displaying anomalous production behavior appear to have produced at a constant rate of 150–200 BOPD for several years, before declining to 10–20 BOPD within 1 year, followed by a subsequent decline at a more shallow rate. The Bigbie well-production history, which exhibits a typical Viola high initial potential followed by a rapid decline, coupled with production forecasts as shown in Figure 10, indicates that the model is capturing the salient characteristics of typical fracture-influenced Viola production.

Reservoir Performance

The production curve shown in Figure 10 emphasizes the typical reservoir performance of conventional vertical Viola completions, which may or may not include the CBZ within the net pay. This plot has great significance relative to expected Viola reservoir performance. It indicates that over 50% of all producible oil reserves will be recovered very early in the life of a typical Viola completion. Owing to the rapid recovery of "flush" production from fracture systems, and the characteristically low matrix permeability of Viola reservoirs, our model predicts that 50%–70% of the recoverable reserves likely will be produced in the first 1–2 years of a fractured Viola reservoir completion.

Based on the match of Bigbie production to the model, reserves for the well are estimated to be in the 220,000–270,000-BO range (Fig. 10). Again, this projected ultimate recovery is based on the premise that all input data accurately reflect reservoir properties and fracture characteristics. Input to the simulator of any factor or combination of properties that is poorly quantified renders the accuracy of the production forecasts unreliable. One such reservoir property that is poorly quantified is fracture porosity. Weber and Freyer (1992) report that fracture porosity is commonly overestimated by a factor of 10 and that fracture porosity rarely exceeds 2%. Overestimation of fracture porosity can lead to inaccurate calculation of recoverable fluid volume, as reported in the modeling study by Cline and Tiab (1994). Fracture porosity on the order of 0.01% can sustain production rates of several thousand barrels per day, owing to associated fracture permeability (Weber and Freyer, 1992). Thus, the use of accurate reservoir-property quantification cannot be overstressed in reservoir modeling (Gilman and Jargon, 1992).

Production-Forecast Sensitivity

As a further step in the modeling process, to assist with development planning and economic evaluation, several cases were run to determine projected ultimate-recovery sensitivities to changes in various reservoir parameters. The greatest impact occurred when the effective well-bore length, the *Y* dimension in the model, was increased by a factor of 2. The *Y* dimension, oriented normal to fracture azimuth, was set equal to 2,000 ft, versus 1,000 ft used in the original model. This would be equivalent to an additional 1,000 ft of well bore within the CBZ, and that the borehole would encounter the same fracture properties and matrix characteristics as found in the productive 1,000 ft of the lateral borehole. As expected, doubling the effective well-bore length essentially doubled the calculated recoverable reserves. The projected ultimate recovery demonstrated far less sensitivity to all other reasonable reservoir-property variations.

Comparison of Production Data with Model Forecasts

A plot of bottom-hole flowing pressure (BHFP) and gas/oil ratio (GOR) versus cumulative oil is shown in Figure 11. Also shown in Figure 11 is the cumulative-production forecast for reservoir model A. This plot includes original production data used to calibrate the model (circles), plus additional production data (triangles) acquired after calibration of the model was completed. The production data correspond to the model fairly well up to the rapid excursion of actual GOR from the model GOR at a cumulative production of roughly 90,000 BO. Figure 12 is a plot of cumulative production compared to the forecast from the model. Again, the production data match the model very well until cumulative production of roughly 90,000 BO was reached, at which time production dropped sharply from the model projection. Deviation from the model in both figures is attributable to inaccurate characterization of the fracture system in the model.

Deviation from Model Projections

An explanation for deviation of actual data from model projections in Figures 11 and 12 is that the reservoir model likely incorporated greater extension-frac-

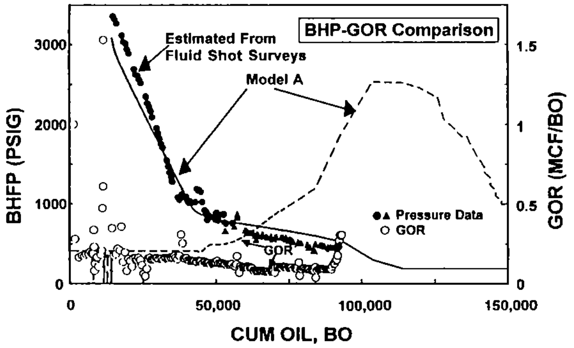


Figure 11. Combined plot of bottom-hole flowing pressure and GOR, versus cumulative oil, with overlay of cumulative-production-forecast curve from model A, shown for comparison. Actual production data in the form of bottom-hole flowing pressure match the model A forecast reasonably well, up to cumulative production of roughly 90,000 BO, when the GOR deviated radically from its previous trend. At this point, the well effectively "gassed out" and ceased oil production.

ture continuity (*X* dimension parameter), and/or less vertical-fracture continuity (*Z* dimension parameter) than exists. The significance of the earlier statement, regarding basic assumptions about poorly constrained or quantified fracture extent in three dimensions, now becomes readily apparent. Reservoir simulators provide the most reliable means for horizontal-well-performance analysis, yet reservoir description utilizing semiquantitative data for loosely constrained geological parameters is the limiting factor in the accurate prediction of future reservoir performance (Gilman and Jargon, 1992).

In retrospect, model input for fracture continuity in the *X* dimension, which lies in the plane of the CBZ reservoir, should have been decreased, and/or vertical-fracture continuity out of the CBZ in the *Z* dimension should have been increased. Either of these modifications would have calculated a value closer to actual ultimate recovery than the original projection, as Bigbie well production declined to an uneconomic rate at roughly 90,000 BO cumulative recovery, far short of the projected 220,000–270,000 BO predicted by the model. Less fracture extent in the CBZ reservoir would decrease recovery volume, because recovery is proportional to reservoir volume. Increased fracture height would predict the contribution of some fraction of total fluid recovery from the reservoir volume, which would include the Viola section above the CBZ. However, offset core data indicate minimal matrix-storage capacity and very low matrix permeability in the overlying Viola Limestone. The imaging log demonstrated this section to be poorly fractured; hence, this interval is essentially impermeable and devoid of mobile fluids. Thus, recovery would be diminished if vertical fractures extend into the overlying Viola Limestone, because this portion of the reservoir volume would be nonproductive. With one or both of these modifications to the model, projected recovery would likely be much closer to actual recovery from the CBZ.

SUMMARY AND CONCLUSIONS

A largely compressional regional structural model developed for the Marietta basin of southern Oklahoma predicts that regional extension fractures will be developed in the more fracture-prone lithologies in the subsurface. In the Viola "chocolate brown zone" (CBZ), the existence of unidirectional fractures, and their orientation consistent with model predictions (parallel to paleoprincipal stress direction), were identified on wireline micro-resistivity imaging logs and in Viola cores from the horizontal borehole section of the offset well, Seagull No. 1–20 Wade. The macrofractures encountered range from unmineralized and permeable to mineral occluded and impermeable. The contribution of fractures below the limit of resolution of current borehole-imaging tools cannot be discounted as a source of enhanced reservoir permeability (N. F. Hurley, personal communication). Fractures on a scale of micrometer (μm) width (incipient fractures of Belfield, 1988) may induce local, but substantial, reservoir permeability anisotropy. Though lacking significant lateral or vertical continuity, incipient fractures can influence production on a well-to-well scale (Belfield, 1988). Unmineralized fractures that are "propped" open by the *in situ* stress regime remain highly permeable to reservoir fluids and impose significant reservoir permeability anisotropy. This fracture system contains recoverable hydrocarbons and facilitates improved recovery of hydrocarbons stored in a low-permeability matrix that can be commercially exploited through selectively placed, and appropriately drilled and completed, horizontal wells (Gonzalez, 1997).

In the Viola horizontal-well exploration play, drill-site selection should be based on identification of the most intensely fractured or fracture-prone stratigraphic interval and geographic locality. Drill-site selection based on these geologic and petrophysical criteria should provide the greatest opportunity for establishment of commercial production in the Viola CBZ. A favorable stress regime, to induce a closely spaced fracture system or to prop open an existing fracture network, in addition to a favorable burial history, is needed to establish commercial production from the CBZ. Reservoir modeling can provide the expected range of ultimate recovery from fractured Viola Limestone reservoirs, given reasonable limits on the input data. The pre-drilling prediction of expected recovery volumes is recommended as a critical part of the horizontal-well exploration strategy, owing to the large inherent risk associated with fractured reservoirs. This evaluation may preclude the need for large-scale leasehold acquisition and significant capital expenditure where they are unjustified because of unfavorable reservoir properties.

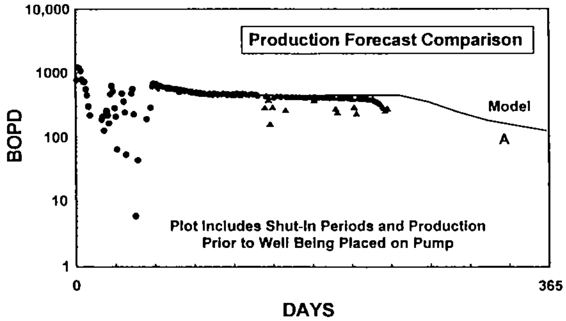


Figure 12. Comparison of model A oil-production forecast with production data used to calibrate the model (circles) and additional data obtained after calibration was completed (triangles). The model matched actual production data reasonably well, until cumulative production of roughly 90,000 BO was reached, at which time production declined significantly.

Reservoir and Production Characteristics

A comprehensive understanding of reservoir-interval petrophysical properties, and the origin, distribution, and nature of fractures, is essential to economic exploitation of fractured Viola reservoirs. Reservoir and production characteristics of the CBZ were described by Candelaria and Roux (1994) and are summarized as follows:

- Matrix permeability within the CBZ is very low (<0.001 md, at overburden stress). As a result, fluid conductivity through the reservoir matrix is minimal, and production is strongly dependent on fracture permeability.

- Fractured-reservoir production is largely controlled by two components of the fracture system: swarm volume and fracture spacing. Low fracture-swarm density and relatively widely spaced fractures generally will not be conducive to hydrocarbon migration from within micropores of the tight matrix to the adjacent fracture-permeability pathway and to the well bore in an economic time frame.
- Fracture geometry, determined from drawdown/buildup tests, imaging logs, and core, is a critical factor for ultimate recovery. Fracture height within the CBZ is more important than length, because recovery is directly proportional to fracture height.
- Ductile interbeds will severely impede vertical-fracture propagation through the reservoir interval. Brittle, thin-bedded, homolithic reservoirs are the best candidates for development of numerous closely spaced fractures.
- In general, Viola production is characterized by delivery at high initial rates, owing to depletion of fractures, followed by rapid decline (as a result of low matrix permeability feeding the fracture system). Given some degree of matrix permeability, production will level out at a rate that is sustainable by the interfracture reservoir cell blocks. This sustained rate may not be economic, depending on up-front expenses and drilling and completion costs.
- Fracture-permeability anisotropy may develop adjacent to faults or along flexural or fold axes, but it may vary in orientation at different places relative to the fold or fault; reservoir performance will be governed by the most permeable fracture set, irrespective of origin.

Lorenz and others (1991) stated that it has been widely recognized that many oil reservoirs exhibit permeability anisotropy, as evidenced from production data, water-flood performance, and well-interference tests. They document various lines of evidence supporting their view that the role played by regional fractures, particularly regional extension fractures, in establishing reservoir anisotropy is greater than currently recognized. It is their contention that this role has been widely underappreciated by the petroleum industry to date. We advocate that through appropriate geological and petrophysical data collection and interpretation, regional fractures can be predicted in the subsurface, accurately modeled, and economically exploited, utilizing appropriate technology. It is imperative to gather as much information as possible, and to develop a comprehensive understanding of all the factors—geologic, petrophysical, and engineering—that affect the range of expected reservoir performance, since exploitation of fractured reservoirs carries a significant element of associated risk in both exploration and development programs. However, when adequately quantified and risk-weighted, fractured reservoirs can be successfully and economically developed, and, furthermore, they constitute an underexploited exploration domain.

ACKNOWLEDGMENTS

This study is based on the results of work conducted while both authors were at ARCO Oil and Gas Co. This manuscript was reviewed by Neil Hurley at Marathon Oil Co.'s research laboratory, and by Christy Reed at ARCO International Oil and Gas Co. Their input greatly improved the organization and content. We want to express our appreciation to Seagull Mid-South, Inc., a subsidiary of Seagull Energy Corp., and to ARCO Oil and Gas Co. for permission to publish these data. In particular, we want to thank Gary Boland, at Seagull, for his support and contribution of data that made this study possible. Drafting services were provided by Margaret Schmidt, at Aqua Graphics in Midland, Texas.

REFERENCES CITED

Allen, G. D., 1983, Petroleum potential of the Viola Limestone, Marietta Basin, Oklahoma: Baylor University unpublished M.S. thesis, 182 p.

Belfield, W. C., 1988, Characterization of a naturally fractured carbonate reservoir: Lisburne field, Prudhoe Bay, Alaska: Society of Petroleum Engineers Paper 18174, 63d Annual Technical Conference and Exhibition, p. 677–685.

Brown, W. G., 1984, Washita Valley fault system: a new look at an old fault, *in* Borger, J. G., III (ed.), Technical Proceedings of American Association of Petroleum Geologists, Mid-Continent Section, 1981 regional meeting: Oklahoma City Geological Society, p. 68–80.

Brown, W. G.; and Grayson, R. C. (eds.), 1985, Tectonism and sedimentation in the Arbuckle Mountain region, southern Oklahoma aulacogen: Baylor Geological Society, Waco, Texas, 43 p.

Cadenhead, John; Grace, Mike; and Newberry, Bill, 1994, Production potential evaluation of tectonically enhanced fracture systems from electrical images [abstract]: American Association of Petroleum Geologists Annual Convention Program with Abstracts, v. 3, p. 114.

Candelaria, M. P.; and Roux, B. P., 1994, Reservoir model of fractured Viola Limestone in a horizontal well completion, Marietta basin, Oklahoma, *in* Gibbs, J. F. (ed.), Synergy equals energy, 1994 symposium: West Texas Geological Society Publication 94-94, p. 39–56.

Cline, S. B., and Tiab, D., 1994, Quantification of the relative importance of fracture and matrix flow units to reservoir storage capacity and transmissibility: Society of Petroleum Engineers Paper 27716, Permian Basin Oil and Gas Recovery Conference, p. 775–790.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle, and Simpson Groups, Cambrian and Ordovician, Oklahoma: a review of correlation tools and techniques available to the explorationist, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Dott, R. H., 1934, Overthrusting in Arbuckle Mountains, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 18, p. 567–602.

Elkins, L. F.; and Skov, A. M., 1960, Determination of fracture orientation from pressure interference: Petroleum Transactions, American Institute of Mining Engineers, v. 219, p. 301–304.

Galvin, P. K., 1983, Deep-to-shallow carbonate ramp transition in Viola Limestone (Ordovician), southwest Arbuckle Mountains, Oklahoma [abstract]: American Association of Petroleum Geologists Bulletin, v. 63, p. 466–467.

Gilman, J. R.; and Jargon, J. R., 1992, Evaluating horizontal vs. vertical well performance: World Oil, April 1992, p. 67–72.

Glaser, G. C., 1965, Lithostratigraphy and carbonate petrology of the Viola Group (Ordovician), Arbuckle Mountains, south-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 197 p.

Gonzalez, C. M., 1997, Viola fractures—friend or foe?, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 76–77.

Gramberg, J., 1965, Axial cleavage fracturing, a significant process in mining and geology: Engineering Geology, v. 1, p. 31–72.

_____1989, A non-conventional look at rock mechanics and fracture mechanics: Balkema, Rotterdam, 256 p.

Ham, W. E., 1951, Structural geology of the southern Arbuckle Mountains: Tulsa Geological Society Digest, v. 19, p. 68–71.

_____1973, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, 61 p.

Holzhausen, G. R.; and Johnson, A. M., 1979, Analyses of longitudinal splitting of uniaxially compressed rock cylinders: International Journal of Mechanics, Mining Science and Geomechanics, Abstracts, v. 16, p. 163–177.

Hurley, N. F.; Thorn, D. R.; Carlson, J. L.; and Eichelberger, S. L. W., 1994, Using borehole images for target zone evaluation in horizontal wells: American Association of Petroleum Geologists Bulletin, v. 78, p. 238–246.

Johnson, K. S., 1991, Geologic overview and economic importance of Late Cambrian and Ordovician rocks in Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 3–14.

Lorenz, J. C.; and Finley, S. J., 1989, Differences in fracture characteristics and related production: Mesaverde Formation, northwestern Colorado: Society of Petroleum Engineers Formation Evaluation, v. 4, p. 11–16.

Lorenz, J. C.; Teufel, L. W.; and Warpinski, N. R., 1991, Regional fractures I: A mechanism for the formation of regional fractures at depth in flat-lying reservoirs: American Association of Petroleum Geologists Bulletin, v. 75, p. 1714–1737.

Mankin, C. J. (coordinator), 1987, Texas–Oklahoma tectonic region: American Association of Petroleum Geologists, Correlation of Stratigraphic Units in North America, 1 sheet.

Nelson, R. A., 1985, Geologic analysis of naturally fractured reservoirs: Gulf Publishing Co., Houston, 320 p.

Schatski, N. S., 1946, The Great Donets Basin and the Wichita system: comparative tectonics of ancient platforms: SSSR, Akademii Nauk, Izvestia, Geologicheskii Seriya 6, p. 57–90.

Stearns, D. W.; and Friedman, M., 1972, Reservoirs in fractured rock, *in* King, R. E. (ed.), Stratigraphic oil and gas fields—classification, exploration methods, and case histories: American Association of Petroleum Geologists Memoir 16, p. 82–106.

Sykes, Michael; Puckette, Jim; Abdalla, Azhari; and Al-Shaieb, Zuhair, 1997, Karst development in the Viola Limestone, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 66–75.

Teufel, L. W.; and Lorenz, J. C., 1992, Control of fractured-reservoir permeability by spatial and temporal variations in stress magnitude and orientation [abstract]: American Association of Petroleum Geologists Annual Convention Program with Abstracts, v. 2, p. 131.

Wavrek, D. A., 1992, Characterization of oil types in the Ardmore and Marietta basins, southern Oklahoma aulacogen, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 185–195.

Weber, K. J.; and Freyer, U. O., 1992, Relationship of tectonic style to the occurrence and distribution of fracture porosity [abstract]: American Association of Petroleum Geologists Annual Convention Program with Abstracts, v. 2, p. 138.

Wickham, J. S., 1978, The southern Oklahoma aulacogen, *in* Denison, R. E., and Wickham, J. S. (eds.), Structural style of the Arbuckle region: Geological Society of America, South-Central Section, Guidebook for Field Trip 3, p. 8–41.

Oklahoma Geological Survey Circular 99, 1997

Influence of Vertical Permeability Barriers on Ultimate Recovery from Oil Creek Reservoirs

James M. Forgotson, J. Thomas Boyce, Roy M. Knapp, and Huaibo Liu
University of Oklahoma
Norman, Oklahoma

Paul W. Smith
NOREX Corporation
Norman, Oklahoma

ABSTRACT.—Within the study area, Ts. 7–11 N., Rs. 3–4 W., the Oil Creek sandstone, typically 50–60 ft thick, occurs in the lower part of the Simpson Group. It consists of porous and permeable sandstone containing several thin (a few inches to a few feet), tight streaks. Some of these impermeable zones appear to be continuous throughout the area of a productive Oil Creek structure and may provide barriers that compartmentalize the reservoir. Detailed examination of cores indicates that the Oil Creek sandstone was deposited in environments that changed through time (with fluctuations) from shoreface to foreshore. The highest values of porosity and permeability were created by solution of dolomite cement and matrix that originally composed approximately 20% of the rock. These rocks probably were deposited in a high-shoreface to lower-foreshore environment. The tight streaks within the more porous and permeable interval contain a dolomite matrix greater than 25% of the total rock volume. These tight zones may have been deposited in the middle to lower shoreface. Sandstones deposited in the upper-shoreface to foreshore environments contained less than 5% carbonate matrix and have a porosity of less than 10% and a permeability of less than 5%. Tight streaks in this rock type were formed by quartz overgrowth and pressure solution.

Generally, Oil Creek reservoirs consist of oil structurally trapped above an oil–water contact. Most Oil Creek reservoirs have robust water drives and experience early water production that is thought to be from bottom-water coning. Because the water drives are effective, reservoir pressures remain high, and recoveries from water-swept areas should be high. However, completions limited to zones above a tight streak can result in oil trapped below the streak, because the tight streak creates a vertical barrier to flow in the vicinity of the well. The amount of oil so "trapped" depends on the relief in the formation, the effectiveness of the seal, its areal extent, and the robustness of the aquifer. If the zones are not in hydraulic communication, all the recoverable oil is available to completions in the lower zone(s). If the aquifer is robust and zones above and below the seal are in hydraulic communication, the oil is trapped at high pressure, and could be recovered from lower-zone completions. If the aquifer is limited and zones are in hydraulic communication, production of liquids from above the seal will lower pressures in both zones. If the reservoir pressure is reduced below the bubble point, a secondary gas cap will develop in the lower zone(s) and displace oil downward. The amount of recoverable oil may be significantly reduced, depending on how much oil has been forced into the water zone. Oil in the gas cap will be at residual oil saturation and may not be producible even if the lower zone is opened.

INTRODUCTION

The Ordovician Oil Creek sandstone in the area of Oklahoma including McClain, Cleveland, and Oklahoma Counties (Fig. 1) consists of clean sands, 50–60 ft in thickness. A typical completion practice has been to complete only the uppermost portion of the sand to prevent water coning and delay the onset of water production. An investigation of Oil Creek cores identified the presence of thin layers of tight and hard sandstones that divide the producing interval into tight and porous zones. The streaks seem to be continuous over a large area, forming barriers to vertical fluid movement that affect water injection and recovery.

A core from the Mid-Continent Petroleum Co. No. 2 Kunkel well, sec. 31 T. 9 N., R. 3 W., McClain County, was subjected to detailed analysis. Cores from another six wells were also examined. Sixty-three thin sections and 53 plugs from these cores were analyzed.

The tight streaks in the Kunkel core had no oil stain (Fig. 2), and their permeability was below the measurement range of the instrument used, suggesting that they are effective barriers to vertical fluid flow. The presence of these barriers prompted a simulation study to investigate the depletion mechanisms that would be active in a stratified reservoir producing from the uppermost layer.

Forgotson, J. M.; Boyce, J. T.; Knapp, R. M.; Liu, Huaibo; and Smith, P. W., 1997, Influence of vertical permeability barriers on ultimate recovery from Oil Creek reservoirs, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 194–202.

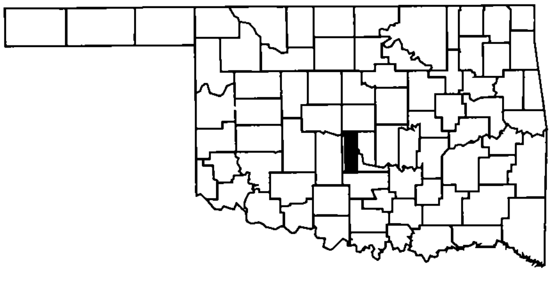


Figure 1. Locality map of the study area.

The goal of this study was to identify reservoir conditions that would cause oil to be "trapped" beneath these vertical barriers, unrecoverable from the existing completion, and presenting an opportunity for additional recovery.

SEDIMENTARY FACIES AND DIAGENETIC ALTERATION

Sedimentary Facies

The Oil Creek sandstone in the area studied consists of clean, fine to very fine sands, overlain by shale and underlain by wavy laminated fine sandstone, siltstone, and thin layers of carbonate. A detailed examination of cores and thin sections from six wells indicates that the Oil Creek sandstone was deposited in environments that changed from shoreface (dominant) to foreshore. The grains of the sandstones are composed of mainly quartz and a few heavy minerals. They are well sorted and well rounded and generally bioturbated. An interpretation of the Oil Creek core from the No. 2 Kunkel well shows the relationship between depositional environment and lithology (Fig. 3).

Diagenetic Alteration

The Oil Creek sands have undergone deep-burial diagenesis, including compaction, pressure solution, cementation, and dissolution. Both cementation and dissolution have played a significant role in determining the reservoir properties.

The Oil Creek sandstone contains variable amounts of dolomite matrix, mostly in the lower- to middle-shoreface sands. Compaction mainly affected dolomite-matrix-rich sands, resulting in tight, impermeable sandstones (Fig. 4A). Pressure solution that occurred in dolomite-poor, upper-shoreface and foreshore sands reduced the intergranular porosity to 12% or less of the bulk volume.

The cement in the Oil Creek sandstones is dominantly dolomite and overgrowth quartz. Some gypsum cement occurs as coarse, tabular crystals. Fine to medium crystals of dolomite cement were partially formed from recrystallization of carbonate matrix and partially from precipitation of dolomite crystals. Dolomite cement makes up less than 10% of the bulk volume. Overgrowth quartz cement is common in the Oil Creek sandstone, especially in the sands without dolomite matrix, in which it may constitute up to 15% of total rock volume. The petrological relationship shown in Figure 4B indicates that the overgrowth quartz formed earlier than the precipitated dolomite cement. Dissolution of dolomite cement and recrystallized dolomite has resulted in the main reservoir porosity in the Oil Creek sandstone. Petrological evidence is clearly shown in the thin section pictured in Figure 4C. Generally, in a carbonate-cemented sandstone, the silicate clasts may be replaced to some extent by the cement forming irregular connections between grains and cements (Liu and others, 1995). Pores larger than sand-grain size also indicate the development of porosity by dissolution (Fig. 4D).

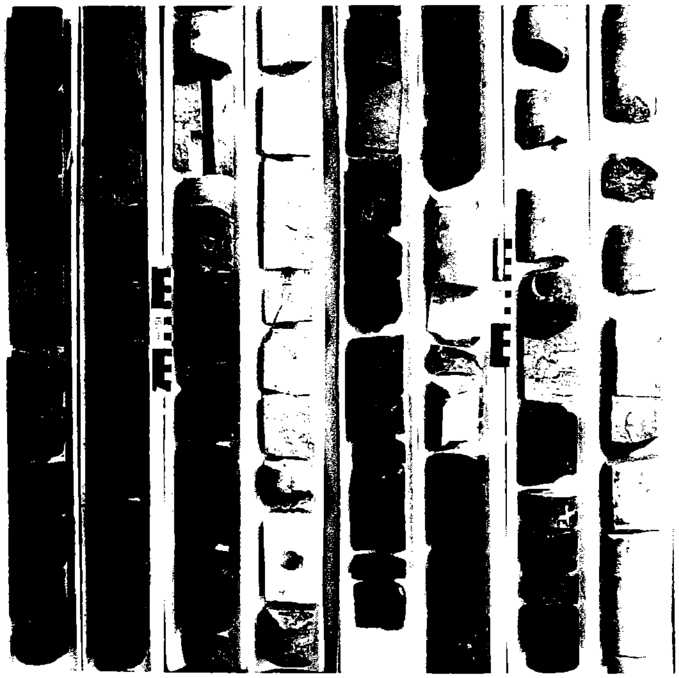
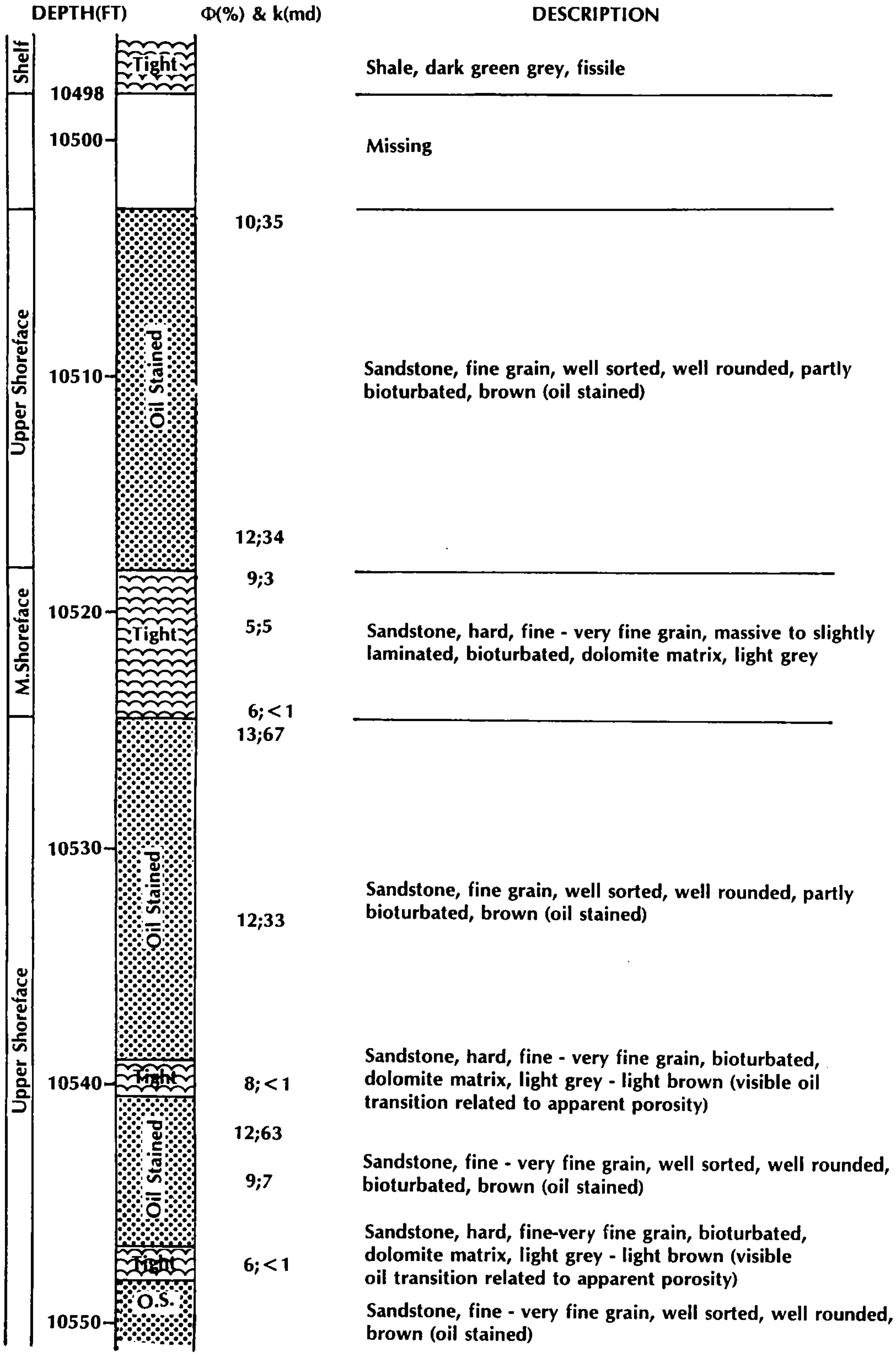


Figure 2. Photograph of cores from the No. 2 Kunkel well, sec. 31, T. 9 N., R. 3 W., McClain County, Oklahoma. The dark cores are oil-stained porous sandstone; the light cores are tight zones. The bottom is at the lower right, and the top at the upper left.

Origin of Porosity and Tight Zones

The Oil Creek sandstone exhibits two types of porosity: (1) primary porosity and (2) secondary solution porosity. The former occurs mainly in the upper-shoreface to foreshore sands in which diagenesis was controlled by pressure solution and quartz overgrowth. Porosity of this type is usually less than 12% (Fig. 5; Table 1). The second type was formed by dissolution of the early dolomite matrix and cement, which composed up to 25% of the rock volume. This type of porosity ranges from 10% to 20% (Tables 2,3). Data (Table 1) indicate that zones with solution porosity have relatively higher permeability, usually greater than 50 md, than the zones with only primary porosity.



Shale, dark green grey, fissile

Missing

Sandstone, fine grain, well sorted, well rounded, partly bioturbated, brown (oil stained)

Sandstone, hard, fine - very fine grain, massive to slightly laminated, bioturbated, dolomite matrix, light grey

Sandstone, fine grain, well sorted, well rounded, partly bioturbated, brown (oil stained)

Sandstone, hard, fine - very fine grain, bioturbated, dolomite matrix, light grey - light brown (visible oil transition related to apparent porosity)

Sandstone, fine - very fine grain, well sorted, well rounded, bioturbated, brown (oil stained)

Sandstone, hard, fine-very fine grain, bioturbated, dolomite matrix, light grey - light brown (visible oil transition related to apparent porosity)

Sandstone, fine - very fine grain, well sorted, well rounded, brown (oil stained)

Figure 3. Core description of the Oil Creek sandstone in the No. 2 Kunkel well, showing porous and tight zones and depositional environments.

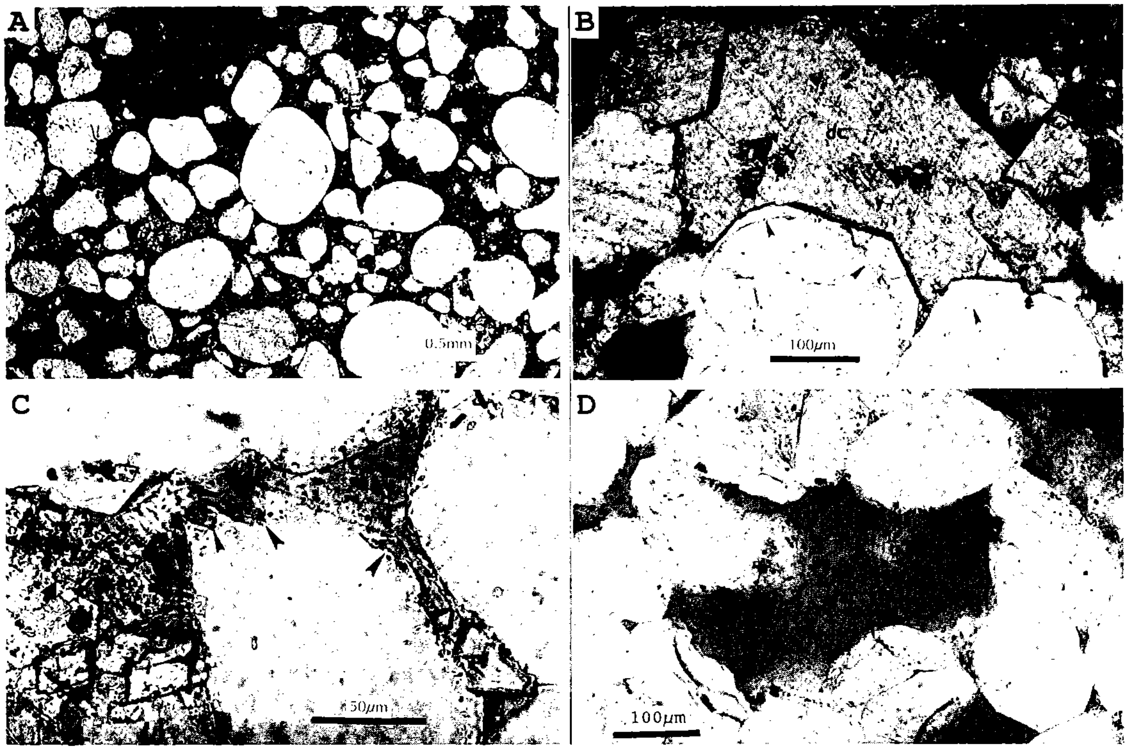


Figure 4. Photographs of thin sections of the Oil Creek sandstones showing: (A) Sandstone with dolomite matrix from the tight zone in the No. 2 Kunkel well, 10,523 ft (see Fig. 3). (B) Generation relationship between quartz overgrowth and dolomite cement (*dc*). Margins of the original quartz grains occur as dusty ghosts (arrows). The dolomite cement (*dc*) was precipitated after formation of the authigenic quartz cement and slightly replaced both quartz grains and quartz cement (thick arrow). No. 1 Berry Unit well, sec. 32, T. 9 N., R 3 W., McClain County, Oklahoma, 10,498 ft. (C) Solution porosity. Casts of dolomite crystals cutting into the quartz grain (thin arrows) indicate dissolution of early replacement dolomite. Solution is also evidenced by some solution relicts of dolomite matrix (thick arrows). No. 2 Kunkel well, 10,518 ft. (D) Porosity formed by solution of dolomite matrix and cement. Note that pores are larger than grains. No. 1 Berry Unit well, 10,524 ft.

The common tight zones in the Oil Creek sandstone are composed of dolomite-matrix-rich sandstone that occurs as thin layers ranging from a few inches to a few feet in thickness. The dolomite matrix in these zones is usually greater than 25% of the total rock volume. Porosity that may reach 8% in these streaks is dominated by very small intercrystal pores. The permeability in these zones is very low, mostly less than 1 md (Table 1; Fig. 3). The tight zone at approximately 10,520 ft in the No. 2 Kunkel well is shown on the sonic and density logs of this well (Fig. 6). A tight zone at 9,242 ft in the Dune Resources No. 1–21 Dolly well is shown on the logs of this well (Fig. 7).

Another type of tight streak that occurs in the Oil Creek sandstone was formed by severe pressure solution and quartz-grain overgrowth. This type occurs within the upper-shoreface porous sands, forming irregular low-permeability patches.

SIMULATION STUDY

Model Description

The model was configured as an anticlinal structure, occupying an 80-acre spacing unit. Three layers were incorporated into the model, with rock and fluid characteristics similar to those in the No. 2 Kunkel well. The oil–water contact was 125 ft below the top of a dome that slopes away from the peak at a dip of about 5°. The initial pressure was above the bubble point, so no gas phase was present. The oil in place in the top layer was

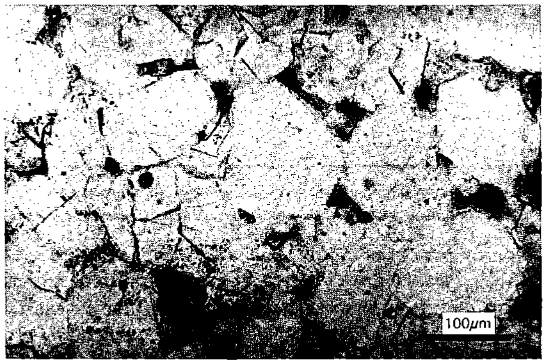


Figure 5. Photograph of thin section showing residual primary porosity after pressure solution and quartz overgrowth. Porosity is low and poorly connected. No. 2 Kunkel well, 10,517 ft.

TABLE 1.—POROSITY AND PERMEABILITY DATA FROM OIL CREEK SANDSTONE CORED WELLS

Well	Location	Depth (ft)	Porosity (%)	Kh (md)	Kv (md)	Kv/Kh
No. 2 Kunkel	T9N–R3W–S31	10,503.0	10	35	15	0.44
	NW NE	10,517.0	12	34	16	0.47
		10,518.0	9	3	12	3.84
		10,521.0	5	5	NS	
		10,524.0	4	NS	<1	
		10,524.5	6	<1	NS	
		10,525.0	13	67	125	1.68
		10,533.0	12	33	NS	
		10,540.0	8	<1	2	
		10,542.0	12	63	NS	
		10,544.0	9	7	NS	
		10,547.0	6	<1	6	
No. A–1 Leeper	T9N–R4W–S24	10,398.0	9	6	NS	
	S/2 SE NE	10,399.0	14	6	NS	
		10,399.5	13	50	NS	
		10,402.0	11	5	NS	
		10,403.0	8	12	NS	
		10,403.3	9	8	NS	
		10,408.0	6	7	NS	
		10,409.0	4	15	NS	
		10,411.0	7	5	NS	
No. 1 Berry Unit	T9N–R3W–S32	10,496.1	1	5	NS	
	NW SW NW	10,497.1	5	4	NS	
		10,498.2	15	34	NS	
		10,500.2	16	10	NS	
		10,502.7	15	121	NS	
		10,508.8	7	4	NS	
		10,512.5	10	4	NS	
		10,515.9	20	161	NS	
		10,524.0	17	64	NS	
		10,530.1	14	93	NS	
No. 1 Marcum	T7N–R3W–S23	10,087.1	17	29	NS	
	NE NW NW	10,093.4	15	43	5	0.12
		10,099.8	2	4	5	1.16
		10,103.8	15	78	77	0.99
No. 2 Czar Morava	T11N–R4W–S2	9,326.1	15	285	NS	
	C SE NE	9,332.9	13	105	NS	
		9,337.2	12	138	NS	
No. 1 Johnson	T10N–R3W–S2	8,364.2	7	13	NS	
		8,376.0	6	2	NS	
		8,383.9	6	1	NS	
		8,384.1	11	48	NS	
		8,384.7	14	42	NS	
		8,396.1	9	6	NS	
		8,404.9	8	2	NS	

Note: NS = no sample; <1 = permeability below instrument range.

approximately equal to the combined oil in place in the lower two layers. The effect of impermeable streaks between the layers was achieved by setting the vertical permeability to zero, thus preventing vertical flow. A producing well was drilled at the crest of the anticline and completed only in the uppermost layer. Aquifers with total volumes ranging from 10 to 100 times the size of the reservoir were connected to the downdip edges of the three layers. The withdrawal rate from the well was maintained at 100 barrels of oil per day (BOPD); if fluid entry dropped below this rate, the well was maintained in a pumped-off condition. An economic limit of 90% water cut or 5 BOPD was set to end the simulation run. Producible reserves remaining in the lower zones were determined by closing the well connection to the uppermost layer after the economic limit was reached, then

TABLE 2.—MODEL DESCRIPTION

Structure	Anticline
Area	80 acres
Closure	125 ft
Oil in place (total)	1 MMBO

Layer properties

Layer no.	Thickness (ft)	Porosity (%)	Horizontal permeability (md)
1	15	12	35
2	10	12	50
3	5	12	60

Relative permeabilities

Wettability	Water wet	End points	
Connate-water sat.	35%	$K_{O(Swc)}$	1.0
Residual-oil sat.	35%	$K_{W(Sro)}$	0.2
Critical gas sat.	4%	$K_{G(Sro.Swc)}$	0.7

Fluid properties

Oil gravity	36° API
Gas gravity	0.85
Initial pressure	3600 PSIA
Bubble point	2000 PSIA
Formation-volume factor @ BP	1.34

Note: MMBO = million barrels of oil.

opening the well connection to the lower two layers and producing to the same economic limit.

Rock and PVT Properties

The properties of pressure, volume, and temperature (PVT properties) used in the model were typical of hydrocarbons produced from Oil Creek reservoirs in the vicinity of the No. 2 Kunkel. Standing's correlations were used to develop continuous properties as a function of pressure (Craft and others, 1991). The porosity and absolute permeability values used in the model were averages taken from analysis of the No. 2 Kunkel core. The relative permeability relationships were generated as a function of saturation using correlations developed by Honarpour and others (1986) for strongly water-wet sandstones. A summary of reservoir and fluid characteristics is shown in Table 2.

Aquifer Configuration

Two aquifer configurations were used. The "common" configuration connected the layers to a common aquifer of the specified volume, thus placing the layers in hydraulic communication through the aquifer. The "independent" configuration distributed the total aquifer volume among the individual layers on the basis of layer thickness. The aquifer for each layer was isolated from the others, thus allowing each layer to act as an independent reservoir. The simulation results are classified by the configuration used and the total aquifer volume.

Simulation Result

Simulation runs were made for five configurations, tabulated in Table 3. Case 1 allows the top layer to respond as a separate reservoir with an aquifer volume of 50 million barrels, 100 times the oil volume in the reservoir. Recovery is approximately 60% of the oil in place in this layer, with the well reaching economic limit by watering out. The pressure in the lower zones when they are watered out is similar to that from the top layer, because the same ratio of aquifer volume to oil reservoir volume is maintained.

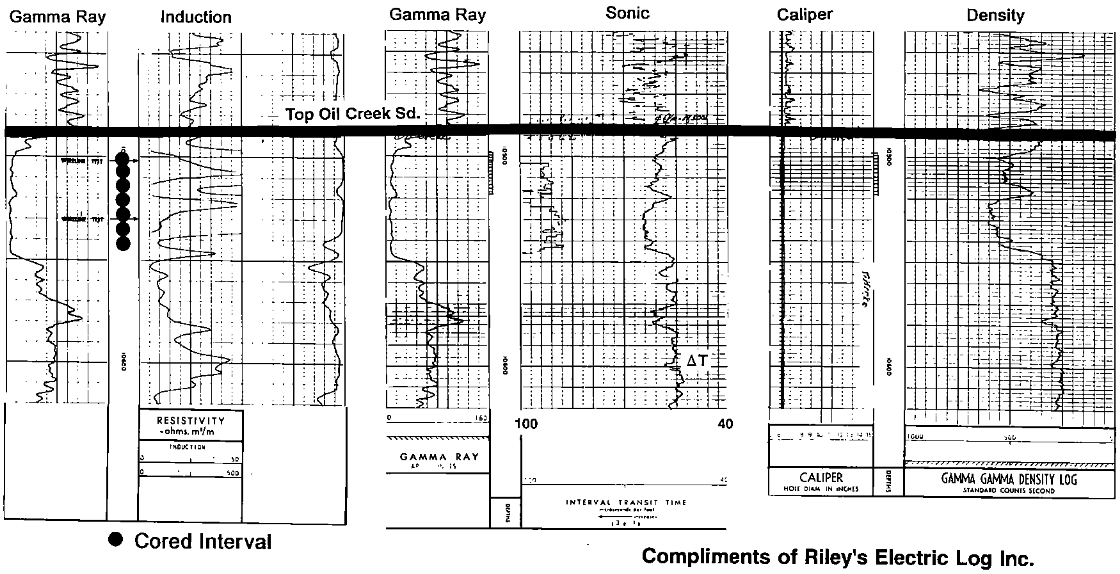
Case 2 contains the same total aquifer volume, but the layers are in hydraulic communication through the aquifer. The large expansive energy contained in the 100-million-barrel aquifer maintains pressures above bubble point throughout the reservoir. Recoveries from both the top and lower zones are similar to case 1 because of the robust water drive present. Economic limits for all zones are reached by watering out.

Case 5 is similar to case 1 in that the upper layer acts

TABLE 3.—SIMULATION RESULT

Aquifer configuration and volume	Case	Producing life (years)	Water breakthrough (years)	Oil recovery (MBO)	Final pressure (PSIA)	Lower zone pressure (PSIA)	Lower zone reserves (MBO)
Independent 100 MMBW	1	11	7	310	1875	3600	290
Common 100 MMBW	2	10.5	7	310	2560	2970	300
Common 25 MMBW	3	9.5	7	293	890	1725	139
Common 10 MMBW	4	15	7.5	252	430	1225	7
Independent 10 MMBW	5	6	None	155	210	3600	152

Note: MMBW = million barrels of water; MBO = thousand barrels of oil.



Compliments of Riley's Electric Log Inc.

Fig. 6. Well logs of Oil Creek sandstone in Mid-Continent Petroleum Co. (Producers Development Co.) No. 2 Kunkel well, sec. 31, T. 9 N., R. 3 W., McClain County, Oklahoma. The tight zone at approximately 10,520 ft can be seen on the sonic and density logs.

as a separate reservoir. The much smaller 5-million-barrel aquifer results in a limited water drive, however, and recovery is only about half of that achieved with the robust aquifer in case 1. The pressure in the lower zones is similar to that in the top zone because the ratio of aquifer volume to oil reservoir volume is maintained. The economic limit for each zone is reached by a low oil-production rate, with only minimal water production.

In case 4, all three layers are in hydraulic communication through the 10-million-barrel aquifer. This allows a curious effect to occur: recovery from the top layer is high, but minimal recovery is achieved from the lower layers. The relatively small aquifer allows reservoir pressure to drop below the bubble point. Gas evolving and expanding from the oil in the lower zones provides additional energy to supplement the aquifer during production from the top zone, increasing recovery substantially. This increase comes at the expense of the lower zones, however. Minimal energy is available to produce the lower zones when they are completed, and the oil has undergone substantial shrinkage owing to the evolution of gas. The small recovery from the lower zones would probably not warrant completion.

Case 3 represents an intermediate case with a common aquifer of 25 million barrels. The aquifer provides significant energy, but reservoir pressure drops below the bubble point. Recovery from the top layer is high because of the combined water drive and gas-expansion energy. Recovery from the lower zones is reduced, owing to the small energy available when these layer are completed. The economic limit for all layers is reached by watering out.

SUMMARY AND CONCLUSIONS

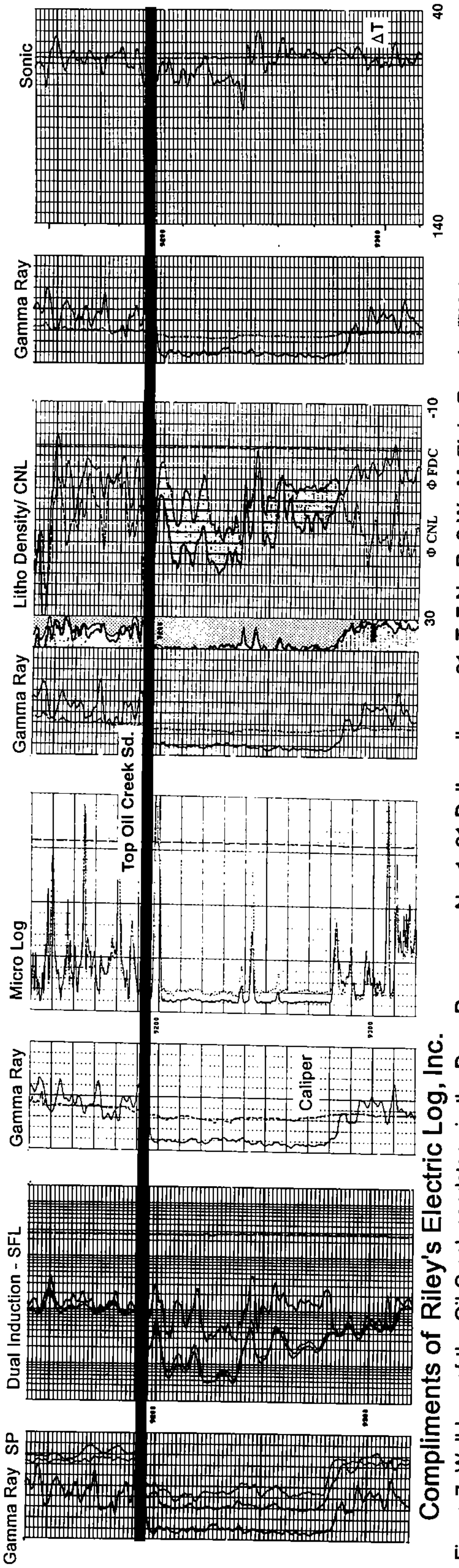
The Oil Creek sandstone was deposited in environments ranging from lower shoreface through foreshore. Within producing intervals, two types of tight zones occur that are caused by (1) a high percentage of dolomite matrix (>25%) and (2) quartz overgrowth resulting from pressure solution. Zones with high porosity were formed by solution of the dolomite matrix and dolomite cement that originally composed up to 25% of the bulk volume. Impermeable streaks within the Oil Creek Formation present the opportunity for recovering significant "trapped" oil volumes if wells have been completed only in the uppermost part of the formation.

An example of this is illustrated by the Forest I Dev. Co. No. 1A–11 Benson Trust well, drilled in 1991 in the E½SW¼ sec. 11, T. 7 N, R. 3 W., McClain County, Oklahoma. This well, completed only in the Oil Creek sandstone below a tight streak, had a cumulative production greater than 37,000 BO through 1995 with an average gas/oil ratio of approximately 277 (Fig. 8). Three wells in the North Washington field had previously been drilled in sec. 11 and completed in the upper part of the Oil Creek sandstone. These wells had been abandoned after watering out in the Oil Creek, Tulip Creek, and Bromide reservoirs. Drill-stem-test results from the old well in the NE¼NW¼ sec. 11 reported a producing rate of 40 BO/hr. An initial production rate of 265 BO/day was reported for the old well in the NE¼SE¼ sec. 11. The first month's production for the new well completed below the tight streak averaged approximately 70 BO/day.

The presence of significant oil reservoirs in lower intervals is dependent on the following conditions.

1. The streaks must be impermeable, with sufficient structural closure to trap oil.

2. The lower intervals must contain sufficient reservoir energy to recover the trapped oil after depletion of the upper zone. If the intervals share a common large aquifer, significant recovery could be expected from the lower intervals. If the lower intervals are isolated from the upper interval, significant recovery can occur, particularly if the lower intervals are associated with large aquifers. Reservoirs in the lower intervals could be



Compliments of Riley's Electric Log, Inc.

Figure 7. Well logs of the Oil Creek sandstone in the Dune Resources No. 1-21 Dolly well, sec. 21, T. 7 N., R. 2 W., McClain County, Oklahoma. The tight zones can be seen on the micro, sonic, and density logs.

adversely impacted if they share a common limited aquifer with the top interval. This condition may cause the reservoir energy in the lower intervals to be partially depleted, resulting in poor recovery when perforated.

REFERENCES CITED

Craft, B.; Hawkins, M.; and Terry, R., 1991, Applied petroleum reservoir engineering [2d edition]: Prentice Hall, Englewood Cliffs, New Jersey, p. 31–48.

Honarpour, M.; Koederitz, L. F.; and Harvey, A., 1986, Relative permeability of petroleum reservoirs: CRC Press, Boca Raton, Florida, p. 37–41.

Liu, Huaibo; Blatt, Harvey; Wu, Zhiyong; and Forgotson, J. M., 1995, Diagenesis and porosity evolution of the Spiro Sandstone in the South Hartshorne gas field, Oklahoma, USA [in Chinese with English abstract]: Journal of Jianghan Petroleum Institute, v. 17, no. 2, p. 1–9.

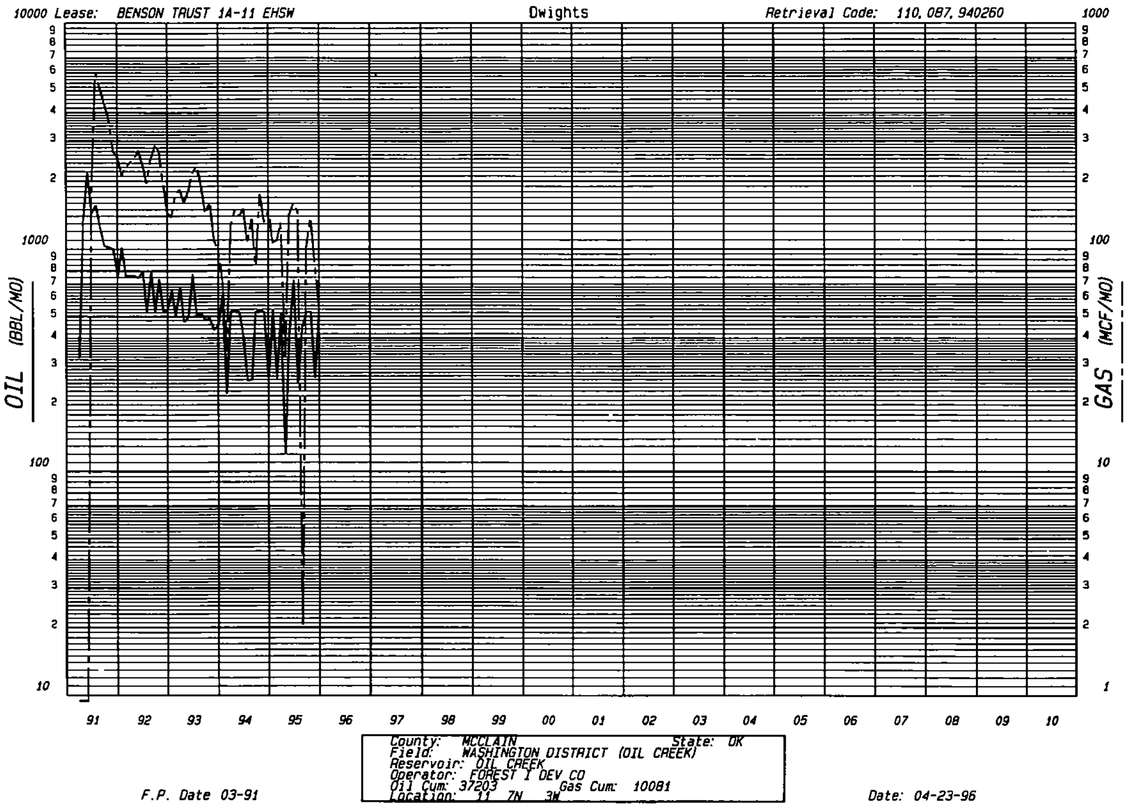


Figure 8. Production data for the Oil Creek reservoir in the Forest I Dev. Co. No. 1A–11 Benson Trust well, McClain County, Oklahoma.

Characterization of High-Molecular-Weight Paraffin in Ordovician Simpson Group Reservoirs (Oklahoma and Texas)—Implications for Advanced Recovery Technologies

N. F. Dahdah and D. A. Wavrek
University of Utah
Salt Lake City, Utah

ABSTRACT.—Crude oils with high pour points and undesired flow properties have been documented in a variety of geologic provinces, representing a condition that is frequently attributed to paraffin or wax. Recent advances in analytical technologies allow this material to be separated into individual compounds by high-temperature gas chromatography (HTGC). Although the oil type that is indigenous to the Simpson Group petroleum system is characterized by a diminutive C_{20+} fraction, HTGC indicates the presence of compounds exceeding nC_{60}. As tradition dictates that the high-molecular-weight compounds are derived from higher plants (cuticular material), their presence in crude oils generated from marine sequences in the lower Paleozoic (Ordovician Simpson Group) requires an alternative origin (e.g., algae). Thus, paraffin from the alternative organic-matter sources (higher plant vs. algal) may respond to specific production chemicals.

INTRODUCTION

The chemical composition of crude oil is known to be highly complex, the main groups being aliphatic (saturate) and aromatic hydrocarbons plus resins and asphaltenes (Tissot and Welte, 1984). The aliphatic hydrocarbon fraction contains the normal (straight) and branched alkanes along with the cycloalkanes (naphthenes), whereas the aromatic hydrocarbon fraction contains pure aromatic compounds, cycloalkanoaromatic (naphthenoaromatic) molecules, and the simple cyclic sulfur compounds. The resin and asphaltene fractions have a similar composition, with their distinction based on solubility. Asphaltenes are generally precipitated from a crude oil in excess solvent, whereas the resins are separated from the saturate and aromatic fractions by liquid chromatography. Each compound class coexists in an equilibrium state within the crude-oil reservoir, although the production of petroleum can induce changes (e.g., decreased temperature and/or pressure) that may lead to the precipitation of solid components. Indeed, the component known as paraffin or paraffin wax is well known for its deleterious behavior. In strict chemical terms the paraffin fraction should be composed of straight chain aliphatic hydrocarbons (i.e., alkanes), although the industry practice usually includes a complex mixture of aliphatic compounds (normal, branched, and naphthenic alkanes). Information on the high-molecular-weight (HMW) paraffin has been limited to bulk methods of characterization (e.g., direct-insertion-probe mass spectrometry), as the requirements for separating the individual compounds exceeded the limits of analytical technology. However, advances in capillary-column technology (Lipsky and Duffy, 1986a,b) and supercritical fluid chromatography (Hawthorne and Miller, 1987; Stadler and others, 1993) have enabled investigators to study this fraction directly. This paper provides a report of our progress in developing instrumentation to study the compounds present in the high-molecular-weight fraction by high-temperature gas chromatography (HTGC).

Gas chromatography (GC; Fig. 1) is commonly used to separate individual components in a complex mixture. The technique relies on the ability of the components to be separated within an elongated tube (column) by differential partitioning between two phases: a stationary liquid phase and a mobile gas phase. Several types of columns are available for use in GC analysis, but the one used in this study has a capillary design (<0.35 mm diameter). The stationary phase in this type of column is a thin coating on the inner surface of the tube. The column is mounted in an oven with one end of the column attached to an inlet while the other end is connected to a detector. The column is continuously swept with the mobile gas phase. The mixture is introduced to the column via the inlet, and separation occurs

Dahdah, N. F.; and Wavrek, D. A., 1997, Characterization of high-molecular-weight paraffin in Ordovician Simpson Group reservoirs (Oklahoma and Texas)—implications for advanced recovery technologies, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 203–208.

as individual molecules of each solute are swept toward the detector as they enter the moving stream of carrier gas after desorption from the stationary phase. Thus, the time that a solute spends in the column is dependent on the ratio of time spent in the mobile phase versus the stationary phase, a property that is a function of the vapor pressure exerted by the individual component at a given temperature. The column is mounted in an oven, where the temperature can be isothermal or programmed to aid in the separation of the less volatile components. The abundance of each component is recorded with a detector (e.g., flame ionization detection or FID) and presented as a function of time (Fig. 2). The basic system can be modified for specific applications (Freeman, 1981; Jennings, 1987; Jennings and Rapp, 1983).

Conventional GC analysis of crude oils provides data on components containing up to 35 carbons (C_{35}). This type of analysis is widely used to screen and correlate samples, because it provides information on biogenic source input, diagenetic environment, and secondary alteration processes. The former items are useful to differentiate individual petroleum systems in the region (Wavrek, 1992; Wavrek and others, 1997), and the latter is essential for evaluating secondary alteration mechanisms that can have an adverse affect on the quality of petroleum (e.g., biodegradation). This type of analysis provides a significant amount of information, but it does not provide information on the fraction that is believed to be responsible for paraffin wax deposits in reservoirs, oil-well equipment, and pipeline facilities. This is attributed to the fact that the temperature required to elute this fraction from the column has been greater than the stability range for a conventional stationary phase (325°C). Fortunately, recent advances in capillary-column technology (Lipsky and Duffy, 1986a,b; Dawes and Cumber, 1989) provided stationary phases that are stable at significantly higher temperatures (450°C), which allows compounds greater than C_{100} to elute from the column. Utilization of these phases has allowed novel applications in the emerging field of HTGC. In the course of developing this technology, it became apparent that the operating parameters needed to be refined. The results of this research are reported in this paper, along with practical examples from Simpson Group reservoirs in southern Oklahoma.

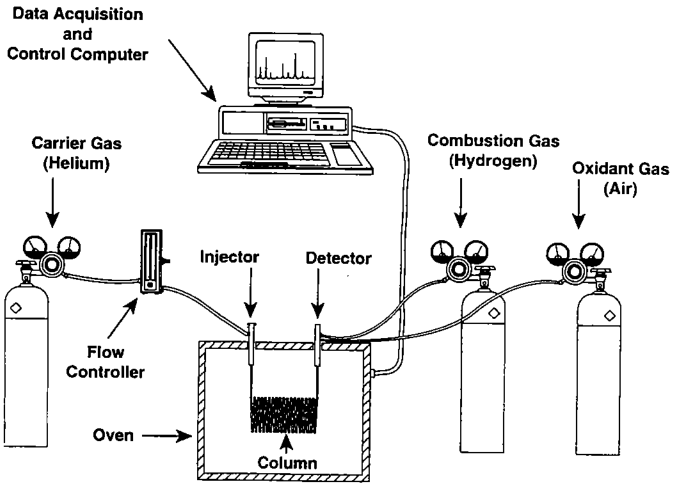


Figure 1. Basic components of gas-chromatograph (GC) instrumentation (from Tashiro and Clement, 1990).

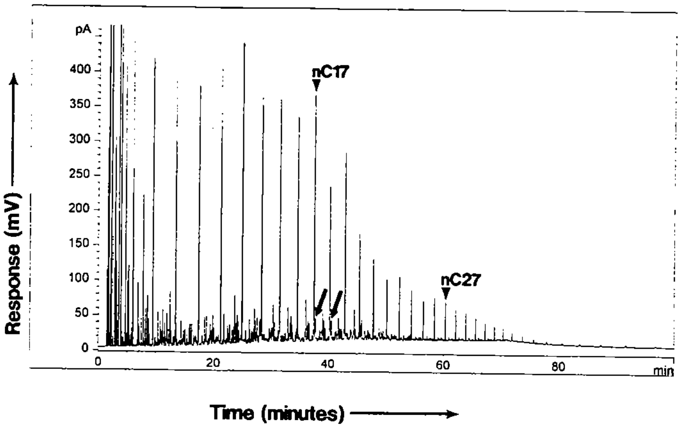


Figure 2. Conventional GC analysis of crude oil from Simpson Group petroleum system (TX060C) in the southern Midcontinent. Arrows identify pristane and phytane, respectively.

DEVELOPMENT OF TECHNIQUE

For an analytical method to gain acceptance in an industrial application, a reasonable level of accuracy and precision must be attained at a reasonable cost with readily available instrumentation. Proponents of the supercritical fluid chromatography (SFC) technology (Hawthorne and Miller, 1987; Smith and others, 1987; Stadler and others, 1993) cite advantages of this technique for analysis of samples containing organic components that lack sufficient thermal stability and/or volatility to be separated by conventional GC methods. Additional benefits of the SFC technology include the direct analysis of nonvolatile polar components (i.e., avoids derivatization) and a low carrier flow volume that allows direct coupling to a mass spectrometer (SFC–MS). However, we decided to pursue the HTGC technology on the basis of instrument availability, low operating cost, reliability, ease of operation, and chromatographic resolution. The latter is particularly important, as the focus of this research is investigation of the compositional variability of compounds in the HMW range. Specifically, it can be demonstrated that the composition of the paraffin fraction is dependent on the origin of the organic matter in the correlative source-rock facies (Carlson and others, 1993; Wavrek and Dahdah, 1995). An additional benefit of the HTGC technology is the direct application to high-temperature gas chromatography–mass spectrometry (HTGC–MS; Fig. 3), which can be used in ion monitoring or in SCAN mode to provide critical data for the identification of individual peaks (Fig. 4). However, preliminary research indicated that potential problems with the type of inlet, the solvent system, and the oven program needed to be investigated. It was also established that the ability to provide quantitative results would be a necessary enhancement for the technique to be successfully applied to wax-related production problems.

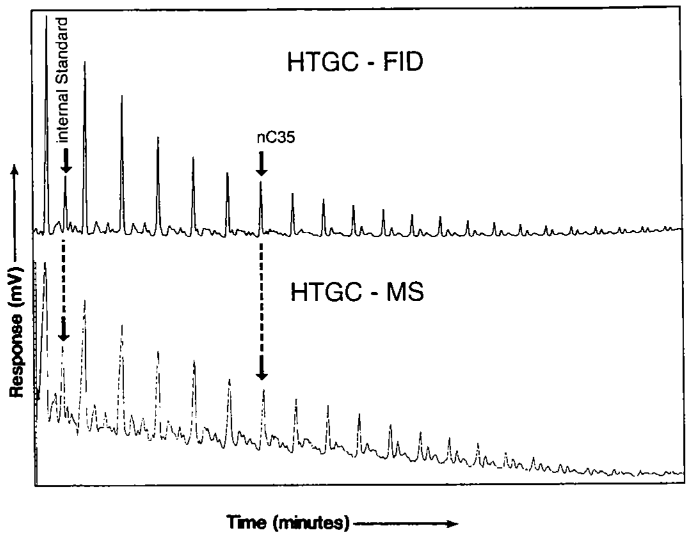


Figure 3. Illustration of the response from different HTGC detectors. The flame ionization detector (FID) is routinely used for monitoring the response of hydrocarbons eluting from the column, although the results can be directly compared to data obtained with a mass spectrometer (MS). The HTCG–MS data in this illustration are displayed as a total ion count (TIC).

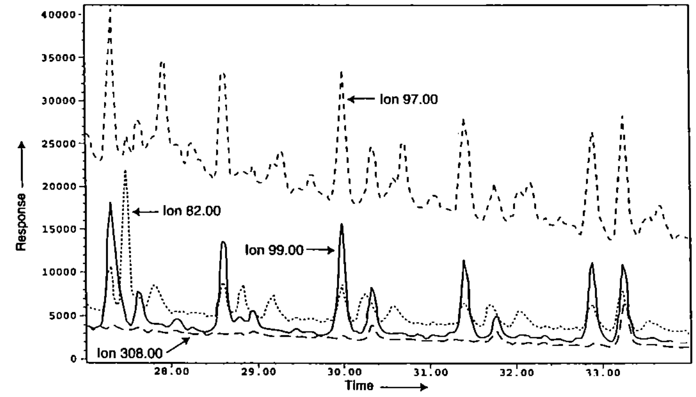


Figure 4. Illustration of the HTGC–MS data displayed as single ion monitoring (SIM) analysis to aid in the identification of individual peaks. The signal obtained from different mass-to-charge (m/z) ratios will show enhanced response from particular compounds: *n*-alkanes (m/z 99), *n*-alkylcyclohexanes (m/z 82), and methyl-*n*-alkylcyclohexanes (m/z 97). The m/z 308 trace is used to monitor for a parent mass (molecular weight of entire compound).

The purpose of the inlet (Fig. 1) is to introduce the sample to the analytical column. With capillary columns, a split injection with flash vaporization is generally utilized, owing to the limited capacity of the system. This inlet is favored in many applications, but it is responsible for introducing analytical artifacts when HMW material is present (Fig. 5). In fact, the problem of introducing high boiling and thermally-labile substances to the gas chromatograph has been studied by a number of chemists (Desty, 1965; Grob and Grob, 1978; Hinshaw, 1985). This work determined that successful transfer could be achieved with either the cool on-column or the temperature-programmed injection methods. The primary problem with the on-column technique is that residue from the whole oil or bitumen (resin or asphaltene) restricts the orifice and contributes to the rapid deterioration of column performance (Sinninghe Damste and de Leeuw, 1990). This problem was not encountered in this research, possibly because of the solvent system and maintenance program used. The solvent system developed for this HTGC application was an aliphatic:aromatic mixture consisting of nonane:toluene. The solvent system has the dual purpose of providing the samples with similar viscosity for consistent syringe ejection. The solvent system also introduces the internal standard at a concentration of 2,500 ppm. The aliphatic:aromatic solvent system was selected to provide solvating activity to a wide variety of crude-oil and bitumen samples. Perdeuterated trioacontane ($nC_{30}D_{62}$) was selected as the internal standard on the basis of routine criteria (Lee and others, 1984). Additional hints for successful sample introduction include mild heating prior to injection (40°C), along with a slight agitation. Finally, it was concluded that the use of a guard column was not necessary, as problems associated with the apparatus outweigh the potential benefits. The frequency for column maintenance was determined by monitoring chromatographic resolution; approximately one-half turn from the head of the column was generally removed at intervals commensurate with 30 injections. With this routine, it is established that excellent to good chromatographic resolution can be achieved for 100 samples oven programmed to 410°C, although this number decreases to 30 for samples analyzed at 450°C (discussed below).

A variety of oven programs were evaluated for the HTGC application. The purpose of the oven program is to provide adequate thermal energy to volatilize (required for elution) the HMW compounds. Studies of paraffin from a worldwide sample bank indicate that an empirical relationship exists between paraffin-related production prob-

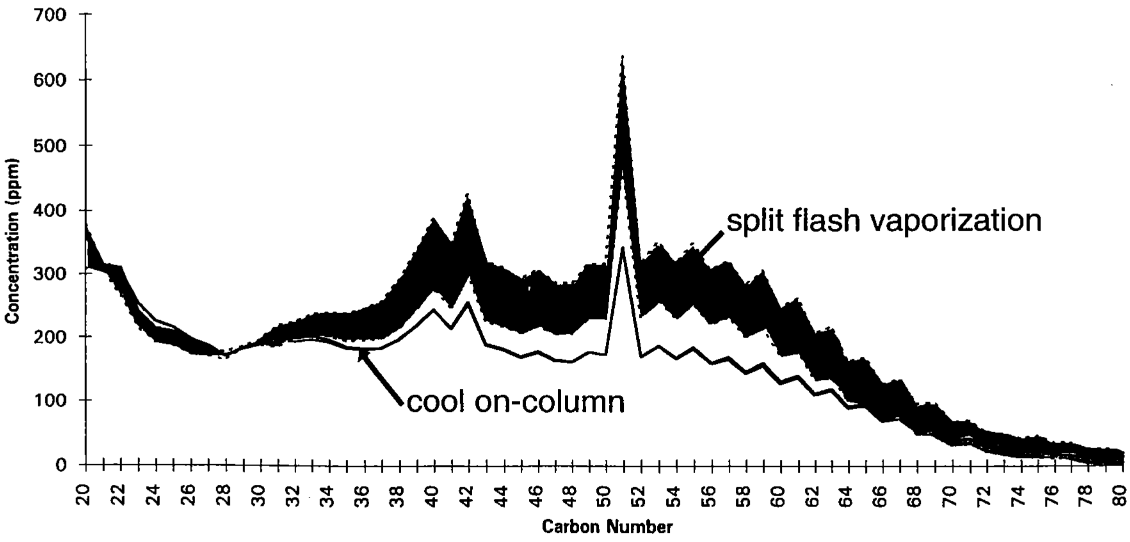


Figure 5. Comparison of the analytical precision obtained for two different injection methods. Quantitative results obtained from replicate analysis indicate significant variance with the split-mode injection, in comparison to the on-column technique.

lems and compounds in the range of C_{40} to C_{80}. Thus, an oven program was established to analyze this carbon-number range in less than 60 min (Fig. 6). This program provides excellent chromatographic resolution at minimal cost. In practice, the oven is programmed to 410°C, an analytical compromise that minimizes other potential problems with residual materials in the column. Byproducts formed from thermal decomposition have not been observed in analyses performed at 410°C, although research continues on this subject.

EXPERIMENTAL PROCEDURES

The instrument used in this HTGC study is a Hewlett-Packard 5890A gas chromatograph equipped with a flame ionization detector (GC–FID) and outfitted with a nonpolar Restek MXT-1 (30 m × 0.28 mm × 0.1 μm) capillary column. A cool on-column injection technique was used. The oven was programmed from 70°C to 410°C (11 min isothermal) at a ramp rate of 10°C/min. The total run time of 45 min allowed the elution of nC_{84}. Quantification of the HMW fraction was accomplished with perdeuterated triaconane ($nC_{30}D_{62}$ at 2,500 ppm) that was introduced as part of the solvent sample preparation.

RESULTS AND DISCUSSIONS

Crude oils with high pour points and undesired flow properties have been documented in a variety of geologic provinces, conditions that are frequently attributed to "paraffin or wax." Hedberg (1968) recog-

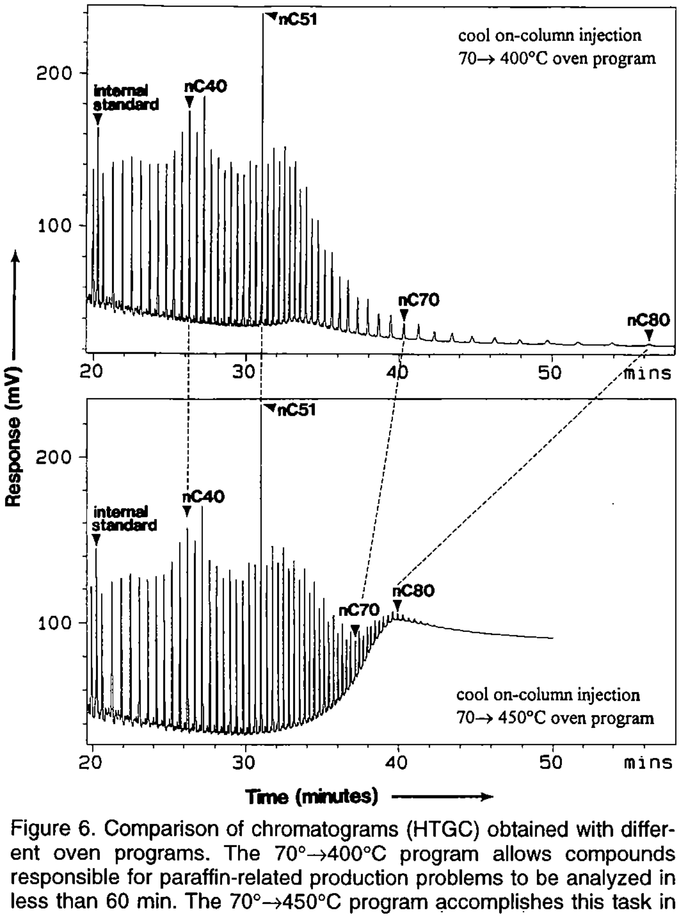


Figure 6. Comparison of chromatograms (HTGC) obtained with different oven programs. The 70°→400°C program allows compounds responsible for paraffin-related production problems to be analyzed in less than 60 min. The 70°→450°C program accomplishes this task in 40 min, but the higher temperature contributes to column degradation; the "hump" at the end of the trace is due to column bleed. This sample was collected as a stock-tank paraffin deposit.

TABLE 1.—OIL WELLS THAT PRODUCE FROM THE SIMPSON PETROLEUM SYSTEM

Code	Field	Operator	Well	Location	API well no.	Reservoir	Perf. (ft)	API gravity	Total sulfur	Nickel (ppm)	Vanadium (ppm)
OK097C	Ardmore SW	Triple Dee	SW Ardmore Unit	26-5S-1E		Tulip Creek	2100	37°	0.27%	6	10
OK208C	Sho–Vel–Tum	L. E. Jones	No. 1 Harley	24-2S-4W	35-137-22431	Oil Creek	7426–7454	42°	0.51%	1	2
OK286C	Ardmore SW	Mack	Marris Tank	36-5S-1E		McLish	2700	30°	0.27%	4	5
TX060C	Walnut Bend	ARCO	No. 1 McGeorge		42-097-00753	Oil Creek	8156–8160	46°	0.21%	3	5

nized a number of common features within the global occurrence of high-paraffin oils that led him to suggest a relationship with the organic matter from which the oil was derived, namely, an association with source-rock facies containing a significant component of terrigenous organic matter and/or organic matter derived from organisms indigenous to brackish-water columns. These observations remain valid, as the origin of the paraffin associated with oils derived from terrigenous source rocks is generally attributed to the cuticular coating of higher plants and/or the reworking of this material by microbial activity (Tissot and Welte, 1984; Tegelaar and others, 1989). However, the origin of paraffin in petroleum systems of lower Paleozoic marine sequences requires an alternative explanation.

The Middle Ordovician Simpson Group of the southern Midcontinent commonly contains oils with distinctive GC traits (Wavrek, 1992). These oils (Fig. 2) are dominated by *n*-alkanes with a strong odd-carbon preference in the C_{11} to C_{20} range and contain relatively minor amounts of nC_{20+} hydrocarbons. These oils display minor to trace amounts of isoprenoids and anomalously light carbon-isotope values. The *n*-alkylcyclohexanes and *n*-alkylbenzenes display a distinctive carbon-number preference, along with the methyl-*n*-alkylcyclohexanes (Burgess and Wavrek, 1993). These molecular traits have been correlated to source-rock facies in the Simpson Group and correspond to organic-matter input from the Ordovician alga *Gloeocapsomorpha prisca*. This organism has been studied in numerous Ordovician-age petroleum systems (Martin and others, 1963; Fowler and Douglas, 1984; Reed and others, 1986; Hoffmann and others, 1987; Longman and Palmer, 1987; Fowler, 1992; Burgess and Wavrek, 1993; Wavrek and others, 1997). Despite the diminutive C_{20+} fraction of this oil type, HTGC analysis indicates the presence of compounds exceeding nC_{60} (Fig. 7). Features identified in the HTGC that appear to be indigenous to this group of oils (Table 1) include enhanced nC_{41}, nC_{42}, and nC_{51} alkanes. The documentation of HMW *n*-alkanes in these oils is significant, since an origin from higher plant debris and/or nonmarine algae can be ruled out, which is in contrast to the routine sources of these compounds (Tissot and Welte, 1984; Tegelaar and others, 1989). Thus, an origin of these compounds from marine algae, possibly reworked by microbes, is likely. The application is that different organic-matter sources may create waxes that respond to different production chemicals (e.g., flow and crystal modifiers, viscosity improvers, pour-point depressants).

CONCLUSIONS

Significant advances in the control of paraffin deposition can be anticipated when HTGC is used to quantitatively determine the distribution of the HMW components (C_{40+}) in crude oils. The results suggest that a universal solution to the problem is unlikely, since these compounds can originate from a variety of sources. In particular, tradition dictates that the HMW compounds are associated with higher plants (cuticular material); thus, their presence in crude oils generated from the lower Paleozoic (Ordovician Simpson Group) requires an alternative origin (e.g., marine algae). Indeed, this suggests that production chemicals may be developed for specific types of paraffin-related production problems. The versatility of the analytical technique is increased by adapting the technology to readily available instruments.

ACKNOWLEDGMENTS

We wish to thank W. H. Kanes of the Earth Sciences and Resources Institute at the University of Utah and the University of South Carolina for providing the opportunity of pursuing this fundamental research. The authors are indebted to the operators who shared their expertise and samples (ARCO, Mack, L. E. Jones, K. Walker, Triple Dee) that make these studies possible. J. B. Fisher at Amoco Production Research is thanked for the elemental analyses. David Curtiss (USC-ESRI) is also thanked for his assistance in completing this research.

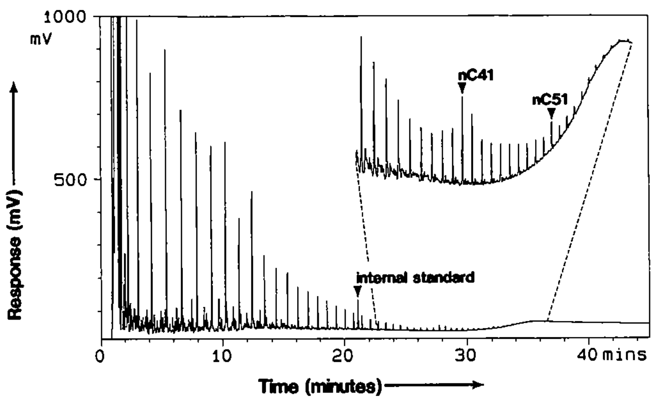


Figure 7. HTGC analysis of crude oil (TX060C) from Simpson Group petroleum system in the southern Midcontinent. Note that the high-molecular-weight (HMW) alkanes extend beyond nC_{60} and that nC_{41}, nC_{42}, and nC_{51} display an enhanced abundance.

REFERENCES CITED

Burgess, J. D.; and Wavrek, D. A., 1993, Morphological and chemical variations within the alga *Gloeocapsomorpha prisca*: evidence for separate species: Proceedings of Society for Organic Petrography Research Conference, Norman, Oklahoma, p. 34–36.

Carlson, R. M. K.; Teerman, S. C.; Moldowan, J. M.; Jacobson, S. R.; Chan, E. I.; Dorrough, K. S.; Seetoo, W. C.; and Mertani, B., 1993, High temperature gas chromatography of high-wax oils: Proceedings of Indonesian Petroleum Association, 22d annual convention, October 1993, v. 1, p. 483–507.

Dawes, P.; and Cumber, M., 1989, Capillary columns designed for high temperature GC: American Laboratory, v. 21, p. 102–111.

Desty, D. H., 1965, Capillary columns: Advanced Chromatography, v. 1, p. 199–228.

Fowler, M. G., 1992, The influence of *Gloeocapsomorpha prisca* on the organic geochemistry of oils and organic-rich rocks of Late Ordovician age from Canada, *in* Schidlowski, M., and others (eds.), Early organic evolution: implications for mineral and energy resources: Springer–Verlag, Berlin, p. 336–356.

Fowler, M. G.; and Douglas, A. G., 1984, Distribution and structure of hydrocarbons in four organic Ordovician rocks: Organic Geochemistry, v. 6, p. 105–114.

Freeman, R. R., 1981, High resolution gas chromatography: Hewlett-Packard, 197 p.

Grob, K.; and Grob, K., Jr., 1978, On-column injection onto glass capillary columns: Journal of Chromatography, v. 151, p. 311–320.

Hawthorne, S. B.; and Miller, D. J., 1987, Analysis of commercial waxes using capillary supercritical fluid chromatography–mass spectrometry: Journal of Chromatography, v. 388, p. 397–409.

Hedberg, H. D., 1968, Significance of high-wax oils with respect to genesis of petroleum: American Association of Petroleum Geologists Bulletin, v. 52, p. 736–750.

Hinshaw, J. V., Jr., 1985, Programmed temperature injection in open-tubular gas chromatography: Instrumentation Research, p. 14–24.

Hoffman, C. F.; Foster, C. B.; Powell, T. G.; and Summons, R. E., 1987, Hydrocarbon biomarkers from Ordovician sediments and the fossil alga *Gloeocapsomorpha prisca* Zalessky 1917: Geochimica et Cosmochimica Acta, v. 51, p. 2681–2697.

Jennings, W. G., 1987, Analytical gas chromatography: Academic Press, New York, 259 p.

Jennings, W. G.; and Rapp, A., 1983, Sample preparation for gas chromatographic analysis: Hüthig, New York, 104 p.

Lee, M. L.; Yang, F. J.; and Bartle, K. D., 1984, Open tubular gas chromatography: Wiley, New York, 445 p.

Lipsky, S. R.; and Duffy, M. L., 1986a, High temperature gas chromatography: the development of new aluminum clad flexible fused silica glass capillary columns coated with thermostable nonpolar phases. Part 1: Journal of High Resolution Chromatography and Chromatography Communications, v. 9, p. 376–382.

_____1986b, High temperature gas chromatography: the development of new aluminum clad flexible fused silica glass capillary columns coated with thermostable nonpolar phases. Part 2: Journal of High Resolution Chromatography Communication, v. 9, p. 725–730.

Longman, M. W.; and Palmer, S. E., 1987, Organic geochemistry of Mid-Continent Middle and Late Ordovician oils: American Association of Petroleum Geologists Bulletin, v. 71, p. 938–950.

Martin, R. L.; Winters, J. C.; and Williams, J. A., 1963, Distribution of *n*-paraffins in crude oils and their implication to origin of petroleum: Nature, v. 199, p. 110–113.

Reed, J. D.; Illich, H. A.; and Horsfield, B., 1986, Biochemical evolutionary significance of Ordovician oils and their sources: Organic Geochemistry, v. 10, p. 347–358.

Sinninghe Damste, J. S.; and de Leeuw, J. W., 1990, Analysis, structure and geochemical significance of organically-bound sulphur in the geosphere: state of the art and future research, *in* Durand, B.; and Behar, F. (eds.), Advances in organic geochemistry 1989: Pergamon, Oxford, p. 1077–1101.

Smith, R. D.; Kalinoski, H. T.; and Udseth, H. R., 1987, Fundamentals and properties of supercritical fluid chromatography–mass spectrometry: Mass Spectrometry Reviews, v. 6, p. 445–496.

Stadler, M. P.; Deo, M. D.; and Orr F. M., Jr.; 1993, Crude oil characterization using gas chromatography and supercritical fluid chromatography: Proceedings of International Symposium on Oilfield Chemistry, SPE Paper 25191, p. 413–420.

Tashiro, C.; and Clement, R. E., 1990, Characteristics of modern GC instrumentation, *in* Clement, R. E. (ed.), Gas chromatography [chapter 2]: Wiley, New York, p. 25–54.

Tegelaar, E. W.; Matthezing, R. M.; Jansen, J. B. H.; Horsfield, B.; and de Leeuw, J. W., 1989, Possible origin of *n*-alkanes in high-wax crude oils: Nature, v. 342, p. 529–531.

Tissot, B. P.; and Welte, D. H., 1984, Petroleum formation and occurrence [2d edition]: Springer–Verlag, Berlin, 699 p.

Wavrek, D. A., 1992, Characterization of oil types in the Ardmore and Marietta basins, southern Oklahoma aulacogen, *in* Johnson, K. S.; and Cardott, B. J. (eds.), Source rocks in the southern Midcontinent, 1990 symposium: Oklahoma Geological Survey Circular 93, p. 185–195.

Wavrek, D. A.; and Dahdah, N. F., 1995, Characterization of high molecular weight compounds—implications for advance-recovery technologies, SPE 28965: Proceedings of Society of Petroleum Engineers, International Symposium on Oil Field Chemistry, San Antonio, p. 207–212.

Wavrek, D. A.; Garcia, M. A.; and Ferebee, C. D., 1997, The Viola Group as a petroleum system: implications for horizontal-drilling prospects, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 78–86.

Diagenetic Banding: A Sealing Mechanism in Simpson Sandstone Reservoirs in Central Oklahoma

Azhari Abdalla, Jim Puckette, and Zuhair Al-Shaieb
Oklahoma State University
Stillwater, Oklahoma

ABSTRACT.—Diagenetic banding in sandstones results primarily from the processes of pressure solution, pore-fluid interaction, and precipitation. Bands consist of silica and carbonate-cemented layers that are separated by porous intervals. Band boundaries may be sharp or gradational. Faults, fractures, stylolites, and pressure-solution features such as penetrating grain boundaries are possible mechanisms for the derivation of silica cements. Cement precipitation was localized in areas that were finer grained or lacked grain-coating clays.

Cementation bands are economically significant phenomena, since they contribute to reservoir heterogeneity. Intrafacies cementing can compartmentalize compositionally homogeneous clastics. Permeability contrasts generated within diagenetically banded rock fabrics restrict flow and isolate fluid compartments.

INTRODUCTION

Compositionally homogeneous Simpson Group sandstones display diagenetic banding structures that formed from the interplay of stress-induced mineral reactions, pore-fluid interactions, and precipitation. Tigert and Al-Shaieb (1990) recognized the importance of this phenomenon as a seal-generating mechanism. Permeability contrasts created by diagenetically banded rock fabrics serve as both traps and reservoirs in the Simpson (Tigert and Al-Shaieb, 1990) and Springer (Al-Shaieb and others, 1993) sandstones in the Anadarko basin.

GENESIS OF BANDING PATTERNS

Silica-cement bands are the most common bands in sandstones and consist of zones of enhanced quartz overgrowths alternating with bands of preserved porosity. The silica apparently was derived from quartz-grain pressure solution and reflects mechano-chemical processes associated with burial compaction, tectonism, dissolution, and precipitation. Several processes were described by Dewers and Ortoleva (1990, 1993), Ortoleva and others (1987, 1993), and Qin and Ortoleva (1994) to explain the mechanics of band genesis. These processes involve stress-mediated dissolution and reprecipitation at free faces in contact with pore fluid and include porosity feedback, contact-area feedback, and clay-coating-mediated feedback.

Porosity feedback encourages dissolution in more porous rocks where grain stresses are higher, and precipitation in neighboring lower porosity areas. In contact-area feedback, dissolution is slower at larger grain-to-grain contacts than at smaller ones of similar volume. Clay-coating feedback is the most easily recognized process in sandstones. Clay coatings tend to inhibit silica precipitation on free faces. Solutes derived from dissolution at grain contacts precipitate faster in areas of thinner clay coatings.

Simpson sandstones contain diagenetic cementation bands that are manifestations of these processes. While stress-induced dissolution and reprecipitation increase with increased burial depth, relatively shallow-buried Simpson quartz arenites also display a variety of cement features. These occurrences are commonly associated with faulting and fracturing. Silica-cemented fractures have been documented in outcrop (Pittman, 1981; Gillert, 1952). Silica-cemented sandstone occurs proximal to faults in a shallow oil field in Creek County, Oklahoma (O'Brien and Derby, 1997). In this case, nonproduction near the crest of an anticlinal fold was attributed to the near-total occlusion of porosity by silica cement. No deformation zones were cored, but cataclasis and grain stress associated with fault displacement may have been a source of the silica cement. Cemented granulation/gouge zones were cored in McClain County, Oklahoma, where they contribute to the sealing of the Simpson reservoirs (Tigert and Al-Shaieb, 1990).

Bromide sandstones in McClain County contain silica bands that were apparently generated by localized dissolution and precipitation. Sandstones with thin or nonpervasive clay-grain coatings (Fig. 1) compacted and became sources of silica that was exported. Adjacent intervals received imported silica and became silica-cemented bands. Many cemented bands contain fewer pressure-solution features (Fig. 2), suggesting that the

---

Abdalla, Azhari; Puckette, Jim; and Al-Shaieb, Zuhair, 1997, Diagenetic banding: a sealing mechanism in Simpson sandstone reservoirs in central Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 209–217.

overgrowths increased grain-to-grain contact and slowed dissolution (Al-Shaieb and others, 1994). In this example, clay coatings on adjacent free faces inhibited silica precipitation, and porosity was preserved. Dissolved silica was exported to precipitate in adjacent bands. Clay-coating-mediated feedback is also manifested by very porous oil-stained reservoirs adjacent to silica-cemented sandstone (Fig. 3) and detrital matrix-rich rocks where framework grain morphology is preserved (Fig. 4).

The "Second Wilcox" (Bromide) Sandstone in Seminole County, Oklahoma, contains bands that formed in response to localized dissolution and reprecipitation. These bands exhibit a variety of morphologies. Some bands have sharp boundaries (Fig. 5) that reflect the changes in the character of the layers, such as grain size or amount of clay coating. Other bands have gradational contacts (Fig. 6) that reflect gradual changes in these components. Clay-coating-mediated feedback is common, and illite has inhibited precipitation on free faces across a wide range of grain sizes (Fig. 7). Enhanced dissolution and silica export are evident in bands where contacts between clay-coated grains in porous layers show only minor dissolution and contacts between grains in adjacent layers have become highly sutured (Fig. 8). Stylolites cross-cutting quartz overgrowths (Fig. 9) indicate that additional pressure solution occurred after initial silica cementation. Silica liberated during this phase may have precipitated as post-syntaxial-overgrowth intergranular-quartz cements in the silica bands.

Silica bands occur on several scales. Cemented-band/porous-band alternations range from a few millimeters thick within a 10-cm interval up to several bands that are 10 to 15 cm thick within a 20–30-cm interval (Al-Shaieb and others, 1994). Some cored cemented intervals exceed 1 m in thickness. Based on drilling time, cement bands encountered in the Seminole area have been estimated to range from 15 to 30 cm in thickness (F. Toll, personal communication, 1980).

A second type of band in sandstones is composed of carbonate (Fig. 10) that postdates the silica bands. Many carbonate-cementation bands consist of calcite and/or dolomite that alternates with porous bands (Al-Shaieb and others, 1994). Carbonate bands occur on scales similar to those observed for silica bands. In the Bromide sandstone interval, the earliest diagenetic calcite cements apparently were derived from compaction dissolution of carbonates found within or adjacent to the sandstones. Later poikilotopic calcite cement represents an intermediate stage

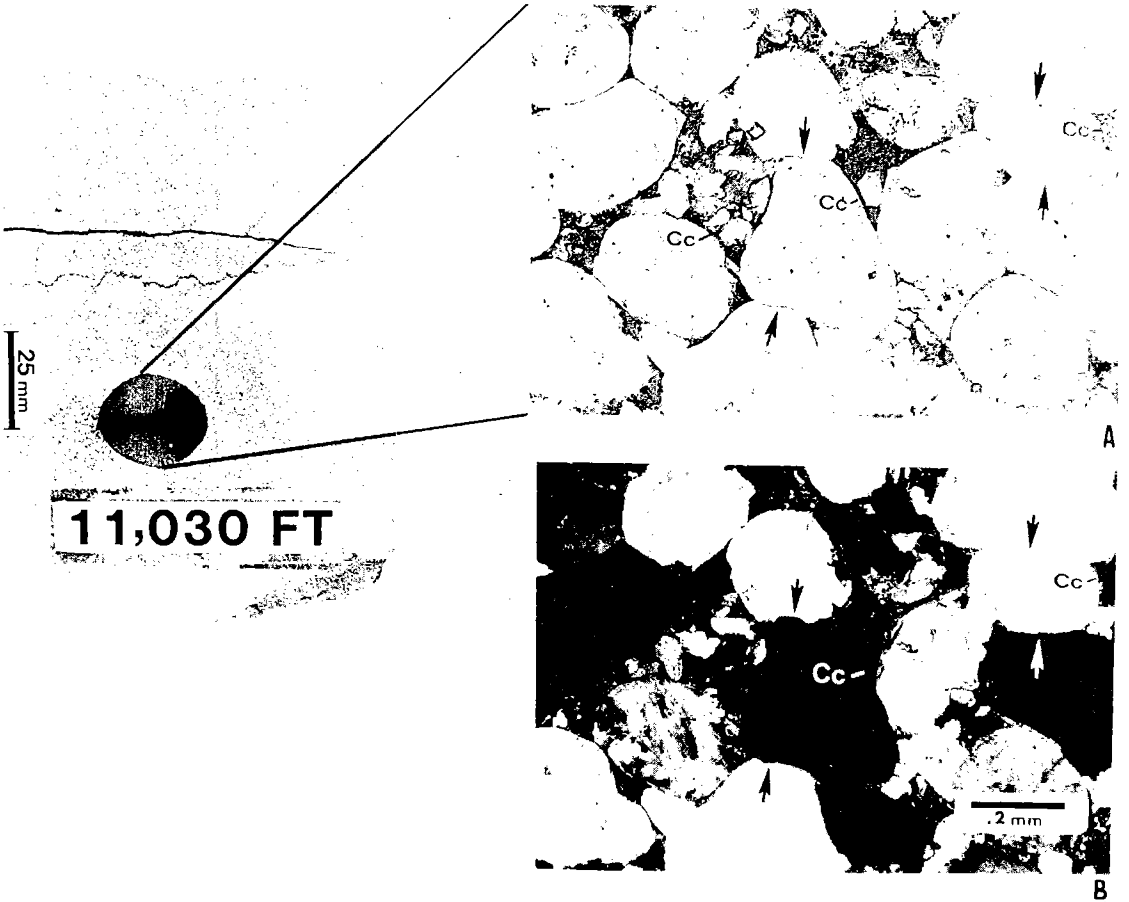


Figure 1. Silica-exporting interval in the "First Bromide" sandstone. Dissolution features include penetrating grain contacts (arrows) and stylolites (core photograph). Clay coatings (*Cc*) inhibited silica cementation on free faces adjacent to grain contacts. Gulf No. 1 Weaver. Depth, 11,029.8 ft. (A) Plane-polarized light (PPL). (B) Cross-polarized light (CPL).

between initial pore-filling cement and later fracture-filling cements. A description of the mechanism for the generation of calcite cements and the poikilotopic textures evident in some samples is found in Qin and Ortoleva (1994).

Fluid-inclusion microthermometry of Simpson sandstone cements in McClain County indicates four primary cementation episodes (Al-Shaieb and others, 1994). The first episode consists of silica cement with two-phase aqueous fluid inclusions that have homogenization temperatures (T_h) that range from 70° to 100°C. This phase is represented by early quartz overgrowths. Secondly, calcite cement with two-phase aqueous inclusions was precipitated. The T_h values for this episode range from 80° to 100°C. The third episode consists of calcite that contains petroleum-bearing and aqueous inclusions with T_h that range from 95° to 140°C. These cements may have been associated with heated basinal fluid migration. The final episode is higher temperature silica cement with T_h values that range from 110° to 120°C. This cement precipitated in intergranular voids between the earlier quartz overgrowths. These cementing episodes overlap (Fig. 11) and suggest that band genesis involves transitory dynamic processes that are primarily controlled by burial depth and pore-fluid chemistry.

CEMENT BANDS AND RESERVOIR HETEROGENEITY

Observed heterogeneity in Simpson Group sandstones can be directly linked to mechanical and chemical diagenetic processes. Carbonate- and/or silica-cemented zones alternating with porous and permeable zones can generate distinct bands of varying thickness and porosity that are not related to depositional facies. Cemented zones can be identified on micro-resistivity logs as breaks in inferred permeability within apparently homogeneous units (Fig. 12). The importance of these banded structures to well productivity is a function of their thickness and distribution. Some of these structures are thin and laterally limited and do not significantly impact production. These features are easily breached by small fractures that allow fluid communication across the barriers. On the other hand, thicker and more laterally extensive cemented zones have the integrity necessary to serve as barriers to fluid movement and pressure equilibration.

In the Gulf No. 1 Weaver well in McClain County, multiple bands of permeable and impermeable strata act collectively as a pressure seal (Tigert and Al-Shaieb, 1990). The permeable layers are reservoirs within the seal zone. In the Seminole field, additional oil was recovered

Figure 2. Silica-cemented band (*Sb*), exhibiting extensive quartz overgrowth (*Qo*). Detrital grain (*Dg*) morphologies are preserved, suggesting that this zone imported silica and did not experience significant stress-induced dissolution. Gulf No. 1 Weaver. Depth, 11,030.5 ft. (A) PPL. (B) CPL.

from below a cementation band in the "Second Wilcox" sandstone after the reservoir above the band was depleted (F. Toll, personal communication, 1980). Pressures on both sides of this cemented zone were similar, but the oil-bearing reservoir below the band was isolated from the overlying salt-water-bearing (oil-depleted) interval.

SUMMARY AND CONCLUSIONS

Simpson sandstones contain cementation bands that formed through a variety of stress-related mechano-chemical processes. These processes resulted in pressure-solution-induced dissolution and precipitation of silica and carbonate cements. Many porous sandstones contain clay-coated grains that inhibited cement precipitation, whereas silica exported from these zones augmented quartz cementation in silica bands. Band-generating carbonate apparently was imported from nearby carbonate units. Bands in sandstones are multi-episodic and formed within a variety of thermal and fluid domains that reflect the stages of basin evolution. These bands constitute a significant geologic phenomenon, since they can serve as barriers to fluid flow and may form trapping mechanisms for petroleum.

ACKNOWLEDGMENT

The authors gratefully acknowledge the Gas Research Institute for funding this research through contract nos. 5089-26-1805 and 5092-260-2443.

REFERENCES CITED

Al-Shaieb, Zuhair; Puckette, Jim; Rice, A.; and Abdalla, Azhari, 1993, Preferential cementing and auto-isolation in the Lower Cunningham Sandstone: Quarterly Report for Gas Research Institute, Chicago, Illinois.

Al-Shaieb, Zuhair; Puckette, Jim; Abdalla, Azhari; Tigert, V.; and Ortoleva, P., 1994, The banded character of pressure seals, *in* Ortoleva, P. (ed.), Basin compartments and seals: American Association of Petroleum Geologists Memoir 61, p. 351–367.

Dewers, T.; and Ortoleva, P., 1990, A coupled reaction/transport/mechanical model for intergranular pressure solution, stylolites, and differentiation compaction and cementation in clean sandstones: Geochimica et Cosmochimica Acta, v. 54, pt. 2, p. 1609–1625.

______1993, Formation of stylolites, marl/limestone alternations, and clay seams through unstable chemical compaction of argillaceous carbonates, *in* Wolf, K. H.; and Chilingarian, G. V. (eds.), Diagenesis, Volume IV: Elsevier, Amsterdam, p. 155–216.

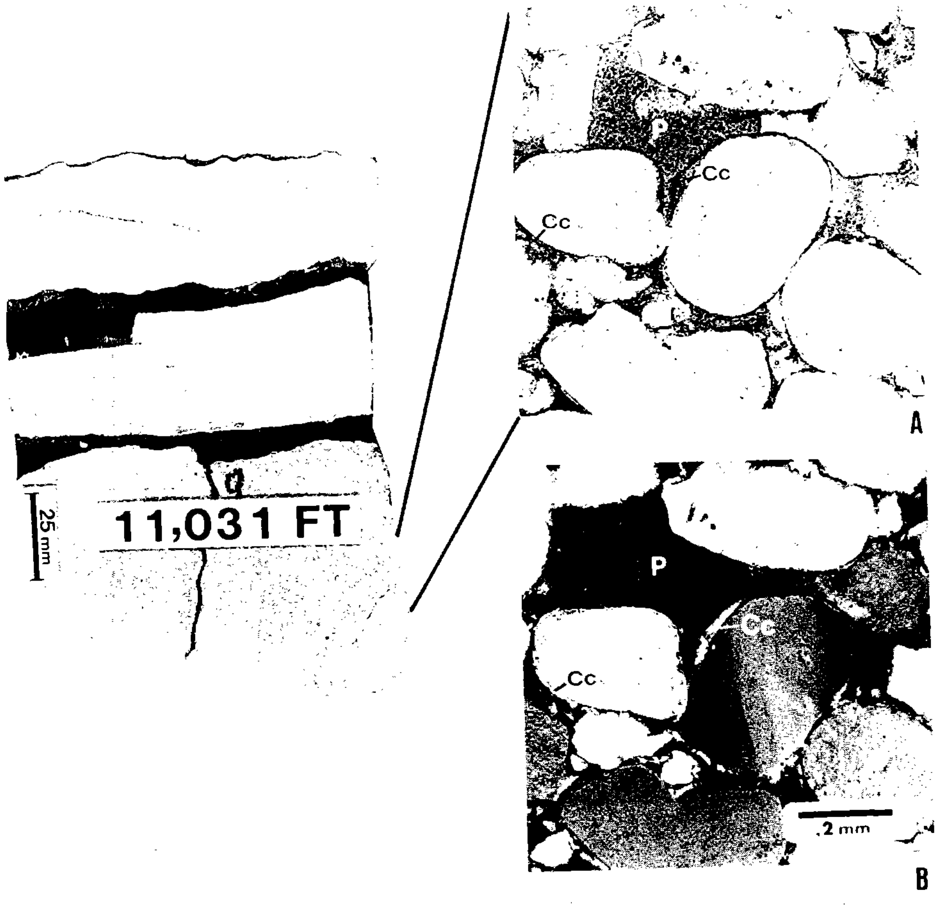


Figure 3. Porous, oil-stained sandstone (darker part of core) with pervasive clay grain coatings (*Cc*) that inhibited silica precipitation and preserved porosity (*P*). Gulf No. 1 Weaver. Depth, 11,031 ft. (A) PPL. (B) CPL.

Gillert, M. P., 1952, The geology of the Simpson group on the northeast flank of the Arbuckle Mountains, Oklahoma: University of Oklahoma unpublished M.S. thesis, 76 p.

O'Brien, J. E.; and Derby, J. R., 1997, Progress report on Simpson and Viola correlations from the Arbuckles to the Ozarks, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 260–266.

Ortoleva, P.; Merino, E.; Moore, C.; and Chadam, J., 1987, Geochemical self-organization I: Reaction-transport feedbacks and modeling approach: American Journal of Science, v. 287, p. 979–1007.

Ortoleva P.; Dewers, T.; and Sauer, B., 1993, Modeling diagenetic bedding, stylolites, concretions, and other mesoscopic mechano-chemical structures, *in* Rezak, R.; and Lavoie, D. (eds.), Carbonate microfabrics: Springer–Verlag, New York, p. 291–300.

Pittman, E. D., 1981, Effect of fault-related granulation on porosity and permeability of quartz sandstones, Simpson Group (Ordovician), Oklahoma: American Association of Petroleum Geologists Bulletin 65, p. 2381–2387.

Qin, C.; and Ortoleva P., 1994, Banded diagenetic pressure seals: types, mechanisms, and homogenized basin dynamics, *in* Ortoleva, P. (ed.), Basin compartments and seals: American Association of Petroleum Geologists Memoir 61, p. 385–400.

Tigert, V.; and Al-Shaieb, Zuhair, 1990, Pressure seals: their diagenetic banding patterns: Earth-Science Review, v. 29, p. 227–240.

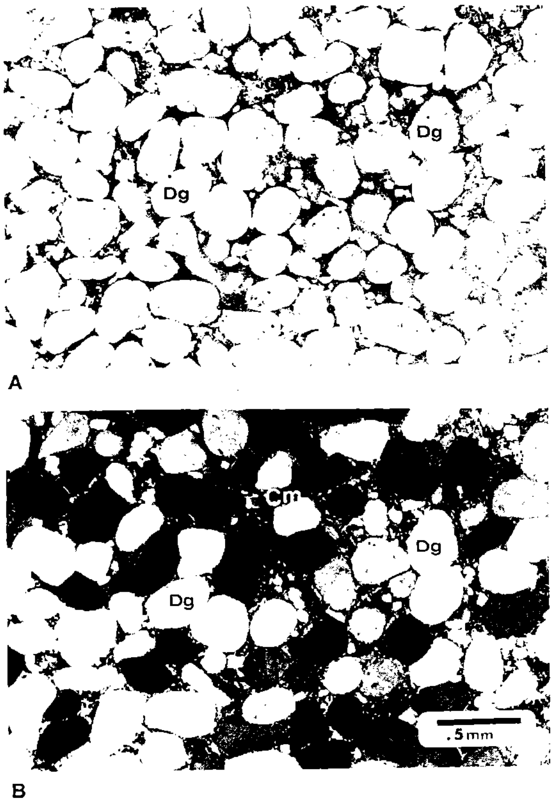


Figure 4. Allogenic clay matrix (*Cm*) that preserved detrital grain (*Dg*) morphology by inhibiting quartz-overgrowth nucleation. Gulf No. 1 Weaver. Depth, 11,052 ft. (A) PPL. (B) CPL.

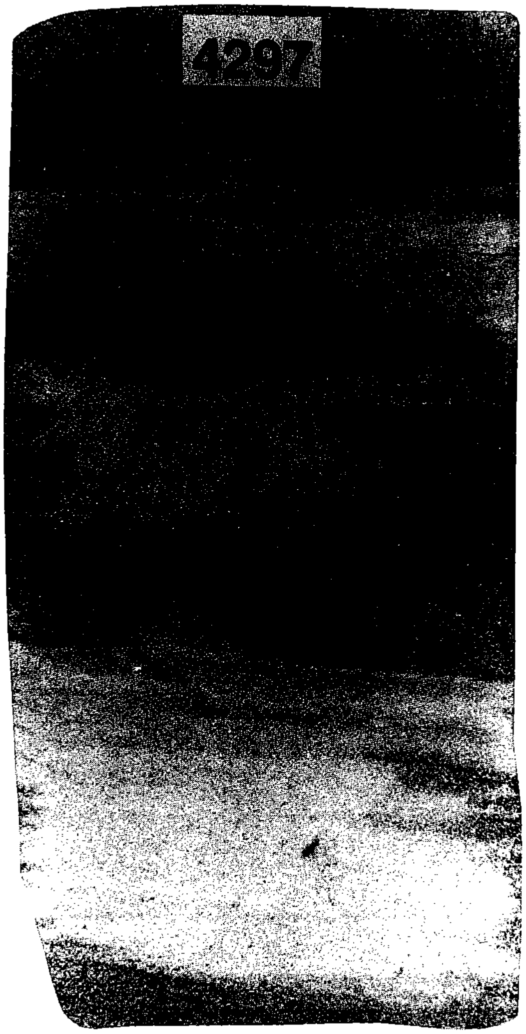


Figure 5. Core photograph illustrating sharp boundaries between silica-cemented bands (lighter) and porous sandstone (darker). Huber No. 1 Snyder. Depth, 4,297 ft.

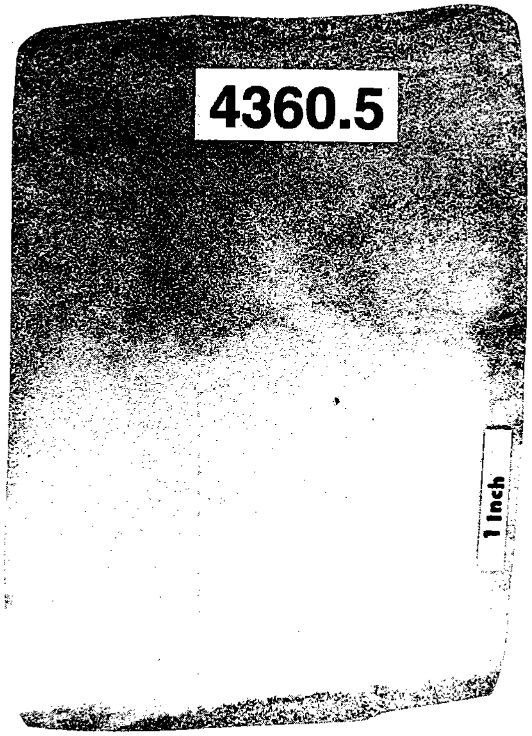


Figure 6. Core photograph illustrating gradational boundary between silica-cemented band and porous sandstone. Huber No. 1 Snyder. Depth, 4,360.5 ft.

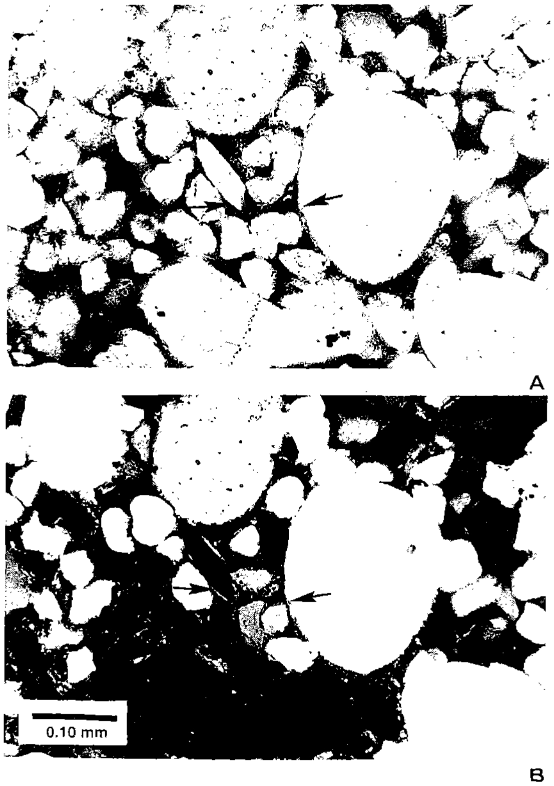


Figure 7. Clay grain coatings (arrows) that inhibited silica precipitation across a range of grain sizes from coarse silt (0.05 mm) to coarse sand (0.9 mm) and preserved porosity. Huber No. 1 Snyder. Depth, 4,256 ft. (A) PPL. (B) CPL.

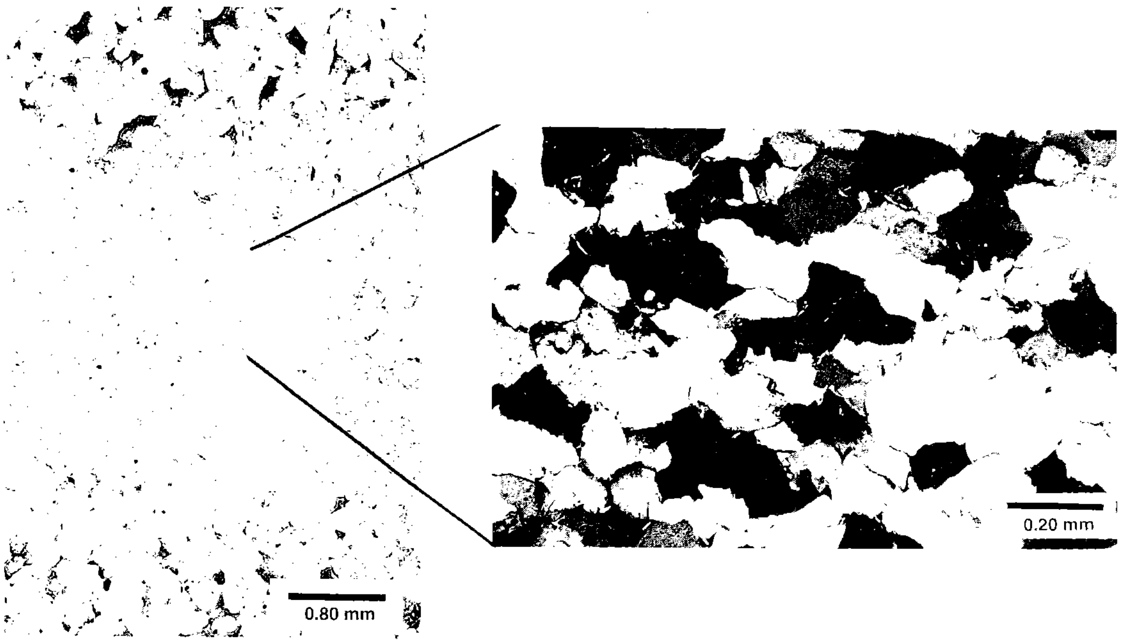


Figure 8. Enhanced dissolution and silica export. Silica band (white), with highly sutured grain boundaries (enlargement), is sandwiched between porous intervals (porosity is gray) with partial clay-grain coatings. Huber No. 1 Snyder. Depth, 4,254 ft.

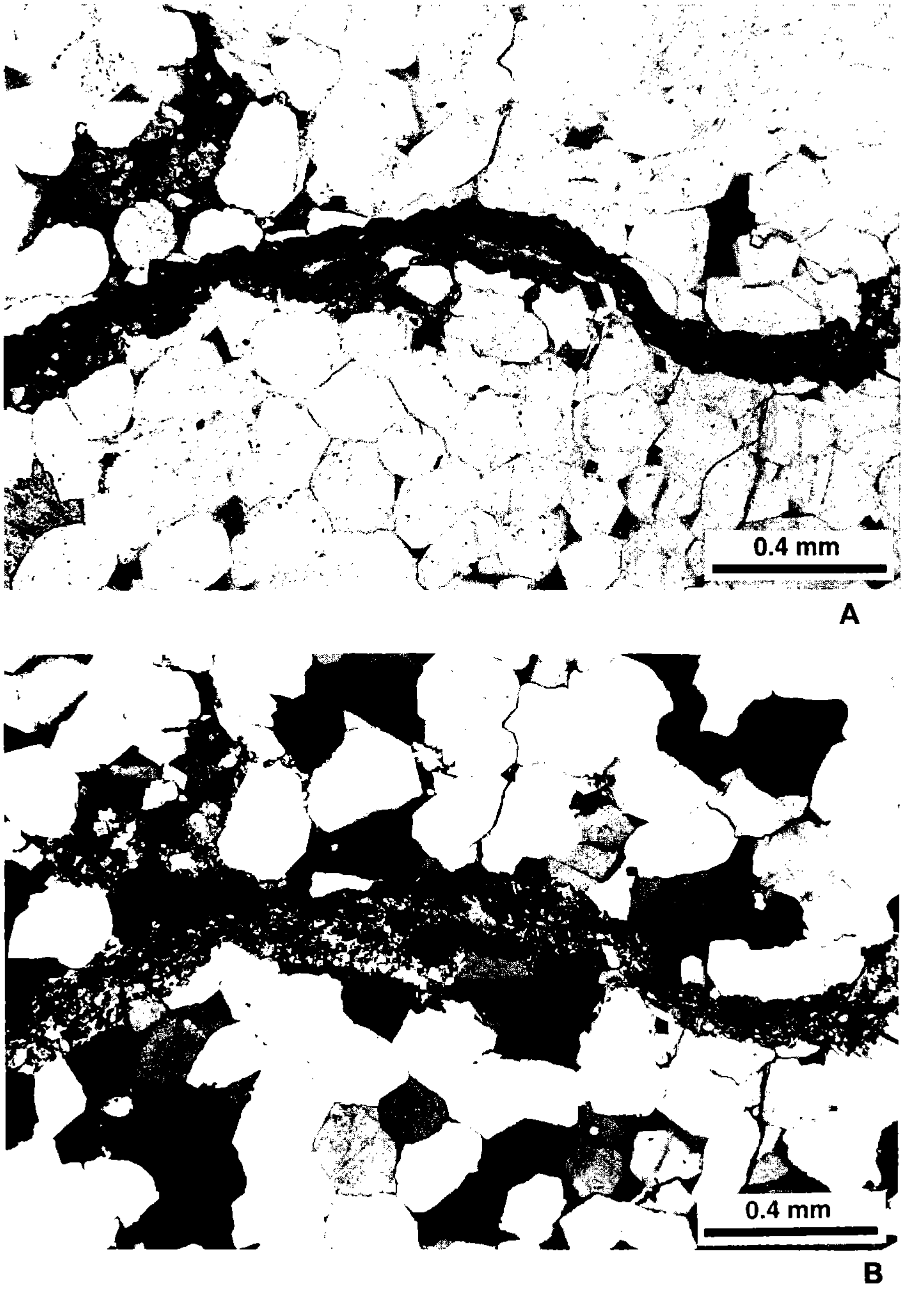


Figure 9. Stylolite cross-cutting quartz overgrowths, indicating that additional pressure solution occurred after initial silica cementation. Silica liberated during this process may have precipitated as the intergranular post-syntaxial-overgrowth cement in silica bands. Huber No. 1 Snyder. Depth, 4,256 ft. (A) PPL. (B) CPL.

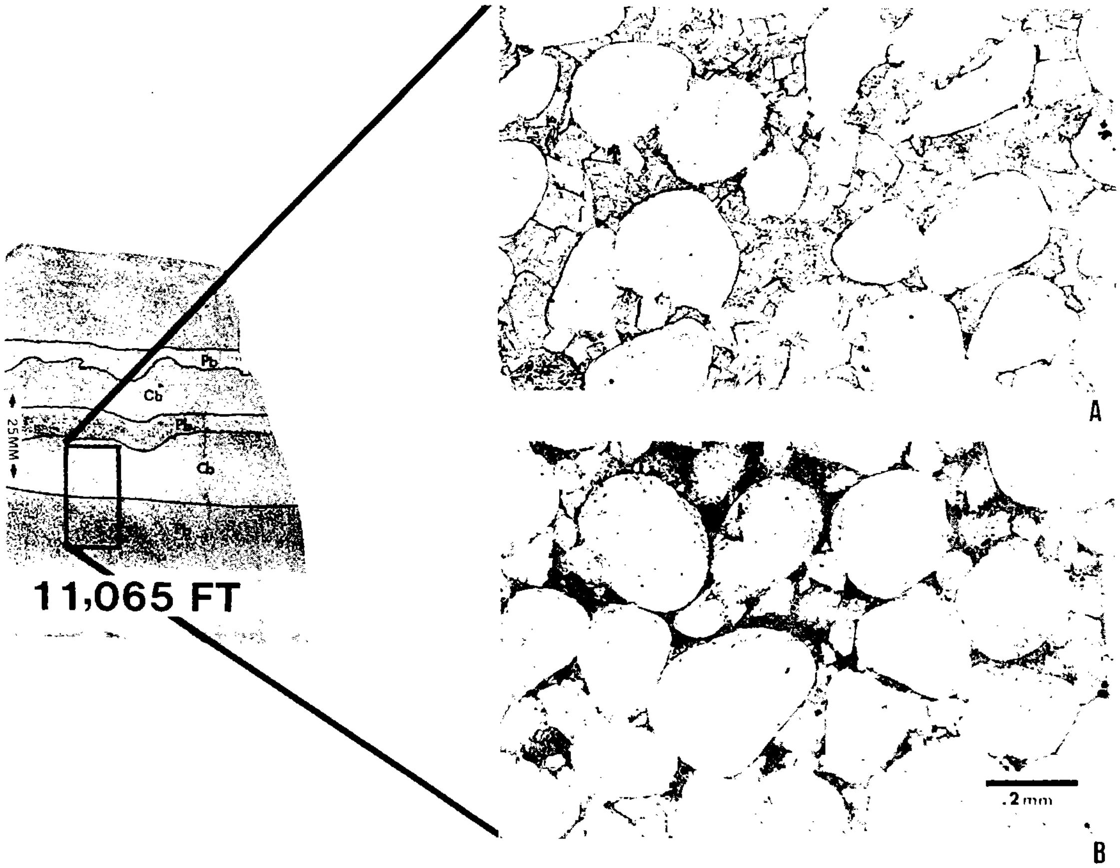


Figure 10. Calcite-cemented bands (*Cb*), alternating with porous bands (*Pb*). (A) Carbonate band. (B) Porous band. Gulf No. 1 Weaver. Depth, 11,065 ft.

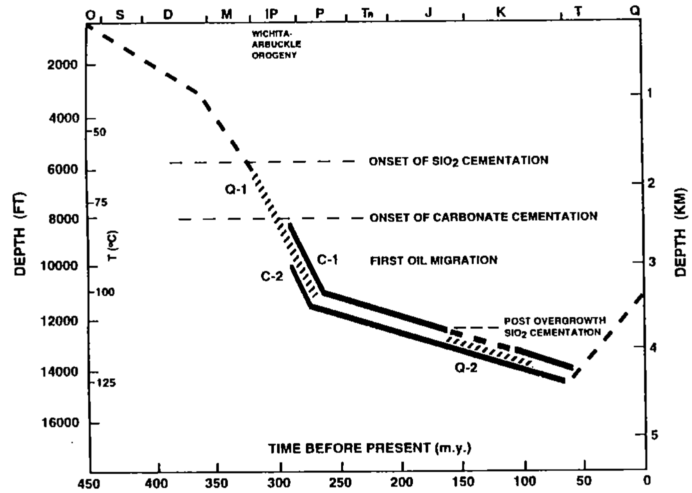


Figure 11. Burial-history curve and timing of the various phases of cementation in the Simpson interval, Gulf No. 1 Weaver. *Q-1* represents initial silica cementation in the form of syntaxial quartz overgrowths. *C-1* and *C-2* correspond to episodes of carbonate cementation that reflect changes in pore-fluid chemistry as hot basinal fluids (including oil) migrated through the rocks. *Q-2* represents a phase of higher temperature post-overgrowth silica cement. (Modified from Al-Shaieb and others, 1994.)

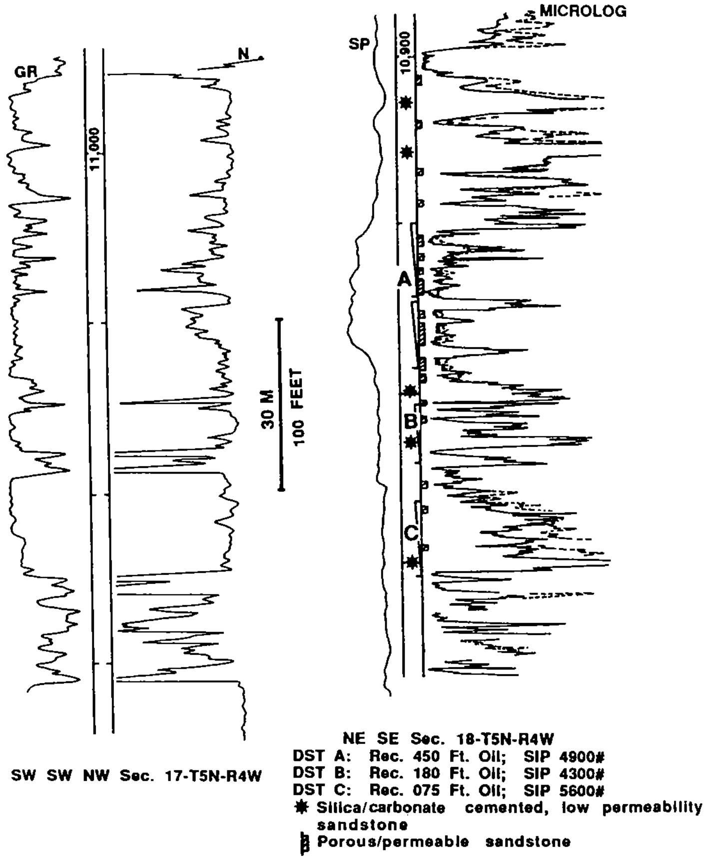


Figure 12. Wireline-log schematic illustrating cementation bands on micro-resistivity log (microlog). Low-permeability zones are indicated by breaks in hachured pattern along vertical column. Stars indicate cemented zones approximately 10 ft thick that apparently isolate reservoirs. Reservoir pressures (shut-in pressures, *SIP*) from drill-stem tests (*DST*) suggest vertical isolation between intervals *A* and *B*. Gamma-ray (*GR*) and neutron (*N*) curves indicate that cemented zones occur within sandstones and do not represent shale beds. *SP* is the spontaneous-potential curve. Bromide sandstone, McClain County, Oklahoma.

PART II

ABSTRACTS AND SHORT REPORTS RELATED TO POSTER PRESENTATIONS

Sequence Stratigraphic Model for the Simpson Group of the Southern Midcontinent: Key to a New Stratigraphic Play

Magell P. Candelaria[1]
Consulting Geologist
Midland, Texas

C. Robertson Handford[2]
Consulting Geologist
Plano, Texas

Christy L. Reed[1]
ARCO International Oil and Gas Company
Plano, Texas

ABSTRACT.—The application of a sequence stratigraphic framework to the Middle Ordovician Simpson Group of the southern Midcontinent indicates that significant, untapped reservoir potential remains. This reservoir potential exists within stratigraphic traps that lie off structure and below seismic resolution. Stratigraphic traps can be predicted and exploited through application of classical sequence model principles. Historically, exploration for Simpson sandstone reservoirs in Oklahoma has been structurally driven. As a consequence, there has been very little exploratory drilling for stratigraphic traps that may exist in sparsely drilled areas off structure. A new approach, utilizing sequence stratigraphy, has led to development of a depositional model for post-Joins strata of the Simpson Group in the southern Midcontinent. Through this depositional model, widely recognized, but poorly understood, stratal geometries and relationships of the Simpson Group strata are clarified and placed within a basinwide or regional stratigraphic framework. Within this sequence framework, the lowermost sandstone of the Oil Creek is interpreted as a lowstand shelf-margin wedge accumulation, and the lowermost sandstones of the McLish and Bromide Formations represent basal transgressive units of a third-order stratigraphic sequence, while the overlying shales and shallow-marine carbonates represent widespread late-transgressive to highstand deposition within each sequence. Sequence boundaries may or may not be demonstrably erosional in the southern Oklahoma region.

Stratigraphic-trap prediction by the described sequence model runs counter to industry dogma that Simpson reservoirs are productive only from structural closures, and hence that exploration efforts should target only structural features. Moreover, this sequence framework facilitates recognition of internal reservoir heterogeneity that can lead to discovery of significant new field reserves and recovery of additional reserves from bypassed pays or poorly swept reservoirs in mature fields.

INTRODUCTION

Exploration for oil and gas fields in Oklahoma since the turn of the century has been almost exclusively oriented toward the search for structural traps. The stratigraphic component of structurally trapped reservoirs has been largely ignored as a result of this exploration strategy. The intent of this paper is to advocate our original concept (Candelaria and others, 1994; Candelaria and Handford, 1995) to establish a regional sequence depositional framework that addresses these stratigraphic issues relative to structurally trapped hydrocarbon reservoirs in the Simpson Group, and to describe hitherto unrecognized potential stratigraphic-trap opportunities. The ubiquitous occurrence of structurally trapped hydrocarbons in Oklahoma has resulted in a paucity of published accounts regarding the search for reservoir/trap relationships between structures or along the flanks of paleostructures.

Lithofacies description and depositional-environment interpretations of the Simpson Group are numerous (Decker and Merritt, 1931; Schramm, 1964; Ireland, 1965;

---

[1] Formerly ARCO Oil and Gas Company, Midland, Texas.
[2] Formerly ARCO Exploration and Production Technology Company, Plano, Texas.

Candelaria, M. P.; Handford, C. R.; and Reed, C. L., 1997, Sequence stratigraphic model for the Simpson Group of the southern Midcontinent: key to a new stratigraphic play, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 218–223.

Lewis, 1978; McPherson and others, 1988), yet published literature contains few accounts of studies focused on stratal geometries and their significance with respect to stratigraphic-trap potential. A few studies (Dapples, 1955; Ireland, 1965; Longman, 1981; Johnson, 1991) have made reference to stratal geometries and the likelihood that Simpson sands, so well developed in the Ardmore basin of southern Oklahoma, are transgressive units. However, these studies have not emphasized, nor have they integrated, the described stratal relationships into an internally consistent regional sequence stratigraphic framework, as was proposed in our earlier work (Candelaria and others, 1994). Working from a sequence stratigraphic perspective, we proposed that stratigraphic traps may have been set up by deposition of (1) lowstand sandstones along the margin of the southern Oklahoma aulacogen, (2) retrogradational shoreface sandstones that are both temporally and spatially separated from each other, and (3) aggradational carbonate shoal facies and progradational carbonate banks. We suggested that this stratigraphic architecture is likely more commonplace than is presently recognized or appreciated for the Simpson Group. It was further stated that when incorporated in a well-log-based exploration strategy, this reinterpretation of stratal architecture could aid in the prediction of subtle stratigraphic traps that escape seismic detection. This approach may lead to an era of renewed exploration for stratigraphic traps in the Simpson Group.

STRATIGRAPHY

The Middle Ordovician Simpson Group of the southern Midcontinent (Decker and Merritt, 1931) consists of interbedded quartz arenites, skeletal limestones, and gray-green marine shale (Ham, 1973). The Simpson Group consists of five formations, in ascending order: Joins, Oil Creek, McLish, Tulip Creek, and Bromide Formations (Decker and Merritt, 1931). In terms of regional stratigraphy, several workers (Cram, 1948; Ham, 1955; Gahring, 1959; Statler, 1965) did not recognize the Tulip Creek as a formation. Instead, they argued that the Tulip Creek is only a local facies of the Bromide Formation. Thus, they included the Tulip Creek interval as the lower part of the Bromide Formation. We will follow this reasoning and will omit discussion of the Tulip Creek as a separate formation. Whether the Tulip Creek deserves formational status or not, exclusion of the Tulip Creek interval from the following discussion of the sequence stratigraphy of the Simpson Group neither assists nor weakens our proposed sequence stratigraphic model.

SEQUENCE STRATIGRAPHY

The chronostratigraphic framework of the Simpson Group (Fig. 1) clearly illustrates the time-transgressive nature of lithostratigraphic units of the Simpson Group, as previously interpreted by numerous workers (Dapples, 1955; Schramm, 1964, 1965; Ireland, 1965; Statler, 1965; Longman, 1981; Johnson, 1991). In retrospect, Statler (1965), who clearly illustrated these relationships, was ahead of his time, as his chronostratigraphic correlations have since gone unappreciated until recently. From the perspective of a sequence stratigraphic interpretation, Statler's work becomes much more meaningful and significant in terms of establishing a framework for stratal geometries and stratigraphic-trap relationships as incorporated into the sequence stratigraphic model described below. We propose that each major sandstone unit of the post-Joins Simpson Group—the basal Oil Creek, basal McLish, and basal Bromide (correlative to the Tulip Creek of many workers)—represents local lowstand to widespread transgressive deposits of third-order sequences.

Oil Creek Formation

The basal Oil Creek sandstone attains a maximum thickness of approximately 350 ft within the Ardmore basin, and its distribution is largely restricted to the northeast margin of the basin, as it pinches out by basinward downlap to the west and southwest (Schramm, 1964). Basal Oil Creek sand is anomalous in that it is 2 to 3 times the thickness of basal sandstones of other Simpson Group formations. Within our sequence model, the basal Oil Creek sandstone is interpreted to represent lowstand systems-tract deposition along the basin margin of the southern Oklahoma aulacogen (Fig. 2). Sands derived from preexisting mature sandstones farther north on the craton were likely reworked and transported basinward during lowstand exposure of the cratonic shelf. These mature siliciclastics were deposited as a basin-margin lowstand wedge in post-Joins depositional time. In this model we do not invoke significant water depth in the aulacogen at the time of Oil Creek lowstand deposition. Depositional facies described for the basal Oil Creek sandstone are interpreted as being of fairly shallow-water origin, probably indicative of shoreface environments (McPherson and others, 1988).

Within a sequence stratigraphic framework, third-order lowstand of sea level exposed the cratonic shelf subaerially (the "quiescent periods" of Longman, 1981). During this time, siliciclastics were transported via fluvial and eolian processes across the emergent shelf to the basin margin. Siliciclastics of the basal Oil Creek sandstone were deposited as thin, lowstand paralic deposits, and as a much thicker accumulation along the aulacogen basin margin (Fig. 2). The geometry and distribution of thick basal Oil Creek sandstone are interpreted as a lowstand wedge accumulation (LSW) of the lowstand systems tract. The basal Oil Creek sandstone, as well as younger sands higher in the Oil Creek section, exhibit depositional features indicative of shallow depositional environments (McPherson and others, 1988; Forgotson and others, 1997). In the model we propose, the thinner Oil Creek sands on the shelf farther to the north represent widespread transgressive systems tract (TST) accumulations, as suggested by Johnson (1991). During third-order sea-level rise (transgression), the former lowstand shoreline was transgressed and capped by a ravinement surface. As sea level continued to rise, the shoreline retreated, leaving a series of discontinuous sand bodies stranded along the cratonic shelf as transgression continued (Statler, 1965). We interpret these sands as backstepping or retrogradational shoreface complexes (Fig. 3), which overlie the previously exposed shelf (third-order sequence boundary). Depositional facies within these sand bodies exhibit upward-shallowing features interpreted as representing a progression from lower

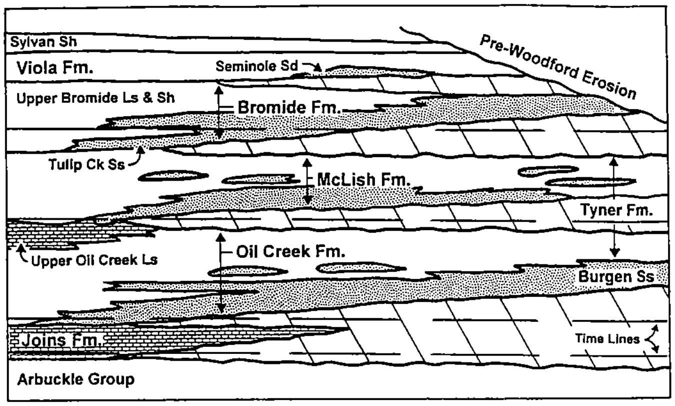


Figure 1. Chronostratigraphic diagram (modified from Statler, 1965), illustrating the time transgressive nature of the Simpson Group lithostratigraphic units in Oklahoma. Note also that isolated sand bodies, as originally depicted schematically by Statler, represent stranded shoreface sandstones in our sequence model. These isolated shoreface complexes are potential stratigraphic-trap reservoirs, which historically have not been targeted by structurally driven exploration strategies. Diagram extends from south (left) to northeast (right).

shoreface to foreshore environments (Forgotson and others, 1997). Marine shale or muddy skeletal limestones were deposited basinward of the contemporaneous shoreface complex, eventually burying the stranded, retrogradational shoreface complexes. As transgression continued, these low-permeability limestone facies isolated potential reservoir sandstones within relatively impermeable strata. Shoreface sands deposited in such a depositional system are likely not in stratigraphic continuity, hence stratigraphic-trap possibilities may exist within porous, discontinuous, transgressive shoreface complexes (Posamentier and others, 1992). In addition, reservoir heterogeneities internal to a sand body exist and have been documented in various fields. These observations indicate that Oil Creek sandstone reservoirs are not simple blanket sandstones with uniform reservoir properties. Internal heterogeneities give rise to complicated reservoir characteristics and reduced recovery efficiency, and may result in bypassed pay zones in many fields where such heterogeneity remains unrecognized.

A dark, organic-rich shale identifiable in the Oil Creek as far north on the craton as northeastern Kansas (Watney and others, 1997) marks the maximum transgression or maximum flooding surface (MFS) of the Oil Creek TST. Above the maximum flooding surface, a shallow-marine environment conducive to widespread carbonate deposition was established across the southern craton. In our sequence model, this carbonate environment represents the highstand systems tract (HST). Highstand deposition consists of skeletal wackestones, packstones, and grainstones, ranging from subtidal skeletal-rich facies to supratidal algal-dominated facies (Ham, 1973). Highstand carbonates are locally interbedded with thin siliciclastic intervals of shoreface, or possibly deltaic, origin. Deposition of predominantly shallow-water carbonate lithologies likely established prograding carbonate banks and aggradational packstone/grainstone shoals. These facies may provide local reservoir units where porosity has been preserved. Peritidal intervals in the upper Oil Creek and McLish Formations, characterized by "birdseye" (fenestral) limestone deposited in peritidal environments, produce oil from closed structures in several fields in southern Oklahoma (Ham, 1954; Suhm, 1997).

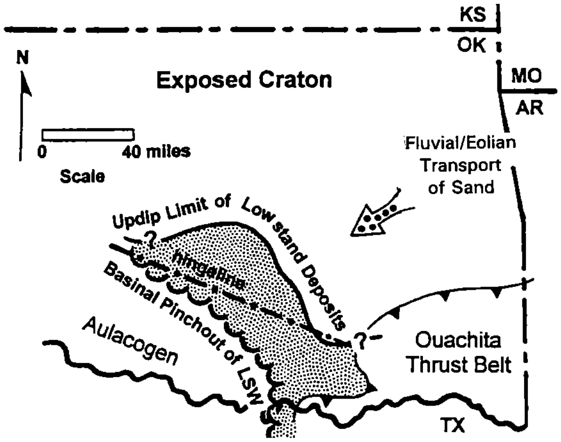


Figure 2. Schematic diagram representing lowstand deposition of the basal Oil Creek sandstone. The thick, basal Oil Creek sandstone is interpreted as a lowstand wedge accumulation of stacked shoreface sands along the northeast margin of the former southern Oklahoma aulacogen. On the basis of basal-sandstone thickness, geometry, and distribution, we conclude that analogous lowstand accumulations did not develop during McLish and Bromide time.

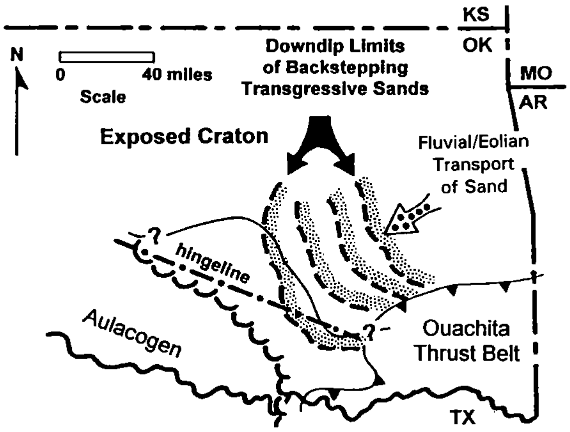


Figure 3. Transgressive systems tract (TST) deposition followed lowstand deposition of the basal Oil Creek sandstone. TST deposits consisting of retrogradational shoreface complexes account for the widespread nature of the basal sandstone of the Oil Creek farther to the north on the cratonic shelf. A similar depositional environment is inferred for the basal sandstones of the McLish and Bromide Formations, because the geometry of these thinner basal sandstone units does not support deposition as a lowstand wedge or within a lowstand systems tract.

A relative sea-level fall concluded Oil Creek highstand deposition and subaerially exposed the craton prior to onset of McLish deposition. A major unconformity developed at this time (Derby and others, 1991), possibly as a result of a pause in the continuous subsidence of the southern Oklahoma aulacogen. This unconformity marks the third-order sequence boundary between Oil Creek and McLish depositional sequences. During this time, quartz sands were transported across the exposed shelf and accumulated as shoreface complexes of the basal sandstone of the McLish Formation.

McLish and Bromide Formations

A similar sequence model, as described above for the Oil Creek, is invoked to explain stratal relationships within the McLish and Bromide Formations. The only significant difference is that during early McLish time, subsidence of the former aulacogen slowed sufficiently, or sediment supply was less voluminous, to preclude accumulation of thick lowstand clastics along the basin margin. This difference, with respect to contemporaneous basin history, is significant with respect to sequence interpretation of McLish and younger strata, as well as to sandstone-reservoir geometry and distribution. As determined from stratal thicknesses and distribution, no comparable siliciclastic LSW developed during either McLish or Bromide depositional episodes. Within our model, the basal sands of the McLish and Bromide Formations consist largely of shoreface complexes deposited during transgressive episodes, as opposed to regressive deposition as proposed by Longman (1981) for the Bromide sands. At their maximum development, these basal sands are considerably thinner, as transgressive deposits, than the basal Oil Creek lowstand wedge sandstone (Fig. 4). In our interpretation, these basal sands of the McLish and Bromide Formations represent retrogradational shoreface deposits reworked within a shoreface environment on the cratonic shelf. The TST sandstones of the McLish and Bromide are of comparable thicknesses as they thin northward by onlap.

A maximum-flooding surface, which is not always characterized by dark, organic-rich marine shale, particularly in the more updip localities within shallow-water environments, marks the transition from transgressive deposition to highstand deposition within the McLish and Bromide depositional sequences. Above the maximum-flooding surface, highstand deposits consisting of mixed shallow-marine skeletal carbonates, shale, and minor siliciclastics constitute highstand systems tract deposition in the McLish and Bromide, analogous to the underlying Oil Creek Formation. The presence of a third-order sequence boundary separating the McLish HST from the overlying TST of the Bromide Formation has not been demonstrated biostratigraphically. However, a third-order boundary is invoked at this stratigraphic position in the described model for the reasons given below, thus separating the McLish third-order sequence from the overlying Bromide sequence.

In terms of reservoir potential, where TST shoreface sandstones lie on the flanks of structures or are isolated between structures, these strata represent stratigraphic traps of high-reservoir-quality sandstone, which, to date, remain largely untapped as exploration targets. Porous, peritidal HST carbonates of the McLish, known to produce from structural closures, and porous packstone/grainstone shoal facies of the McLish and Bromide may be productive from stratigraphic traps in off-structure areas. These reservoir units may provide additional exploration potential when correlation techniques, developed within a sequence framework, are employed and where stratigraphic trapping geometries may be predicted.

SEQUENCE BOUNDARIES

Adherence to the classical sequence stratigraphic model as it was defined (Mitchum and others, 1977; Van Wagoner and others, 1988) requires existence of a sequence boundary between successive third-order sequences (within our model, between each formation of the Simpson Group). This requirement exposes no significant weakness in the proposed sequence model. By definition, a third-order sequence boundary is an unconformity across which stratal discordance may be evident. Perhaps more importantly, the definition of *sequence boundary* also provides that the correlative conformable surface may be its lateral extension. Hence, evidence of disconformity between each inferred third-order sequence of the Simspon Group (each formation in this proposed model) is not required to be evident within the study area. Studies of the correlative stratigraphic section elsewhere on the craton, such as parts of Kansas (Watney and others, 1997) and Arkansas (O'Brien and Derby, 1997), for example, demonstrate evidence of disconformity between formations of the Simpson Group and coeval strata. Thus, correlative surfaces that appear conformable over wide areas in southern Oklahoma may, in

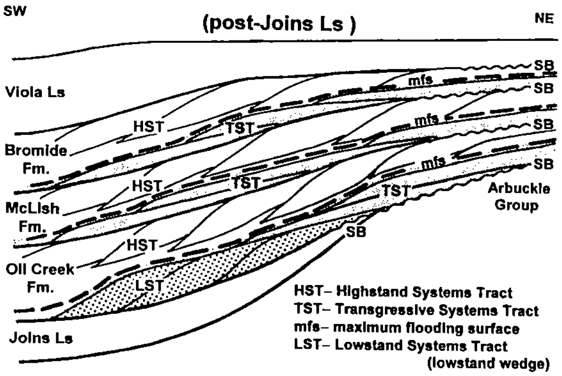


Figure 4. Sequence stratigraphic framework of the entire Simpson Group. The basal Oil Creek sandstone represents a lowstand wedge accumulation of stacked shoreface sands. Back-stepping cratonward are shoreface sands reworked as thinner, widespread, transgressive systems tract deposits of the Oil Creek, McLish, and Bromide Formations. On the cratonic shelf, these TST sandstones overlie their respective underlying third-order sequence boundaries (*SB*). The TST culminates in a maximum flooding surface, which is the downlap surface onto which progradational carbonate banks and minor shoreface siliciclastics were deposited during a third-order sea-level highstand for each of the Oil Creek, McLish, and Bromide sequences.

fact, be sequence boundaries, without violation of the definition of third-order sequences and their bounding surfaces, as originally described.

SUMMARY AND CONCLUSIONS

The use of a sequence stratigraphic model assists in explaining and clarifying the various Simpson Group sand-body geometries and distributions. Moreover, this sequence model assists prediction of potential stratigraphic-trap origin and occurrence as well as reservoir-facies geometry. It is important within this context to bear in mind that basal Oil Creek sand is not likely to be a continuous lithostratigraphic unit everywhere. Indeed, this proposed model suggests that Oil Creek sands of reservoir potential may consist of both LST and discontinuous TST deposits.

In areas such as Oklahoma, where well control is highly concentrated on structural features, with little off-structure well control, it becomes critical (for successful exploitation of stratigraphic-trap plays) that the depositional system be identified correctly. Accurate interpretation of the depositional environment is critical to prediction of sand-body geometry, continuity, and internal heterogeneity. In stratigraphic-trap plays, it is critical that discontinuous reservoir units not be correlated as coeval and continuous; they may, in fact, represent distinct depositional episodes and separate reservoir units (Posamentier and others, 1992). The benefits of accurate knowledge of the depositional system and stratal geometries to secondary-recovery efforts and field development are obvious. For stratigraphic plays such as this, close integration of wireline-log petrofacies with depositional facies, as interpreted from cores, is an absolute requirement for successful prediction of trap style, geometry, and distribution.

From our sequence stratigraphic interpretation, we conclude the following:

- Three third-order sequences—Oil Creek, McLish, and Bromide—have been identified by well-log correlation within post-Joins Simpson Group strata of southern Oklahoma.
- Highly productive siliciclastic strata of the Simpson Group are interpreted as both lowstand wedge accumulations that fill shelf-proximal areas of the contemporaneous basin, and as retrogradational (transgressive) shoreface complexes on the craton.
- Retrogradational shoreface sands may be discontinuous bodies of high reservoir potential in local stratigraphic-trap geometry and thus may constitute a significant, and yet unrecognized, exploration opportunity in southern Oklahoma.
- Sequence interpretation affords widespread exploration opportunity in sparsely drilled, off-structure areas, and in areas where seismic data are difficult to acquire or are of limited resolution.

The application of this sequence stratigraphic approach to Simpson Group reservoir prediction may usher in a new era of exploration in the southern Midcontinent. The proposed sequence model is counter to industry dogma that "Simpson reservoirs are productive only from structural closures." This well-log-based sequence stratigraphic model can explain and delineate internal reservoir heterogeneities, as well as identify off-structure stratigraphic-trap geometries. Stratigraphic traps within the Simpson remain largely unexplored and lie waiting for aggressive operators willing to apply new techniques in their search for economic quantities of oil and gas from historically prolific Simpson Group reservoirs.

REFERENCES CITED

Candelaria, M. P.; and Handford, C. R., 1995, Sequence stratigraphic model for the Simpson Group of the southern mid-continent, *in* Hyne, N. J. (ed.), Sequence stratigraphy of the mid-continent: Tulsa Geological Society Special Publication 4, p. 319–332.

Candelaria, M. P.; Handford, C. R.; and Reed, C. L., 1994, Sequence model for the Simpson Group of the southern mid-continent: A tool for stratigraphic trap prediction [abstract], *in* Gibbs, J. F. (ed.), Synergy equals energy, 1994 symposium: West Texas Geological Society Publication 94–94, p. 177.

Cram, I. H., 1948, Cumberland oil field, Bryan and Marshall Counties, Oklahoma, *in* Howell, J. V. (ed.), Structure of typical American oil fields: American Association of Petroleum Geologists, v. 3, p. 341–358.

Dapples, E. C., 1955, General lithofacies relationship of St. Peter sandstone and Simpson group: American Association of Petroleum Geologists Bulletin, v. 39, p. 444–467.

Decker, C. E.; and Merritt, C. A., 1931, Stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle, and Simpson Groups, Cambrian and Ordovician, Oklahoma: a review of correlation tools and techniques available to the explorationist, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Forgotson, J. M.; Boyce, J. T.; Knapp, R. M.; Liu, Huaibo; and Smith, P. W., 1997, Influence of vertical permeability barriers on ultimate recovery from Oil Creek reservoirs, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 194–202.

Gahring, R. R., 1959, History and development of North Madill field, Marshall County, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 43, p. 274–286.

Ham, W. E., 1954, Algal origin of the "birds-eye" limestone in the McLish formation: Oklahoma Academy of Science Proceedings, v. 33, p. 200–203.

_____1955, Regional stratigraphy and structure of the Arbuckle Mountain region, *pt. 2 of* Geology of the Arbuckle Mountain region: Oklahoma Geological Survey Guidebook 3, p. 29–61.

_____1973, Regional geology of the Arbuckle Mountains, Oklahoma: Oklahoma Geological Survey Special Publication 73-3, 61 p.

Ireland, H. A., 1965, Regional depositional basin and correlations of Simpson Group, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 74–89.

Johnson, K. S., 1991, Geologic overview and economic importance of Late Cambrian and Ordovician rocks in Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 3–14.

Lewis, R. D., 1978, Environments of deposition and paleoecology of the Oil Creek Formation (Middle Ordovician), Arbuckle Mountains and Criner Hills, Oklahoma [abstract]: West Texas Geological Society Bulletin, v. 78-69, p. 88.

Longman, M. W., 1981, Deposition of the Bromide Formation, Arbuckle Mountains, Oklahoma: ontogeny of an ancient carbonate shelf: Oklahoma City Geological Society, Shale Shaker, v. 32, no. 2, p. 1–18.

McPherson, J. G.; Denison, R. E.; Kirkland, D. W.; and Summers, D. M., 1988, Basal sandstone of the Oil Creek Formation in the quarry of the Pennsylvania Glass Sand Corporation, Johnston County, Oklahoma, *in* Hayward, O. T. (ed.), Centennial field guide: Geological Society of America, South-Central Section, v. 4, p. 165–170.

Mitchum, R. M.; Vail, P. R.; and Thompson, S., III, 1977, Seismic stratigraphy and global changes of sea level, Part 2: The depositional sequence as a basic unit for stratigraphic analysis, *in* Payton, C. E. (ed.), Seismic stratigraphy—applications to hydrocarbon exploration: American Association of Petroleum Geologists Memoir 26, p. 53–62.

O'Brien, J. E.; and Derby, J. R., 1997, Progress report on Simpson and Viola correlations from the Arbuckles to the Ozarks, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 260–266.

Posamentier, H. W.; Allen, G. P.; James, D. P.; and Tesson, M., 1992, Forced regressions in a sequence stratigraphic framework: concepts, examples, and exploration significance: American Association of Petroleum Geologists Bulletin, v. 76, p. 1687–1709.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

_____1965, Resume of Simpson (Ordovician) stratigraphy, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 26–34.

Statler, A. T., 1965, Stratigraphy of the Simpson Group in Oklahoma, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 162–211.

Suhm, R. W., 1997, Simpson stratigraphy of the southern Midcontinent, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 3–38.

Van Wagoner, J. C.; Posamentier, H. W.; Mitchum, R. M.; Vail, P. R.; Sarg, J. F.; Loutit, T. S.; and Hardenbol, J., 1988, An overview of the fundamentals of sequence stratigraphy and key definitions, *in* Wilgus, C. K.; Hastings, B. S., Kendall, C. G. St. C.; Posamentier, H. W.; Ross, C. A.; and Van Wagoner, J. C. (eds.), Sea-level changes—an integrated approach: Society of Economic Paleontologists and Mineralogists Special Publication 42, p. 39–45.

Watney, W. L.; Stephens, Bryan; and Newell, K. D., 1997, Shallowing-upward events and their implications for internal correlations and depositional environment of the St. Peter Sandstone in the Forest City basin, northeastern Kansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 267–275.

Stratigraphy of the Middle to Upper Ordovician Everton Formation, St. Peter Sandstone, Joachim Dolomite, and Plattin, Kimmswick, and Fernvale Limestones (Simpson–Viola Equivalents) of Northern Arkansas

William W. Craig
University of New Orleans
New Orleans, Louisiana

INTRODUCTION

Arkansas strata equivalent to the Oklahoma Simpson Group are assigned, in ascending order, to the Everton Formation, St. Peter Sandstone, Joachim Dolomite, and Plattin Limestone; the overlying Kimmswick and Fernvale Limestones of northern Arkansas are broadly coeval with the Viola Group (Fig. 1). These strata crop out in a broad east–west belt across the northern part of the State. They are best exposed in a much narrower zone along the drainages of the Buffalo and White Rivers (Fig. 2), the valleys of which are dissected 120–150 m below the surrounding upland.

The cumulative thickness of these Middle to Upper Ordovician strata is slightly less than 400 m, but nowhere is this maximum preserved at a single locality. The sequence is thickest in the east, but it thins markedly westward through both depositional pinchout and erosional truncation of individual units. In Newton County, in the west, the entire succession is composed of 90–110 m of the Everton Formation, overlain by an unevenly distributed Fernvale, 0–7.5 m thick, and a few thin, scattered occurrences of Plattin Limestone. West of Newton County, the succession passes beneath Carboniferous strata and remains in the subsurface until it reappears in eastern Oklahoma. These Arkansas equivalents to the Hunton–Viola Groups are composed of interbedded carbonate and quartz arenite in the lower part of the section and relatively pure carbonate in the upper part. They represent deposits that accumulated in alternating shallow subtidal and tidal-flat environments.

STRATIGRAPHY

Everton Formation

The Everton Formation is an intergradational complex of limestone, dolomite, and quartz arenite. The stratigraphy and nomenclature of the unit were established by Purdue and Miser (1916), McKnight (1935), and Suhm (1974). In addition, studies of Everton outcrops in Newton, Boone, and Carroll Counties by Kuhn (1984) and Zimmerman (1989) provided the writer with much of his understanding of the unit. All members of the Everton contain beds deposited both below and above low mean tide, but individual members tend to be characterized by one or the other of these two broad depositional realms. Following Kuhn's (1984) distinction, Everton rocks deposited in subtidal environments differ from those of tidal-flat origin in that subtidal rocks are characterized by a greater percentage of grainstone, commonly oolitic; an absence of mud cracks; rare quartz-sandy conglomerates with limestone rip-up clasts (storm deposits); rare fenestral fabric; an absence of pervasive dolomitization; abundant interbedded sandstone; fewer stromatolitic boundstones and cryptalgal laminations; and a more varied fauna. The wackestone and mudstone deposited in intertidal and supratidal environments possess features opposite to these.

The lower member of the Everton, the Sneeds Dolomite (Fig. 3), is a laterally persistent unit that thickens from 15 m in the west to 25 m in the east along the courses of the Buffalo and White Rivers (Suhm, 1974). The Sneeds marks the initial transgression of the Everton over the eroded surface of the underlying Middle Ordovician Powell Formation. Following this initial transgression, the area rapidly aggraded, forming tidal-flat conditions in which most of the Sneeds accumulated. Above the Sneeds, Suhm (1974) recognizes two informal members of interbedded limestone and sandstone, which he designates A and B. Member A, which has a maximum thickness of 25 m, is restricted to the eastern part of the Buffalo–White River traverse; member B, which is as thick as 30 m, is restricted to the western part. They grade laterally into, and are separated by, a dolomite that occupies the entire thickness of the Ever-

---

Craig, W. W., 1997, Stratigraphy of the Middle to Upper Ordovician Everton Formation, St. Peter Sandstone, Joachim Dolomite, and Plattin, Kimmswick, and Fernvale Limestones (Simpson–Viola equivalents) of northern Arkansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 224–226.

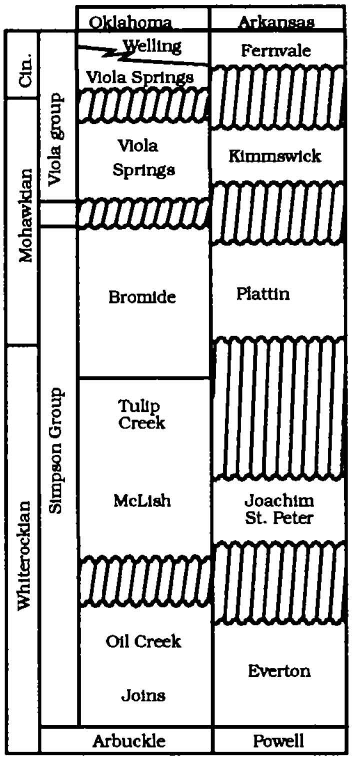


Figure 1. Correlation of Simpson and Viola Group formations in Oklahoma with units of equivalent age that crop out in northern Arkansas. Correlation based on occurrence of major conodont groups.

ton between the Sneeds and the upper part of the formation (Fig. 3). These members represent renewed transgression. North of the traverse, in the drainages of the King's River, Piney Creek, and Crooked Creek, member B rests unconformably on a greatly thinned Sneeds, or onlaps the Sneeds and rests directly on the Powell. Suhm interprets members A and B as products of a dominantly subtidal lagoonal environment that was established behind two prominent barrier islands, now represented by the Newton Sandstone Member in the west and the slightly older Calico Rock Sandstone Member in the east (Fig. 3). The Calico Rock has a maximum thickness of 45 m; it thins and eventually disappears to the west. The Newton, with a maximum thickness of 40 m, thins and disappears to the east. These sandstones rest conformably on members A and B in most places along the Buffalo–White River traverse, but to the north the contact between member B and the overlying Newton is scoured, suggesting transgression of the barrier over the shallow carbonate bottom of member B.

A widespread unit of interbedded sandstone and dolomite, which ranges in thickness from 18 to 42 m, occurs above the Newton Sandstone. Suhm designates this rock informally as member C and interprets it as a deposit of a chenier plain that accumulated above the transgressive Newton. The lithic character of member C dolomites leaves little doubt that much of the unit was deposited under subaerial influence. Apparently, exposure of parts of the surface was prolonged enough at times to allow incipient soil development, because Zimmerman (1989) reports the presence at several levels of calcitans, grain and channel cutans, glaebules, and circumgranular cracks.

The uppermost member of the Everton is the Jasper Limestone, which has a varied faunal and lithic character indicating accumulation under open subtidal conditions. The Jasper ranges from 15 to 30 m thick, rests conformably on member C, and represents the last transgressive phase of Everton deposition.

Supra-Everton Formations

A synopsis of the stratigraphic and depositional frameworks of the supra-Everton Simpson and Viola Groups is provided in Craig (1991). Only a brief account of these strata is given here.

The St. Peter Sandstone ranges from 0 to 60 m thick across northern Arkansas. It is a supermature quartz arenite that is identical to, and indistinguishable from, the Newton, Calico Rock, and other quartz sandstones of the Everton Formation. The unit represents a major transgression and rests everywhere with unconformity on the Everton. Directly following the transgression, deposition of the Joachim Dolomite began, rapidly aggrading nearshore parts of the sandy shelf to form a broad tidal flat. The transition from the St. Peter to the Joachim is gradational. The basal Joachim is shallow subtidal to low intertidal in origin. Above its basal few meters, the Joachim is dominated by stromatolitic, mud-cracked dolomudstone and dolograinstone, interpreted as intertidal to supratidal in origin.

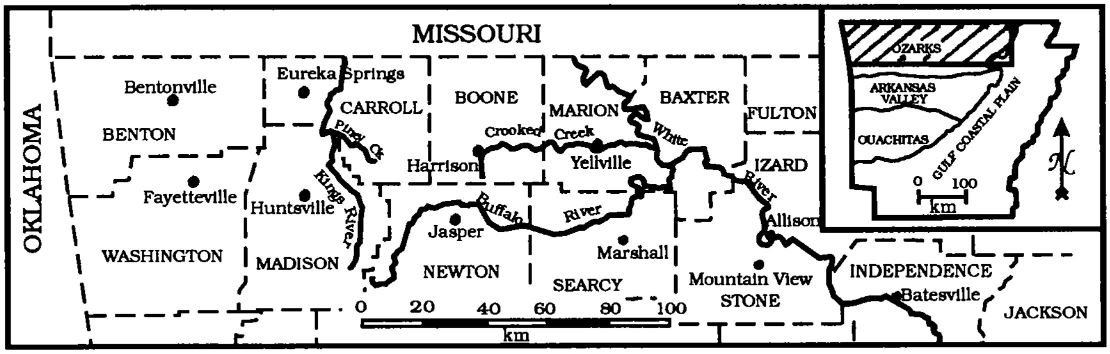


Figure 2. General outcrop area of Simpson-age rocks in northern Arkansas.

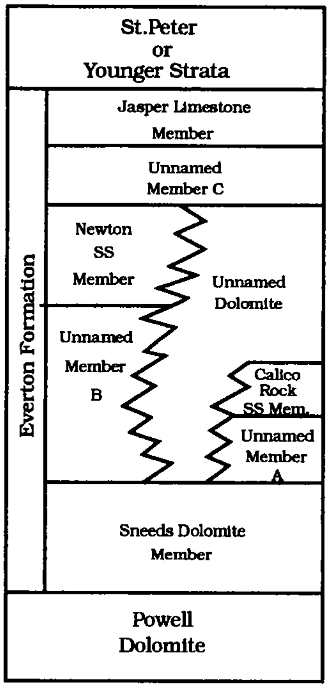


Figure 3. Everton Formation stratigraphy along drainages of the Buffalo and White Rivers, from near Jasper to Mountain View, northern Arkansas (modified from Suhm, 1974).

The maximum thickness of the Joachim in northern Arkansas is in Izard County, where it is 45 m thick. It thins to the west and is known only from scattered outcrops west of western Stone County.

The Plattin Limestone attains a maximum thickness of 75 m just north of Batesville, Independence County. It thins to the west and occurs only as thin, isolated outcrops in eastern Newton County. The Plattin is dominated by interbedded millimeter-scale laminations of lime mudstone and peloidal packstone/grainstone. Mud cracks, fenestral fabric, and calcite pseudomorphs after evaporites are common. These characteristics identify the bulk of the Plattin as a product of supratidal conditions. The base of the limestone in eastern exposures contains a mollusk wackestone of low faunal diversity, suggesting subtidal influence. A somewhat more diverse *Tetradium* fauna occurs near the top of the Plattin, marking a short-lived marine incursion late in the deposition of the unit.

Above the Plattin is the Kimmswick Limestone, a bioturbated skeletal wackestone, packstone, and poorly washed grainstone with a diversified fauna. The overlying Fernvale is a thick-bedded, commonly cross-bedded, coarse-grained crinozoan grainstone. Both of these Viola Group equivalents are of shallow subtidal origin.

Controversy exists regarding the interpretation of formational contacts in this succession of strata, particularly those between the supra-Everton units. Although these contacts are essentially without relief, several lines of evidence suggest that most of them are unconformable (see Craig, 1991, for more details).

Individual formations of the Arkansas equivalents of the Simpson–Viola Group thin to the west by loss of both upper and lower strata, suggesting that both depositional pinchout and erosional truncation occur in this direction. This indicates the presence of a persistent structural high in northwestern Arkansas during deposition of these strata. This feature has been termed the *South Ozark arch* by Suhm (1997), who interprets it as an extension of the Ozark dome. A westward increase in the detrital content, especially mature quartz sand, by supra-Everton strata supports this conclusion.

CORRELATION

The general type region for formations of the Oklahoma Simpson and Viola Groups is in the Arbuckle Mountains, where the record for rocks of this age is much more complete than in northern Arkansas. Detailed correlation between the thicker sections in Oklahoma and the thinner, less-complete strata of this age in Arkansas is unclear. The general age equivalency between Arkansas and Oklahoma units shown in Figure 1 is based on conodonts.

REFERENCES CITED

Craig, W. W., 1991, Stratigraphic and depositional framework, supra-Everton Middle and Upper Ordovician strata, northern Arkansas, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 212–214.

Kuhn, D. E., 1984, Stratigraphy and petrology of the lower half of the Everton Formation (Early–Middle Ordovician), Newton, Boone, and Carroll Counties, Arkansas: University of New Orleans unpublished M.S. thesis, 186 p.

McKnight, E. T., 1935, Zinc and lead deposits of northern Arkansas: U.S. Geological Survey Bulletin 853, 311 p.

Purdue, A. H.; and Miser, H. D., 1916, Eureka Springs and Harrison quadrangles (Arkansas–Missouri): U.S. Geological Survey, Geologic Atlas of the United States, Folio 202, 21 p.

Suhm, R. W., 1974, Stratigraphy of Everton Formation (early medial Ordovician), northern Arkansas: American Association of Petroleum Geologists Bulletin, v. 58, p. 685–707.

_____1997, Simpson stratigraphy of the southern Midcontinent, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99 [this volume], p. 3–38.

Zimmerman, W. G., Jr., 1989, Petrology and environment of deposition of the upper part of the Everton Formation (lower Middle Ordovician), Newton County, Arkansas: University of New Orleans unpublished M.S. thesis, 156 p.

Seismic Evidence of the Development of Abrupt Sedimentary Buildups in the Simpson Group of the Marietta Embayment, Oklahoma

Gary L. Garner
Garner Resources, Inc.
Oklahoma City, Oklahoma

ABSTRACT.—The Marietta Simpson embayment of southern Oklahoma is a starved, shallow subbasin of the larger Ardmore basin and northeastern Oklahoma Simpson depocenters. The Simpson Group of the Marietta embayment is characterized by regional deposition of thinly interbedded marine shales and limestones. Dramatic new seismic evidence from the Marietta embayment suggests the development of local steep-flanked sedimentary buildups of up to 800 ft of gross thickness. Some buildups are over 0.5 mi wide and 1 mi long. Accurately detailed interval-velocity analysis derived from seismic data shows 15,200–15,700 ft/sec off-anomaly velocities across an interval from the top of the McLish limestone to the top of the Oil Creek limestone. Measured seismic velocities for the same interval through the anomalies range on average 14,200–14,600 ft/sec. The seismic character in the anomalies is generally "massive" in appearance and void of continuous reflections, with steeply dipping reflection events on their flanks. Drill-cutting sample studies of nearby wells provide no evidence of appreciable sand or oolites in the off-anomaly normal section. Considerable fossil material, including unidentified tabulate corals, however, is found in the samples. A well drilled very close to one of the anomalies encountered several zones of loosely consolidated limestone and fossil "hash" within the Oil Creek shale. It is believed that the observed seismic velocities could be the result of an anomalous buildup of cleaner shales, but such an environment of deposition, and subsequent diagenetic history (especially shale-compaction amounts) cannot be easily explained. It also is believed that the anomalies are possibly noncompactable "reef" material with very high porosities (12%–15% by conversion of the measured velocities to average porosities). Such reef thicknesses could measure 170–600 ft of buildup. Numerous Middle Ordovician Chazyan to Black Riveran reefs occur in outcrops in New York and Virginia. These measure a few tens of feet to over 800 ft in thickness. The existence of reefs in the subsurface Simpson of the Midcontinent region would be a new and potentially highly economic exploration target. Subsurface anomalies of indeterminate origin and diagenetic history such as these must be tested if we are to find substantial new oil and gas reserves from our current exploration in mature oil provinces.

INTRODUCTION

The current study covers a small area (approximately 50 mi^2) in the northeastern part of central Jefferson County, Oklahoma. It lies at the northwest end of the Marietta basin, approximately 15 mi southwest of the Healdton field. Few studies of this area have been published, and therefore most of the observations in this study are conclusions of the author. The purpose of this paper is to offer evidence of an entirely new, and potentially major, oil and/or gas play in the Simpson Group. It represents a "frontier"-type petroleum objective in a mature basin, which has not been drilled or described previously. A multidiscipline approach has been utilized, including the study of well data, drill cuttings, seismic character, and velocity.

GENERAL GEOLOGY

The study area is in a regional pre-Pennsylvanian, northwest-trending graben that has preserved an early Paleozoic rock section dipping steeply to the southeast into the Marietta basin. Arbuckle Group rocks subcrop beneath the pre-Pennsylvanian unconformity to the north and west of the area, and Viola and Simpson Group rocks are preserved within the graben. A broad, southeast-plunging anticline is expressed at the pre-Pennsylvanian unconformity inside the graben boundaries. The anticline is more pronounced at the base of the Viola, with attendant thinning of the strata from the base of the Viola to the McLish (Fig. 1). This, plus numerous normal faults isolated in the Simpson, indicates gentle structural growth during Simpson Group deposition. This structure was mostly obliterated when the Viola unconformity developed. Major movement occurred on the graben-bounding faults during pre-Pennsylvanian erosion, and the area was tilted to the southeast during Pennsylvanian deposition.

Much of the Simpson faulting is early Oil Creek in age, but some faulting continued from early Oil Creek

---

Garner, G. L., 1997, Seismic evidence of the development of abrupt sedimentary buildups in the Simpson Group of the Marietta embayment, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 227–234.

time in the southeast through late Simpson time in the northwest. Separate, late Simpson-age faulting intersects this growth-fault system. Structure and isopach maps, derived from seismic data, show the existence of local Simpson "thick" anomalies along the early Oil Creek–age faults (Fig. 2). These anomalies appear to have developed at a specific fault "paleo-elevation" between the 300- to 400-ft base of Viola to McLish isopach. It is on a less steep flank of the anticline, and, with the faulting, the proper water depth to initiate buildup seems to have developed only in this limited area. With fewer than 10 deeper Simpson well penetrations in the region, none of the anomalies has been tested. The depth to the Simpson ranges from approximately 5,000 ft in the northwest to approximately 7,000 ft in the southeast. Simpson thicknesses range in wells from approximately 1,300 ft in the northwest to over 1,500 ft in the southeast. Seismic data indicate that as much as one-third of the section is lost by thinning along the axis of the Simpson-age plunging anticline, which is central to the area.

The Viola has not been studied in any detail during this investigation. Oil production in the area is from the Viola, however, and is stratigraphically controlled. The Viola thins slightly and drapes over the deeper Simpson anomalies. Seismic line A (Fig. 3), adjacent to the crest of one of the features, shows approximately 60 ft of Viola relief to the northeast in 800 ft, or about a 4.5° dip, and

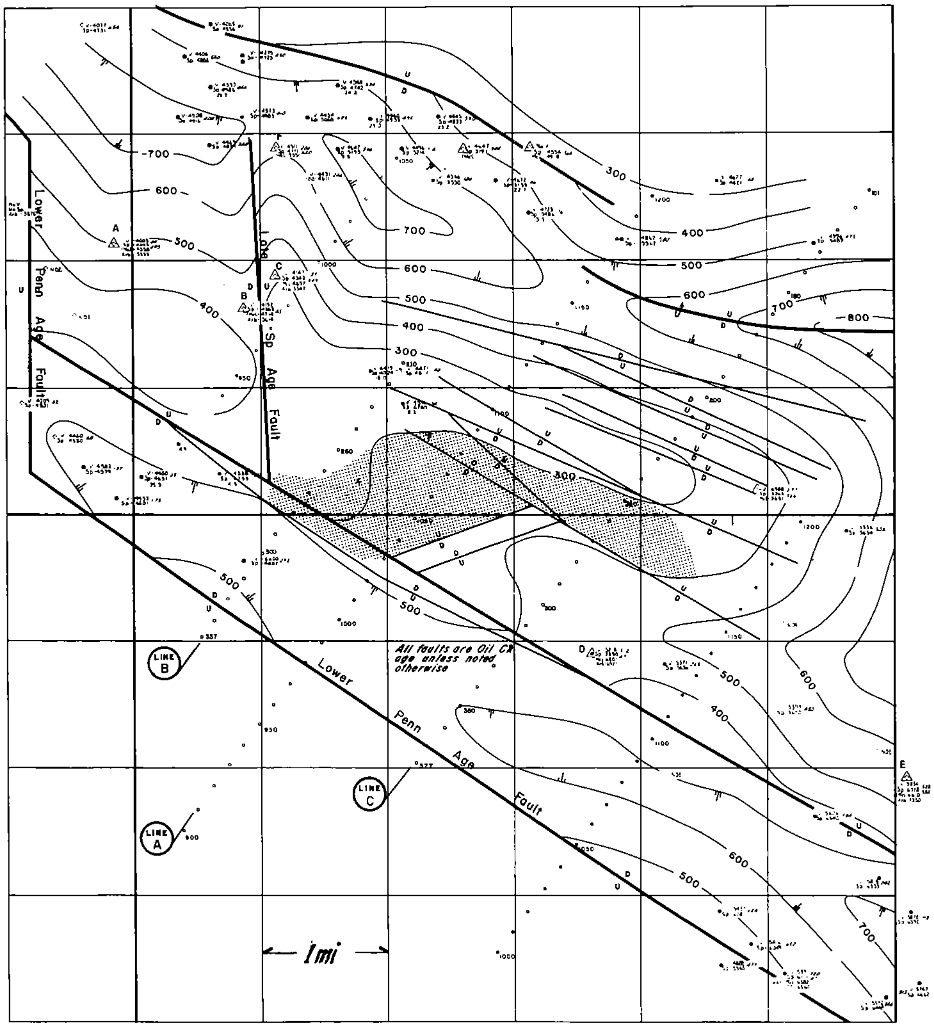


Figure 1. Isopach map of strata from the base of the Viola to the McLish within a pre-Pennsylvanian graben, showing Simpson anticline highly faulted with numerous Oil Creek–age normal faults. Shaded area denotes the location of multiple Simpson "buildups" on the less steep flank of the anticline, between the 300- and 400-ft contours and along the upthrown side of several of the Oil Creek–age faults.

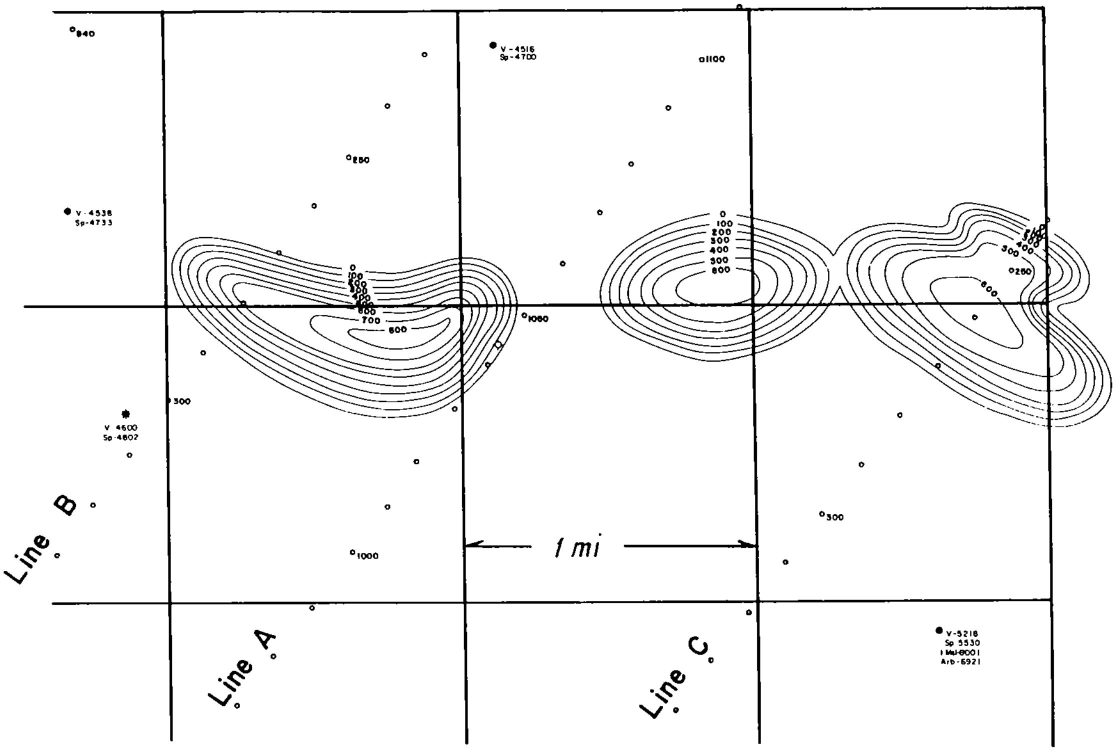


Figure 2. Isopach map showing gross thickness (in feet) of Simpson sedimentary buildup. Several pertinent seismic lines (A, B, and C) are shown also.

shows approximately 120 ft of Viola relief to the southwest in about 1,200 ft, or about a 6° dip. This Viola relief should be greater at the actual apex of the feature, since seismic line A has recorded "sideswipe" from the feature.

SIMPSON STRATIGRAPHY

The only comprehensive Simpson lithofacies and isopach mapping in this area was published by Martin Schramm (1964). In that paper, the Simpson of this area is placed in the Marietta embayment with low-relief separation from the Ardmore basin and northeastern shelf of Oklahoma. This area was a quiet, shallow southwestern subbasin of the greater Simpson epicontinental sea. It received fewer coarse clastics and much more limestone deposition, owing to its relative isolation from sandstone sources. Its relationship to the ancestral Muenster arch nearby has not been clearly understood or considered by Schramm, or by others.

The Simpson of the Marietta embayment is primarily a sequence of thinly interbedded, fine- to medium-crystalline limestones and marine shales. In the study area, the sequence thins abruptly to the northwest, affecting the thickness and character of the McLish limestone and the upper Oil Creek limestone below it in the approximate middle of the sequence (see sonic and synthetic seismogram of Fig. 3). This, in turn, has affected the seismic response. The upper Oil Creek limestone unit becomes broken and more interbedded with shales downdip, and as the entire sequence thins updip, it becomes less distinguishable on seismic records. The lower or basal Oil Creek limestone is present everywhere and produces an excellent area-wide high-amplitude seismic reflection.

Well-sample studies have revealed that the area has very sparse sand-sized grains and very few oolites, either embedded in the shales or in the limestone interbeds. An abundant fossil population does exist, however, embedded in the shales and in the limestone units. This consists mostly of large ostracodes and small echinoderms, brachiopods, and pelecypods, and unidentified isolated tabulate corals.

SEISMIC ANOMALIES

Approximately 35 mi of excellent-quality CMP seismic data in 7 lines has been utilized in the study. All the seismic anomalies appear similar, and the same analysis was made of most of the lines independently, with the same results. Discussion of seismic characteristics of one, therefore, will apply to the others.

The westernmost anomaly is characterized on line A by a buildup or thickening starting at least 60–120 ft above the basal Oil Creek limestone, and continues higher into the Simpson until it appears to be near the Viola (Trenton) unconformity. The McLish limestone reflection in the approximate middle of the Simpson section disappears through the anomaly, and dips steeply away on the flanks. Along the north axial plunge of the anomaly, the McLish limestone reflection on line B is unbroken and exhibits up to 170 ft of relief over the feature (Fig. 4). An isochron from the Viola to the basal Oil Creek limestone exhibits 15 msec seismic thickening on line A, and 30 msec on line B. Other anomalies are similar in thickness to that of line B. Because of the carbonate and shale envi-

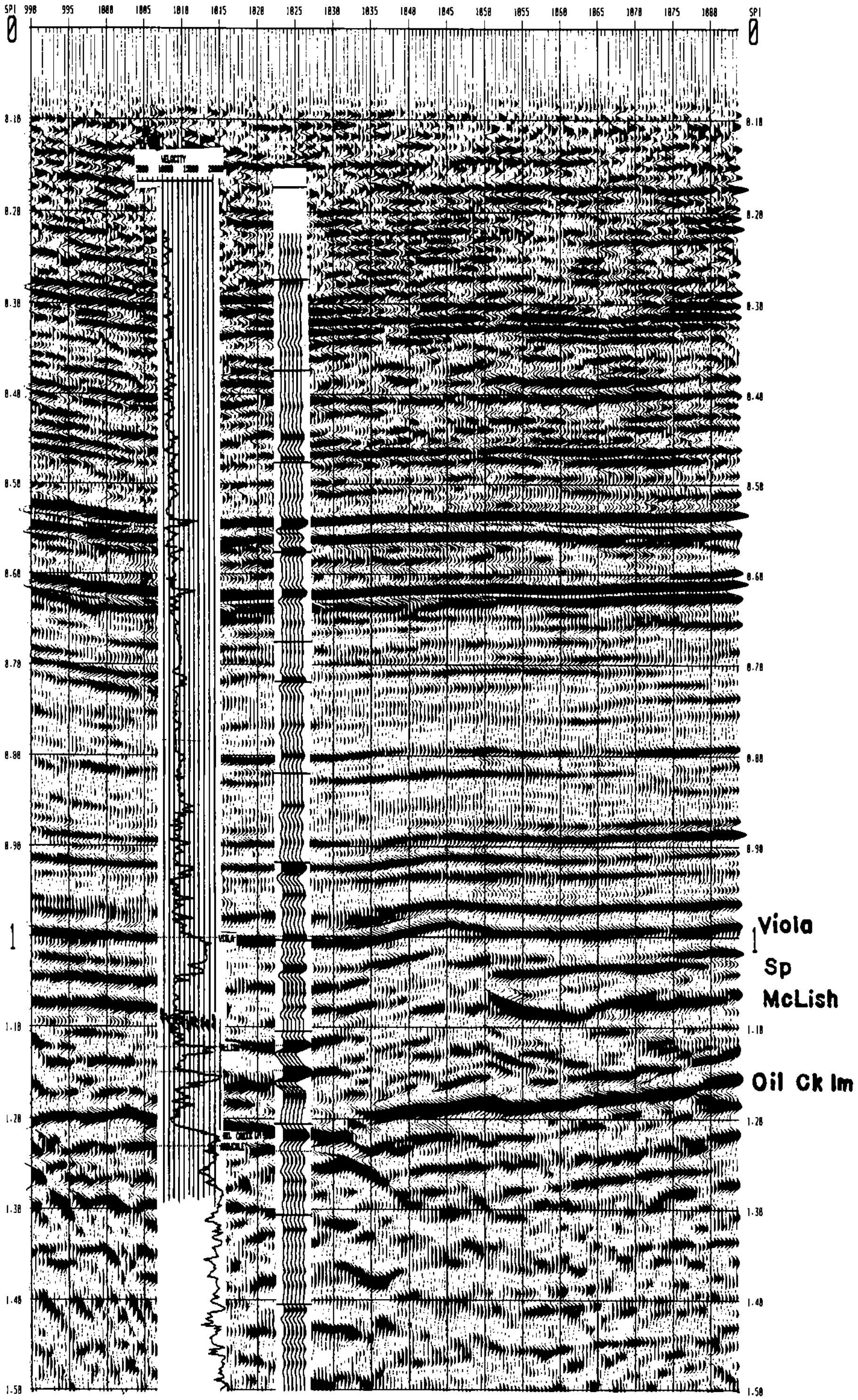


Figure 3. Seismic line A, showing Simpson "buildup" and attendant drape of overlying Viola and Pennsylvanian strata. Note steep dips and McLish terminations into the anomaly on both flanks. H:V is approximately 2:1 at Simpson depth.

ronment and the geometry of the buildup, the anomaly is best explained as an organic carbonate buildup ("reef") in the section. Seismic modeling supports a carbonate buildup interpretation, but a seismic model of an entirely "shale" buildup does not match the seismic data.

DETAILED SEISMIC-VELOCITY ANALYSIS

Seismic-velocity measurements have been effective in separating lateral velocity variations in most basins worldwide. These measurements are especially accurate over several hundreds of interval feet in areas of good seismic data and given long source-to-receiver recording offsets. The technique is not widely utilized as an interpretation aid by most geophysicists, however. Well logs in the study area were converted to velocities for synthetic seismic construction, and were used for reflection identification and model studies. Seismic-interval velocities were computed on nearby seismic data from Viola to McLish, and McLish to basal Oil Creek limestone, for velocity comparison to well interval velocities. The result was a generally good match to the well velocities over the same intervals.

A detailed velocity analysis of one of the anomalies was conducted on line B where the McLish was continu-

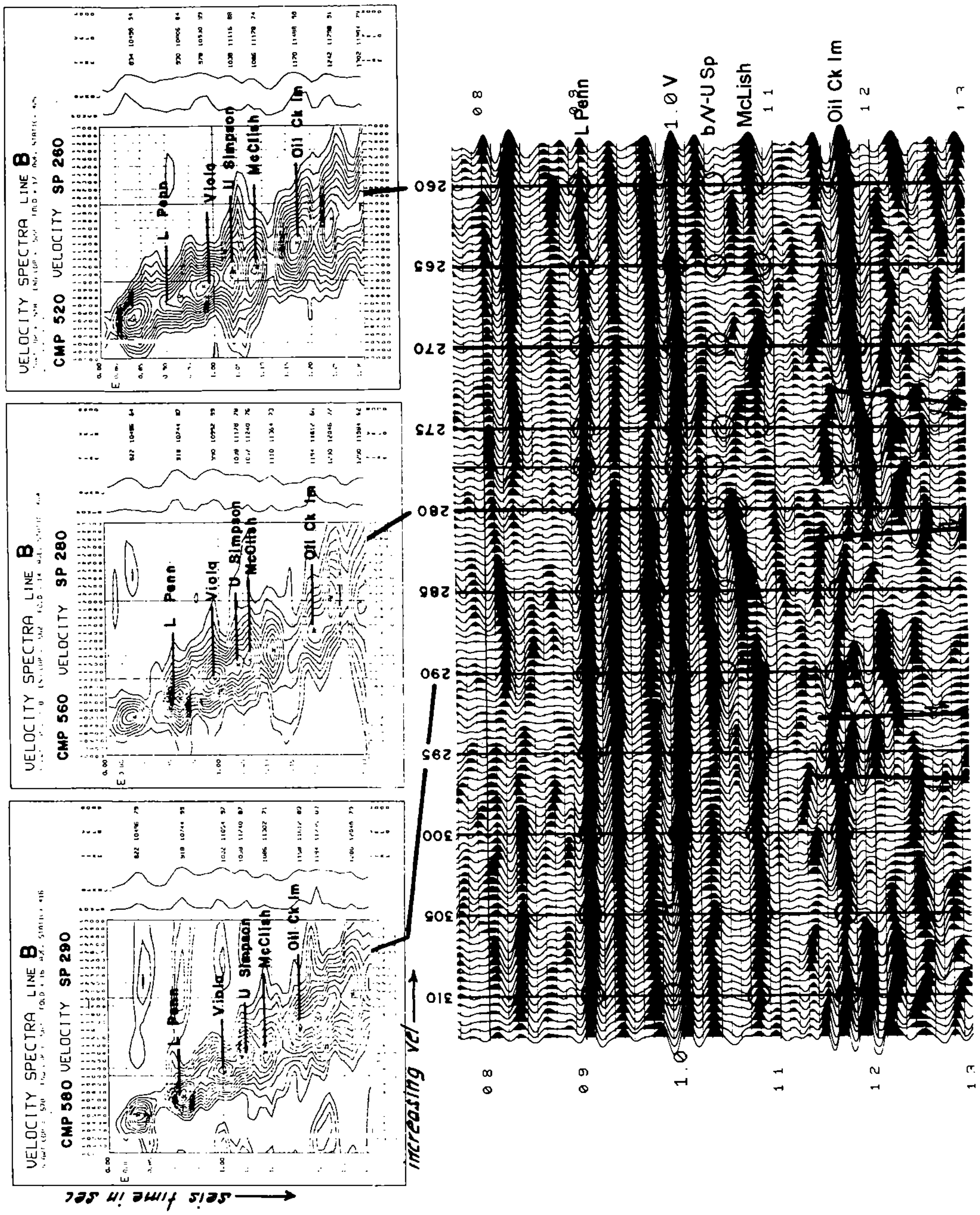


Figure 4. Seismic line B, time section, showing velocity spectra locations and typical off-anomaly and on-anomaly examples of velocity spectra.

ous, and because the data were recorded with 6,600-ft offsets and high common midpoint (CMP) fold (up to 18, average 15). Although the anomaly appeared to be maximum on line A, that line was not conducive for reflecting accurate velocity measurements for several reasons. The maximum recording offsets were only 2,600 ft, the McLish limestone was not continuous over the feature, and it has recorded a "sideswipe" response with complex ray-path geometry even though the data quality is excellent. Velocity spectra (Fig. 4) were computed every 10 CMPs and plotted with 100-ft/sec velocity increments for line B. These were computed after residual normal moveout (NMO) and residual time-variant (TV) static calculation, and short automatic gain control (AGC). A narrow velocity search window and short stepdown were utilized in order to maximize accuracy, and the results were stable and considered good. It is believed that velocity picks can be made to within approximately 50 ft/sec.

RESULTS

The velocity study clearly establishes slower velocities through the anomaly in the range of 14,200–14,600 ft/sec from the McLish limestone to the basal Oil Creek limestone. The same off-anomaly interval includes up to 200 ft of dense McLish limestones plus an approximately 50% carbonate/shale ratio. Clean Simpson shale velocities range from 12,500 to 13,000 ft/sec. This results in off-anomaly velocities over the same interval of approximately 15,200–15,700 ft/sec in control wells and seismic records. The seismic time section of Figure 4 was converted to seismic depth (Fig. 5) by using the measured seismic velocities. This revealed the off-anomaly interval to be approximately 500 ft thick, and the equivalent anomaly interval to be approximately 750 ft thick. Approximately 100 ft of lower Oil Creek shale is needed beneath the anomaly to provide a consistent reflection from the basal Oil Creek limestone. That leaves approximately 600 ft of anomalous buildup to the base of a thinner McLish limestone. At the apex of the anomaly (line A), the McLish apparently is not present, and the anomaly thickness possibly continued to build to near the top of the Simpson for a total of approximately 800 ft.

The anomaly velocities are not typical of normal porous reef velocities. They are more typical of either lessened carbonate in the predominantly shale sequence or of a silt or sand clastic buildup. Depending on the carbonate matrix velocity used, however, a carbonate buildup with an average 12%–15% porosity will convert by calculation to these velocities. All characteristics of the anomalies must be considered for a satisfactory explanation of the feature, and not just the velocity information. These characteristics are summarized below.

Seismic Character

The internal seismic character of the anomaly generally is devoid of continuous seismic reflections, making it more massive in nature on all lines. Interbedded sands or siltstones with cleaner shale would result in numerous and more consistent reflecting events. There is undoubtedly some internal bedding or "hard" streaks, as seen on line B at 1.1 sec from SP 280–285. These are not correlative from line to line, however, and also may be the result of inaccurate 2-D migration from very steep flanks. The overall anomaly appearance, however, is heterogeneous and poorly bedded.

Geometry

The anomalies are subcircular to oval and cover 200–500 acres. All are more or less symmetrical in cross section, with very steep flanks, possibly approaching 60°–70°.

Structure Influence

All anomalies identified so far are on and along the upthrown side of earliest Oil Creek (Chazyan)–age faults. This is evidenced by clear seismic displacement of the basal Oil Creek limestone on one or more sides of an anomaly, and no apparent displacement above or through it. This is indicative of a positive sea floor at or near a similar water depth under each anomaly. The westernmost anomaly crosses its west-bounding fault to the low side and into the small graben on line B. Regional southeast dip in this area is steep, however, and rapid loss of proper water depth may have forced that anomaly to continue development into the graben area.

Differential Compaction

Some of the strongest evidence for reef development, rather than shale with a lesser carbonate component, is exemplified by compaction beneath the dense, area-wide McLish limestone. Since it is present throughout the area with more or less uniform thickness, it can be assumed to have been deposited in a more or less slightly starved time-synchronous period over the region. The McLish limestone has approximately 170 ft of relief in 600 ft for an approximate slope of 17° on both sides of the anomaly on line B. Upper Simpson units thin above and lap onto the McLish surface. Although probable, there is no direct evidence of how much McLish limestone thinning may have occurred. The anomaly beneath this McLish structure rests on a negative tectonic structure (a graben) at the basal Oil Creek limestone level. Assuming that all of the McLish relief is the result of compaction of the off-anomaly shales and little or no compaction of the anomaly rocks, the degree of compaction would amount to approximately 25% of original off-anomaly thickness. That would be consistent with known marine-shale compaction amounts with limestone interbedding. This would mean that the original off-anomaly shale thicknesses for the same interval amounted to approximately 670 ft at the end of more or less uniform McLish deposition. After compaction, this amounted to 500 ft of off-anomaly shale thickness and 170 ft of McLish drape currently over 600 ft of anomalous rocks. A purely shale anomaly would require twice the shale thickness in the anomaly before compaction in comparison to the same off-anomaly interval. It would have had to be deposited in a growing depression, then elevated 170 ft locally to give the McLish limestone its current relief. This would have had to occur across local positive- and negative-structure elements. Such a geologic history would be highly improbable.

Prograding Sedimentation

One of the most compelling reasons not to believe the existence of a massive reef buildup in this area is that

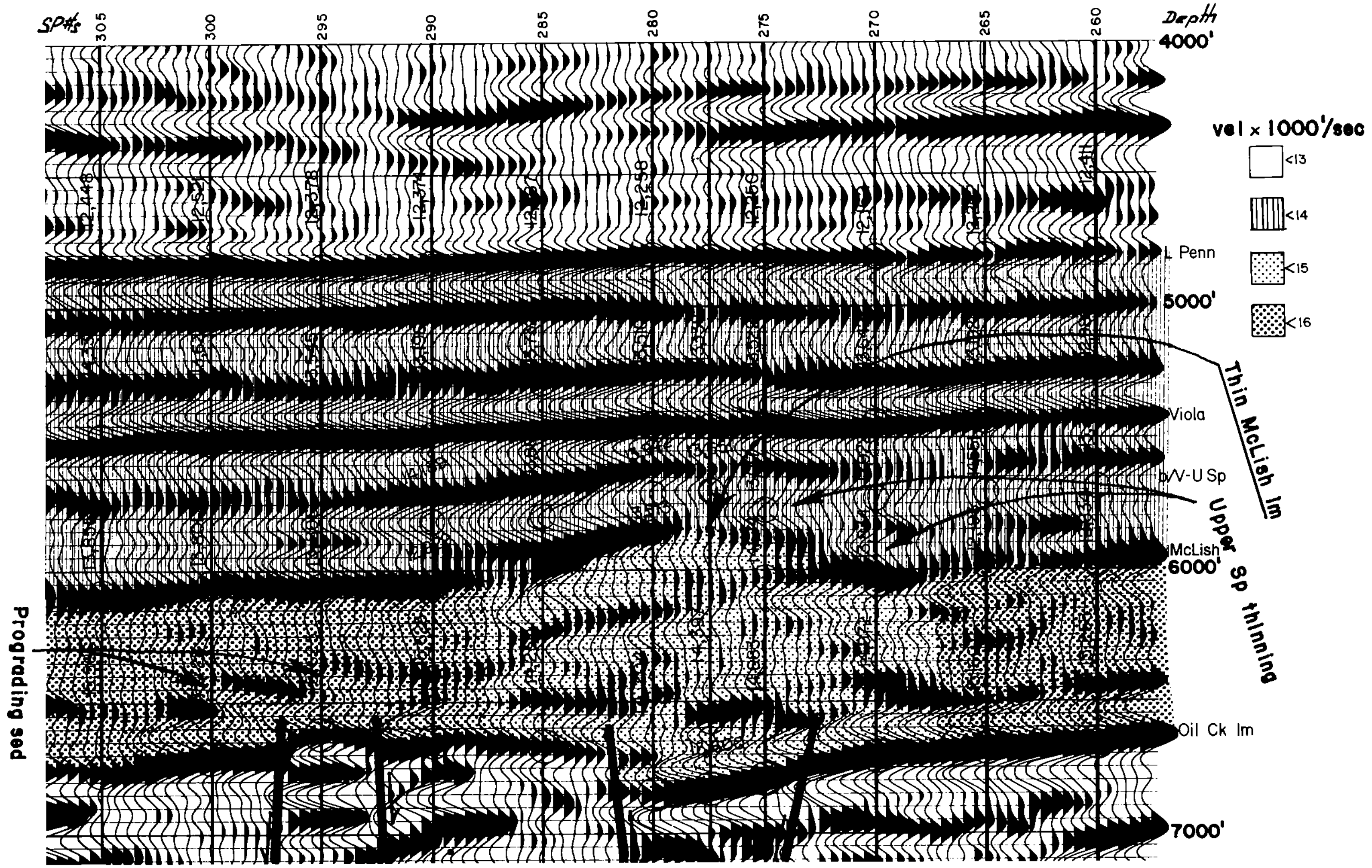


Figure 5. Seismic line B, depth section, with interval velocity analysis showing slower velocities within the anomaly in comparison with those of the same off-anomaly interval.

no well has established an energy-rich environment so necessary to initiate and sustain reef growth. Line B shows clearly a prograding depositional pattern in the Simpson above the basal Oil Creek limestone near the base of, and progressing into, the anomalous interval. This is indicative of a locally higher energy environment at the approximate time of initiation of the anomalous buildup. The progradation is from the southwest, and at this location is approximately 4 or 5 mi from the axis of the current Muenster arch.

Well Evidence

A well was drilled very close to one of the anomalies, and encountered severe deviation problems. No similar deviation problems were encountered or reported from other Simpson wells in the area. The overall Simpson section of the deviated well was similar to the other wells in all respects, including numerous thin correlatable marker limestones. Deviation began in the middle of the Viola, and despite many different drilling techniques used in an attempt to correct the problem, it persisted until steering tools were used to bring it into compliance. The generally normal Simpson section of this well precludes any chaotic thrusted steep dips. Steeper dips than normal must be present, however, and they indicate that the well was drilled on the flank of "something" structurally anomalous. The lower part of the same well bore evidenced anomalous rock characteristics in samples. Most fossil material from other Simpson wells in the area normally consists of "embedded" whole or fragmented skeletal remains in the clean shales and consolidated limestone interbeds. This well encountered considerable loosely compacted limestone and fossil "hash." This detrital "hash" is similar to descriptions of Middle Ordovician Chazyan to Black Riveran reefs and reef flanks in New York and Virginia (Finks and Toomey, 1969; Read, 1982). Those outcropping reefs built up from a few tens to over 800 ft in thickness.

CONCLUSIONS

There is no doubt that abrupt, steep-flanked, anomalous sedimentary buildups occur in the Simpson Group in this study area. Most of the evidence resulting from this study has led to the author's conclusion that the buildups are organic and reefal in nature, and not composed of sand, silt, oolite, or shale clastics. Given that this is true, seismic-velocity studies indicate that the reefs must be very porous.

The possible existence of very thick and porous reefs in the Simpson Group in the Midcontinent provides a potentially important new petroleum reservoir of major proportions. It represents a "frontier" oil play in a mature basin environment, and it is this type of play that must and will be tested in the search for new oil and gas resources as fewer reserves continue to be established.

REFERENCES CITED

Finks, R. M.; and Toomey, D. F., 1969, The paleoecology of Chazyan (lower Middle Ordovician) "reefs" or "mounds": New York State Geological Association, Trip F, p. 93–100.

Read, J. F., 1982, Geometry, facies, and development of Middle Ordovician carbonate buildups, Virginia Appalachians: American Association of Petroleum Geologists Bulletin, v. 66, p. 189–209.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

Wettability Alterations in Reservoir Rocks from Polar Constituents in Crude Oil

Anuj Gupta
University of Oklahoma
Norman, Oklahoma

ABSTRACT.—Improving oil production from a reservoir depends on a thorough understanding of the in-situ wettability, which is controlled by the interaction between the reservoir fluids and the reservoir matrix. This paper presents a new method that utilizes thin-film ellipsometry for determining the wettability of a system and for detecting wettability alterations on contact with crude oils or other surface-active chemicals. Surface-active chemicals, when present in aqueous phase or in oleic phase, tend to alter the electrical double-layer forces and destabilize the brine film. This allows the oleic phase to contact the mineral surface and possibly alter the surface wettability. The effect of brine composition, pH, oil-phase composition, and contact time on the wettability of various substrates was studied. The profiles and the film-thickness variations measured after an initial short contact with the oil phase are presented for various crude-oil/brine/mineral systems. The results are, in general, consistent with the predictions of computed isotherms for this system and with the published results of an adhesion map.

INTRODUCTION

Oil production from a reservoir, and, in general, multiphase flow in a porous medium, are dependent on the in-situ wettability, which is controlled by the interaction between the reservoir fluids and the reservoir matrix. Many researchers now believe that most hydrocarbon reservoir rocks were water-wet to begin with. As hydrocarbons invaded such rocks, the larger pores were displaced first, followed by the smaller pores. An aqueous film initially existed in the pore space and prevented the contact of pore walls with oil. Some of the rock surfaces may have been exposed to the crude oil over geologic time. Based on the relative strengths of oil/rock and brine/rock interactions, one of the following could occur. In very strongly water-wet rocks, where the brine films remain stable and where diffusion is not significant, the rock surface remains water-wet. In cases where the film destabilizes, the surface may still remain water-wet if the crude-oil components do not interact with the rock surface. When the film is unstable and some of the oil components can adsorb on the rock surface, the exposed surface will become oil-wet. The extent of wettability alteration will depend on the rock-pore topology and the applied capillary pressure. In extreme cases, all the pores may turn oil-wet. In less extreme cases, a so-called "mixed-wet" porous medium may result, wherein the larger pores are oil-wet and the smaller pores are water-wet. In recent years, many reservoirs have exhibited such mixed-wet behavior. The prediction of displacement efficiency in such reservoirs is complicated by the fact that the wettability in such media is a nonunique function of in-situ saturations.

It is the objective of this study to identify conditions under which the wetting film is destabilized and wettability alteration occurs. This study seeks to provide a better understanding of the mechanisms leading to the generation of mixed wettability states in reservoir rocks.

Many researchers have shown that surface-active chemicals, when present in aqueous phase or in oleic phase, can drastically alter the aqueous-film stability and wettability behavior of a mineral/brine/oil system. A surfactant added to the aqueous phase would seem to have a more immediate effect on the behavior of an originally water-wet surface. However, surfactants in the oleic phase can have an equally important effect. For instance, surfactants in the oil phase tend to concentrate near the oil/brine interface and very often alter the charge-potential behavior at the oil/water interface. This, in turn, could alter the electrical double-layer forces and destabilize the brine film. The above demonstrates that the surfactants in the oleic phase could trigger brine-film rupture. This would allow the oleic phase to contact the mineral surface and possibly alter the surface wettability.

Brine films are very important for maintaining the continuity of the wetting aqueous phase. Important wettability changes may result if the brine film ruptures. This phenomenon is investigated experimentally in our work, as described in a separate publication (Gupta and Sharma, 1992a,b).

Thin-film studies are a means to enhance the understanding of wettability, since the wettability of a surface by a fluid is intimately linked with the stability of thin fluid films on the surface. For example, brine films are

---

Gupta, Anuj, 1997, Wettability alterations in reservoir rocks from polar constituents in crude oil, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 235–237.

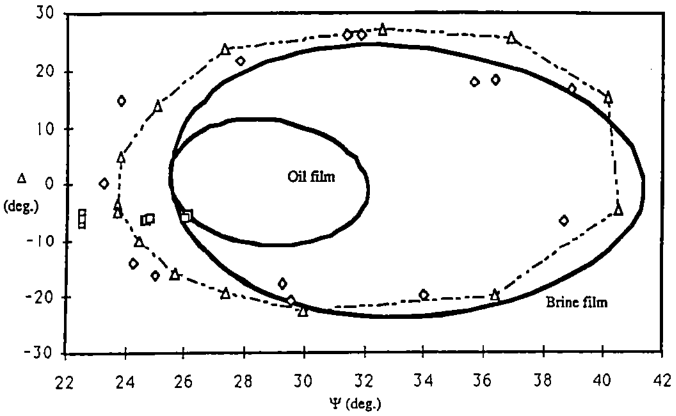


Figure 1. Initial film variation, indicating a bulk brine film in a glass/brine/hexadecane system for 0.01 M NaCl brine at pH ~2.25.

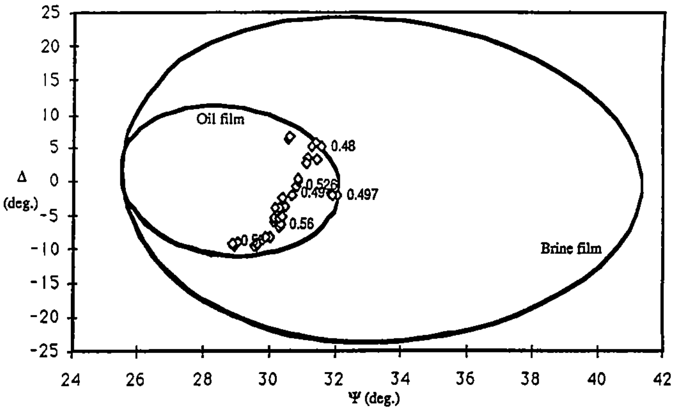


Figure 2. *X*-direction profile and time variation after 24-hr contact of Moutray crude oil with glass, showing oil film in glass/brine/Moutray crude-oil system for 0.01 M NaCl brine at pH = 4.5.

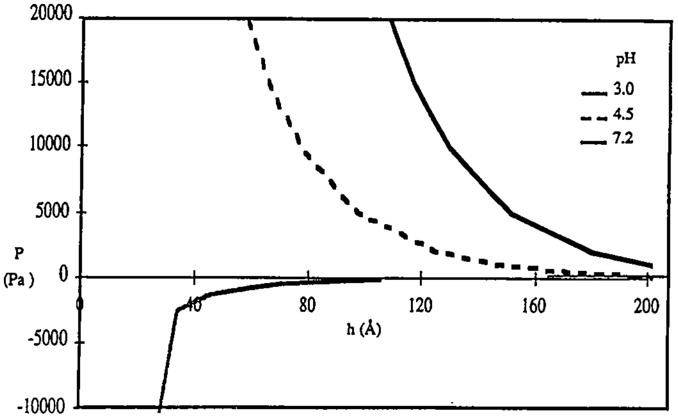


Figure 3. Disjoining pressure isotherms for brine films between silica and Moutray crude oil, computed by using charge-regulation model. Brine concentration = 0.01 M NaCl.

very important for maintaining the continuity of the wetting aqueous phase in hydrocarbon reservoir rocks, and important wettability changes may result if the brine film ruptures.

A new method is presented that utilizes thin-film ellipsometry for determining the wettability of a system and for detecting wettability alterations on contact with surface-active chemicals such as asphaltenes and resins. Surface-active chemicals, when present in aqueous phase or in oleic phase, tend to alter the electrical double-layer forces and destabilize the brine film. This allows the oleic phase to contact the mineral surface and possibly alter the surface wettability.

FILM-STABILITY TESTS FOR BRINE FILM IN A GLASS/BRINE/OIL SYSTEM

The objective of our study is to identify the conditions under which the wetting brine films rupture in a glass/brine/oil system. A water-wet substrate will exhibit only brine films, and such measurements will follow a characteristic curve corresponding to the aqueous film; also, an oil-wet surface will exhibit hydrocarbon films when contacted with the bulk hydrocarbon phase, and such measurements will follow a characteristic curve corresponding to hydrocarbon film. Figures 1 and 2 show such crossplots for a brine film ($n = 1.333$) and a hexadecane film ($n = 1.4412$). As is clear from these plots, brine films can be distinguished from hexadecane films by taking a series of measurements. This procedure allows a very specific distinction between water-wet and oil-wet surfaces.

The glass substrate, the porous disc, and the cell and tubing were cleaned in order to remove any surface contamination. This ensured a film-free top surface. The water-wetness of the film surface was verified by taking a series of readings at different spots on the film surface. When the surface was truly water-wet and clean, the readings followed the brine Ψ–Δ crossplot. When the readings indicated a dirty surface or an oil-wet surface, the experiment was terminated and the cleaning procedure was repeated.

After verifying the cleanliness of the film surface, the hydrocarbon phase was introduced into the film cell. The oil reservoir was raised until the top of the oil phase was at the film level and oil replaced air as the nonwetting phase. Oil was allowed to press against the substrate surface for a time, ranging from a few minutes to several hours. At the end of this

TABLE 1.—SUMMARY OF FILM-STABILITY TESTS

W \ NW	C_{16}	C_{16+} Stearic acid	Moutray crude oil
0.01 M NaCl,			
low pH	U	U	U
Med. pH	S	U	S
High pH	S	U	S
0.005 M NaCl, + CTAB			
Below CMC	U		
Above CMC	S		

Note: S = stable aqueous film; U = unstable aqueous film.

period, the oil reservoir was lowered, causing the oil phase to retreat and introducing an air bubble against the substrate. Ψ and Δ were again measured for the film at various points on the surface. When the film thickness was varying at a point, a series of measurements was taken to follow the film thickness and to characterize the wetting behavior of the surface. On the basis of whether the Ψ–Δ at the end of the test followed a brine-film crossplot or an oil-film crossplot, the wettability of the substrate could be established.

These experiments allowed us to study the effect of brine composition, pH, oil-phase composition, and contact time on the wettability of various substrates.

RESULTS, OBSERVATIONS, AND CONCLUSIONS

The profiles and the film-thickness variations measured after an initial short contact with the oil phase are presented for various crude-oil/brine/mineral systems. Samples of experimental measurements and theoretical disjoining isotherms are presented in Figures 1 through 3, and in Table 1. The results are, in general, consistent with the predictions of computed isotherms for this system and the published results of an adhesion map presented by Buckley and others (1987). It is concluded that the proposed procedure of thin-film-stability analysis by using ellipsometry provides a more fundamental and specific distinction between water-wet and oil-wet surfaces than is achievable with contact angle measurements.

Applications

This paper presents a powerful tool for identifying reservoir conditions under which wettability alteration takes place. By using this method, the effect of drilling, completion, stimulation, and EOR fluids on in-situ reservoir wettability can be studied conveniently. A knowledge of in-situ wettability, in turn, is needed for an accurate description and modeling of multiphase displacements.

Technical Contribution

1. A method has been developed for determining microscopic reservoir wettability with greater reliability and flexibility than is possible with contact angle measurements.
2. This work enhances the understanding of wettability and the mechanisms leading to the generation of mixed wettability states in reservoir rocks.
3. This procedure allows a specific distinction between water-wet and oil-wet surfaces.

REFERENCES CITED

Buckley, J. S.; Takamura, K.; and Morrow, N. R., 1987, Influence of electrical surface charges on the wetting properties of crude oils: Society of Petroleum Engineers, 1987 annual technical conference and exhibition, Dallas, Texas, SPE Paper 16964.

Gupta, Anuj; and Sharma, M. M., 1992a, Stability of thin aqueous films on solid surfaces, Part I—Ellipsometric measurement of disjoining pressure isotherms for aqueous films bounded by glass and mercury: Journal of Colloid and Interface Science, v. 149, p. 392–406.

_____1992b, Stability of thin aqueous films on solid surfaces, Part II—A model for aqueous films bounded by dissimilar charge regulating surfaces: Journal of Colloid and Interface Science, v. 149, p. 407–424.

Hydrocarbon Microseepage Signature of the Clarita Prospect, Coal County, Oklahoma

Daniel C. Hitzman and Brooks A. Rountree
Geo-Microbial Technologies, Inc.
Ochelata, Oklahoma

ABSTRACT.—In 1990, a reconnaissance surface geochemical survey using the Microbial Oil Survey Technique (M.O.S.T.) evaluated approximately 2 mi^2 of the Clarita prospect, Coal County, Oklahoma, sec. 25, T. 1 N., R. 8 E., and successfully predicted a discovery well and warned against drilling an offset dry hole. The faulted anticline reservoir was first drilled in 1991, in an area that demonstrated strong hydrocarbon microseepage indicative of a producing reservoir. A second well was drilled in an area of promising structure, but with a low hydrocarbon microseepage signature. The second well was dry.

The M.O.S.T. method selectively measures specific microorganisms found in shallow soil samples. Microbial population anomalies are mapped as hydrocarbon microseepage signatures that are indicative of buried reservoirs of both oil and gas. As first developed by Phillips Petroleum Company, M.O.S.T. is used to enhance prospect evaluations and pinpoint exploration leads. M.O.S.T. has been utilized for almost every environment, geologic province, and reservoir location, such as Oklahoma's Viola–Simpson play, with successful results.

Fifty-three M.O.S.T. samples targeted the Clarita prospect drill site and were compared to two other M.O.S.T. surveys conducted the same day in Coal and Hughes Counties. The Clarita microbial results defined a strong microseepage signature that correlated with a seismic interpretation. Microbial results successfully predicted the outcome of the No. 1 Clarita well, which produced a combined 150 barrels of oil per day after completion.

INTRODUCTION

The Microbial Oil Survey Technique (M.O.S.T.) is based on the presence of hydrocarbon microseeps leaking from buried reservoirs. The microseeps are detected by observing concentrations and distributions of hydrocarbon-indicating microorganisms found in shallow soils. More specifically, when the upward-migrating hydrocarbon gases from hydrocarbon reservoirs enter the shallow soil environment they are utilized by a specific group of microorganisms. There is a direct, positive relationship between the hydrocarbon concentrations in the soils and these microbial populations. This relationship between increased hydrocarbon concentrations and increased hydrocarbon-indicating microorganism populations is easily measurable and distinctly reproducible (Beghtel and others, 1987). High microbial-population distributions are therefore reliable indicators of hydrocarbon-gas migration (Pareja Lopez and others, 1993).

The specific microorganism populations are measured from shallow soil samples collected from depths between 6 and 8 in. The soils are analyzed by microbiological screening techniques for hydrocarbon-indicating microbes (Hitzman, and others, 1994). The process used in this survey screened for only those microorganisms that indicate the presence of light hydrocarbons, particularly butane.

Sample patterns and sample density are selected to best define the hydrocarbon potential of the target area, subject to considerations of terrain and accessibility. Reconnaissance and more detailed surveys of acreage or prospects may be completed in this manner. The predictive value of this technology has been demonstrated by extensive field surveys. Microbial surveys are highly effective when used in conjunction with geological and geophysical data.

MICROBIAL EXPLORATION FOR THE CLARITA PROSPECT

Microbial surveys both confirm and deny the presence of commercial hydrocarbons. In 1990, a reconnaissance microbial survey defined the microseepage signature over an approximately 2-mi^2 area of the Clarita prospect. Fifty-three shallow soil samples were collected every 530 ft in a pattern of four intersecting traverses. Six samples were collected to evaluate the signature of an older nearby oil and gas field. Most of the samples evaluated a seismic structure and its potential for hydrocarbons (Fig. 1).

The highest grouping of microbial samples pinpointed a locality almost exactly where the No. 1 Clarita well was staked. Microbial results predicted this to be a successful well and pointed to more hydrocarbon microseepage to the northeast. The No. 2 Clarita dry hole was drilled to the northwest in an area showing a lower microbial signature. As expected, the older, unpressured field to the west showed an even lower microseepage signature (Fig. 2).

Hitzman, D. C.; and Rountree, B. A., 1997, Hydrocarbon microseepage signature of the Clarita prospect, Coal County, Oklahoma, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 238–240.

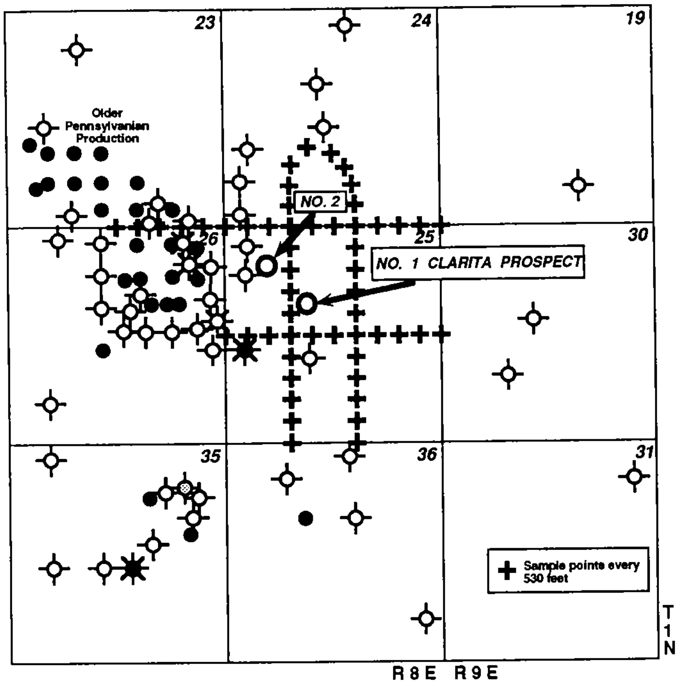


Figure 1. Sample traverses intersect across the Clarita prospect.

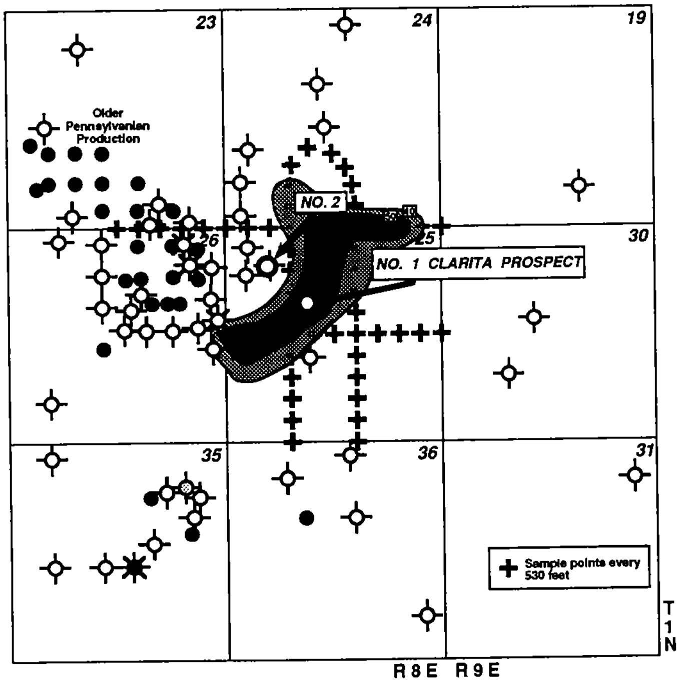


Figure 2. Microbial contours define microseepage signature of the Clarita prospect.

A microbial lineplot shows the contrast between high and low samples near the drill sites and earlier dry holes. These data can be directly compared to seismic profiles for comparison of structures and faults, and their microseepage potential (Fig. 3).

Clarita Discovery

The stratigraphic section in the part of Coal County, Oklahoma, where the Clarita prospect was tested consists of approximately 6,000 ft of sedimentary rocks. The Simpson strata targeted for this prospect produce oil and gas from the Oil Creek and McLish sandstones of Middle Ordovician age. Based on log studies and seismic data, the Clarita prospect was described as a faulted anticline with a closure of nearly 300 ft, according to Quitman Winters (personal communication, 1991).

In 1992, Tierra Petroleum drilled the No. 1 Clarita to a total depth of 6,217 ft. Oil was initially pumped from the McLish (5,936–5,965 ft) at a rate of 120 barrels of oil per day (BOPD) and from the Oil Creek (6,215–6,217 ft) at 30 BOPD. Following that success, the No. 2 Clarita was drilled approximately 1,320 ft northwest of the No. 1 location. The No. 2 ran 30 ft low and was pronounced a dry hole.

Prospect Comparisons

The Clarita prospect was one of three prospects sampled and ranked according to their probable successes. Different sampling patterns were utilized for each area, but collection and laboratory procedures were identical. Of the three prospects, the Clarita demonstrated the strongest and best defined microbial signature (Fig. 4). On the basis of a frequency-distribution analysis of the sample sets, the Clarita prospect shows a distribution with a right-hand skewness and high values—both indicative of commercial production.

CONCLUSIONS

Simpson–Viola targets in Oklahoma that are similar to the Clarita prospect can be screened and more fully defined by their microseepage signatures as measured by microbial surveys. The integration of surface geochemical studies with geological and geophysical studies will improve oil and gas predictions.

ACKNOWLEDGMENTS

The authors would like to acknowledge Quitman Winters, Winters and Associates, Edmond, Oklahoma; Scott Scad and

William Rowsey, Araxas Exploration, Muskogee, Oklahoma; and Mustafa Saribudak, Magna Search International, The Woodlands, Texas, for their assistance with this project.

REFERENCES CITED

Beghtel, F. W.; Hitzman, D. O.; and Sundberg, K. R., 1987, Microbial Oil Survey Technique (MOST) evaluation of new field wildcat wells in Kansas: Association of Petroleum Geochemical Explorationists Bulletin, v. 3, no. 1, p. 1–14.

Hitzman, D. C.; Tucker, J. D.; and Rountree, B. A., 1994, Development drilling in correlation with hydrocarbon microseepage signatures: American Association of Petroleum Geologists, Annual Meeting Proceedings, Denver.

Pareja Lopez, J.; Tucker, J. D.; and Hitzman, D. C., 1993, Hydrocarbon microseepage signatures of seismic structures identified by microbial surveys, Sub-Andean region, Bolivia: American Association of Petroleum Geologists, Annual Meeting Proceedings, New Orleans.

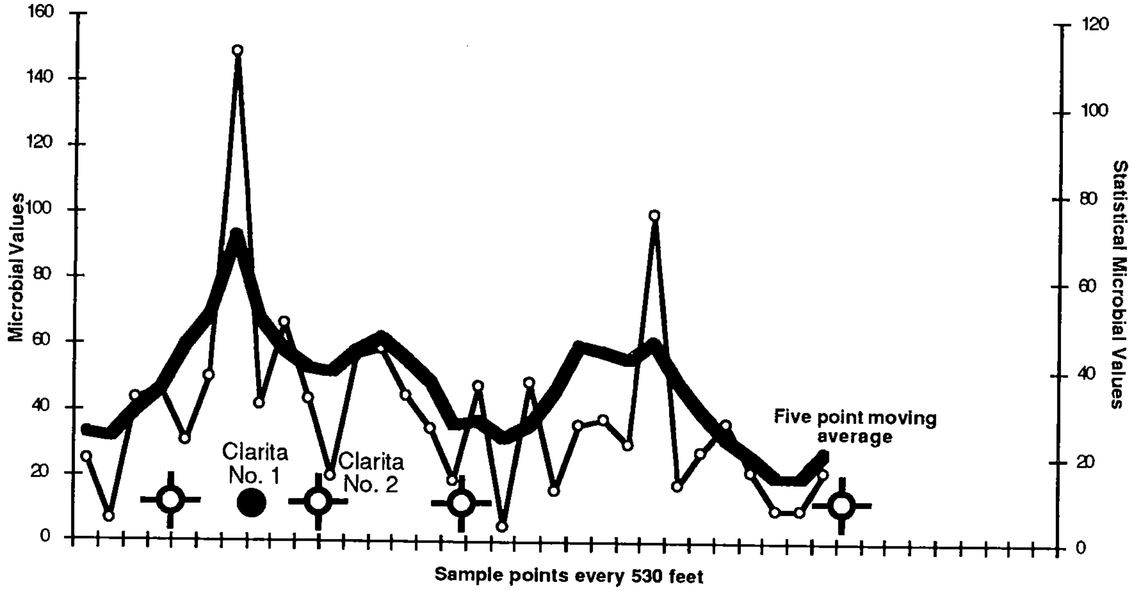


Figure 3. Microbial lineplot profile of the Clarita prospect.

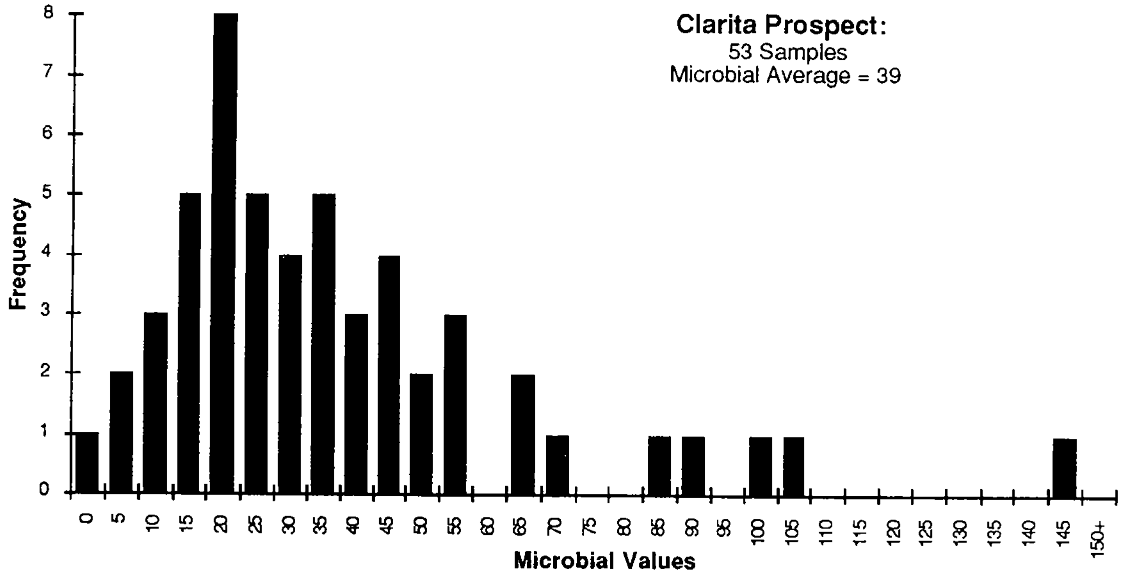


Figure 4. Frequency distribution histogram of the Clarita prospect with positive right-hand skewness.

Tobosa Basin Karsting in Trans-Pecos Texas

David V. LeMone
University of Texas at El Paso
El Paso, Texas

ABSTRACT.—Exceptional surface analogs of karsting have been observed in carbonates in the Franklin Mountains of trans-Pecos Texas. These carbonates are related to the early Paleozoic Tobosa basin. Karst features are observed at the top of the Lower Ordovician El Paso Group and the Silurian Fusselman Formation. Karsting extends down to 1,000 ft in the El Paso Group in well-developed caverns and sinkholes. This unit, to the east in the Permian basin of west Texas, is overlain by Simpson Group equivalents, which may act either as a seal or as a source. Ellenburger (Upper Cambrian–Lower Ordovician) production from 426 fields is greater than 1.5 billion barrels of oil and 11 trillion cubic ft of gas. A significant amount of this production is associated with karst features. The El Paso Group–Montoya Group disconformity represents a time span on the order of 27 million years.

Karst production also is well known from the Silurian Fusselman Formation (e.g., caverns, Dollarhide field, Andrews County). The Fusselman (Middle Silurian)–Canutillo (Middle Devonian) disconformity represents a time span on the order of 40 million years and is reflected by a distinct, highly radioactive lag-gravel unit in the Franklin Mountains. As in the underlying El Paso Group, karst sinkholes, breccia-filled solution channels, terra rosa, etc., are observed. Silurian karst blocks are recognized down in the Montoya and El Paso Groups, indicating interconnection. Karst control, post–El Paso as well as post-Fusselman, has most likely developed by jointing resulting from recurrent fault movements in a pattern inherited from an ancestral Precambrian framework.

LeMone, D. V., 1997, Tobosa basin karsting in trans-Pecos Texas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 241.

Controls of Quartzarenite Diagenesis in the Simpson Group, Oklahoma: Implications for Reservoir-Quality Prediction

Mark E. Mathisen
Mobil Exploration and Producing Technical Center
Dallas, Texas

INTRODUCTION

Quartzarenite diagenesis is typically controlled by a combination of regional basin-scale and local facies-scale variations. The diagenesis literature is extensive and documents many factors that have controlled diagenesis in cored wells, hydrocarbon fields, and productive basins. A meaningful comparison of these data sets and the development of predictive reservoir-quality models are difficult, however, owing to variations in texture, composition, stratigraphy, structure, thermal history, depth, pressure, pore-fluid geochemistry, and flow.

The purpose of this paper is to identify the controls of Oklahoma Simpson Group quartzarenite diagenesis and to discuss implications for the prediction of reservoir quality in quartz-rich sandstones. Sampling was designed to identify both the local and regional controls of Simpson quartzarenite diagenesis. Wireline logs and core descriptions were used to select 152 core samples from 20 wells in various structural provinces at depths between 1,000 and 21,900 ft (Fig. 1). The diagenetic variability between samples was defined by using qualitative and quantitative petrography and X-ray diffraction of selected samples. The regional controls provide constraints for the development of predictive models, whereas the local controls document the diagenetic variability that can be anticipated from facies-scale variations. Seismic-stratigraphic modeling of Simpson diagenetic facies suggests that seismic data also can be used to aid prediction of porous-versus-tight diagenetic facies and reservoir quality. Although based on data from Oklahoma, the modeling should be applicable to both mature and frontier areas where quartz-rich reservoirs can be anticipated.

LOCAL CONTROLS

Core descriptions and wireline-log characteristics of each sampled interval were analyzed to identify local well-scale controls, such as stratigraphic position, thickness, and lithology. Variable cementation patterns that were observed are due to stratification, bed thickness, adjacent lithofacies, fractures, and faults. Several thick sands examined in this study suggest that quartz cementation is more extensive along the upper parts of thick beds. Upward-migrating quartz solutions cool and precipitate at the top of thick beds, where they may tend to get trapped by lithofacies changes.

Local controls of diagenesis are often observable in thin section. The sampling done for this study suggests that approximately one-third of the shallow- to transitional-marine sandstones in a quartzarenite formation (54 of 152 Simpson samples) are characterized by poor sorting, early calcite cement, and bioturbation, which can significantly reduce porosity and limit initial reservoir potential.

During diagenesis, however, numerous factors can increase porosity in these sands. The dissolution of early calcite cement, for example, can contribute to secondary porosity. The recrystallization of a tight carbonate mud to dolomite often can create a distinct amount of secondary porosity. Burrowed sand, with minor amounts of clay, that had relatively poor reservoir potential at shallow depths can, after burial and cementation of the surrounding sand, form the better reservoir facies at depth.

Increased quartz cement was observed along several fractures seen in thin sections, suggesting that fractures and faults may have increased fluid flow and quartz cementation. Partial cementation of fractures by quartz crystals can also prevent fractures from closing and maintain fracture permeability.

Permeability barriers parallel to stratification can be formed by the interaction of compaction and cementation. Clay-rich laminae typically inhibit early "frame-strengthening" cements, such as quartz and carbonate, in many samples. With burial, pressure solution occurs and stylolites develop, resulting in permeability barriers that extend across thin sections.

REGIONAL CONTROLS

To determine the regional controls of diagenesis, it is necessary to factor out the influence of locally controlled variables such as grain size and sorting. Since well-sorted, fine-grained samples should have similar fluid-flow characteristics, variations in the diagenesis of well-sorted samples are more likely to reflect processes operating on a regional scale. The well-sorted samples (98 of 152) were therefore selected for comparison (Fig. 2) and inter-

---

Mathisen, M. E., 1997, Controls of quartzarenite diagenesis in the Simpson Group, Oklahoma: Implications for reservoir-quality prediction, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 242–246.

pretation of the regional factors that can control diagenesis and reservoir quality. These data indicate that the diagenesis of well-sorted Simpson quartzarenites is strongly influenced by several known or predictable regional controls: depth, temperature, and uplift.

Depth

With subsidence and burial to various depths, and with a normal geothermal gradient, compaction, cementation, and dissolution interact to reduce or preserve reservoir quality with depth (Figs. 2–4).

Compaction typically reduces the porosity of a well-sorted sand from approximately 40% to 20% during shallow burial. Compaction rates can vary, however, depending on the pore-fluid pressure and the types of cement that precipitate. Quartz and carbonate cements tend to increase the rock-frame strength and limit compaction, whereas clay content facilitates mechanical compaction, grain suturing, and pressure solution.

An increase in quartz cement with depth is the dominant diagenetic factor controlling quartzarenite-reservoir porosity. Significant overgrowth development can occur at shallow depths, down to several thousand feet. These overgrowths may not be significant volumetrically, and may actually preserve porosity by strengthening the rock and reducing the rate of compaction. Progressive quartz cementation results in thicker overgrowths at 5,000–10,000 ft, and this can significantly reduce porosity. At depths greater than 10,000 ft, pore-filling quartz starts to occlude porosity. At 16,000 ft, porosity can be totally occluded by pore-filling quartz.

Pore-lining clay increases from shallow to moderate depths, inhibits quartz cementation, and preserves reservoir quality. The growth of authigenic clay is difficult to predict, owing to variations in sand composition and texture, which control areas where clay is most likely to form. In most quartzarenites, authigenic clay is not a major cement. However, where present, it can partially to completely prevent the formation of quartz cement in sandstones as deep as 16,000 ft. Although authigenic clays are known to reduce permeability, the relatively thin clay rims observed in many Simpson sands have not, given the corresponding prevention of quartz cement, significantly reduced reservoir quality.

Carbonate cements occur at shallow to moderate depths and can completely occlude porosity. The occurrence of early and late carbonate is controlled by the availability of biogenic carbonate in the sands and nearby limestones, and therefore it is difficult to predict.

Dissolution processes, which affect both sand grains

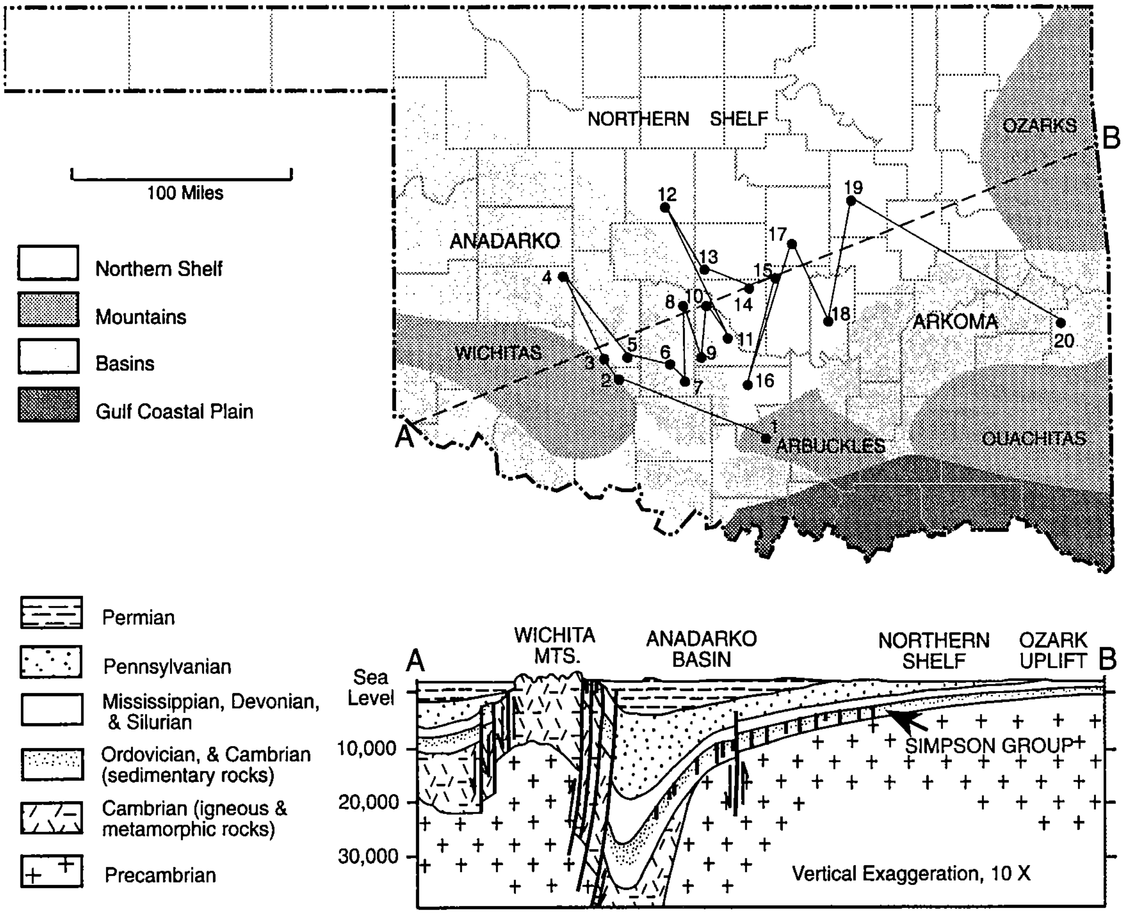


Figure 1. Areal distribution and structural provinces for wells (numbered 1–20) in which the Simpson Group was sampled.

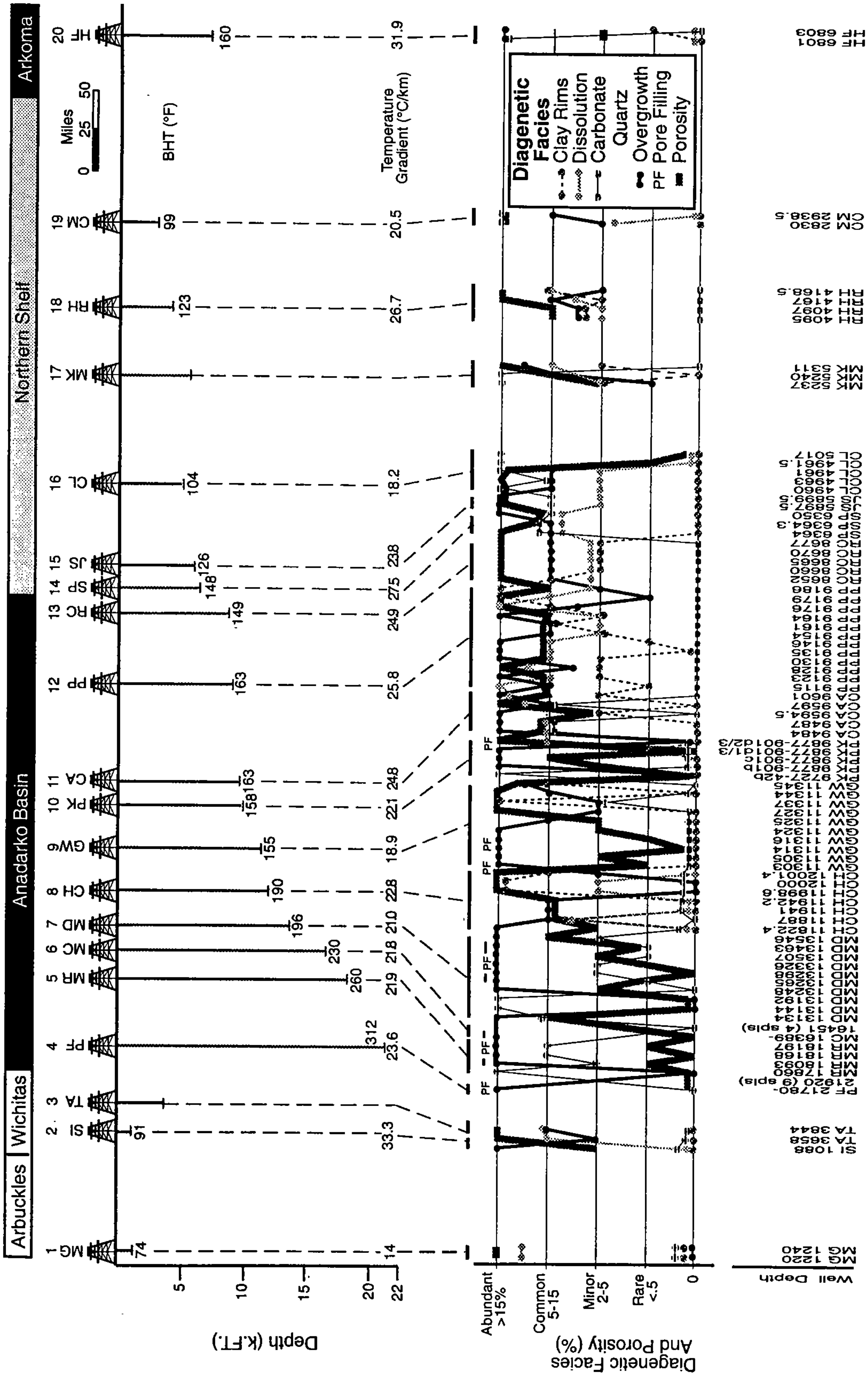


Figure 2. Variations in diagenesis of well-sorted Simpson Group sandstones with depth, structural position, and temperature.

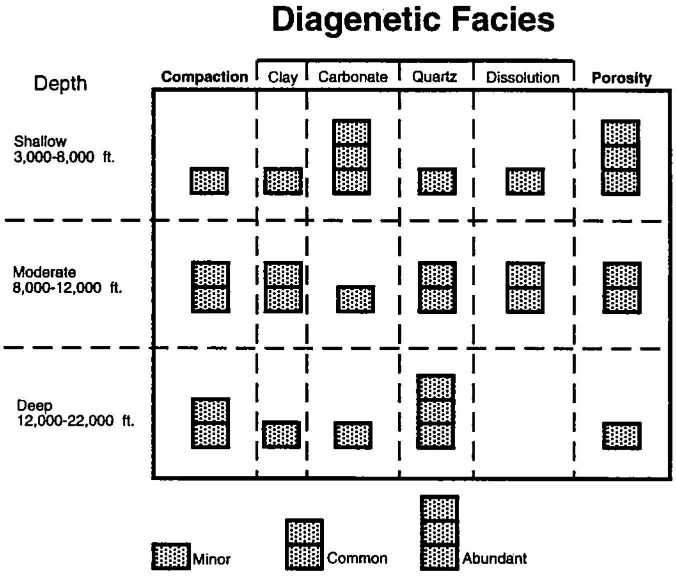


Figure 3. Distribution of diagenetic facies and porosity with depth for Simpson Group sandstones.

and carbonate cement, have the greatest effect on reservoir quality at moderate depths of 8,000 to 12,000 ft. At shallow depths, the dissolution of carbonate and grains may not, because of the abundant primary porosity, significantly increase porosity. At moderate depths the dissolution of carbonate can offset the normal porosity reduction owing to increasing quartz and can sufficiently increase porosity to form reservoir-quality sand. The significance of carbonate disssolution is indicated by the fact that carbonate cement, although abundant at shallow depths, is rare at depths greater than 13,000 ft.

Temperature

Abundant quartz cement in relatively shallow, high-geothermal-gradient Arkoma basin sandstones at 6,800 ft, versus porous, normal-gradient Anadarko basin sandstones at the same depth (Fig. 2), suggests that temperature is a fundamental control of quartz-cement variations between basins. The high-gradient Arkoma basin sandstones, with a temperature of 160°F at 6,800 ft, have extensive quartz cement typical of 9,900-ft-deep Anadarko basin normal-gradient sands from a well with approximately the same temperature (158°F). These data suggest that basins or areas with high geothermal gradients will have correspondingly greater amounts of quartz cement and reduced reservoir quality.

Uplift

Shallow sandstones from the Witchita and Arbuckle Mountain uplifts have more extensive cement and grain dissolution than Anadarko basin–Northern shelf sandstones from similar depths (Fig. 2). The more extensive dissolution is probably due to higher pore-fluid flow rates and/or increased meteoric waters at shallow depths. These data suggest that quartzarenite-reservoir properties can be significantly enhanced by dissolution processes following uplift.

The preservation of quartz cement during uplift, however, may cause shallow uplifted sandstones to contain the quartz cement and reduced porosity typical of greater depths. Estimates of the amount of uplift may be critical to predicting porosity in uplifted sandstones.

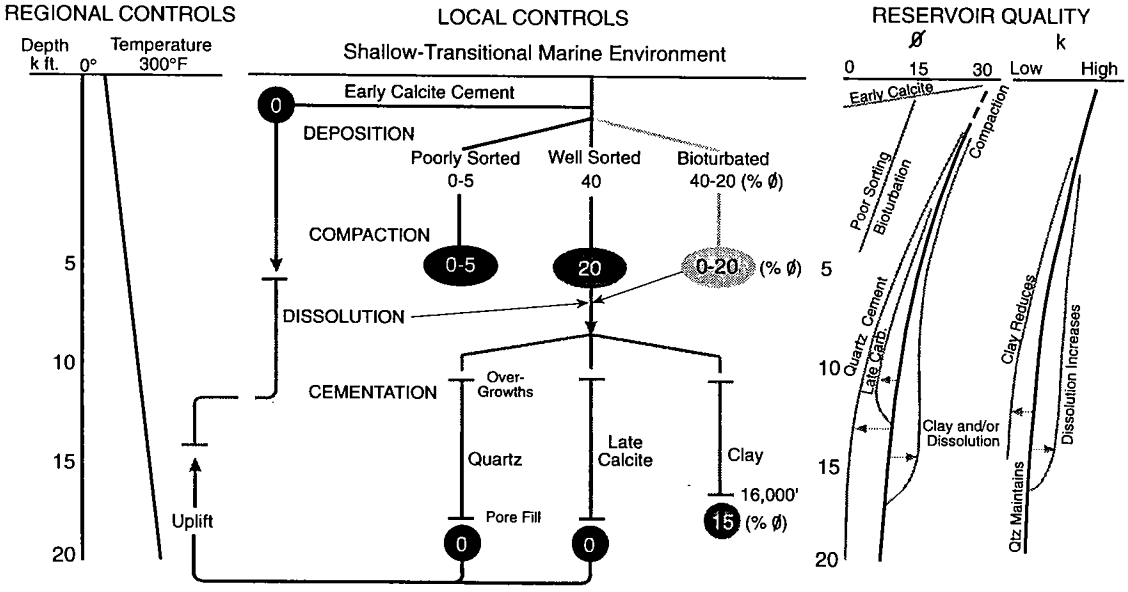
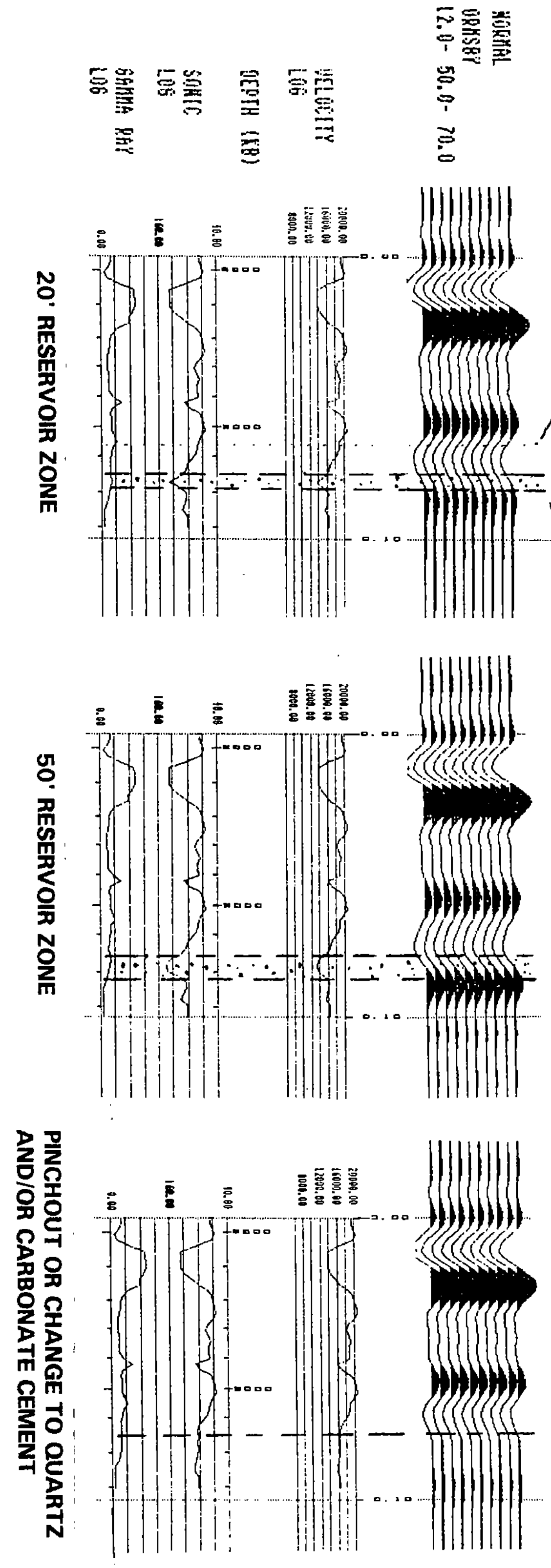


Figure 4. Predictive model of quartz-rich sandstone diagenesis and reservoir quality. The decrease in Oklahoma Simpson quartzarenite porosity and permeability with depth is affected by three regional controls: depth, temperature, and uplift. Also, there are numerous local controls, such as deposition, compaction, cementation, and dissolution processes.

Figure 5 (left). Sonic log and synthetic seismograms, documenting contrast in velocity and reflection character resulting from diagenetically controlled reservoir-quality variations.



IMPLICATIONS FOR RESERVOIR-QUALITY PREDICTION

Geologic Model

Since well-sorted sands are a major lithofacies in multicycle, shallow- to transitional-marine quartzarenites, the well-sorted Simpson quartzarenite-diagenesis data can be used to develop a qualitative model for predicting quartz-rich sandstone diagenesis and reservoir quality. The regional controls of diagenesis, depth, temperature, and uplift form the basis for a predictive model (Fig. 4) of well-sorted quartzarenite diagenesis, whereas the local controls of diagenesis document the variability in quartz-rich sandstone diagenesis and reservoir quality that can be expected for a given depth, temperature, or structural setting.

Seismic Prediction of Diagenesis and Reservoir Quality

The contrast in porosity between various quartzarenite diagenetic facies can be sufficient to cause reflections on seismic data. Seismic-stratigraphic modeling of a sampled Simpson sand with a 20-ft-thick reservoir zone shows the contrast in seismic expression (Fig. 5) that can be caused by the velocity contrast between relatively tight quartz-cemented facies and a thin 20-ft-thick porous zone formed by (1) clay rims that prevented extensive quartz cement, and (2) dissolution processes.

The impedance contrast is sufficient to cause a pronounced reflection from the 20-ft-thick sand. A thicker sand will produce a distinctly larger reflection, whereas a pinchout, or a diagenetic facies change to quartz or carbonate cement, will cause the reflection to disappear (Fig. 5). These seismic-modeling results suggest that it may be possible to extend diagenetic-facies interpretations away from wells to more accurately predict the distribution of reservoirs and better understand the geologic controls of diagenetic facies distribution.

Correlation and Distribution of Reservoir and Sealing Facies Within the Viola Formation, South-Central Kansas

K. David Newell
Kansas Geological Survey
Lawrence, Kansas

ABSTRACT.—Lithostratigraphic correlations of wireline logs indicate that the Viola Formation can be subdivided into four major subunits that are mappable over the Sedgwick basin and Pratt anticline. The subunits were originally defined by St. Clair (1982) in a study within Barber and Pratt Counties. From base to top, these subunits are basal limestone, lower cherty dolomitic limestone, upper limestone, and upper cherty dolomitic limestone. The limestones are low-porosity, syntaxially cemented, crinoidal–bryozoan packstones, whereas the cherty dolomites generally are porous mixed-skeletal dolomitized wackestones and mudstones with nodular chert.

Isopach and subcrop mapping reveals that the basal limestone is the most extensive of all the Viola subunits and that the subunits above it were successively eroded off the crest of the northwest-trending Central Kansas arch. The basal limestone is thickest atop the arch. The thickening of this basal unit is attributed to development of crinoidal shoals localized on the crest of the arch as the arch was growing during Viola deposition. Thinning of the basal limestone unit locally occurs on structural crests along a north-northeast trend over the Pratt anticline. The Pratt anticline partly overlies the western margin of the Precambrian Midcontinent rift in this area, and the structural activity recorded during Viola deposition represents minor reactivation along a long-lived zone of structural weakness.

The porous, cherty dolomitic subunits compose the most prolific reservoir rocks in the Viola Formation. Major oil fields in the study area occur in structural and stratigraphic traps where these units subcrop beneath either the basal Pennsylvanian angular unconformity or the unconformity at the base of the Devonian–Mississippian Chattanooga Shale. Potential stratigraphic traps may be created by pinchouts of the porous cherty dolomites beneath the nonporous crinoidal–bryozoan limestone subunits, but the efficiency of the crinoidal–bryozoan limestones as seals has not yet been determined.

INTRODUCTION

Studies at the University of Kansas, the Kansas Geological Survey, and Syracuse University (St. Clair, 1982, 1985; Bornemann, 1979; Bornemann and others, 1982; Bornemann and Doveton, 1983) utilized cuttings, cores, and wireline logs to stratigraphically subdivide the Viola Formation on the western flank of the Sedgwick embayment (of the Anadarko basin) in Barber and Pratt Counties. The Viola is divided into four informal units. From base to top, these are basal limestone, 5–25 ft thick; lower cherty dolomitic limestone, 10–104 ft thick; upper limestone, 4–32 ft thick; and upper cherty dolomitic limestone, 4–48 ft thick. The limestones are low-porosity crinoidal–bryozoan packstones, whereas the cherty dolomites generally are porous mixed-skeletal dolomitized wackestones and mudstones with nodular chert (St. Clair, 1982, 1985).

A correlation of the four Viola subunits to geophysical logs is shown in Figure 1. Resistivity and porosity tools respond to the relatively high porosities that typify the cherty dolomites.

ISOPACH AND SUBCROP MAPPING OF VIOLA SUBUNITS

In order to better understand the spatial distribution and thickness of subunits within the Viola Formation, regional stratigraphic cross sections were used as a reference for making subcrop and isopach maps, using 1,709 well logs over the study area (Fig. 2). A subcrop map of Viola subunits using these well data (Fig. 3) shows that the Viola is eroded down to its lowermost subunit, the basal limestone, over the north-northwest-trending crest of the Central Kansas arch, which extends through southwestern Rice, northeastern Reno, and northwestern Sedgwick Counties. Successively younger subunits are arrayed in a generally symmetrical pattern along the northeastern and southwestern flanks of the arch. A comparison of this erosional pattern with that of a "worm's-eye-view" map for rock units positioned on the Viola (Fig. 4) indicates that much of the erosion accounting for the subcrop pattern on the northeastern flank of the arch (i.e., the area encompassing northern Butler, Chase, Harvey, Marion, McPherson, Rice, and northern Sedgwick

---

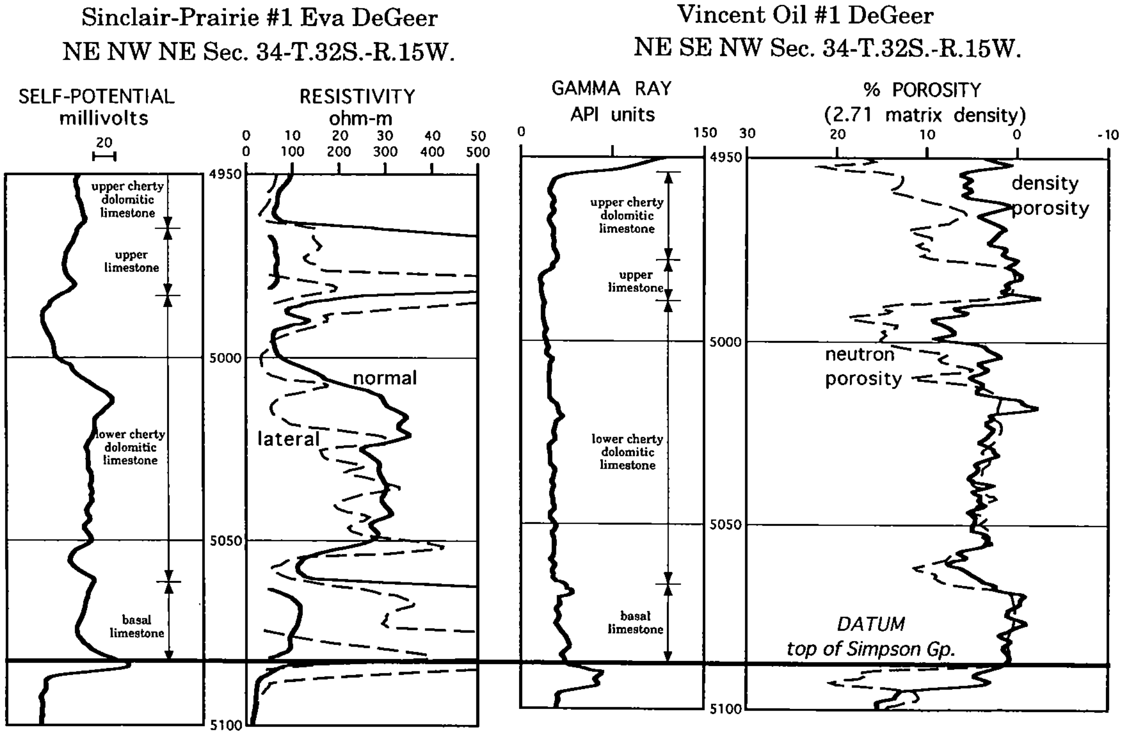
Newell, K. D., 1997, Correlation and distribution of reservoir and sealing facies within the Viola Formation, south-central Kansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 247–259.

Counties) occurred before deposition of the Upper Ordovician Maquoketa Formation. A subtle angular unconformity separates the Viola from the overlying Maquoketa Formation (Wright and Meyers, 1981).

The subcrop map (Fig. 3) reveals a complex group of northwest-trending, township-size uplifts on the southwestern flank of the Central Kansas arch (i.e., in the area of Edwards, Pratt, northern and eastern Barber, and western Harper Counties). In addition to structural influences, the amoeboid appearance of some of these features also can be the result of differential erosion and relief on the unconformity at the base of the Devonian–Mississippian Chattanooga Shale in combination with the low angles of dip that the subunits of the Viola have in relation to this unconformity. Although the locations of faults are difficult to define precisely with present control, some faults may be present in this region of uplifts where trends of subcrop units markedly narrow. The average vertical offset of Ordovician strata along major faults paralleling the Pratt anticline in Pratt County is 150 ft (Brewer, 1959). The Viola unconformably underlies the Chattanooga Shale over most of this region, so the tectonic movement responsible for these structures is assigned a pre-Late Devonian–post-Middle Ordovician age.

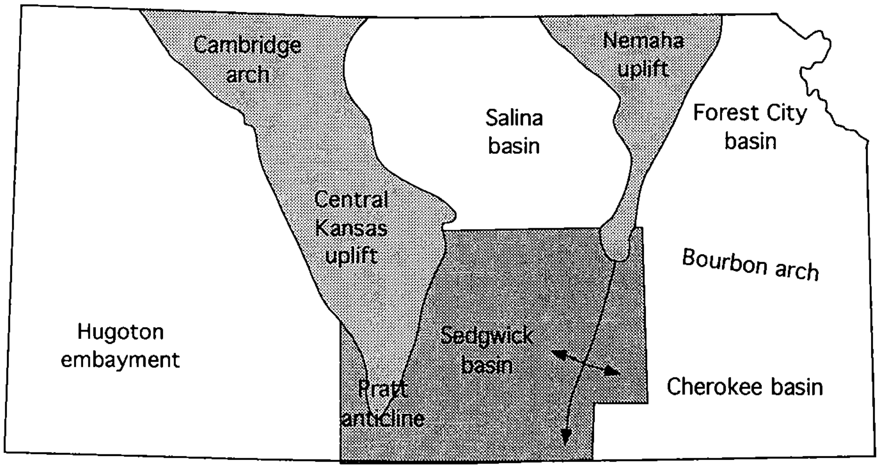
The isopach map of the basal limestone subunit (Fig. 5) reveals this unit to be thickest in the vicinity of Harvey, Marion, McPherson, and Rice Counties. Notwithstanding possible erosional beveling at the base of the Maquoketa Formation, the basal limestone subunit is nearly 60 ft thick in Rice County. Minor thickening is also evident in Pawnee and Edwards Counties just south of the Central Kansas uplift. The marked thickening in the vicinity of the crest of the Central Kansas arch and immediately to the north indicates the persistence of shallow-water conditions that resulted in accumulation of shoals of crinoid and bryozoan fragments. Southwest of its present-day subcrop off the flank of the Central Kansas arch, the basal limestone unit is thinner (10–20 ft), possibly signifying deeper water conditions off the arch, conditions that were less conducive for development of these shoals. Deeper and more open-water conditions would be expected off the Central Kansas arch farther south toward the continental margin and ancestral Anadarko basin.

Another feature of the isopach of the basal limestone is a series of north-northeast-trending isopach thins (less than 10 ft thick) extending from northern Pratt County to northeastern Kiowa County. This trend

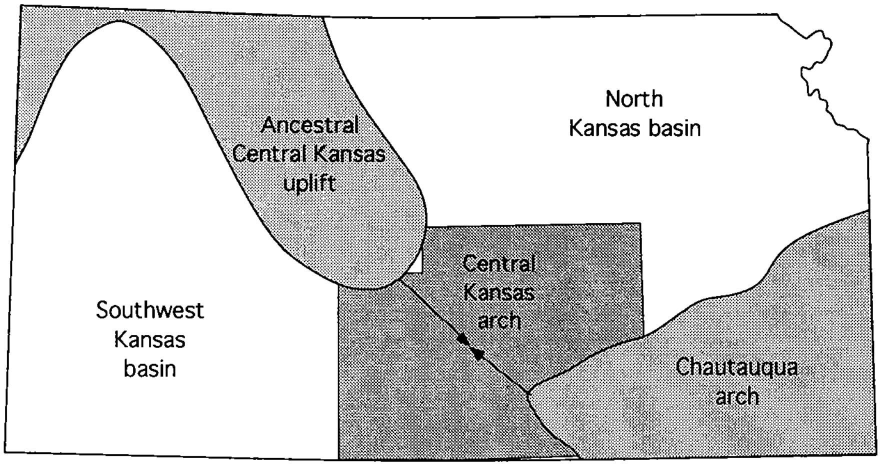

Sinclair-Prairie #1 Eva DeGeer
NE NW NE Sec. 34-T.32S.-R.15W.

Vincent Oil #1 DeGeer
NE SE NW Sec. 34-T.32S.-R.15W.

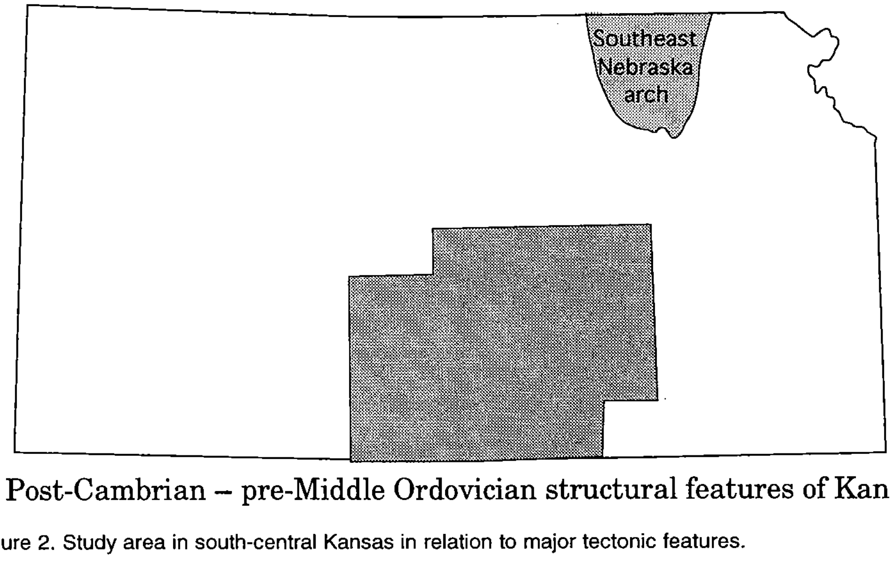
Figure 1. Characteristic geophysical-log signatures of Viola subunits from two wells are approximately 1,900 ft apart. The Sinclair-Prairie No. 1 Eva DeGeer log (from St. Clair, 1982) is a typical older electrical log run in 1947, whereas the more recent Vincent Oil No. 1 DeGeer log, which illustrates the corresponding response of the neutron-porosity, density-porosity, and gamma-ray tools, was run in 1983. The apparent downward offset of the trace of the lateral log versus the normal resistivity log on the Eva DeGeer well is an artifact of the spacing of the electrodes on these respective tools (cf. Schlumberger, 1987, p. 69–74). Lime grainstones (basal limestone and upper limestone) are typically nonporous and have high resistivities, whereas dolomitic mudstones (lower cherty dolomitic limestone and upper cherty dolomitic limestone) have higher porosities and lesser resistivities. Log depths are in feet.



A. Post-Mississippian – pre-Pennsylvanian structural features of Kansas



B. Post-Ordovician – pre-Mississippian structural features of Kansas



C. Post-Cambrian – pre-Middle Ordovician structural features of Kansas

Figure 2. Study area in south-central Kansas in relation to major tectonic features.

spatially coincides with the present-day trend of the Pratt anticline and indicates that contrary to the regional thickening present on the northern flank of the Central Kansas arch, the basal limestone displays localized thinning over smaller structures that probably were active during its deposition. The orientation of the individual thin areas along a north-northeast trend produces a left-stepping en-echelon pattern that is compatible with left-lateral movement. This area may be part of a long-lived zone of structural weakness, because the eastern flank of the Pratt anticline partly overlies the western flank of the 1,100-Ma Midcontinent rift system (cf. Dickas, 1986) and coincides with one of several north-northeast-trending magnetic lineations evident in the Precambrian basement (see Yarger, 1983). Subtle north-northeast trends in chert content and porosity of the Viola Formation in this area were also noted by Doveton and Bornemann (1981), Bornemann and oth-

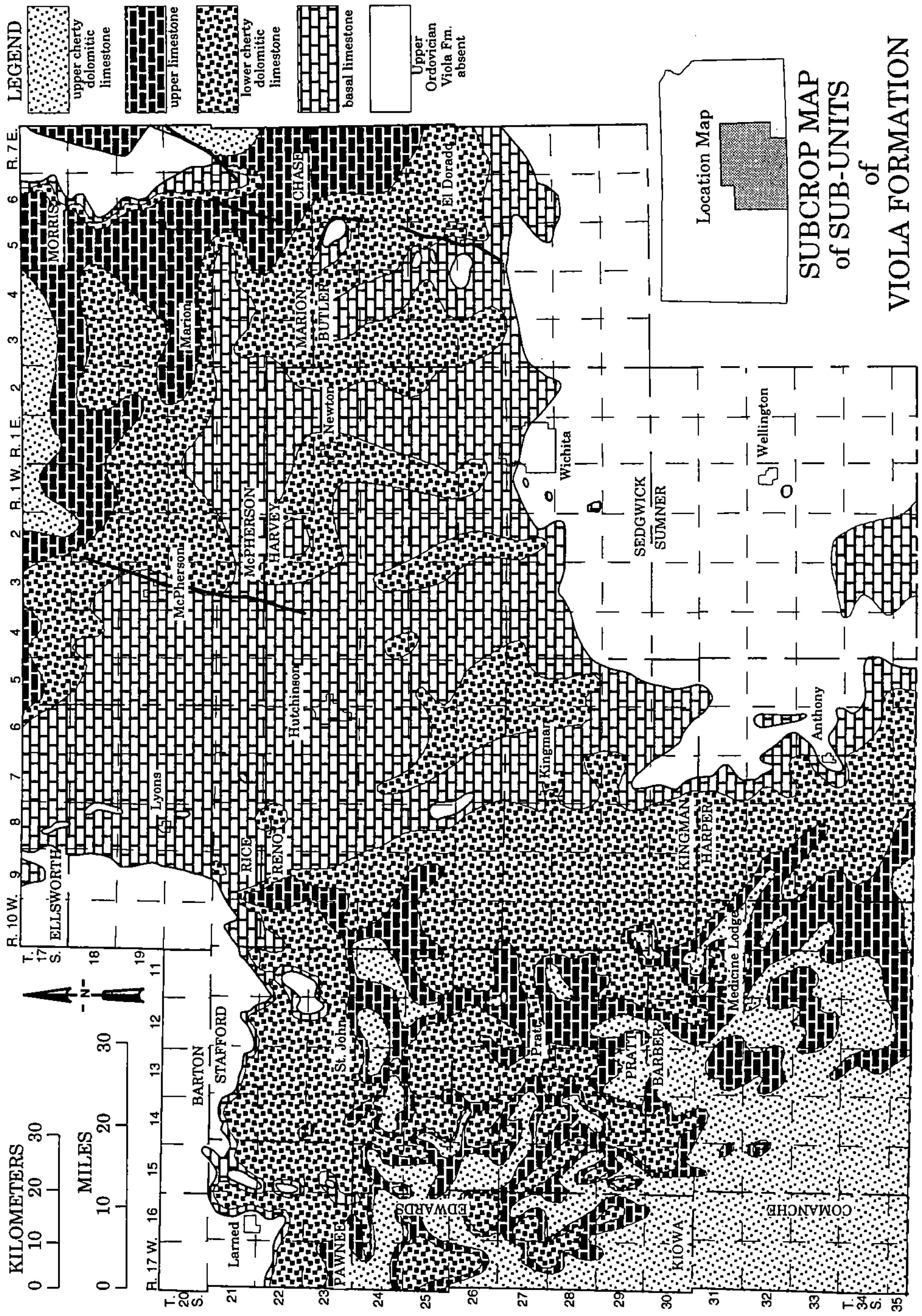


Figure 3. Subcrop map displaying which subunit of the Viola Formation is present at the top of the Viola. The unconformity beveling the Viola Formation varies over the study area (see Fig. 4). The north-northwest-trending crest of the Central Kansas arch (northwestern Sedgwick, eastern Rice, and eastern Reno Counties) is illustrated by the presence of the lowermost subunit of the Viola, the basal limestone, at the top of the Viola Formation. The "worm's-eye-view" map (Fig. 4) complements this map by illustrating the rock unit superjacent to the Viola Formation.

ers (1982), and Bornemann and Doveton (1983).

The isopach map of the lower cherty dolomitic limestone (the Viola subunit directly above the basal limestone; Fig. 6) indicates that the thickness of this subunit is more variable than that of the basal limestone. Many isopach thins, including those evident over the Pratt anticline, are due to local uplift and truncation of this unit at various unconformities above the Viola Formation. This lower cherty dolomitic limestone subunit is largely absent over the Central Kansas arch, but scattered inliers in Harvey, eastern Reno, and Sedgwick Counties indicate that it was probably contiguously deposited over the arch and subsequently eroded. Marked westward thickening is evident along a north–south line roughly corresponding to the eastern border of Comanche, Edwards, and Kiowa Counties (i.e., along the boundary between the R. 15 W. and R. 16 W. tiers of townships). This area corresponds to the

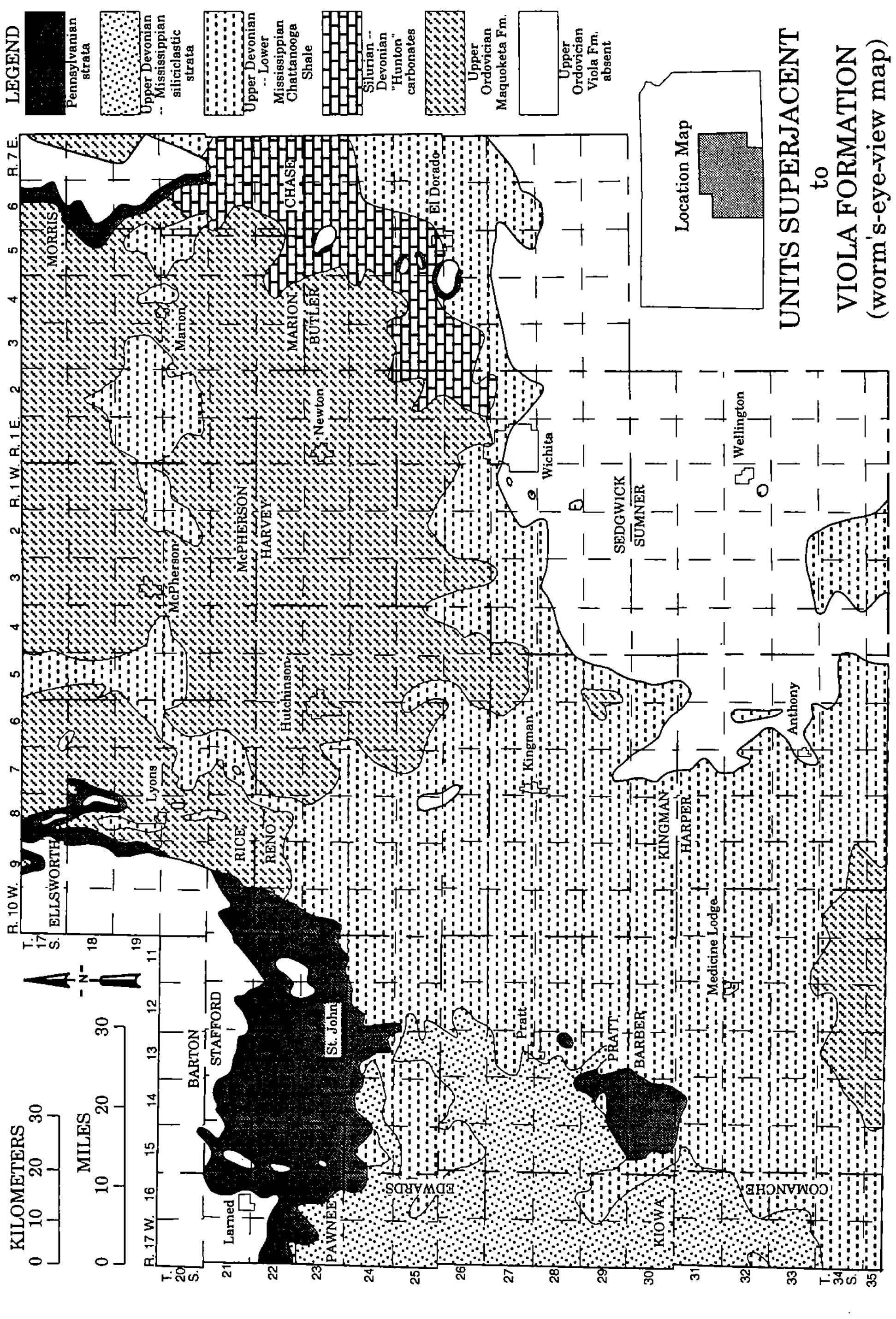


Figure 4. A "worm's-eye view" or "lap-out" map, illustrating units superjacent to the Viola Formation in the study area. The area north of T. 27 S. and east of R. 11 W. is taken from Newell (1986, 1987a,b). The remaining area is from Adkison (1972). Upper Devonian–Mississippian siliciclastic strata present in the western part of the map area are, in part, Mississippian (Kinderhookian) in age and therefore are partly time-equivalent to Chattanooga Shale, Sedalia Dolomite, or Gilmore City Limestone (Goebel, 1968).

western flank of the Pratt anticline and indicates that this anticline grew during deposition of the lower cherty dolomitic limestone subunit. Marked isopach thinning is evident in a northeast trend across central Pratt County, where the lower cherty dolomitic limestone subcrops at the unconformity beneath the Chattanooga Shale and the younger unconformity at the base of the Pennsylvanian System (see Fig. 3). Abnormal thicknesses of detrital chert are present in these localities at the top of the Viola Formation (see Adkison, 1972; Bornemann and Doveton, 1983) and probably represent insoluble material left after dissolution of surrounding carbonate rocks. Adkison (1972) reports the greatest thickness of residual chert (50–100 ft) in central and northern Stafford County where the lower cherty dolomitic limestone subunit subcrops beneath the basal Pennsylvanian unconformity on the southern margin of the Central Kansas uplift.

The distribution and thickness of the upper limestone

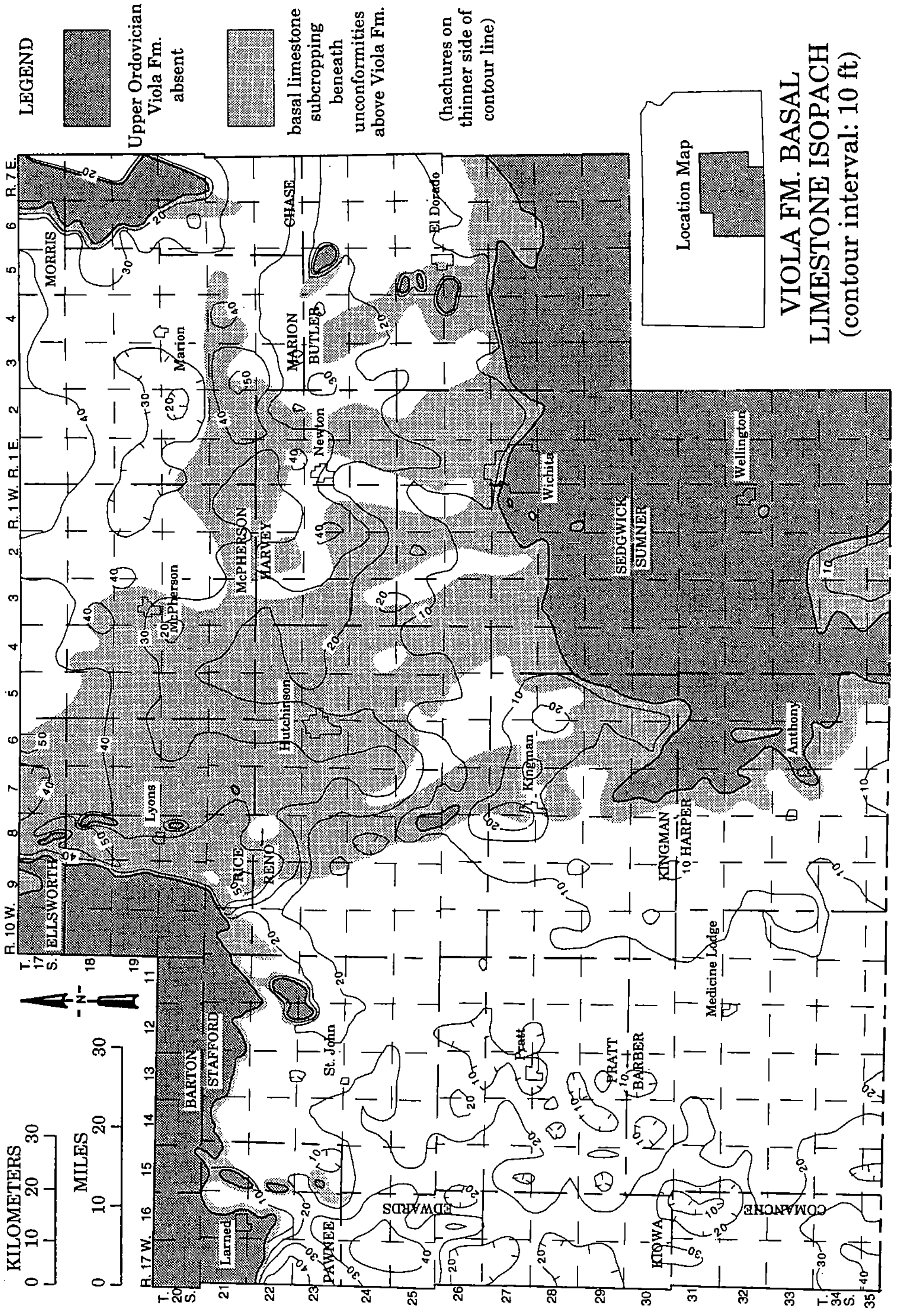


Figure 5. Regional isopach map of the basal limestone of the Viola Formation. The subcrop of the basal limestone (taken from Fig. 3) is shown in gray tone. The basal limestone is relatively thick on top of the Central Kansas arch and directly north of its subcrop (i.e., Marion, McPherson, and Rice Counties), thereby indicating the presence of shallow-water shoals on top of the arch and on the northern flank of the ancestral Anadarko basin.

(the third subunit) of the Viola Formation (Fig. 7) is mostly controlled by its erosion along overlying unconformities at the base of the Maquoketa Formation, Chattanooga Shale, and Pennsylvanian System (see Fig. 4). Scattered areas, where it is greater than 30 ft thick and still overlain by the upper cherty dolomitic limestone of the Viola Formation, are present in Edwards and southern Stafford Counties, directly south of the Central Kansas uplift. These scattered areas are interpreted to be remnants of thick, possibly persistent, crinoidal and bryozoan shoals developed in shallow water near the broad crests of the Central Kansas arch and ancestral Central Kansas uplift. Westward thickening near the western margin of the study area is also evident and may possibly indicate development of persistent shoaling conditions to the west.

The isopach map of the uppermost subunit of the Viola Formation, the upper cherty dolomitic limestone,

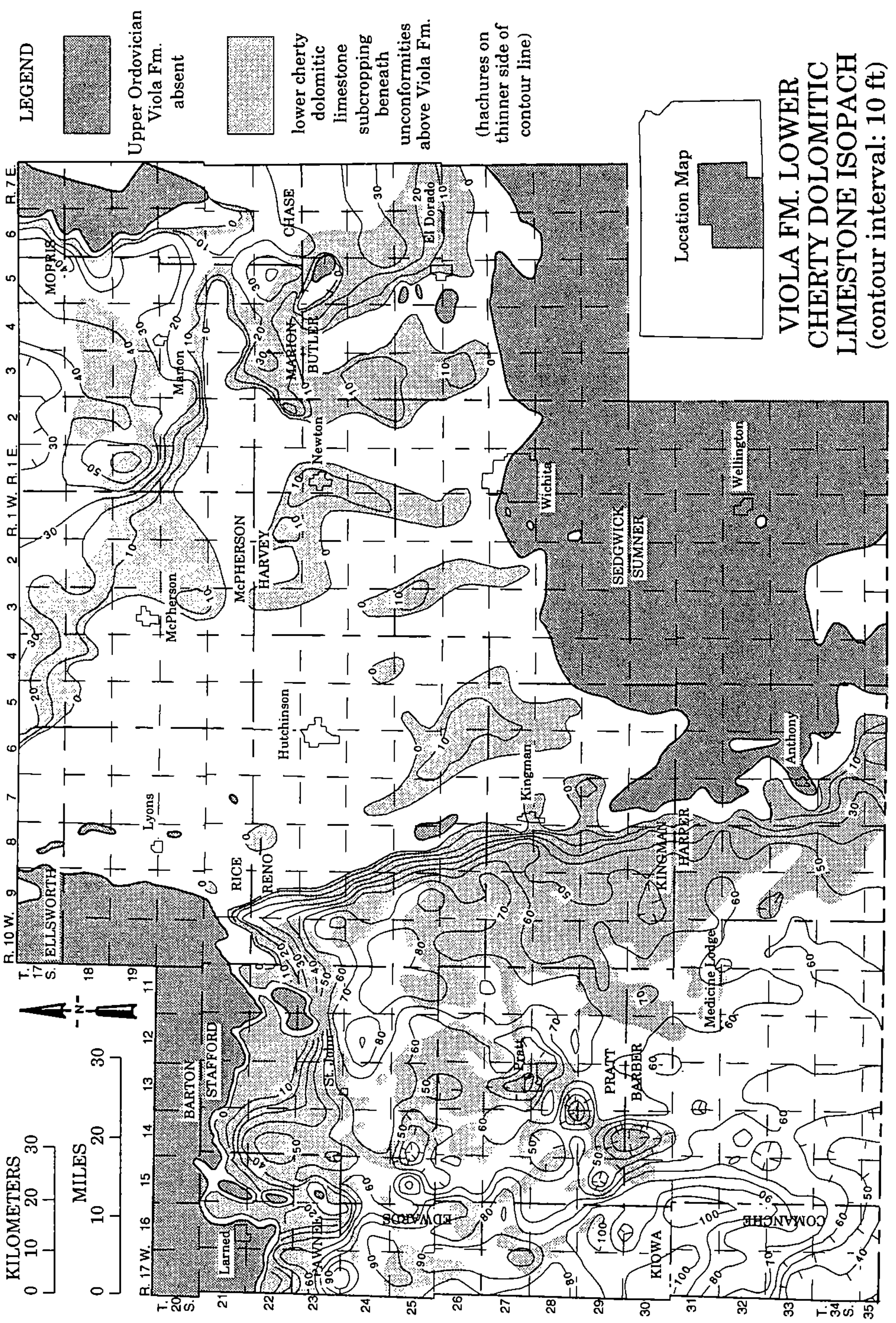


Figure 6. Regional isopach map of the lower cherty dolomitic limestone of the Viola Formation. The subcrop of the lower cherty dolomitic limestone (taken from Fig. 3) is shown in gray tone.

is presented in Figure 8. The thickness and distribution of this unit are entirely controlled by erosion along unconformities above the Viola Formation, hence its geometry gives no hints as to its depositional environment. Areas of drastic changes in thickness, as indicated by closely spaced isopach lines, are due to local geologic structures truncated by angular unconformities above the Viola. Both northeast and northwest trends are developed, which are indicated by the pattern of the contours and subcrop limits (zero line). The northwest trends in northeastern Barber County are subjacent to the unconformity at the base of the Chattanooga Shale (see Fig. 4); therefore, they are pre–Late Devonian in age. Farther north in Edwards and northern Kiowa Counties, the precise age of the strata above the Viola is unclear. Trends in these localities may be attributable to structural movements and subsequent erosion up to as late as Late Mississippian time.

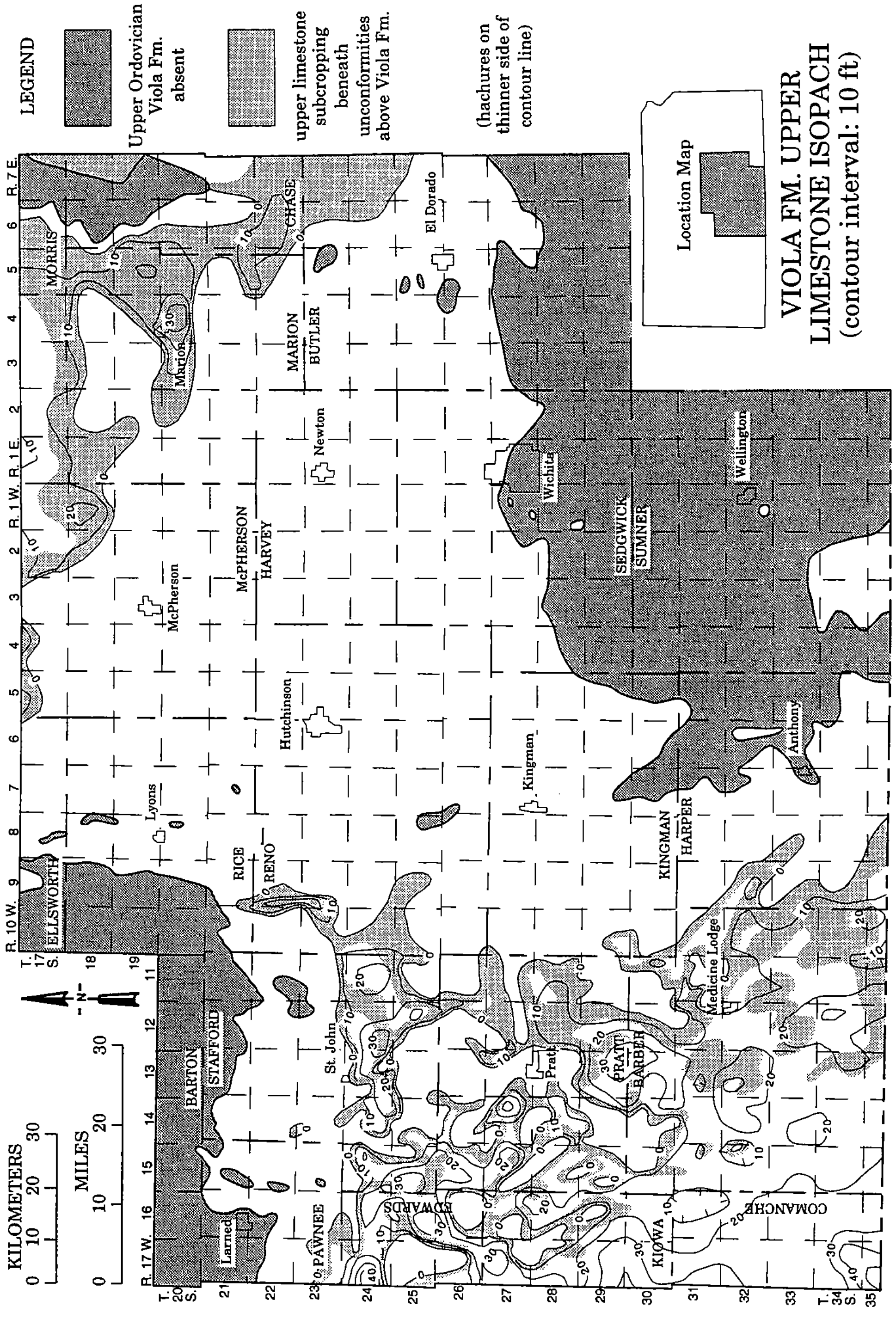


Figure 7. Regional isopach map of the upper limestone of the Viola Formation. The subcrop of the upper limestone (taken from Fig. 3) is shown in gray tone.

CONTROLS ON VIOLA OIL AND GAS PRODUCTION

Insight into geologic controls on Viola petroleum production is gained by comparing the pattern of Viola petroleum production with the regional-structure, "worm's-eye-view," and subcrop maps. The regional structure map of the base of the Viola Formation is overlain with a map showing areas of petroleum production in Figure 9. Two northeast trends of Viola petroleum production obliquely cut across the trend of the south-plunging Pratt anticline: one slightly arcuate (convex southward) production trend extends from central Stafford County to northwestern Reno County; the other trend stretches from west-central Barber County to east-central Pratt County. The pattern of petroleum production indicates that the Pratt anticline does not solely control the distribution of nearby petroleum production,

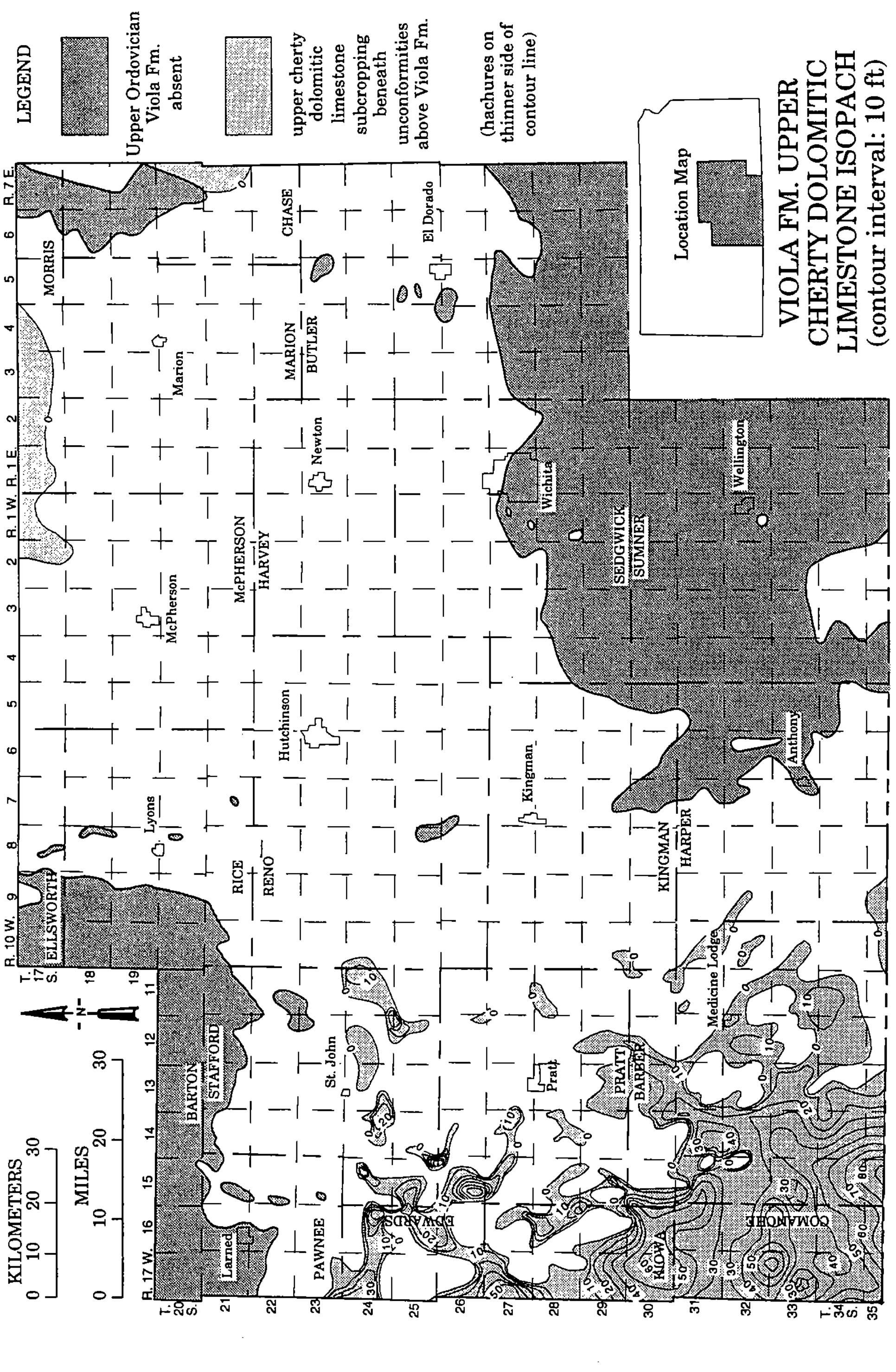


Figure 8. Regional isopach map of the upper cherty dolomitic limestone of the Viola Formation. The subcrop of the upper cherty dolomitic limestone (taken from Fig. 3) is shown in gray tone.

because a predominant north–south trend of production, largely up the plunge of the Pratt anticline, would be the expected distribution if this were the case. Both production trends are represented by a variety of traps producing from cherty dolomites (Newell and others, 1987). The production along the northeastern part of the northern trend (Ts. 22–23 S., Rs. 9–11 W.) is stratigraphically entrapped oil in the Zenith–Peace Creek field, where Viola reservoirs are truncated by the basal Pennsylvanian unconformity and pre-Chattanooga unconformities (Imbt, 1941; Paddleford, 1941; Kornfeld, 1943; Newell and others, 1991). The northeastern end of the southerly trend (T. 28 S., R. 11 W.) is the Cunningham field, which is a combination structural–stratigraphic trap that produces gas (Rutledge and Bryant, 1937; Page, 1940).

The two production trends that obliquely cross the Pratt anticline are spatially associated with broad southwest-plunging apparent synclines expressed on the sub-

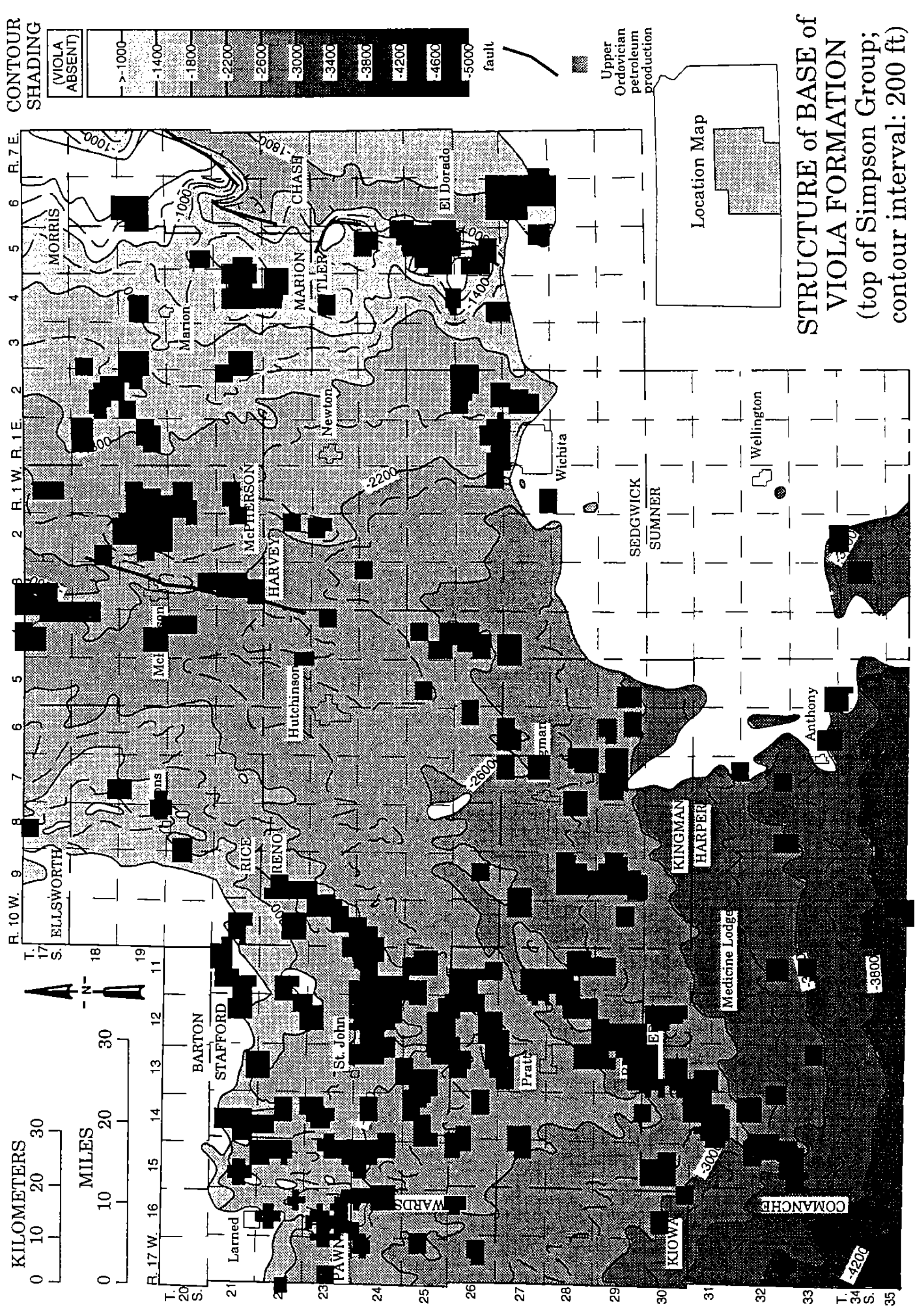


Figure 9. Map showing areas of Viola hydrocarbon production, overlain onto the structure map depicting the base of the Viola (top of the Simpson Group) in south-central Kansas (from Adkison, 1972). Most local structures with closures of less than 100 ft cannot be expressed at this scale.

crop map (Figs. 3,10). Both of these synclines have the upper cherty dolomitic limestone preserved in them. The spatial association of production with the subcrop pattern of the Viola subunits implies that the distribution of reservoir rock at the top of the Viola partly controls migration and accumulation of hydrocarbons within the Viola, and that hydrocarbons migrating up-plunge along the Pratt anticline could have been shunted off its crest but still updip along the subcrop limit of the porous upper cherty dolomite. Detailed mapping may reveal many potential stratigraphic traps, particularly where the zero line of the cherty dolomitic subunits crosses structural noses. However, no traps of this type in the Viola within the study area have been reported in published literature, so the efficacy of the basal and upper limestone subunits as lateral seals beneath the unconformities perhaps needs to be examined in more detail.

The principal controls on the distribution of Viola

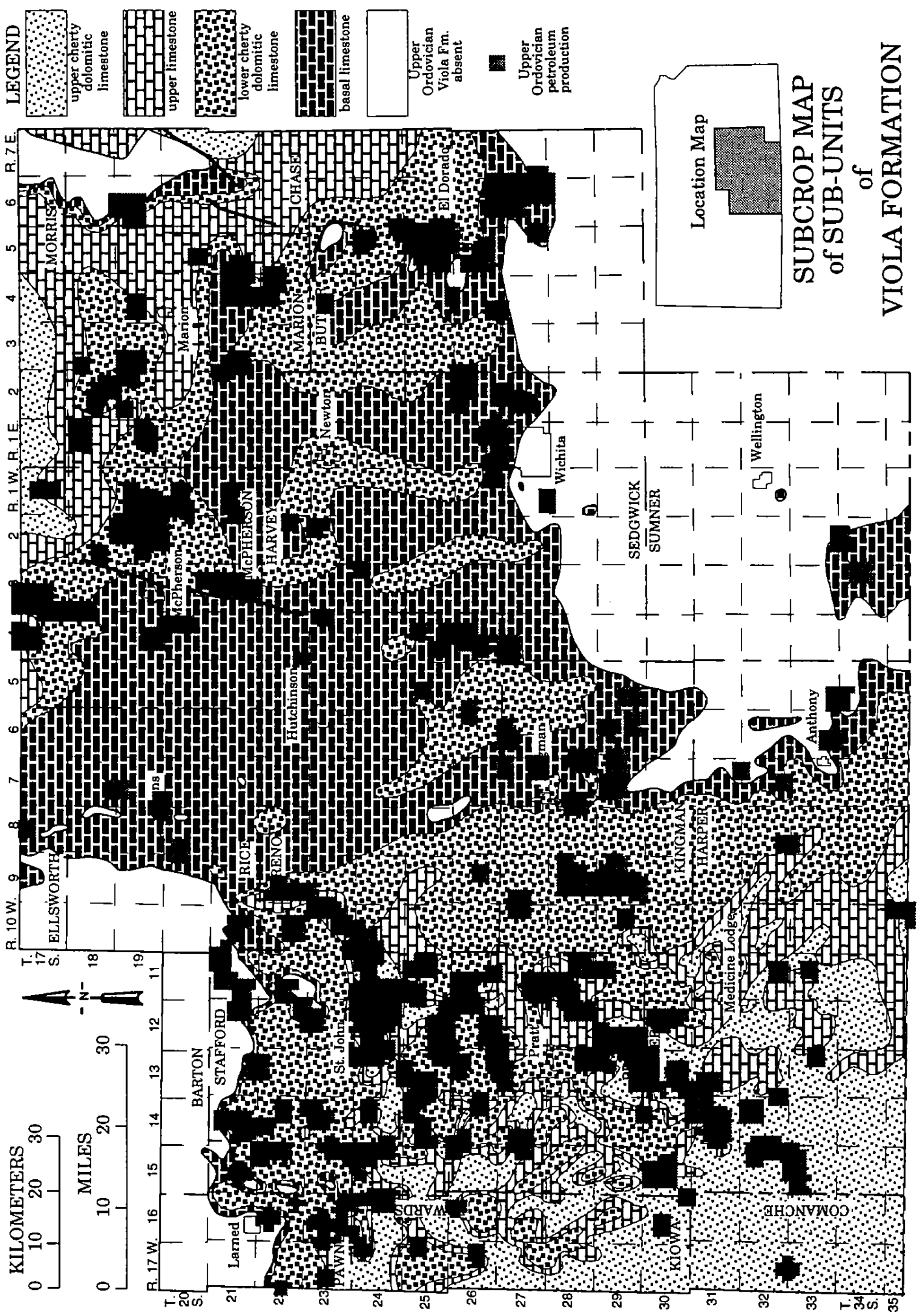


Figure 10. Map showing areas of Viola hydrocarbon production, overlain onto the subcrop map displaying which subunit of the Viola Formation is present at the top of the Viola (see Fig. 3). Two broad southwest-plunging (apparent) synclines, respectively extending southwestward from T. 22 S., R. 9 W., and T. 27 S., R.11 W., are the locus of two productive trends of Viola oil and gas. Most Viola oil and gas fields are associated with subcrops of the upper cherty dolomitic limestone and the lower cherty dolomitic limestone.

petroleum production elsewhere in the study area are unclear; however, most fields are associated with the subcrop of the cherty dolomitic subunits rather than the limestone subunits (Fig. 10). An exception to this is a scattered group of fields that produce from the basal limestone subunit along the southerly pinchout of the Viola on the Chautauqua arch in an area extending from southeastern Kingman County to east-central Butler County. These fields may be related to dolomitization of this unit near the crest of the arch.

Viola production superimposed on the worm's-eye-view map (Fig. 11) shows no obvious correlation with the pattern of units superjacent to the Viola Formation. However, Mississippian siliciclastic strata off the west flank of the Pratt anticline in eastern Edwards, eastern Kiowa, northern Comanche, and western Pratt Counties

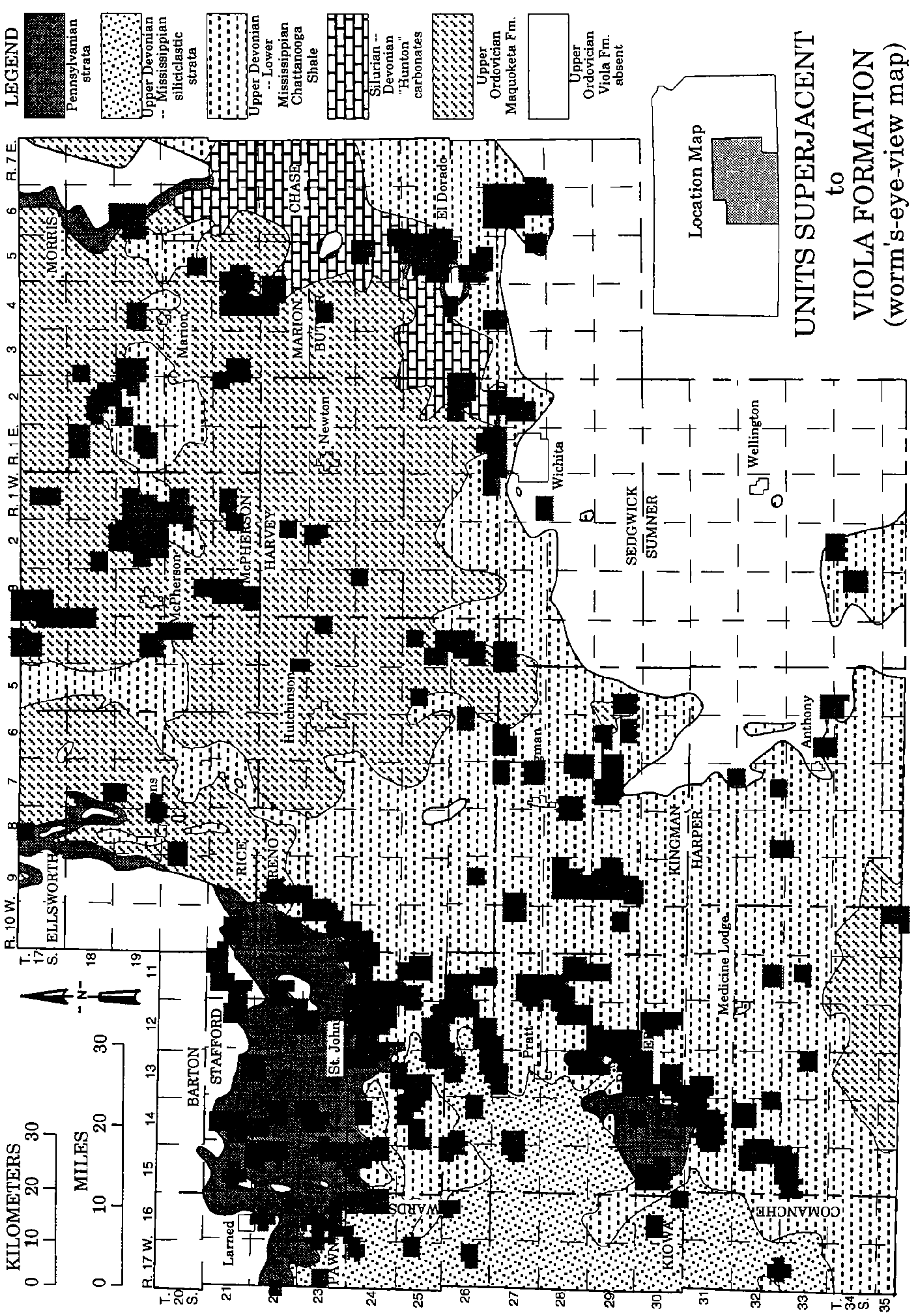


Figure 11. Map showing areas of Viola hydrocarbon production, overlain onto the "worm's-eye-view" map illustrating units superjacent to the Viola Formation (see Fig. 4). No close association of the production trends with the map pattern is evident.

have little associated Viola production, which may mean that these beds are not an effective seal to any Viola reservoir bed directly beneath them.

SUMMARY AND CONCLUSIONS

The Viola Formation can be informally subdivided into four regionally mappable subunits in south-central Kansas. These subunits consist of a stratigraphic alternation of nonporous crinoidal–bryozoan lime packstones that were probably deposited in shallow water, and porous cherty dolomitic mudstones that were probably deposited in deeper water. Regional isopach mapping indicates that several subtle geologic structures were growing during Viola deposition and that these structures had a marked influence on the thickness of the Viola subunits.

Most petroleum production from the Viola Formation in south-central Kansas is from the porous cherty dolomitic subunits. The complex subcrop pattern of these subunits over the Pratt anticline and Central Kansas arch controls the distribution of petroleum production trends within the Viola Formation. Stratigraphic traps are possible where these porous units pinch out updip on structural noses. Porous dolomites that pinch out on the western flank of the Pratt anticline are also potential stratigraphic traps. The crinoidal–bryozoan packstones that are interbedded with the porous dolomites may act as lateral and vertical seals to petroleum accumulations in the porous dolomites, but the efficiency of the packstones as seals are yet to be determined.

ACKNOWLEDGMENTS

Appreciation is expressed to Marvin Carlson (Nebraska Geological Survey), Evan Franseen (Kansas Geological Survey), and Robert Slamal (consultant, Wichita, Kansas) for reviewing this manuscript.

REFERENCES CITED

Adkison, W. L., 1972, Stratigraphy and structure of Middle and Upper Ordovician rocks in the Sedgwick basin and adjacent areas, south-central Kansas: U.S. Geological Survey Professional Paper 702, 33 p.

Bornemann, Erhard, 1979, Well-log analysis as a tool for lithofacies determination in the Viola Limestone (Ordovician) of south-central Kansas: Syracuse University unpublished Ph.D. dissertation, 151 p.

Bornemann, Erhard; and Doveton, J. H., 1983, Lithofacies mapping of Viola Limestone in south-central Kansas based on wireline logs: American Association of Petroleum Geologists Bulletin, v. 67, p. 609–623.

Bornemann, Erhard; Doveton, J. H.; and St. Clair, P. N., 1982, Lithofacies analysis of Viola Limestone in south-central Kansas: Kansas Geological Survey Petrophysical Series 3, 44 p.

Brewer, J. E., 1959, Geophysical problems on Pratt anticline, Pratt County, Kansas, *in* Hambleton, W. W. (ed.), Symposium on geophysics in Kansas: Kansas Geological Survey Bulletin 137, p. 275–280.

Dickas, A. B., 1986, Comparative Precambrian stratigraphy and structure along the Mid-Continent rift: American Association of Petroleum Geologists Bulletin, v. 70, p. 225–238.

Doveton, J. H.; and Bornemann, Erhard, 1981, Log normalization by trend surface analysis: Log Analyst, v. 22, no. 4, p. 3–8.

Goebel, E. D., 1968, Mississippian rocks of western Kansas: American Association of Petroleum Geologists Bulletin, v. 52, p. 1732–1778.

Imbt, W. C., 1941, Zenith pool, Stafford County, Kansas, *in* Levorsen, A. I. (ed.), Stratigraphic type oil fields: American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 139–165.

Kornfeld, J. A., 1943, Peace Creek field (Kansas), a stratigraphic trap: World Petroleum, v. 14, no. 13, p. 38–47.

Newell, K. D., 1986, Pre-Pennsylvanian subcrop map of Rice and Ellsworth Counties, Kansas: Kansas Geological Survey Open-File Report 86-6 (map, scale 1:100,000).

_____1987a, Pre-Pennsylvanian subcrop map of Salina basin, Kansas: Kansas Geological Survey Open-File Report 87-3 (map, scale 1:500,000).

_____1987b, Pre-Chattanooga subcrop map of Salina basin, Kansas: Kansas Geological Survey Open-File Report 87-4 (map, scale 1:500,000).

Newell, K. D.; Watney, W. L.; Cheng, S. W. L.; and Brownrigg, R. L., 1987, Spatial and stratigraphic distribution of Kansas oil and gas production: Kansas Geological Survey Subsurface Geology Series 9, 86 p.

Newell, K. D.; Cunningham, K. J.; Wong, J.-C.; Watney, W. L.; and Weatherbie, W. J., 1991, Large- and small-scale geological features of the Zenith field and their bearing on planning for enhanced oil recovery operations: Proceedings of Ninth Tertiary Oil Recovery Conference, Wichita, Kansas; Tertiary Oil Recovery Project, University of Kansas, p. 99–130.

Paddleford, J. T., 1941, The Zenith pool of Stafford and Reno Counties, Kansas: Mines Magazine, v. 31, p. 445–448, 454, 470, 472.

Page, J. H., 1940, Larger gas fields in Kansas: American Association of Petroleum Geologists Bulletin, v. 24, p. 1779–1797.

Rutledge, R. B.; and Bryant, H. S., 1937, Cunningham field, Kingman and Pratt Counties, Kansas: American Association of Petroleum Geologists Bulletin, v. 21, p. 500–524.

St. Clair, P. N., 1982, Depositional history and diagenesis of the Viola Limestone in south-central Kansas: University of Kansas unpublished M.S. thesis, 66 p.

_____1985, Core studies of the Viola Limestone in Barber and Pratt Counties, *in* Watney, W. L.; Doveton, J. H.; and Walton, A. W. (compilers), Core studies in Kansas—sedimentology and diagenesis of economically important rock strata in Kansas: Kansas Geological Survey Subsurface Geology Series 6, p. 8–16.

Schlumberger, 1987, Log interpretation principles/applications, volume I: Schlumberger Educational Services, Houston, Texas, 198 p.

Wright, R. P.; and Meyers, W. C., 1981, Organic-walled microplankton in the subsurface Ordovician of northeastern Kansas: Kansas Geological Survey Subsurface Geology Series 4, 53 p.

Yarger, H. L., 1983, Regional interpretation of Kansas aeromagnetic data: Kansas Geological Survey Geophysical Series 1, 36 p.

Oklahoma Geological Survey Circular 99, 1997

Progress Report on Simpson and Viola Correlations from the Arbuckles to the Ozarks

James E. O'Brien
Consultant
Tulsa, Oklahoma

James R. Derby
Consultant
Tulsa, Oklahoma

INTRODUCTION

Correlations based on a network of 274 wireline logs and some samples from closely spaced wells penetrating to the Arbuckle Group across the area from the Pauls Valley uplift (T. 4 N., R. 1 W.) to the flanks of the Ozarks (T. 14 N., R. 26 E.) are shown (Fig. 1). These correlations are tied to a Viola/Simpson core in the Keener No. 1–B Watson well and serve to clarify stratigraphic relations in the Viola and Simpson Groups of the Ordovician of Oklahoma. This paper illustrates the stratigraphic relations along one line of section in this correlation network (Fig. 2; Table 1). This regional correlation network and the new paleontological data from the Keener core confirm and clarify the paleontological outcrop correlations published by Derby and others (1991); a modification of that correlation chart is included here (Fig. 3). Formation tops and thicknesses are given in Table 2.

Historically, the relationship of the Fite and upper Tyner of northeasternmost Oklahoma to the Viola Springs Formation and the Corbin Ranch Member of the Bromide Formation has been disputed. This work demonstrates that the Fite correlates with the subsurface "Viola Dense," and the upper Tyner correlates with the "Viola Dolomite"; both are equivalent to the lower part of the Viola Springs Formation of the Arbuckle Mountain area. The Corbin Ranch Member of the Bromide Formation is equivalent to the subsurface "Bromide Dense," which is truncated by the sub-Viola unconformity and does not extend past the south-central Oklahoma (Arbuckle aulacogen) region. These correlations will require major alterations of subsurface areal-extent and subcrop maps of many authors, and they largely confirm the remarkably accurate subcrop maps of Luther White (1926).

UNCONFORMITIES

Four major unconformities subdivide the Simpson–Viola sequence. All except the Oil Creek–McLish unconformity are clearly demonstrated on the regional correlation by truncation of stratigraphic units (Fig. 2). Unconformities with clear physical evidence are (1) at the base of the Welling, (2) at the base of the Viola (Viola Springs Formation), and (3) at the base of the Simpson–top of the Arbuckle.

The sub-Welling unconformity truncates the upper Viola unit (above the "Viola Dense" and greatly thins the "Dense," which physically traces into the Fite of the Illinois River area (Fig. 2; Table 3). This unconformity disappears westward in the Anadarko basin, which prompted Amsden (*in* Amsden and Sweet, 1983) to combine the Welling and the Viola Formation (*sensu lato*) into the Viola Group and to rename the Viola Formation the *Viola Springs Formation*. However, the

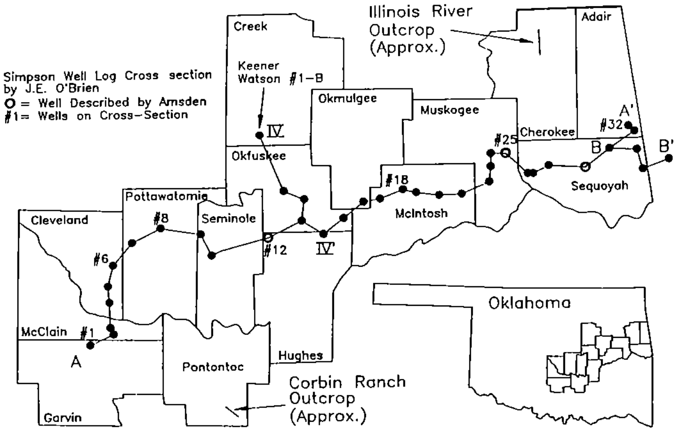


Figure 1. Index map showing location of cross sections displayed in Workshop poster session, and location of wells shown on regional schematic cross section (Fig. 2). The total subsurface correlation network of O'Brien includes 274 wells; only a select few are shown here.

O'Brien, J. E.; and Derby, J. R., 1997, Progress report on Simpson and Viola correlations from the Arbuckles to the Ozarks, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 260–266.

TABLE 1.—WELLS USED IN CROSS SECTION (FIG. 2)

Well no.	Well name and location
1	Grace Petroleum Corp. No. 1–11 Rufus Wigley, NW NE NW 11-14N-1W, Garvin Co., OK
6	Herman Brown No. 3 Roberts, SE SW NW 15-8N-1E, Cleveland Co., OK
8	Woodward and Co. No. 1 Pensoneau, NW SW SW 36-10N-3E, Pottawatomie Co., OK
12	Coker (formerly J. M. Huber) No. 1 Oliphant, SE SE NE 2-9N-8E, Hughes Co., OK
18	Tenneco Oil Co. No. 1 Newton Hill, SW NW SE 4-11N-15E, McIntosh Co., OK
25	U.S. Smelting, Refining and Mining No. 1 Padgett, C NW NW 29-13N-20E, Muskogee Co., OK
32	Continental Oil Co. No. 1 Reinhardt Ranch, N/2 NE 15 14N-26E, Adair Co., OK
---	Keener Oil Co. No. 1–B Watson, S/2 SE NE 15-14N-8E, Creek Co., OK

unconformity at the base of the Welling is easily traced across all of eastern Oklahoma and is represented in the Illinois River outcrops as the unconformity between the Welling (formerly "Fernvale") and the underlying Fite.

The sub-Viola unconformity truncates and completely cuts out the Bromide (including the "Second Wilcox" sand) and greatly thins the McLish. This regional unconformity separates the Viola and equivalent strata above from the Bromide and older Simpson units below. This is the same unconformity that is recognized between the upper and middle Tyner of the Illinois River area.

The Oil Creek–McLish unconformity is recognized on the outcrop section by a gap in the fossil record (Derby and others, 1991; see especially the work of Sweet reviewed therein). Subsurface correlations add no new evidence, as the basal McLish shows no evidence of onlap and the upper Oil Creek units appear to show no truncation. If a hiatus is present, it appears to have affected the region uniformly. However, tracing the Oil Creek–McLish contact to near the outcrop suggests that this hiatus and formation

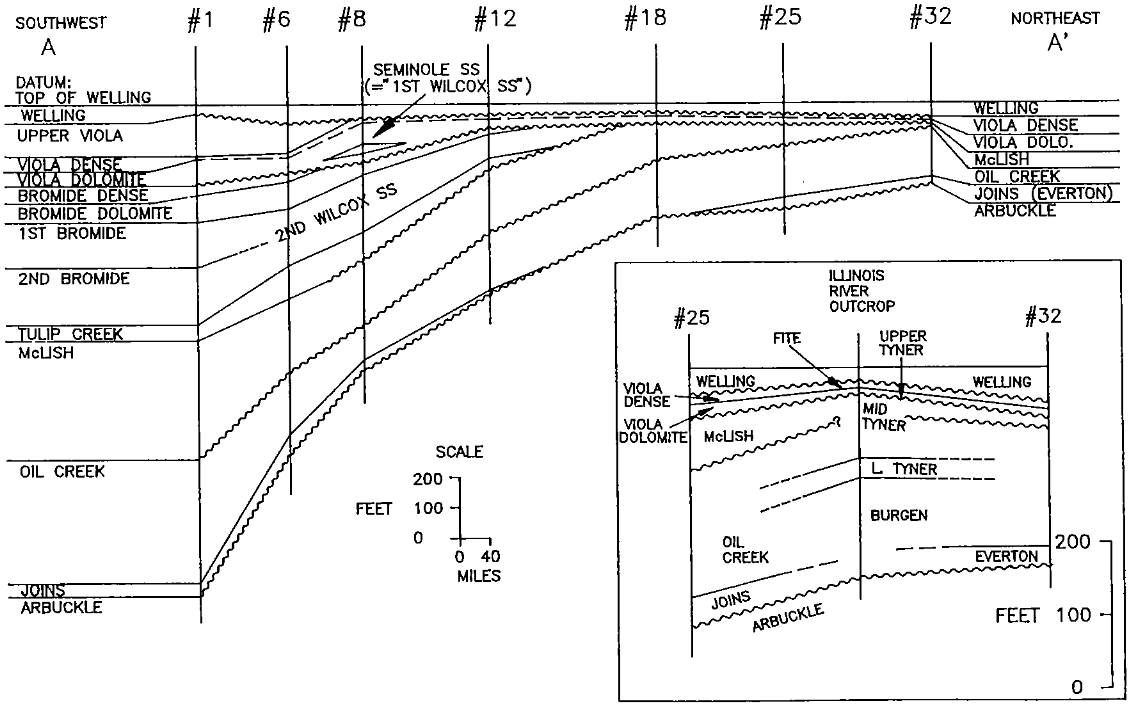


Figure 2. Regional cross section of Simpson and Viola strata from Garvin to Adair Counties, Oklahoma, showing correlation of units and their truncation by regional unconformities.

TABLE 2.—FORMATION TOPS AND THICKNESSES

Formation/ Well no.	Grace No. 1–11 Wigley (No. 1)		Herman No. 3 Roberts (No. 6)		Woodward No. 1 Pensoneau (No. 8)		Coker No. 1 Oliphant (No. 12)*		Tenneco No. 1 Hill (No. 18)		USSRAM No. 1 Padgett (No. 25)*		Continental No. 1 Reinhardt (No. 32)		Keener No. 1–B Watson	
Welling	5120	30	6200	66	5090	50	4190	35	3060	30	1060	37	1129	48	3764	16
Upper Viola	5150	140	6266	94	A		A		A		A		A		A	
Viola "Dense"	5290	10	6360	15	5140	10	4225	15	3090	12	1097	13	1167	10	3780	5
Viola "Dolomite"	5300	88	6375	55	5150	130	4240	30	3102	20	1110	20	1177	10	3785	23
"First Wilcox" ss.	A		A		5220	32	A		A		A		A		A	
Bromide "Dense"	5388	32	6430	25	A		A		A		A		A		A	
Bromide "Dolomite"	5420	90	6455	90	5280	45	4270	20	A		A		A		3808	9
"First Bromide"	5510	150	---		---		---		---		---		---		---	
"Second Wilcox" ss.	---		6545	189	5325	190	4290	80	A		A		A		3817	82+
"Second Bromide"	5660	190	---		---		---		---		---		---		N	
Tulip Creek	5850	53	6734	132	5515	95	4370	37	A		A		A		N	
McLish	5903	397	6866	224	5610	215	4407	213	3122	130	1130	72	1187	15	N	
Oil Creek	6300	406	7090	205	5825	115	4620	187	3252	185	1202	171	1202	162	N	
Joins	6706	44	7295	68	5940	30	4807	15	A		1373	40	1364	26	N	
Arbuckle	6750	85+	7363	131+	5970	144+	4822	211+	3437	407+	1431	109+	1390	204+	N	

Notes: A = absent; N = not drilled; + = incomplete penetration of formation; * = wells described by Amsden (1983). The Coker No. 1 Oliphant well (No. 12) was originally drilled by J. M. Huber as a dry hole, P&A; recompleted in 1976 by Coker. Numerical values are log depths of unit tops followed by unit thicknesses, in feet. The "First Wilcox" sandstone is a subunit within the Viola "Dolomite."

contact may trace to a mud-cracked dolomite (an exposure surface) overlain by shale (a possible flooding surface) 30 ft below the top of the middle Tyner (Table 3).

The Arbuckle–basal Simpson unconformity is well known and is shown in the cross section (Fig. 2) as a variation in thickness and onlap by the Joins. Locally, the Joins is missing on Arbuckle paleo-highs. Although not the subject of this study, truncation of the top of the Arbuckle is well documented. The uppermost Arbuckle formation, the West Spring Creek, is totally absent in northeastern Oklahoma.

STRATIGRAPHIC PROBLEMS

The identification and correlation of various stratigraphic units within the Viola and Simpson Groups have created numerous problems. The problems are compounded by usage of informal subsurface terminology that is similar to, but different from, outcrop terminology. Readers are referred to the comprehensive reviews of Simpson stratigraphy by Schramm (1964, 1965) and Statler (1965), and the modern descriptions by Amsden (*in* Amsden and Sweet, 1983). Specific items of historical confusion are discussed below.

TABLE 3.—COMPOSITE STRATIGRAPHIC OUTCROP SECTION, ILLINOIS RIVER VALLEY, TS. 17–18 N., CHEROKEE COUNTY, OKLAHOMA

Formation	Thickness Meters	Thickness Feet	Description
Welling	5.5	18	Limestone, coarse, organo-detrital, abundant crinoids, moderate brachiopods and bryozoans. Unconformity below.
Fite	2.8	9.2	Limestone, micritic, birdseye-pelletal; ostracodes common.
Upper Tyner	2.6	8.5	Dolomite, fine–medium crystalline; ostracodes. Basal bed with angular chert. Unconformity below.
Middle Tyner	18	59	Mudstone, shale, sandy dolomite, dolomite, and sandstone. Authors suggest a hiatus at top of mud-cracked dolomite 9.2 m (30 ft) below top.
Lower Tyner	8.2	27	Sandy dolomite and mudstone; gastropods and ostracodes. Persistent basal covered interval assigned to Tyner.
Burgen	41.5	136	Sandstone, fine–medium grained, rare inarticulate brachiopods; gray calcareous mudstone; 136 ft is reported in a nearby water well (Huffman, 1958), with unconformity below.
Arbuckle: Cotter Fm.	Variable	Variable	Dolomite, generally coarsely crystalline; minor shale and sandstone. Locally cavernous; may contain Burgen sand in caverns.

Note: See Amsden and Sweet (1983) for map; Bauer (1989) and Derby and others (1991) for Bauer's stratigraphic column; and Huffman (1958) for additional information.

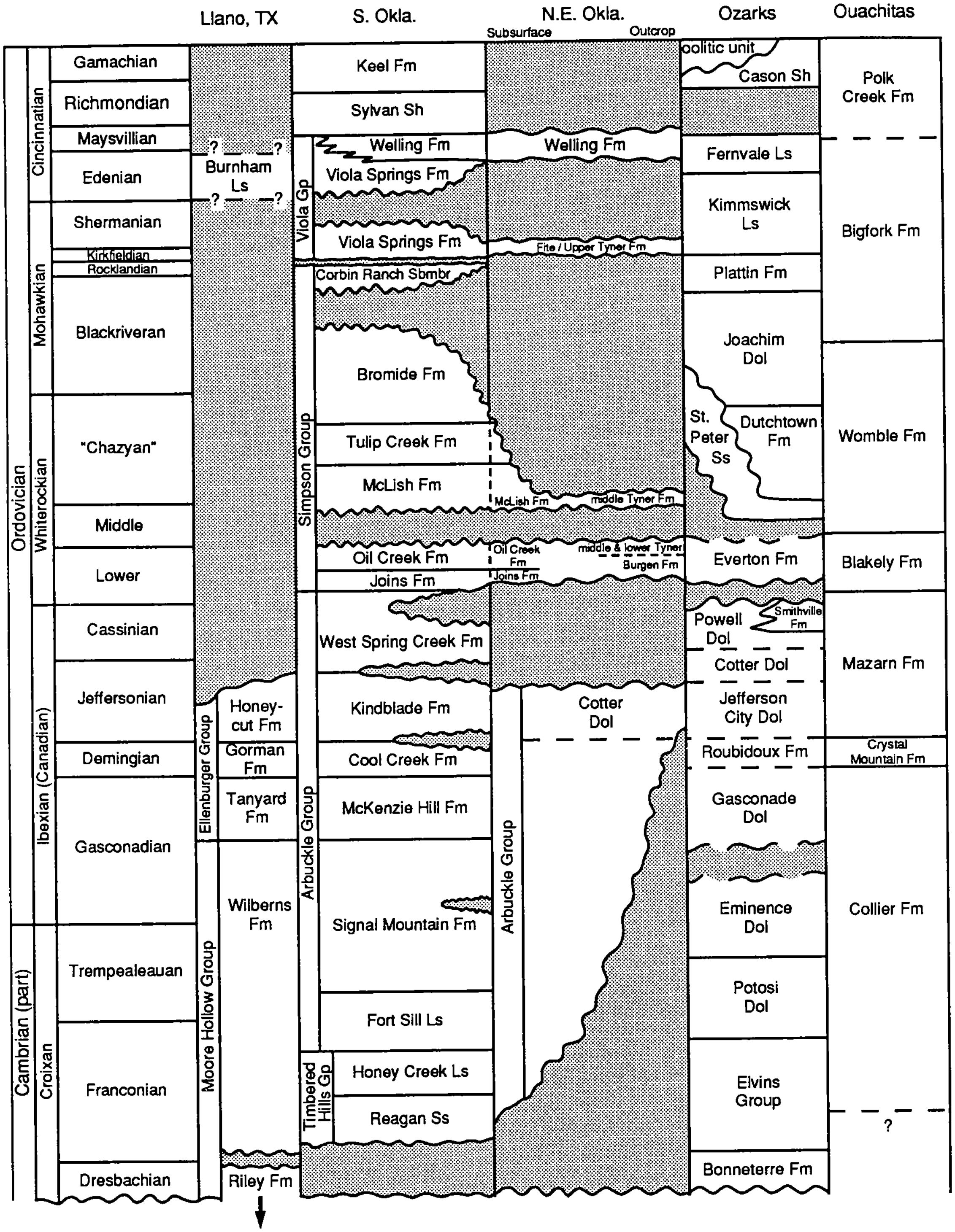


Figure 3. Revised correlation chart of Cambrian and Ordovician strata in Oklahoma. Revised from the diagram prepared by Derby and Repetski (*in* Derby and others, 1991), utilizing data developed in this study. The effect of the regional sub-Viola unconformity is more realistically illustrated here.

TABLE 4.—CORE DESCRIPTION OF KEENER NO. 1–B WATSON WELL

Formation	Member	Depth	Description
Viola Springs	Viola "Dolomite"	3792 (4.2)	Dolomite, very fine-grained, tight; mottled sabkha mudstone. Thin shale at 3795 ft. Sample at 3795.6–3796.2 ft yielded Rocklandian–Kirkfieldian conodonts.
		3796.2 (1.8)	Sandy dolomite, burrowed at top.
		3798 (4)	Sandstone, greenish-white, very fine-grained, dolomitic.
		3802 (6)	Limestone, dolomitic mudstone, thin dissolution breccias at 0.2 ft; shale at 3806.7 ft. Basal 1 ft is rip-up clast conglomerate incorporating underlying lithology.
Unconformity		3808	Regional sub-Viola unconformity; erosional surface.
Bromide	Bromide "Dolomite"	3808 (2)	Dolomite breccia; diagenetic terrane complex.
		3810 (7.1)	Dolomite mudstone, birdseye texture, laminated in part. Sample at 3816–3817 ft yielded Blackriveran conodonts.
	"Second Wilcox"	3817.1 (38 in core)	Sandstone, fine-grained, massive, oil-stained; horizontal burrows in top 2 ft.
			Base of core at 3855 ft.

Note: Described by J. R. Derby, 1989. Location: S½SE¼NE¼ sec. 15, T. 14 N., R. 8 E., Creek County, Oklahoma. Numerical values are unit tops, and values in parentheses are unit thicknesses, both in feet.

Birdseye Limestone

Fine-grained limestone units variously described as "birdseye," "dense," "micrite," or "lithographic limestone" occur in various parts of the Viola and Simpson Groups. Over the years, various workers have miscorrelated these units on the basis of physical similarity. Examples of units that have been a source of confusion are the "McLish Birdseye," the "Bromide Dense" (and its outcrop equivalent, the Corbin Ranch Submember), and the "Viola Dense." In the area of this study, it is extremely easy to mistake the lower Viola Springs ("Viola Dense") of the subsurface for the Corbin Ranch (a submember of the Pooleville Member of the Bromide Formation), especially in areas where the Bromide has been truncated by the pre-Viola unconformity. The "Bromide Dense" of the Pauls Valley area is equivalent to the Corbin Ranch and pinches out northeastward in Pottawattomie County.

For a review of the Corbin Ranch ("Bromide Dense") correlation history, see the discussions by Schramm (1965) and Amsden (*in* Amsden and Sweet, 1983). Both authors provide a great amount of useful information but err in following Harris (1957), Huffman and Starke (1960), and Frezon (1962) by asserting that the Corbin Ranch correlates with the Fite. In the same publication that contains Schramm's (1965) paper, Statler (1965) correctly recognizes the equivalence of the Fite with a "birdseye limestone" in the Viola, the same unit that we call the "Viola Dense." Interestingly, the original name-giver of the Fite, Ira Cram, stated that the Fite *did not* correlate with the outcrop dense limestone (now called Corbin Ranch) nor with a subsurface dense limestone in the Ada district; but he did correlate the Fite with the subsurface "dense lime" traceable into the Seminole district (Cram, 1930), which we now recognize as the "Viola Dense." In the wells studied by Amsden (*in* Amsden and Sweet, 1983) that also fall on our line of sections (Figs. 1,2; Tables 1,2), Amsden correctly identifies as "Fite" the same unit we identify as "Viola Dense." Therefore, there is no disagreement with Amsden on recognition of the Fite, but we reject his correlation and maps showing the truncated edge of the pre–Corbin Ranch Bromide and the truncated edge of the Viola.

The resolution of this stratigraphic problem comes largely from the detailed well-to-well correlation of closely spaced wells, based on both lithologic (cores and cuttings) and wireline logs. Paleontological data (Amsden and Sweet, 1983; Bauer, 1989; Bauer *in* Derby and others, 1991) are sufficient to place the Fite and the upper Tyner in the Rocklandian and/or Kirkfieldian of the Mohawkian Stage, but these data are not sufficiently discriminating to define whether the Fite and the upper Tyner correlate with the Viola or Corbin Ranch, which are relatively close in age (Fig. 3). Well-to-well correlation clearly demonstrates that the "Viola Dense"

Table 5.—Viola and Simpson Stratigraphic Names

	Arbuckle Mountains outcrop		Garvin–McClain County subsurface	Pottawatomie–Seminole County subsurface	McIntosh–Muskogee County subsurface	Cherokee County outcrop
Viola Group	Welling Formation		Welling	Welling	Welling	Welling Formation
	Unconformity					
	Viola Springs Formation		Upper Viola	*Missing*		
			Viola "Dense"	Viola "Dense"	Viola "Dense"	Fite Formation
			Viola "Dolomite"	Viola "Dolomite" (including Seminole ss. = "First Wilcox" ss.)	Viola "Dolomite"	Upper Tyner Formation
Major unconformity						
Simpson Group	Bromide Formation	Corbin Ranch Member	Bromide "Dense"	*Missing*		
			Bromide "Dolomite"	Bromide "Dolomite"	*Missing*	
			"First Bromide" sandstone	"Second Wilcox" sandstone	*Missing*	
			"Second Bromide" sandstone			
	Tulip Creek Formation		Tulip Creek	Tulip Creek	*Missing*	
	Minor unconformity					
	McLish Formation		McLish	McLish	McLish	Middle Tyner
	Major unconformity					
	Oil Creek Formation		Oil Creek	Oil Creek	Oil Creek	Middle and lower Tyner and Burgen
	Joins Formation		Joins	Joins	Joins (Everton)	Burgen (part)
Major unconformity						
Arbuckle Group	Arbuckle Group		Arbuckle	Arbuckle	Arbuckle	Arbuckle Group

and the "Viola Dolomite" are continuous, traceable units from the Arbuckles to the Ozarks, whereas the Bromide (including the Corbin Ranch and the "Bromide Dense") is truncated by the pre-Viola unconformity, and the Tulip Creek pinches out by (unconformable) onlap on the underlying McLish.

Sandstone Units

The "First" and "Second" Bromide sands of the Pauls Valley area merge northeastward and become a single massive sand that is traceable into the "Second Wilcox" of the Seminole area. The "Second Wilcox" pinches out northeastward in McIntosh County in T. 11 N., R. 15 E.

The "Seminole Sand," more commonly known as the "First Wilcox," is a Viola equivalent and unconformably overlies the Bromide sands known as the "Second Wilcox." The "Seminole Sand" ("First Wilcox") is sometimes misidentified as the Bromide "Second Wilcox" when the "Viola Dense" limestone is misidentified as the "Bromide Dense." The Keener well is northeast of the wedge-out of the "Seminole Sand" ("First Wilcox"). The sand interval in the Viola of the Keener is a local sand unit that correlates to a position above the "Seminole Sand."

Paleontology

Conodont identifications by J. E. Repetski (U.S. Geological Survey) and Walter Sweet (Ohio State University) from core samples taken by Derby from the Keener No. 1–B Watson well (Table 4) confirm the log and lithologic correlations and show that the base of the (subsurface) "Bromide Dolomite" at 3,816–3,817 ft in the Keener well is early Blackriveran in age and correlates approximately with the lower Bromide, certainly "no older than Tulip Creek." Presumably, the directly underlying "Second Wilcox Sand" is also early Blackriveran. A conodont assemblage from above the regional unconformity in a sandy dolomite at 3,796 ft ("Viola Dolomite") contains the same species and correlates with the upper Tyner and Fite assemblage reported by Bauer (1989) from northeastern Oklahoma. This sandy-dolomite unit is traceable to a position within the Viola but above the "First Wilcox" sand. Log correlations to the subsurface south of the Illinois River valley appear compatible with this paleontological correlation.

Correlation of Fite and Upper Tyner

The section below the sub-Viola unconformity pinches out northeastward; no part of the Bromide extends northeast of McIntosh County. At the northeast end of the wireline-log section in Adair County, Ts. 15–14 N., R. 26 E., the Fite and a thin "Viola" overlie about 20 ft of McLish. Bauer's work (1989; see summary *in* Derby and others, 1991) on the Illinois River outcrop shows that the Fite and the upper Tyner correlate with the interval around the lower Viola and are separated by a major unconformity from the lower and middle Tyner and the Burgen, which correlate physically with the basal McLish, Oil Creek, and Joins. The combination of Bauer's data and our correlations confirms that the Fite and the upper Tyner correlate with the lower Viola Springs Formation, and not with the Corbin Ranch Submember of the Bromide.

CONCLUSION

We hope that this paper ends the stratigraphic confusion created by earlier correlation of the Bromide Corbin Ranch Member with the Fite. Earlier authors identified the Fite in the subsurface, quite correctly, although we use the subsurface term "Viola Dense" for the same unit (e.g., Amsden and Sweet, 1983). The stratigraphic error lies in miscorrelating the subsurface Fite with the Corbin Ranch. The Corbin Ranch is the equivalent of the subsurface "Bromide Dense," not the "Viola Dense."

Table 5 is an updated stratigraphic chart for the Viola and Simpson Groups.

ACKNOWLEDGMENTS

The authors acknowledge the helpful contributions of their many colleagues, too numerous to list. Specifically, John Repetski and Walter Sweet are thanked for conodont identifications and interpretations. John Repetski also prepared a revised correlation chart (Fig. 3). Peter L. Schultze, of A&M Engineering and Environmental Services of Tulsa prepared the CAD drawings (Figs. 1 and 2).

SELECTED REFERENCES

Amsden, T. W.; and Sweet, W. C., 1983, Upper Bromide Formation and Viola Group (Middle and Upper Ordovician) in eastern Oklahoma: Oklahoma Geological Survey Bulletin 132, 78 p.

Bauer, J. A., 1989, Conodont biostratigraphy and paleoecology of Middle Ordovician rocks in eastern Oklahoma: Journal of Paleontology, v. 63, p. 92–107.

Cram, I. H., 1930, Cherokee and Adair Counties, *in* Oil and gas in Oklahoma: Oklahoma Geological Survey Bulletin 40-QQ, 60 p. [Fite Limestone named.]

Cronenwett, C. E., 1956, A subsurface study of the Simpson group in east-central Oklahoma: Oklahoma City Geological Society, Shale Shaker, v. 7, no. 2, p. 8–29, 34.

Decker, C. E.; and Merritt, C. A., 1931, The stratigraphy and physical characteristics of the Simpson group: Oklahoma Geological Survey Bulletin 55, 112 p.

Derby, J. R.; Bauer, J. A.; Creath, W. B.; Dresbach, R. I.; Ethington, R. L.; Loch, J. D.; Stitt, J. H.; McHargue, T. R.; Miller, J. F.; Miller, M. A.; Repetski, J. E.; Sweet, W. C.; Taylor, J. F.; and Williams, Mark, 1991, Biostratigraphy of the Timbered Hills, Arbuckle, and Simpson Groups, Cambrian and Ordovician, Oklahoma, *in* Johnson, K. S. (ed.), Late Cambrian–Ordovician geology of the southern Midcontinent, 1989 symposium: Oklahoma Geological Survey Circular 92, p. 15–41.

Frezon, S. E., 1962, Correlation of Paleozoic rocks from Coal County, Oklahoma, to Sebastian County, Arkansas: Oklahoma Geological Survey Circular 58, 53 p.

Harris, R. W., 1957, Ostracoda of the Simpson group: Oklahoma Geological Survey Bulletin 75, 333 p.

Herndon, Thomas (ed.), 1965, Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, 305 p.

Huffman, G. G.; and Starke, J. M., 1960, A Chazyan faunule from the lower Tyner, northeastern Oklahoma: Oklahoma Geology Notes, v. 20, p. 268–271.

Montgomery, J. H., 1951, Ordovician formations in the Illinois River Valley of northeastern Oklahoma: Tulsa Geological Society Digest, v. 19, p. 137–168.

Schramm, M. W., Jr., 1964, Paleogeologic and quantitative lithofacies analysis, Simpson Group, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 48, p. 1164–1195.

_____1965, Resume of Simpson (Ordovician) stratigraphy, *in* Herndon, Thomas (ed.), Symposium on the Simpson: Tulsa Geological Society Digest, v. 33, p. 26–34.

Statler, A. T., 1965, Stratigraphy of the Simpson Group in Oklahoma: Tulsa Geological Society Digest, v. 33, p. 162–211.

White, L. H., 1926, Subsurface distribution and correlation of the pre-Chattanooga ("Wilcox" sand) series of northeastern Oklahoma: Oklahoma Geological Survey Bulletin 40-B, 23 p.

Shallowing-Upward Events and Their Implications for Internal Correlations and Depositional Environment of the St. Peter Sandstone in the Forest City Basin, Northeastern Kansas

W. Lynn Watney
Kansas Geological Survey
Lawrence, Kansas

Bryan Stephens
Texaco, Inc.
New Orleans, Louisiana

K. David Newell
Kansas Geological Survey
Lawrence, Kansas

ABSTRACT.—The Middle Ordovician Simpson Group includes the St. Peter Sandstone and the overlying Platteville Formation, a shale and carbonate succession. The Simpson Group records the marine transgression at the base of the Tippecanoe cratonic sequence. The marine inundation continued with deposition of the conformably overlying Viola Limestone. The Simpson Group onlaps an extensive eroded surface on the Lower Ordovician Arbuckle Group and locally older rocks.

The North Kansas basin covered parts of Kansas, Nebraska, and Iowa (including northeastern Kansas) during accumulation of the Tippecanoe Sequence. The Simpson Group thickens regularly into the axis of the basin to thicknesses comparable to those in southern Kansas in proximity to the ancestral Anadarko basin. Preexisting topography is indicated at the base of the Simpson Group by local, abrupt thinning of basal shales and onlap of the lowermost strata. Paleotopography is particularly apparent in association with small structures near and along the Nemaha uplift. Topography is indicative of minor early Paleozoic episodic uplift that preceded more pronounced structural activity of the Nemaha uplift during the late Paleozoic. The Nemaha uplift subsequently bisected the North Kansas basin.

The St. Peter Sandstone is punctuated by sandstone-rich depositional sequences, each usually 20–30 ft thick, bounded by sharply defined, centimeter-thick, eroded "hardgrounds." The bounding surfaces appear to have been lithified early, and possibly were subaerially exposed. Cemented and disrupted clasts of the hardground are incorporated with sandstone and shale to form thin, basal lag deposits in superjacent sequences. The thin conglomeratic, sandy lag is commonly overlain by a thin (less than 2 ft thick), laterally extensive organic-rich, pyritic black shale. These shales are interpreted to be condensed sections and may serve as excellent oil-prone source rocks in the Forest City basin. The black shale is overlain by a thicker, generally shallowing-upward succession of sandstone-dominated and carbonate lithofacies, which later became more abundant in a basinward direction.

A composite succession of typical sandstone-dominated lithofacies includes (1) sandy dolomite and limestone, succeeded by (2) burrowed (predominantly *Skolithos*), slightly argillaceous sandstone with hummocky cross-stratification and scours near its top, then (3) sandstone with small-scale trough cross-stratification, and (4) low-angle, planar-cross-stratified sandstone. The depositional environment apparently ranged from offshore marine (below wave base), affected by occasional storms, to lower shoreface to possible subaerial exposure and eolian sedimentation.

Three distinctive sandstone sequences are noted in the St. Peter Sandstone in the Carter No. 2-A Davis well core from Wabaunsee County, Kansas, drilled in the west-central part of the Forest City basin. Limestone-dominated sequences in the Platteville Formation overlie these units. Lithofacies successions within each sequence are regular, conformable, and "Waltherian" in style, with indications of basinward gradation of sandstone into more dolomitic and shaly facies. Each succeeding sequence is initiated by a significant landward lithofacies shift (backstepping). The stacked successions commonly result in superposition of sandstone on sandstone, separated by thin, subtle to distinct stratal breaks that may be permeability barriers in producing reservoirs. Lithofacies recognized in cores are correlated to wireline logs, including gamma-ray, neutron, density, resistivity, and spectral-gamma-ray logs. The use of logs makes possible the regional mapping of Simpson lithofacies. The sequences are recognized over at least several counties in northeastern Kansas.

Massive, thick, clean sandstone up to 70 ft thick is found near the edge of the basin. Outcrops of equivalent rocks in Missouri suggest eolian deposition, with sand derived from exposed cratonic areas around the ancestral Ozark uplift. In contrast, increasing percentages of dolomite, limestone, and shale suggest that more offshore-marine conditions existed northward toward the center of the North Kansas basin.

In general, sequence characteristics appear to be closely linked to variations in sediment-accommodation space, energy levels, and proximity to sediment supply. High-resolution correlation and mapping of sequences can potentially provide means to refine sandstone trends, characterize stratigraphic complexity, and improve prediction of reservoir characteristics for use in exploration and development.

Watney, W. L.; Stephens, Bryan; and Newell, K. D., 1997, Shallowing-upward events and their implications for internal correlations and depositional environment of the St. Peter Sandstone in the Forest City basin, northeastern Kansas, *in* Johnson, K. S. (ed.), Simpson and Viola Groups in the southern Midcontinent, 1994 symposium: Oklahoma Geological Survey Circular 99, p. 267–275.

PALEOGEOGRAPHY

Northeastern Kansas, the site of this study, lies along the southern margin of the North Kansas basin (Fig. 1). The North Kansas basin was actively subsiding during Middle Ordovician time between the ancestral Ozark uplift and the Transcontinental arch. The area of subsidence coincides closely with the underlying Midcontinent rift system (Berendsen and others, 1992) and may reflect reactivation of this underlying feature. The climate was tropical, lying in the trade-wind belt in proximity to the equator. Extensive quartzose sandstones were deposited around the rim of the basin, with increasing shale and carbonate deposition toward the basin interior.

STRATIGRAPHY

The Simpson Group represents a time-transgressive, marine onlap associated with the Tippecanoe cratonic sequence in northeastern Kansas. It comprises the St. Peter Sandstone and the overlying Platteville Formation. The Simpson Group is succeeded by the Viola Limestone, a regionally extensive marine deposit.

Quartzose sandstone strata in the Simpson Group are divided into unconformity-bounded depositional sequences, originally established from interpretation of core from the Carter No. 2-A Davis Ranch well in Wabaunsee County, Kansas (Figs. 2,3). Several important features of these sequences and included lithofacies were recognized in the No. 2-A Davis core:

1. The St. Peter Sandstone is punctuated by three sand-rich depositional sequences, each 20–30 ft thick.

2. Bounding surfaces are hardground-like and are interpreted as having been exposed subaerially.

3. Thin, black, phosphatic, organic-rich shales provide lithologic contrast to the sequences and facilitate correlation.

4. A typical lithofacies succession indicates abrupt deepening of water, followed by overall gradual shallowing. The typical stratal succession and depositional environment observed and interpreted within each depositional sequence include, from bottom to top: (a) centimeter-thick conglomeratic lag or oolitic ironstone (flooding unit with reduced sedimentation); (b) dark, organic-rich shale (deeper, anoxic-marine, sediment-starved, condensed section); (c) sandy dolomite and limestone (subtidal normal-marine, below wave base); (d) burrowed (*Skolithos*), slightly argillaceous sandstone with hummocky cross-stratification (subtidal, above storm wave base); (e) sandstone with small-scale trough cross-stratification (above wave base, foreshore); (f) low-angle, planar-cross-stratified sandstone (shoreface, beach); and (g) hardground (evidence of emergence?).

5. Depositional environments during one sequence are interpreted to range from emergent conditions to relatively deep-marine conditions, with each sequence reflecting both excess and loss of sediment-accommodation space. Sedimentation hiatuses are developed at hardgrounds and result in temporal distinction of each sequence.

6. Reservoir-quality porosity and permeability are associated with lithofacies (e) and (f).

CORRELATION OF WIRELINE LOGS WITH CORE

Sequences described in the Carter No. 2-A Davis core are correlated to a gamma-ray–neutron-density log from an offsetting well, the Exxon No. 19 G. H. Davis (Fig. 4). The recognition of depositional sequences and lithofacies on the well log is easily accomplished. Each depositional sequence is characterized by overall increasing-porosity trends. Condensed sections of shale are distinguished by a sharp spike on the gamma-ray log.

Regional Stratal Patterns

The construction of subsurface cross sections and maps of the Simpson Group along the axis of today's Forest City basin, using well-log data, indicates northward thickening into the North Kansas basin (Figs. 5,6). The initiation of each depositional sequence is commonly characterized by a significant landward shift (backstepping) of the lithofacies. Basinward changes in lithofacies succession in each sequence include thinning of sandstones and their lateral gradation to shaly and dolomitic sandstones and dolomites. Successive sequences suggest a progressive backstepping of sequences, indicative of inundation of the craton during the early part of the Tippecanoe cratonic sequence. Minor cycles within a sequence are present in more basinward areas, and they lap out landward, reflecting loss of sediment-accommodation space (loss of elevation of depositional surface).

Individual sandstones commonly comprise multiple sequences. Oil-saturated zones in the sandstones correspond to less shaly intervals near the tops of individual depositional sequences, generally the shallower and cleaner lithofacies. Sandstones are very thick (up to 100 ft) around the ancestral Ozark uplift, possibly reflecting proximity to a clastic source area on the exposed craton.

DEPOSITIONAL MODEL OF THE SIMPSON GROUP IN THE FOREST CITY BASIN

Strata within each depositional sequence represent temporally distinct, more genetically coherent marine successions characterized by rapid transgression followed by more gradual shallowing. Lateral and vertical facies patterns suggest that the sand prograded basinward during each sequence. Thus each sequence isolates deposition that was more consistent with a Walther's law style of sedimentation (Fig. 7). Sandstones are commonly part of multiple sequences. The sandstone facies are thicker and stacked on one another near the basin margins, where sandstone is more abundant. Internal characteristics of these temporally distinct sandstones are commonly quite different. Moreover, they are likely compartmentalized by thin, nonporous flooding units, condensed sections, or hardgrounds.

The basic sequence appears to have been driven by regionally acting processes, such as eustasy and subsidence, that controlled the local depositional system. Each sequence is characterized by excess-sediment accommodation and probably forced regression, the latter closing the cycle. Shoreface-sandstone facies locally serve as excellent petroleum reservoirs, whereas the

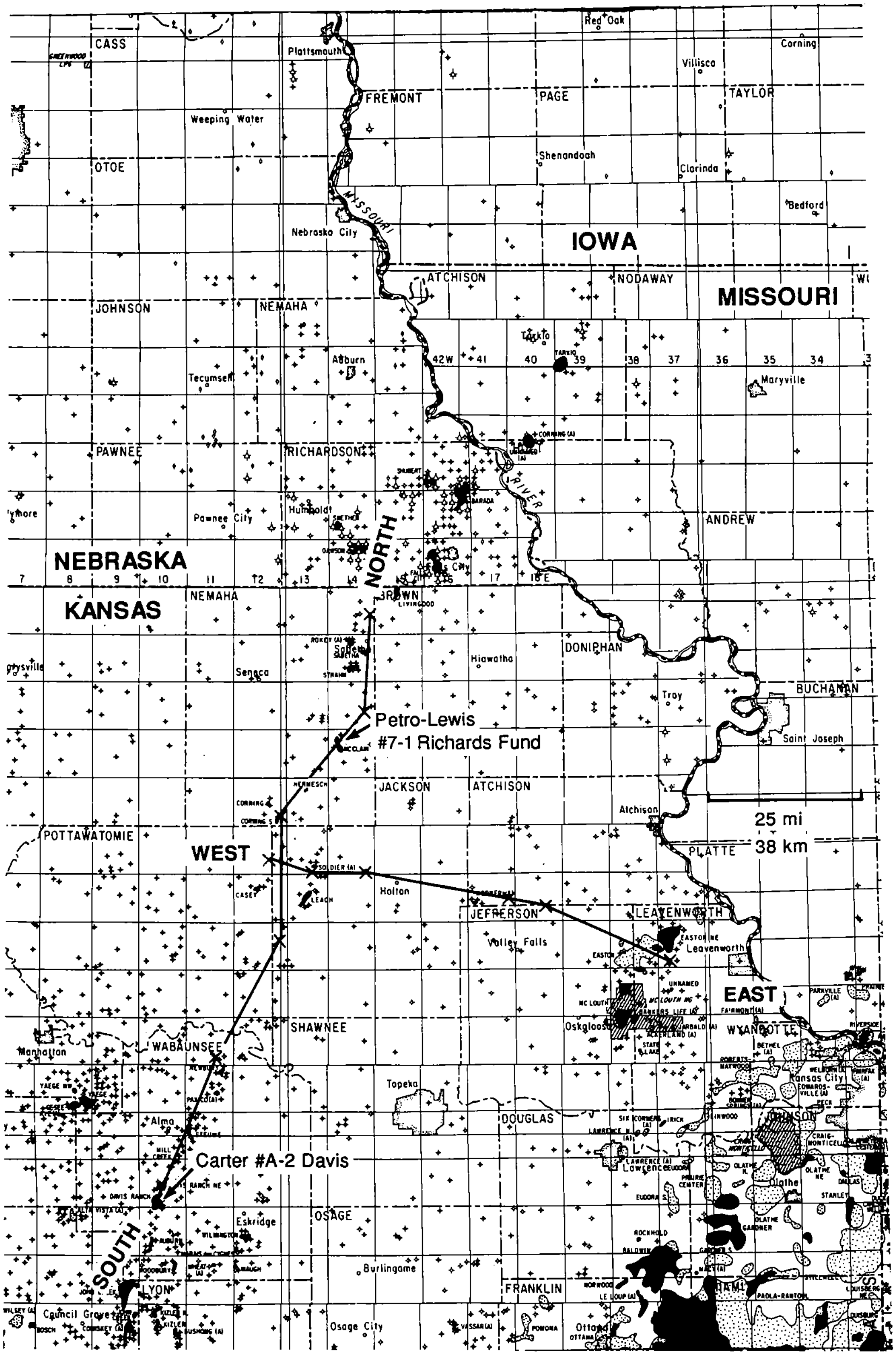


Figure 1. Base map showing location of Carter No. 2-A Davis and Petro-Lewis No. 7–1 Richards Fund wells. Also shown is location of cross sections labeled here *West–East* and *South–North* for Figures 5 and 6, respectively.

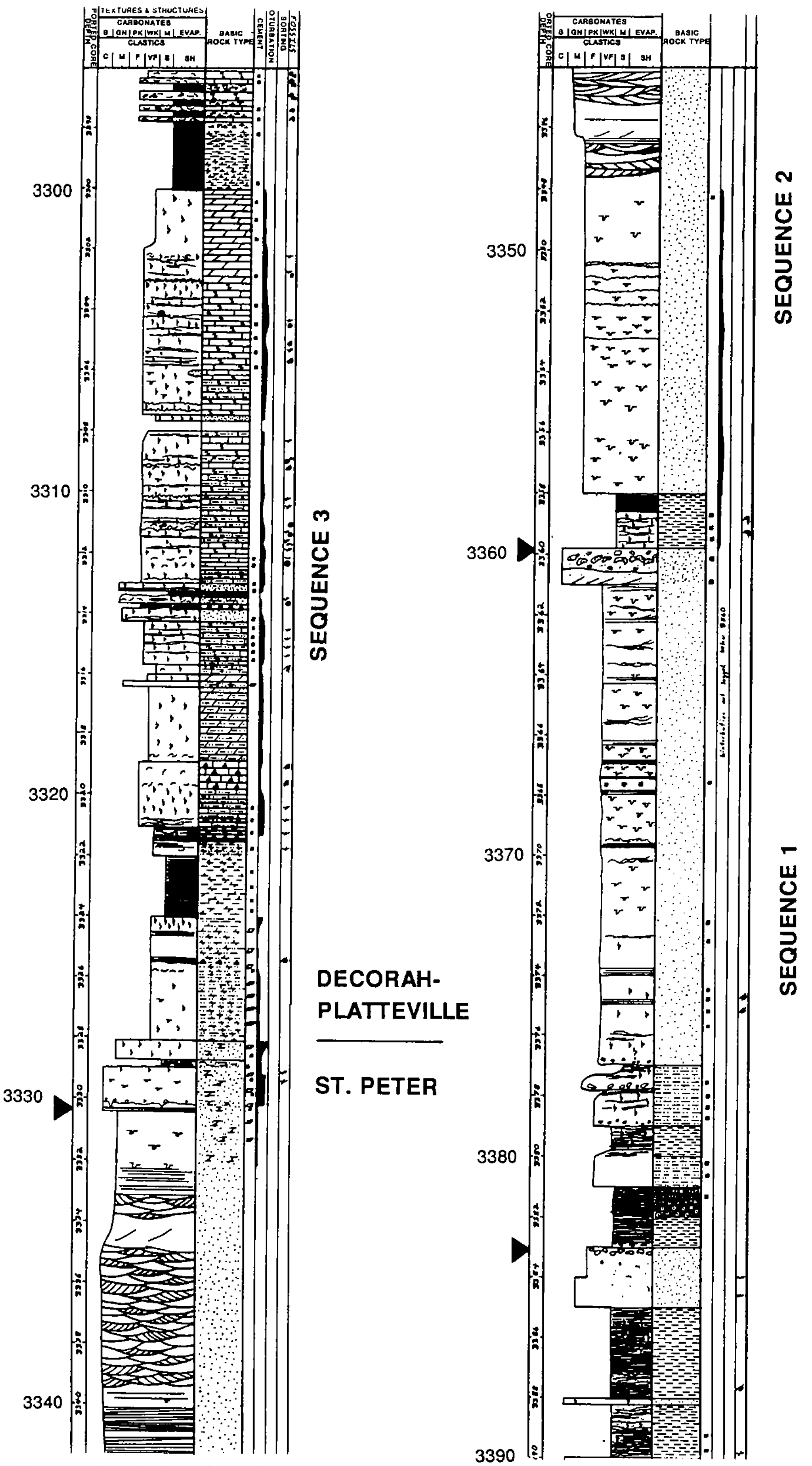


Figure 2. Graphic core description of the Simpson Group interval from the Carter No. 2-A Davis well in sec. 33, T. 13 S., R. 10 E. (see Fig. 1). Arrowheads indicate boundaries of three recognized depositional sequences correlated in the study. See Figure 3 for symbols.

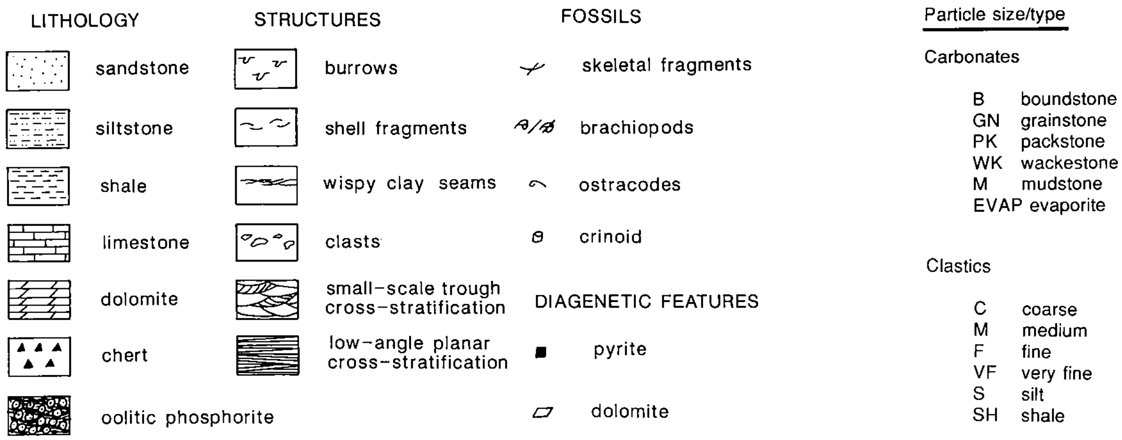


Figure 3. Key to lithology, sedimentary structures, fossils, and particle size/type for core description shown in Figure 2.

shales are potential source rocks in the Forest City basin.

Sequence Characterization from the Natural-Gamma-Ray Spectral Log

Depositional sequences are correlated from the Davis Ranch core, described above, to the Petro-Lewis No. 7–1 Richards Fund well in sec. 7, T. 4 S., R. 14 E., McClain field, Nemaha County, Kansas, a distance of 65 mi. The depositional sequences were further examined in the No. 7–1 Richards Fund well by using a natural-gamma-ray spectral log (Figs. 8,9). Thorium (Th), uranium (U), and potassium (K) logs, components of the natural-gamma-ray log, are shown in Figure 8, accompanied by curves of the Th/U and Th/K ratios (Fig. 9).

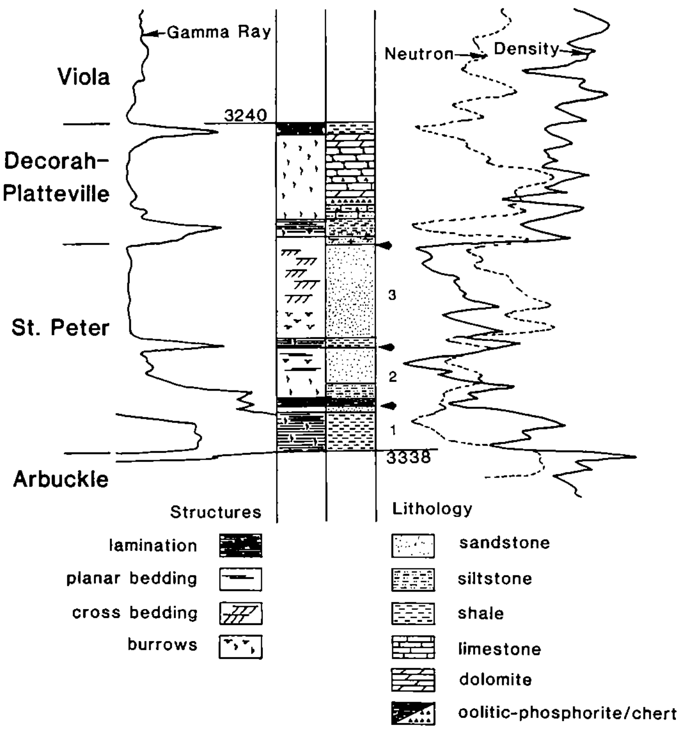


Figure 4. Composite diagram showing geophysical logs of the Exxon No. 19 G. H. Davis well and lithologic description of the Carter No. 2-A Davis well core: both wells are in sec. 33, T. 13 S., R. 10 E. Log is annotated with formations (on left) and shows the location of depositional sequences 1, 2, and 3 in the St. Peter Sandstone, as identified in the core.

A lower Th/U ratio represents more reducing conditions (e.g., uranium uptake in organic carbon), whereas a higher Th/U ratio suggests more oxidized and leached conditions in which U concentration is decreased and Th possibly is enriched. Values are neither highly oxidizing nor strongly reducing. Sequence boundaries are denoted by slight increases in the Th/U ratio, indicating greater oxidation. Uranium concentrations are relatively low, whereas Th concentrations undergo wider variation.

The depositional sequences are characterized by upward increases in the Th/K ratio, suggesting increased oxidation and leaching, with slightly higher ratios closing each sequence. A crossplot of Th and K for the overall interval reveals two contrasting trends of increasing K over Th. Some samples with high Th have especially low concentrations of K. These samples with depleted K come from shales in sequence 1. Berendsen and others (1992) suggested that the depleted K and moderate Th concentrations may reflect derivation of detritus from an intensely weathered land area under tropical conditions. Sequence 1 also contains iron oolites. The concentration of iron is thought to have been derived from related weathering processes (Berendsen and others, 1992). Perhaps the increases in the Th/K ratio at or near the close of each

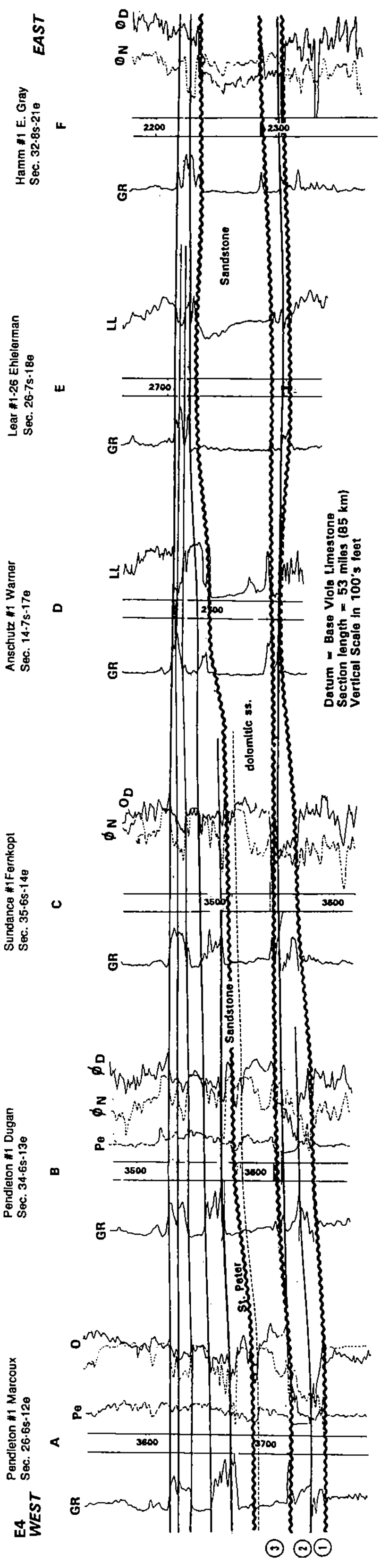


Figure 5. West–east stratigraphic cross section, illustrating the thickening and more massive character of the St. Peter Sandstone in the Simpson Group toward the basin margin and the ancestral Ozark uplift. Datum is the base of the Viola Limestone. Section crosses the central Forest City basin. Index map of the section is shown in Figure 1.

sequence are related to the introduction of more weathered detritus during reemergence of the shelf.

ORGANIC-RICH SHALES IN THE SIMPSON GROUP— PROSPECTIVE SOURCE ROCKS

Shales in the Simpson Group are believed to be the source beds for most of the oil found to date in the Forest City basin, on the basis of geochemical analyses and correlations (Newell and others, 1987). This oil type is also found in Pennsylvanian reservoirs such as at Easton field in Leavenworth County, Kansas, along the eastern and shallower margin of the Forest City basin (Fig. 1).

Oils from the Simpson, Viola, "Hunton," and shallow Cherokee Group in the northern Forest City basin have nearly identical chemical signatures, as revealed by gas chromatography. Oils are similar to the bitumen extracted from shales of the Simpson Group. Analyses of 60 samples of shale from the Simpson and Platteville along the axial regions of the Salina and Forest City basins yielded oil-prone (Type 1) organic matter that varies between nearly zero to more than 15 wt% total organic carbon (Hatch and others, 1987).

The shales in the Simpson Group are typically organic rich and phosphatic. Although they are thin, they are widespread. Geochemical indications, such as heavy carbon isotopes in marine organic matter and anomalous carbon isotopic shifts between organic matter and carbonate, suggest that this was a time of high organic-matter productivity and/or preservation (Hatch and others, 1987).

Rock-Eval pyrolysis indicates that Ordovician shales are in initial stages of oil generation along the axis of the Forest City basin and the axis of the adjacent Salina basin. The modeling of thermal maturation of organic matter indicates that maturation levels that are adequate for petroleum generation were reached well past Late Mississippian–Early Pennsylvanian deformation. This late deformation was responsible for most of the structural trapping within the basin (Newell and others, 1987). Late petroleum generation suggests that favorable stratigraphic traps will be closely linked to the current structural configuration.

SUMMARY AND CONCLUSIONS

Depositional Sequences in the Simpson Group

Depositional sequences in the Simpson Group are recognized and appear to be widely correlatable. Successive sequences undergo marked lithofacies shifts that appear to be regional in extent. Basinal sections are thicker and contain additional minor cycles.

Petroleum Exploration

Simpson Group oil production has been mainly from structural traps. However, opportunities are favorable in the Forest City basin and the southwestern Salina basin to prospect for structural–stratigraphic traps where porous and permeable clean sandstones pinch out updip as depositional sequences onlap the topographic highs and undergo lateral lithofacies change. Thermal maturation may be sufficient for oil generation in the relatively unexplored axis of the Salina basin, which was part of the North Kansas basin before it was bisected by the Nemaha uplift.

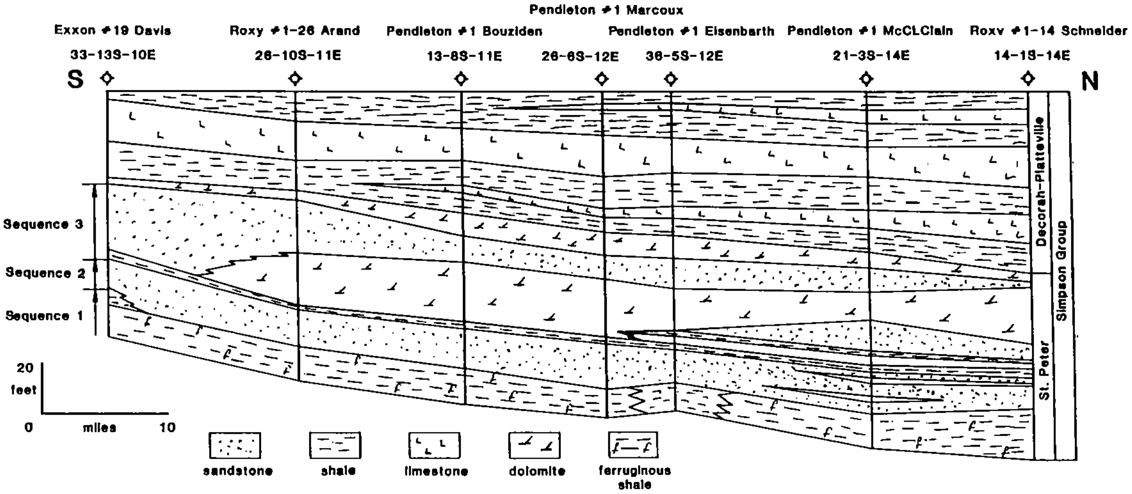


Figure 6. South–north lithofacies cross section, based on neutron-density log tied back to core adjacent to southernmost well, the Exxon No. 19 Davis. Datum is the base of the Viola Limestone. Index map of section is shown in Figure 1.

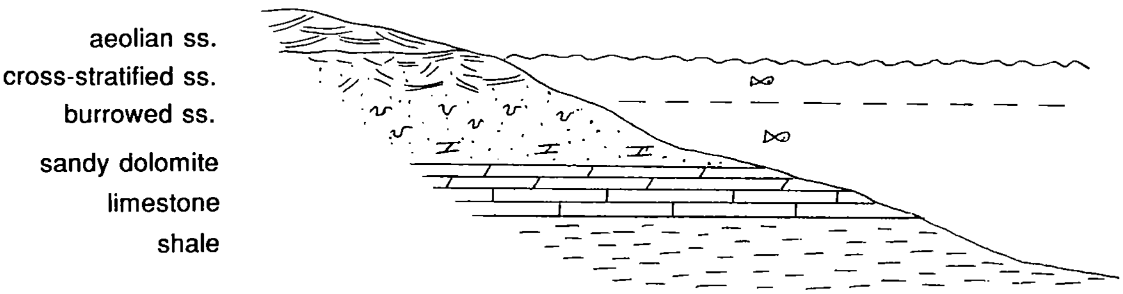


Figure 7. Conceptual depositional profile and lithofacies within a single depositional sequence. This shows lithofacies progradation and obeys Walther's law of facies succession, in which sedimentation is more continuous in time through a depositional environment nearshore to offshore of a sand shelf.

Reservoir Development

Producing zones in the St. Peter Sandstone reveal vertical compartments related to sequence development and facies successions. Local topography can present considerable variations in thickness and lateral extent of favorable reservoir rock. Changes in stratal succession create opportunities for off-structure drilling where early structural movement is indicated. Lateral and vertical changes in stratigraphy and lithofacies must be considered when designing improved oil-recovery activities, particularly involving any displacement process in which reservoir conformance needs to be assured. Also, care must be taken in perforating for production and injection to assure that perforations are in the correct zone.

REFERENCES CITED

Berendsen, Pieter; Doveton, J. H.; and Speczik, S., 1992, Distribution and characteristics of a Middle Ordovician oolitic ironstone in northeastern Kansas based on petrographic and petrophysical properties: a Laurasian ironstone case study: Sedimentary Geology, v. 76, p. 207–219.

Hatch, J. R.; Jacobson, S. R.; Witzke, B. J.; Risatti, J. B.; Abders, D. E.; Watbet, W. L.; Norwell, K. D.; and Vuletich, A. K., 1987, Possible late Middle Ordovician organic carbon isotope excursion: evidence from Ordovician oils and hydrocarbon source rocks, Mid-Continent and east-central United States: American Association of Petroleum Geologists Bulletin, v. 71, p. 1342–1354.

Newell, K. D.; Watney, W. L.; Stephens, B. P.; and Hatch, J. R., 1987, Hydrocarbon potential in Forest City basin: Oil and Gas Journal, Oct. 19, p. 58–62.

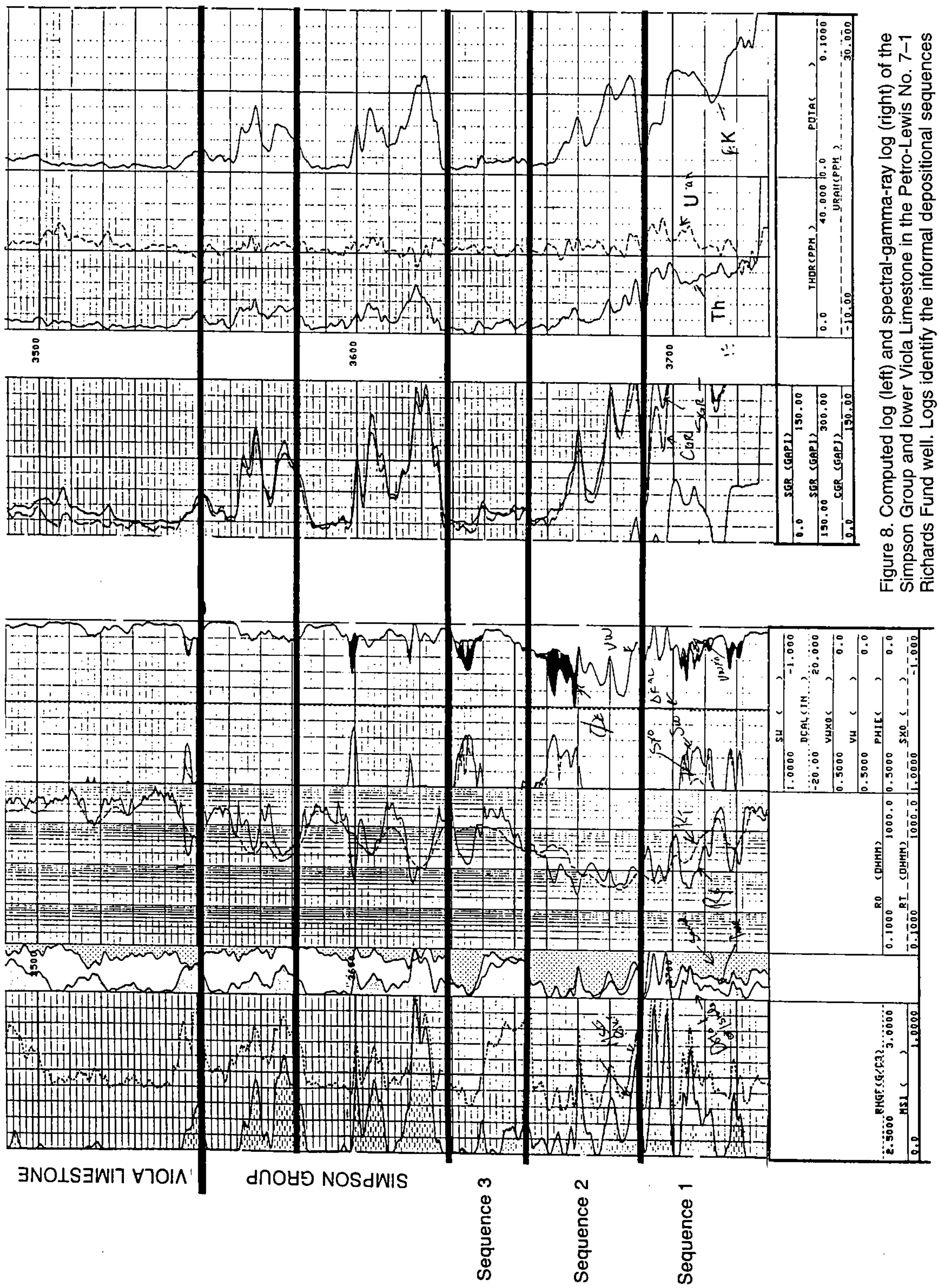
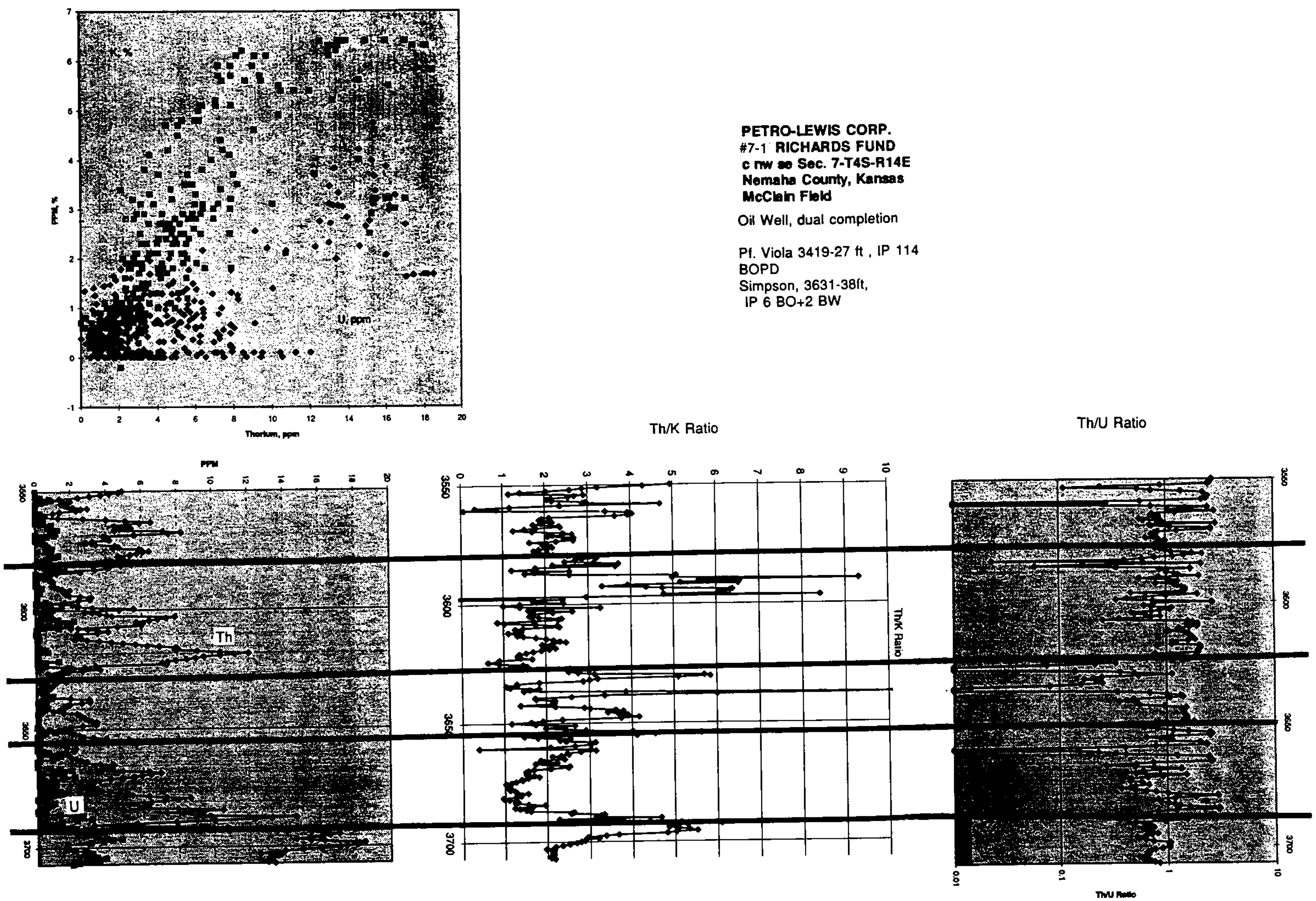


Figure 8. Computed log (left) and spectral-gamma-ray log (right) of the Simpson Group and lower Viola Limestone in the Petro-Lewis No. 7-1 Richards Fund well. Logs identify the informal depositional sequences in the Simpson interval on the basis of regional correlations.



PETRO-LEWIS CORP.
#7-1 RICHARDS FUND
c nw se Sec. 7-T4S-R14E
Nemaha County, Kansas
McClain Field

Oil Well, dual completion

Pf. Viola 3419-27 ft , IP 114
BOPD
Simpson, 3631-38ft,
IP 6 BO+2 BW

Figure 9. Detailed plots of thorium (Th), uranium (U), and potassium (K) in the Simpson Group from the Petro-Lewis No. 7–1 Richards Fund well. Tops of sequences show generally lower Th, except in sequence 1. Th/K ratio shows upward-increasing trend through each cycle. No clear trend is seen in Th/U ratio.