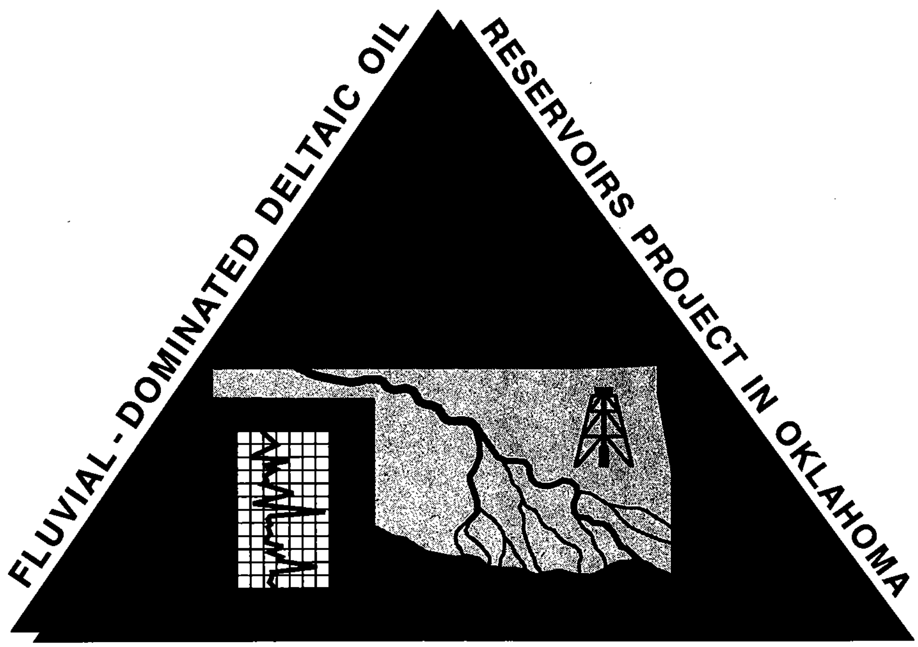
Oklahoma
Geological
Survey
1997

Special Publication 97-1

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Red Fork Play



Oklahoma Geological Survey
Charles J. Mankin, *Director*

Special Publication 97-1
ISSN 0275-0929

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Red Fork Play

PART I.—**Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma**

by
Richard D. Andrews
with contributions from Jock A. Campbell and Robert A. Northcutt

PART II.—**The Red Fork Play**

by
Richard D. Andrews
with contributions from Kurt Rottmann

This volume is one in a series published as part of the Fluvial-Dominated Deltaic (FDD) Oil Reservoirs project, jointly funded by the Bartlesville Project Office of the U.S. Department of Energy and by the State of Oklahoma.

The University of Oklahoma
Norman, Oklahoma

1997

SPECIAL PUBLICATION SERIES

The Oklahoma Geological Survey's Special Publication series is designed to bring timely geologic information to the public quickly and economically. Review and editing of this material has been minimized in order to expedite publication.

This publication, printed by the Oklahoma Geological Survey, is issued by the Oklahoma Geological Survey as authorized by Title 70, Oklahoma Statutes, 1981, Section 3310, and Title 74, Oklahoma Statutes, 1981, Sections 231–238. 2,200 copies have been prepared at a cost of $11,082 to the taxpayers of the State of Oklahoma. Copies have been deposited with the Publications Clearinghouse of the Oklahoma Department of Libraries.

◁ CONTENTS ▷

PART I – Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma 1
Introduction to the FDD Project 1
FDD-Determining Criteria 2
Depositional Setting of Fluvial-Dominated Deltaic Reservoirs 2
Coastal Flood-Plain Systems 2
Fluvial Point Bars 3
Delta Systems 4
Upper Delta Plain 6
Lower Delta Plain 8
Bay Fill and Splays 10
Distributary Channels 11
Distributary Mouth Bars and Bar Fingers 11

PART II – The Red Fork Play 13
Introduction 13
Stratigraphy 13
Red Fork Sandstone Thickness and Distribution 15
Regional Thickness of the Red Fork Interval 15
Red Fork Sandstone Distribution 15
Regional Cross Sections 17
Depositional Model 19
FDD Red Fork Reservoirs 19
N. Carmen Field 21
Otoe City South Red Fork Sand Unit 37
Long Branch Field 50
Acknowledgments 63

Selected References 67

Appendix 1: Various Size Grade Scales in Common Use 73

Appendix 2: Abbreviations Used in Text and on Figures, Tables, and Plates 74

Appendix 3: Glossary of Terms 75

Appendix 4: Well Symbols Used in Figures and Plates 78

Appendix 5: Core Descriptions, Well Logs, and Digital Images of Select Rock Intervals for Three Wells .. 79

LIST OF ILLUSTRATIONS

Figures

1. Components of a delta system 2
2. Model of meandering river system; point-bar characteristics and electric log responses 3
3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies 5
4. Point bars and related flood-plain deposits in a tidally influenced, valley-fill river system (model) 6
5. Fluvial facies descriptions, depositional environment interpretations for Fig. 4 numbered facies 7
6. Classification of delta systems based on relative intensity of fluvial and marine processes 8
7. Idealized cratonic delta sequence 9
8. Schematic model of deltaic depositional environments 10
9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta........ 11
10. Distributary channel model 11
11. Elongate-delta model 12
12. Statewide annual oil and gas production from the Red Fork sandstone 14
13. Generalized distribution and depositional environments of the Red Fork sandstone 15

continued on next page →

14. Stratigraphic nomenclature chart of the "Cherokee" Group 16
15. Regional isopach map of interval from the top of the Pink lime to the top of the Inola Limestone 17
16. Generalized regional structure map of the top of the Pink lime 18
17. Deltaic depositional systems tracts 20
18. Map showing location of the N. Carmen field, southwestern Alfalfa County 22
19. Well information map, N. Carmen study area 23
20. N. Carmen field Red Fork type log 24
21. Structural and stratigraphic cross-section A–A′, N. Carmen field .... in envelope
22. Structural and stratigraphic cross-section B–B′, N. Carmen field .... in envelope
23. Structure map of the top of the Red Fork zone, N. Carmen study area 26
24. Gross sand isopach map of the Red Fork sandstone, N. Carmen field 27
25. Net sand isopach map of the Red Fork sandstone, N. Carmen field 28
26. Depositional facies map of the Red Fork sand interval, N. Carmen study area 29
27. Core porosity and permeability data from the Red Fork sand, N. Carmen field 31
28. Red Fork oil and gas production decline curves, N. Carmen field 32
29. Red Fork cumulative oil production contour map 35
30. Cumulative oil and gas production, date of first production, initial potential, shut-in and tubing pressure, initial gas/oil ratio, and API gravity for wells in N. Carmen field 36
31. Generalized location map of Otoe City South Red Fork study area, Noble County 38
32. Well information map, Otoe City South Red Fork study area 39
33. Otoe City South Red Fork reservoir type log 40
34. Stratigraphic and structural cross-section A–A′, Otoe City South Red Fork field .... in envelope
35. Structural and stratigraphic cross-section B–B′, Otoe City South Red Fork study area .... in envelope
36. Structure contour map on the base of the Pink lime, Otoe City South Red Fork field 41
37. Gross sandstone isopach map of the Red Fork sandstone, Otoe City South Red Fork field 43
38. Net sandstone isopach of the Red Fork sandstone, Otoe City South Red Fork field 44
39. Porosity and permeability data from Red Fork cores of two wells near the Otoe City South field 46
40. Oil production decline curve and cumulative oil production from the Otoe City South Red Fork Sand Unit 47
41. Initial potential production data for wells in the Otoe City South Red Fork Sand Unit 48
42. Cumulative oil production for the Otoe City South Red Fork study area 49
43. Generalized location map of the Long Branch study area, east-central Payne County 51
44. Well information map for wells in the Long Branch study area 52
45. Long Branch field Red Fork type log 53
46. Structural and stratigraphic cross-section A–A′, Long Branch field .... in envelope
47. Structural and stratigraphic cross-section B–B′, Long Branch field .... in envelope
48. Structure map of the top of the Pink limestone, Long Branch field 55
49. Gross sand isopach map of the Red Fork sandstone, Long Branch field 56
50. Net sand isopach map of the Red Fork sandstone, Long Branch field 57
51. Red Fork sandstone facies map, Long Branch field 59
52. Porosity and permeability data from a Red Fork sandstone core in Long Branch field 60
53. Red Fork oil and gas production decline curves, Long Branch field 63
54. Cumulative oil and gas production, date of first production, initial potential, tubing pressure, and initial gas/oil ratio for wells in Long Branch field 65
55. Red Fork cumulative oil production isopach map, Long Branch field 66

Plates

1. Map of the lower Red Fork sandstone play areas .... in envelope
2. Map of the upper Red Fork sandstone play areas .... in envelope
3. Map of the oil and gas wells with production from the Red Fork sandstone .... in envelope
4. Regional stratigraphic cross-sections A–A′, B–B′, and C–C′, Cherokee platform and shelf areas of the Anadarko and Arkoma basins .... in envelope
5. Map of the oil and gas fields with production from the Red Fork sandstone .... in envelope
6. Index to selected references used for Red Fork sandstone mapping .... in envelope

TABLES

1. Annual oil and gas production from the Red Fork sand in Oklahoma, 1979–95 14
2. Reservoir/engineering data for the Red Fork sandstone, N. Carmen field 30
3. Oil and gas production statistics for the Red Fork sand, N. Carmen Red Fork Unit 32
4. Annual Red Fork oil production from wells in N. Carmen field 33
5. Annual Red Fork gas production from wells in N. Carmen field 34
6. Reservoir/engineering data for the Red Fork Sandstone, Otoe City South Red Fork Sand Unit 45
7. Core results for the Otoe City field area 45
8. Oil production statistics for the Otoe City South Red Fork Sand Unit 47
9. Reservoir/engineering data for the Red Fork sandstone, Long Branch field 61
10. Oil and gas production statistics for the Red Fork sand, Long Branch field 62
11. Annual Red Fork oil production for wells in Long Branch field 64
12. Annual Red Fork gas production for wells in Long Branch field 64

PART I

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

Richard D. Andrews
Geo Information Systems

with contributions from

Jock A. Campbell
Oklahoma Geological Survey

and

Robert A. Northcutt
Consulting Geologist, Oklahoma City

INTRODUCTION TO THE FDD PROJECT

This volume is one in a series addressing fluvial-dominated deltaic (FDD) light-oil reservoirs in Oklahoma, published as part of the Fluvial-Dominated Deltaic (FDD) Reservoir project conducted by the Oklahoma Geological Survey (OGS), with participation from the University of Oklahoma Geo Information Systems and OU's School of Petroleum and Geological Engineering (all located in the Sarkeys Energy Center). Primary funding for project, which began in 1993, is provided through a grant from the Department of Energy's Bartlesville Project Office under the Class I reservoir program, and by matching State funds.

The objectives of the Fluvial-Dominated Deltaic (FDD) Reservoir project are to identify all FDD light-oil reservoirs in the State of Oklahoma; to group the reservoirs into plays with similar depositional and diagenetic histories; to collect, organize, and analyze all available data on the reservoirs; to conduct characterization and simulation studies on selected reservoirs in each play; and to implement an information- and technology-transfer program to help the operators of FDD reservoirs learn how to increase oil recovery and sustain the life expectancy of existing wells.

The FDD project was designed to assist operators in Oklahoma by providing them with practical ways to improve production from existing leases and/or to reduce operating costs. Currently available technologies can improve recovery in FDD reservoirs if there is sufficient information about a reservoir to determine the most appropriate course of action for the operator. The needed reservoir-level information is available through the FDD project, and staff will advise interested operators about the implementation of appropriate improved-recovery technologies.

Light-oil production from FDD Class I oil reservoirs is a major component of Oklahoma's total crude oil production. Nearly 1,000 FDD Oklahoma reservoirs provide an estimated 15% of the State's total oil production. Most FDD reservoir production in Oklahoma is by small companies and independent operators who commonly do not have ready access to the information and technology required to maximize exploitation of these reservoirs. Thus, production from Class I oil reservoirs in Oklahoma is at high risk because individual well production commonly is low (1–3 barrels per day) and operating costs are high. Declines in crude oil prices or increases in operating costs can cause an increase in well-abandonment rates. Successful implementation of appropriate improved-recovery technologies could sustain production from these reservoirs well into, and perhaps throughout much of, the 21st century. Without positive intervention, most of the production from Oklahoma FDD oil reservoirs will be abandoned early in the next century.

The technology-transfer program has several parts. Elements include play publications and workshops to release play analyses that identify improved recovery opportunities in each of the plays. In addition, there are other sources of publicly accessible information related to FDD reservoirs, including the OGS Natural Resources Information System (NRIS) Facility, a computer laboratory located in north Norman.

First opened in June 1995, the OGS NRIS Facility provides access to computerized oil and gas data files for Oklahoma and software necessary to analyze the information. Both well history data and oil and gas production data are available for the entire State. Plugging report data are currently being added to the system on a county-by-county basis. Access to the files is through menu-driven screen applications that can be utilized by computer novices as well as experienced users. There are technical support staff to assist operators in obtaining information about their producing properties as well as geological and engineering outreach staff to help operators determine appropriate improved-recovery technologies for those properties. The lab is equipped with Pentium PCs—each with a CD-ROM drive, full-scale inkjet plotter, laser printer, log scanner, and Zip drive. Geology-related software to do mapping, contouring, modeling and simulations, log analysis, volumetrics and economics, pump optimization, fracture design and analysis, and 3D seismic interpretation is available for public use. In the future, it will be possible to access the facility's data files remotely, most likely via the Internet.

Technology-transfer events began with the first workshop and publication, addressing the Morrow play, on June 1, 1995. Other plays in this series include the Booch play, the Layton & Osage-Layton play, the Skinner and Prue plays, the Cleveland and Peru plays, the Red Fork play, the Bartlesville play, and the Tonkawa play.

FDD-DETERMINING CRITERIA

For purposes of this project, fluvial-dominated deltaic (FDD) reservoirs were interpreted to consist of sandstones that were deposited in a deltaic or strictly fluvial environment.

Depositional environments of sandstone bodies in the Midcontinent region were identified using specific criteria which differentiate between fluvial-dominated deltaic (FDD) and marine deposits. These criteria were interpreted from information gathered from well logs and from the literature and include:

1. Electric log signatures (gamma ray, density-neutron, and resistivity are the most dependable).
2. Geometry of the sand body (from isopach mapping).
3. Texture (grain size and sorting).
4. Fossils and trace fossils.
5. Authigenic minerals (formed in-place after deposition). *Glauconite* is considered a marine indicator although its presence can indicate postdepositional reworking by marine processes (then it is allogenic). *Siderite* is considered evidence of subaerial deposition, of fresh-water origin.
6. Sedimentary structures (bedding types, bioturbation, soft-sediment deformation).
7. Thickness.
8. Contacts (sharp or gradational).
9. Rock type and lithologic relationships (vertical and lateral).
10. Paleocurrents.

DEPOSITIONAL SETTING OF FLUVIAL-DOMINATED DELTAIC RESERVOIRS

The depositional setting of a fluvial-dominated deltaic reservoir system is located at the boundary between a continental landmass and the marine environment where the products of a drainage basin are deposited. The character and distribution of the depositional products depend upon the size and relief of the drainage basin, the composition and distribution of the source rocks, the climate of the region, and the behavior of the marine environment. Brief discussions of the significant features of such a depositional setting are presented here to help readers better understand the properties of the individual fluvial-dominated deltaic reservoirs identified in this project.

For more detailed background information, readers are referred to Brown (1979), Coleman and Prior (1982), Galloway and Hobday (1983), and Swanson (1993).

COASTAL FLOOD-PLAIN SYSTEMS

In the context of fluvial-dominated deltaic reservoir systems, a subaerial coastal plain is considered a depositional environment that extends inland from a marine shoreline or landward from a delta plain. A coastal plain can overlie preexisting strata of any origin or age and may include a variety of fluvial depositional settings, such as flood plains (Fig. 1), incised valley-fill systems, and lowlands containing swamps or marshes. These settings may be controlled structurally or they may be topographic depressions caused by subsidence or erosion. In the case of incised valley-fill systems, the transition from fluvial to marine deposits may be abrupt, and there may be little or no delta formation. On the other hand, there may be a gradational transition in the coastal plain from fluvial to deltaic deposits, and it may be difficult to distinguish between coastal-plain (or flood-plain) deposits and those of an upper delta plain (Fig. 1) except by their geographic relationship to the shoreline. Nevertheless, a coastal flood plain is considered distinct from an upper delta plain, and subaerial deposition in an identified coastal flood-plain environment is considered to occur inland from a delta or marine shoreline.

The most common reservoirs in coastal flood-plain environments occur in channel deposits. Several types of such deposits are identified in the Pennsylvanian of the Midcontinent region; they include point bars, braided river deposits, anastomosing river deposits, and longitudinal and transverse river bars. Point bars

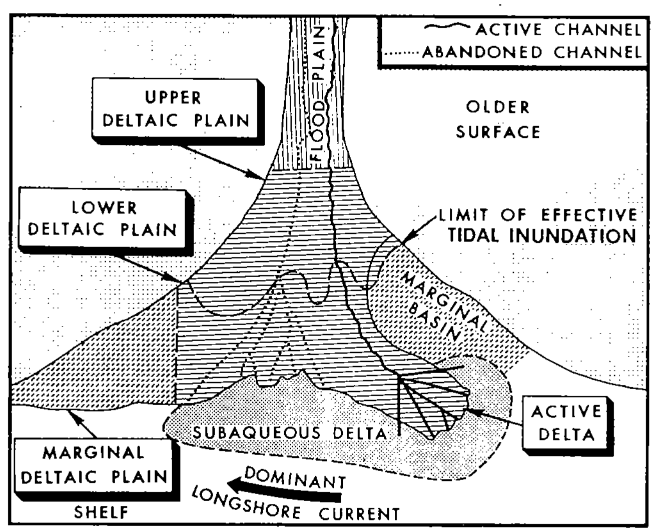
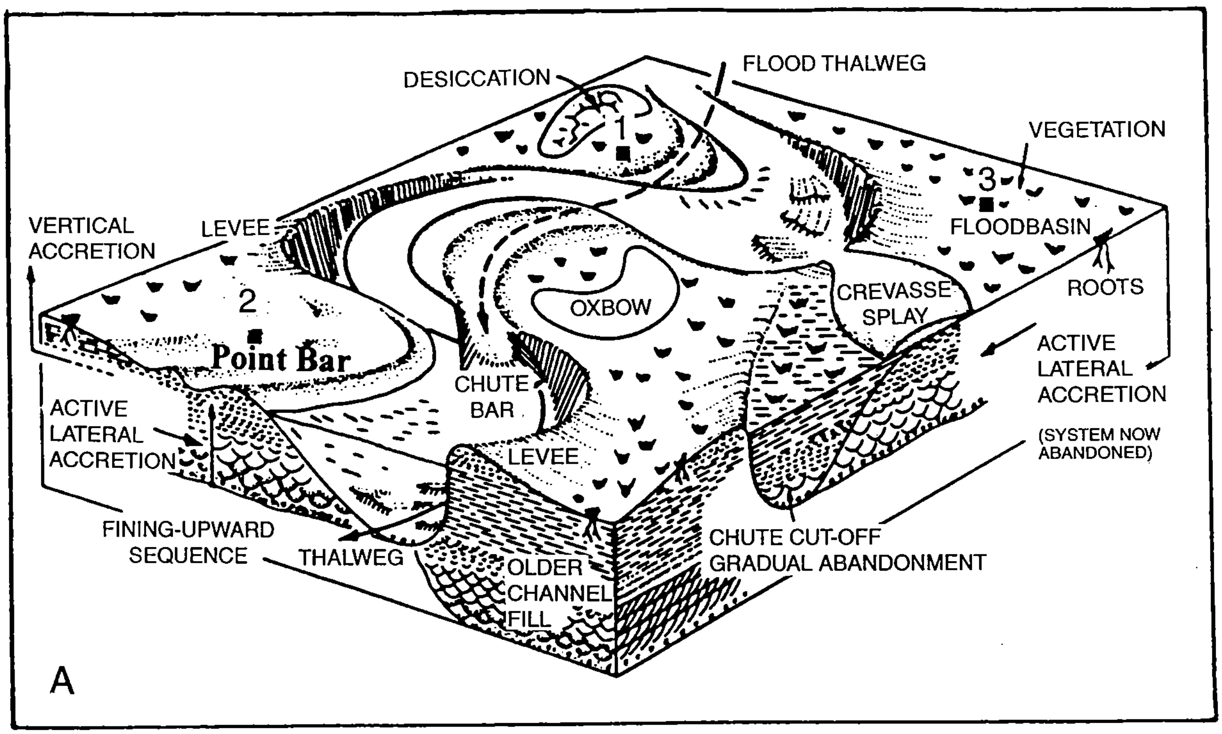


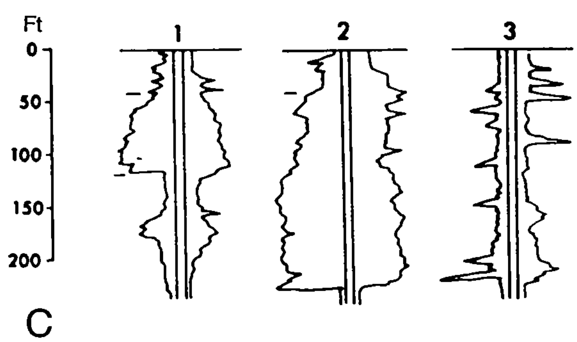
Figure 1. Components of a delta system. From Coleman and Prior (1982).

are the most common components of fluvial systems in Oklahoma.

Fluvial Point Bars

Point bars are fluvial accumulations of sand, silt, and mud that are deposited on the down-flow, inside bank of a meander bend, commonly referred to as the depositional bank (Fig. 2A). They are formed by common depositional processes and are not unique to any single depositional environment. Point bars occur in all coastal flood-plain systems as well as in upper delta plains. Point bars also are found in nondeltaic, semi-marine environments such as estuarine channels where tidal forces, rather than riverine processes, are the principal sources of energy. Individual point bars may be much more than 100 ft thick and can extend





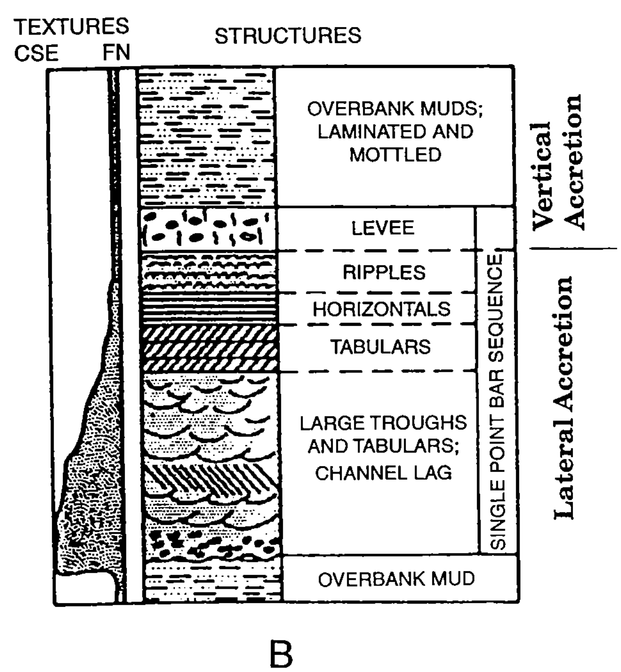


Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified from Brown (1979). (C) Idealized electric log responses related to point-bar deposits in (A). From Coleman and Prior (1982).

laterally for more than a mile. Stacked assemblages commonly are hundreds of feet thick. In the Pennsylvanian of the Midcontinent, point bars commonly are 20–50+ ft thick and occur laterally within meander belts that are <2 mi wide. Important attributes of point-bar deposits are included in a summary of fluvial-deltaic sandstone characteristics (Fig. 3).

In the sense of depositional processes, point bars are unique because they form by lateral accretion rather than direct vertical aggradation of the sand body. This depositional style promotes the lateral growth of a sand body over considerable distances without complete inundation. Lateral accretion also accounts for inconsistent deposition of sand which in turn causes compartmentalization of potential reservoirs. This compartmentalization promotes hydrocarbon entrapment but also is an impediment to hydrocarbon recovery and stimulation, and to reservoir characterization. Figure 4 illustrates the depositional environment of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. This type of depositional model is applicable to many Pennsylvanian sandstones in Oklahoma that were deposited during transgressive events. Descriptions and depositional-environment interpretations are given in Figure 5.

Point bars can make excellent reservoirs but their heterogeneity is a significant problem in reservoir management. In a vertical profile, such as in outcrop, core, or well logs, a typical point bar has a finer grain size upward or blocky textural profile (Fig. 2B). In the lower point bar, coarser fractions commonly are medium to coarse grained, in places are conglomeratic, and commonly contain pebble-size rip-up clasts. Successively higher sediments include fine- to medium-grained sand, silt, and clay. Overall, point bars have individual graded-bed sets that become thinner and finer grained vertically. Shale commonly is interbedded with sandstone in the middle and upper part of a point bar and these bed sets are inclined at a distinct angle that is unrelated to true dip. These shale interbeds, referred to as clay drapes, are effective visual illustrations of the lateral accretionary nature of point-bar deposits. They also are effective in isolating individual sand layers even within a single point bar. Clay drapes originate during periods of decreasing river discharge in mixed-load fluvial systems. Clay drapes seldom are mentioned or implied in most core studies, yet, they can be interpreted from serrated log signatures such as in Figure 2C. They also are visible in outcrops of practically any fluvial meandering system. Sedimentary structures commonly found in lower point-bar sequences consist of massive to graded bedding, high angle tabular and trough cross-bedding, and rip-up clasts. Common sedimentary features found in the upper part of a point bar include root traces, carbonaceous debris, and sandstone with horizontal and ripple laminations.

Because of the above-mentioned heterogeneities in point bars, the potential for hydrocarbon entrapment in a meandering system is very good. However, recovery of oil and/or gas from these types of deposits commonly is restricted to those portions of a point bar that have a reasonable degree of vertical and lateral continuity. Although many authors avoid this issue for fear of being overly pessimistic, in reality, recovery is concentrated in only certain portions of point bars. If a water-saturated zone is present, the best portion of the reservoir (lower point-bar facies) may occur below the oil/water contact. Hydrocarbons then may be concentrated within the central and upper portions of the point bar which commonly are finer grained and more likely to have the greatest amount of reservoir heterogeneity. If the upper part of a point bar is absent due to erosion or nondeposition, hydrocarbons then may be trapped lower within the point-bar interval. This situation is considerably more favorable for oil recovery because sandstone within the lower part of a point bar is generally coarser grained, occurs in thicker beds, and normally has better effective porosity. Consequently, recoverable reserve calculations can be vastly incorrect when they are based on the assumption that the entire sand body represents the true reservoir thickness. Corresponding recoveries from primary production methods commonly are only about 10–20% of the calculated recoverable reserve, and yield is mostly in the range of 50–150 BO/acre-ft, which is typical for many Pennsylvanian sandstones in Oklahoma. Secondary recovery methods, such as water flooding, normally will double the primary recovery, but reservoir response is highly dependent upon proper field engineering and reservoir characterization.

Point bars sometimes are referred to as shoestring or ribbon sands because of their tendency to occur in a sinuous, meandering pattern. An awareness of this characteristic pattern is important to understanding the spatial relationships within, and the physical parameters of, fluvial systems and associated sand deposits. Swanson (1976) and Coleman and Prior (1982) show that the average meander amplitude of an active meandering stream is about half the width of its enclosing meander belt. But as a meander system aggrades vertically above its own flood plain, the hydraulic difference creates instability and leads to avulsion, a lateral shift of the fluvial system to other portions of the flood plain. Obviously, in such a system, lateral and vertical relationships of sandstone beds are complicated.

DELTA SYSTEMS

In this study, a delta is defined as an accumulation of river-derived sediment that is deposited as an extension to the coast (Fig. 1). In a relatively stable tectonic setting and in a moderately subsiding shelf, sediments commonly consist of sand and finer grained clastics, which are deposited in interdistributary bays and in front of the delta. In such settings, however, marine forces such as waves and tidal currents commonly redistribute the sediments and produce different delta

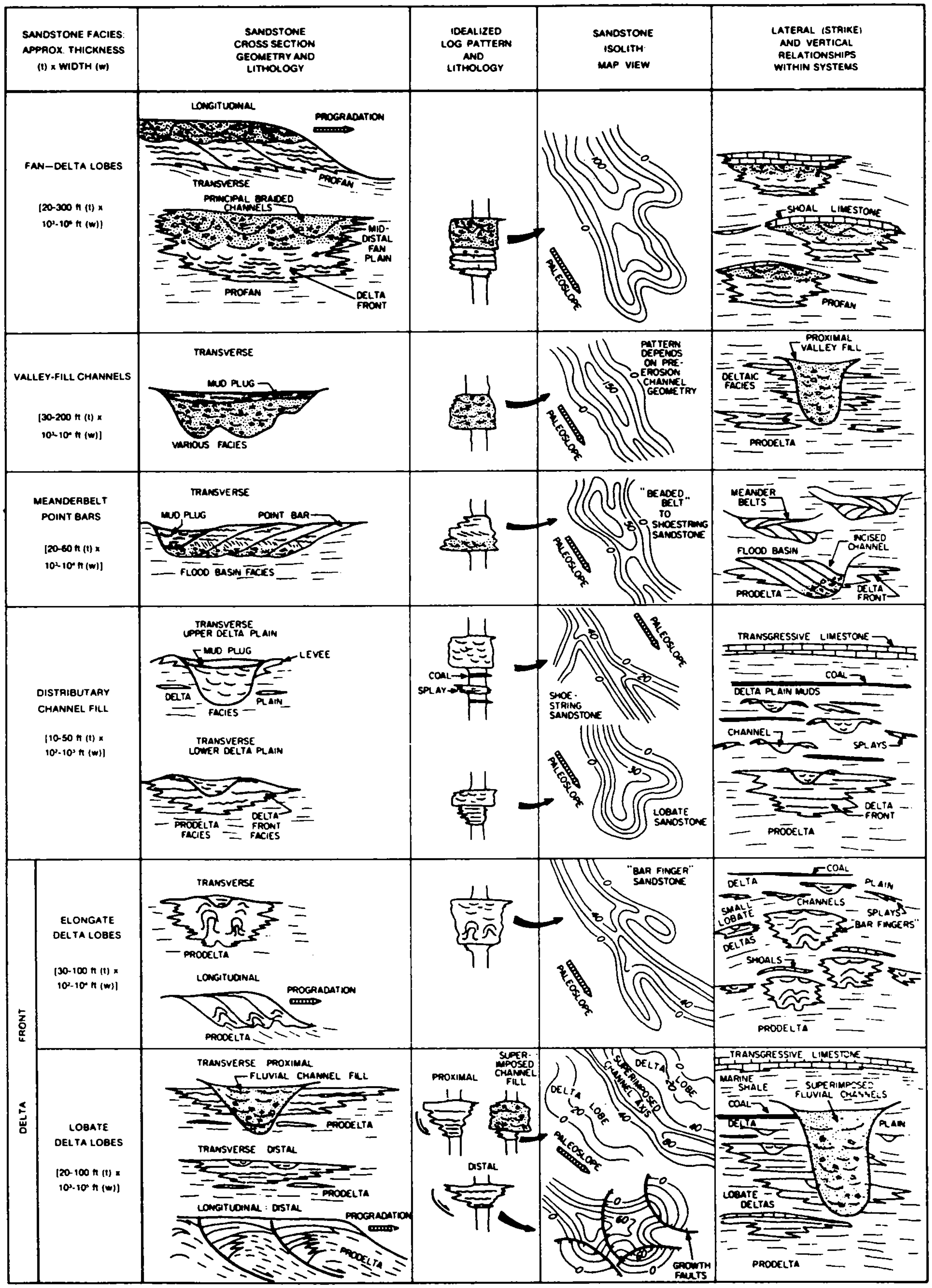


Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

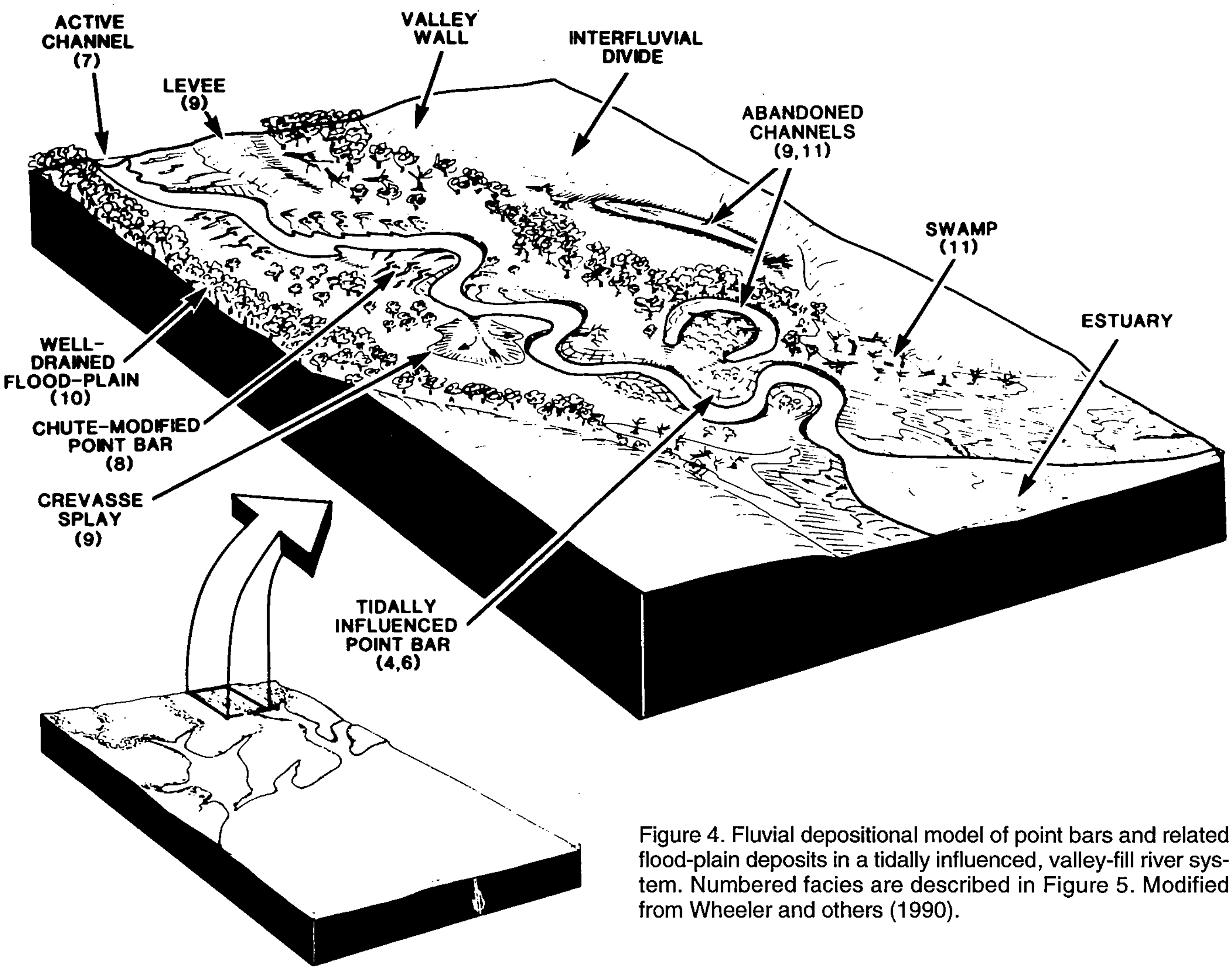


Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

morphologies. Figure 6 illustrates the classification of delta systems, which is based on the relative intensity of fluvial versus marine processes. The main emphasis in this project is on reservoir-quality sandstones that are components of fluvial-dominated delta systems.

The basic components of a prograding delta system are shown in Figure 1 and include the upper delta plain, lower delta plain, and subaqueous delta or delta front. In an idealized vertical depositional sequence, fluvial point bars and distributary channels of the delta plain overlie delta front sands and prodelta shale. This relationship is illustrated in Figure 7, which also shows typical log patterns, lithology, and facies descriptions of the various depositional phases of a typical progradational sequence. Progradation refers to a depositional system that is built seaward (offlap). Sedimentary facies in a progradation typically show an upward shallowing depositional origin. Progradation is similar in meaning to regression, which refers to a general retreat of the sea from land areas so that shallower water environments occur in areas formerly occupied by deeper water. This is in contrast to transgression (onlap), which occurs when the position of the sea moves landward and brings deeper water depositional environments to areas formerly occupied by shallower water or by land.

Upper Delta Plain

As shown in Figure 1, the upper delta plain extends from the down-flow edge of the coastal flood plain to the limit of effective tidal inundation of the lower delta plain. The upper delta plain essentially is the portion of a delta that is unaffected by marine processes. Recognizable depositional environments in the upper delta plain include meandering rivers, distributary channels, lacustrine delta-fill, extensive swamps and marshes, and fresh-water lakes. Some of these environments are recognized in normal well log interpretations. For example, meandering rivers have the classic bell-shaped electric log curves of fluvial point bars, and distributary channels tend to have more blocky log profiles. Coal and interbedded shale deposits, evidence of swamps and marshes, also can be interpreted from well logs. Although not diagnostic by

#	FACIES DESCRIPTION	INTERPRETATION
1	**DARK-GRAY, THINLY LAMINATED SHALE:** Slightly calcareous or dolomitic; thinly planar- to wavy-laminated, fissile or platy; includes starved ripple-laminations; rare Planolites, Zoophycus, and Thalassinoides; occurs in both the lower and upper Morrow; ranges from 1 to 57ft (0.3 to 17.4m) in thickness.	**OFFSHORE MARINE:** Inner to Outer Shelf
2	**SHALY CARBONATE:** Gray to dark-gray calcareous wackestone to packstone; generally wavy-laminated but may be burrow-mottled or cross-bedded; skeletal material generally re-oriented and moderately abraded; includes crinoid, brachiopod, bryozoan, mollusc and pelecypod fragments; 0.5 to 10ft (0.2 to 3.1m) thick in the upper Morrow, up to 18ft (5.5m) thick in the lower Morrow.	**SHALLOW MARINE:** Open Shelf or Transgressive Lag
3	**SKELETAL WACKESTONE TO GRAINSTONE:** Gray to tan, limestone or dolomite; planar- to wavy-laminated or cross-bedded; may appear massive or nodular due to weathering or burrowing; includes crinoids, brachiopods, bryozoans, corals, molluscs, gastropods, echinoderms, peloids and intraclasts; occurs only in the lower Morrow; 0.5 to 46ft (0.2 to 14m).	**RESTRICTED TO OPEN MARINE PLATFORM:** Shoals and Bioherms
4	**INTERLAMINATED TO BIOTURBATED SANDSTONE AND SHALE:** Includes interbedded and homogenized lithologies; light-gray, very fine- to fine-grained sandstone and gray to dark-gray shale and mudstone; planar-, wavy- and ripple-laminated; convoluted bedding common; glauconitic; moderately burrowed to bioturbated; Thalassinoides, Planolites, Skolithos, Asterosoma, Chondrites and Rosellia(?); occurs in both the lower and upper Morrow; 1 to 28ft (0.3 to 8.5m) thick.	**NEARSHORE MARINE OR ESTUARINE:** Shoreface or Delta Front; Tidal Flat or Tidal Channel
5	**CROSS-BEDDED, FOSSILIFEROUS SANDSTONE:** Light-gray, fine- to coarse-grained quartz arenite to sublitharenite; trough or tabular cross-bedded in 3 to 18in (7.6 to 45.7cm) thick sets; up to 50% skeletal debris; crinoid, brachiopod, bryozoan and coral fragments; glauconitic; occurs only in the lower Morrow; units up to 25ft (7.6m) thick.	**UPPER SHOREFACE OR TIDAL CHANNEL**
6	**CROSS-BEDDED SANDSTONE WITH SHALE DRAPES:** Gray to tan, fine- to coarse-grained quartz arenite or shaly sandstone; trough or tabular cross-bedded with incipient stylolites, shale drapes and interlaminations between foreset laminae; foresets are often tangential with the lower bounding surfaces and grade laterally into ripple laminations, some oriented counter to the cross-bedding; cross-bed set thickness is 3 to 12in (7.6 to 30.5cm); sparsely burrowed, Planolites; glauconite and carbonaceous debris; occurs primarily in the upper Morrow; up to 28ft (8.5m) thick.	**FLUVIAL OR ESTUARINE:** Upper Point-Bar or Flood-Plain; Tidally Influenced Fluvial Channel
7	**CONGLOMERATE TO CONGLOMERATIC SANDSTONE:** Gray to light-brown; granules and pebbles of mudstone and composite quartz; matrix is fine- to very coarse-grained, poorly sorted, quartz arenite or sublitharenite to subarkose; massive appearing, planar-bedded or cross-bedded; carbonaceous debris; glauconite and phosphate scarce; occurs only in the upper Morrow; up to 21ft (6.4m) thick.	**FLUVIAL CHANNEL:** Braided Stream, Channel-Bottom Lag or Lower Point-Bar
8	**COARSE-GRAINED, CROSS-BEDDED SANDSTONE:** Medium- to very coarse-grained quartz arenite or subarkose to sublitharenite; trough or tabular cross-bedded in sets ranging from 3in (7.6cm) to over 2ft (0.6m) thick; in many cases foreset laminae alternate between coarser and finer grain-size fractions; convoluted bedding is common; carbonaceous debris, including coaly fragments, macerated organic material ("coffee grounds"), leaf and log impressions is prevalent; Planolites burrows are rare; occurs in the upper Morrow; units up to 29ft (8.8m) thick.	**FLUVIAL CHANNEL:** Chute-Modified Point-Bar
9	**RIPPLE-LAMINATED SANDSTONE:** Very fine- to fine-grained quartz arenite; symmetrical or asymmetrical ripples; glauconite and carbonaceous debris are common; trace fossils include Planolites and Skolithos; occurs with many other facies throughout the Morrow; ranges up to 30ft (9.2m) thick.	**FLUVIAL OR MARINE SHOREFACE:** Upper Point-Bar, Splay, Levee or Abandoned Channel-Fill; Middle Shoreface
10	**GRAY-GREEN MUDSTONE:** May have brick-red iron oxide speckles; generally blocky and weathered in appearance; very crumbly; moderate to abundant amounts of carbonaceous debris; compaction slickensides and root-mottling common; calcareous nodules occur in the lower Morrow and beds are 0.5 to 2ft (0.2 to 0.6m) thick; up to 30ft (9.2m) thick in the upper Morrow.	**FLUVIAL FLOOD-PLAIN OR EXPOSURE SURFACE:** Well-Drained Flood-Plain; Alteration Zone or Soil
11	**DARK-GRAY CARBONACEOUS MUDSTONE:** Generally planar-laminated; abundant carbonaceous debris including leaf and stick impressions; pyrite, root traces and slickensides common; occurs only in the upper Morrow; units range up to 30ft (9.2m) in thickness.	**FLUVIAL FLOOD-PLAIN:** Swamp or Abandoned Channel-Fill
12	**COAL:** Massive or laminated; commonly pyritic; occurs only in the upper Morrow; generally 1 to 6in (2.5 to 15.2cm) thick, but ranges up to 2ft. (0.6m).	**SWAMP**

Figure 5. Fluvial facies descriptions and depositional environment interpretations for numbered facies shown in Figure 4. This information was used originally by Wheeler and others (1990) to describe the Morrow in southeastern Colorado and southwestern Kansas, but it is also useful in clastic facies interpretations of many other Pennsylvanian meandering river systems in Oklahoma.

themselves, point bars, coal, and migratory distributary channels are primary elements that characterize the upper delta plain. By combining information about those elements with other data, such as from cores or sequential stratigraphic analysis (Fig. 7), a more accurate depositional interpretation can be made. Such a combination of data can lead to a better understanding of sandstone distribution trends and reservoir characteristics in any depositional environment.

The principal reservoirs found within the upper delta plain are fluvial point bars and distributary channel sands. Point bars have been discussed in the section on coastal plain deposits. Distributary channels are more characteristic of the lower delta plain and are discussed in the following section.

Lower Delta Plain

In the rock record, each component of a delta has characteristics that are determined largely by vertical

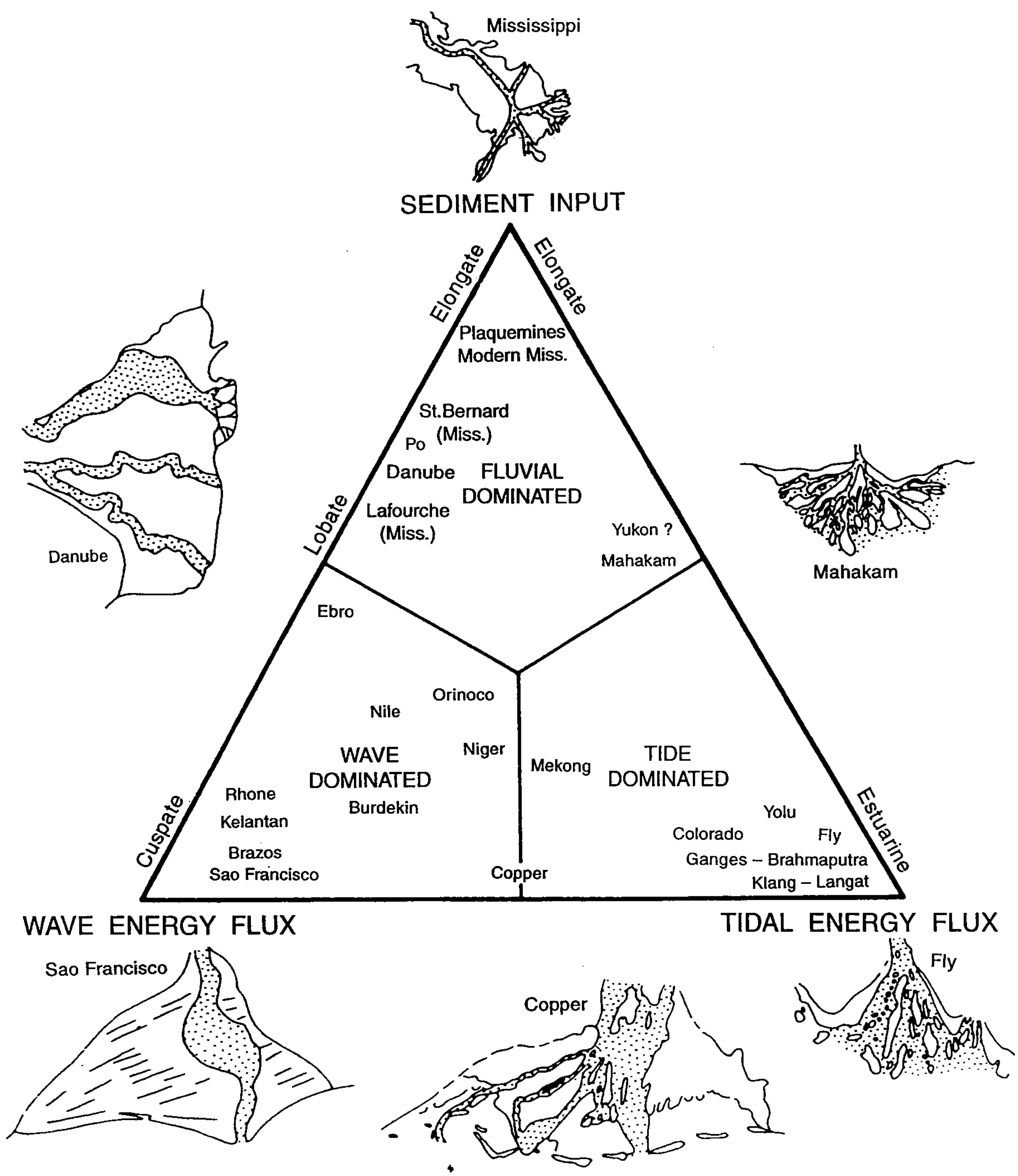


Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

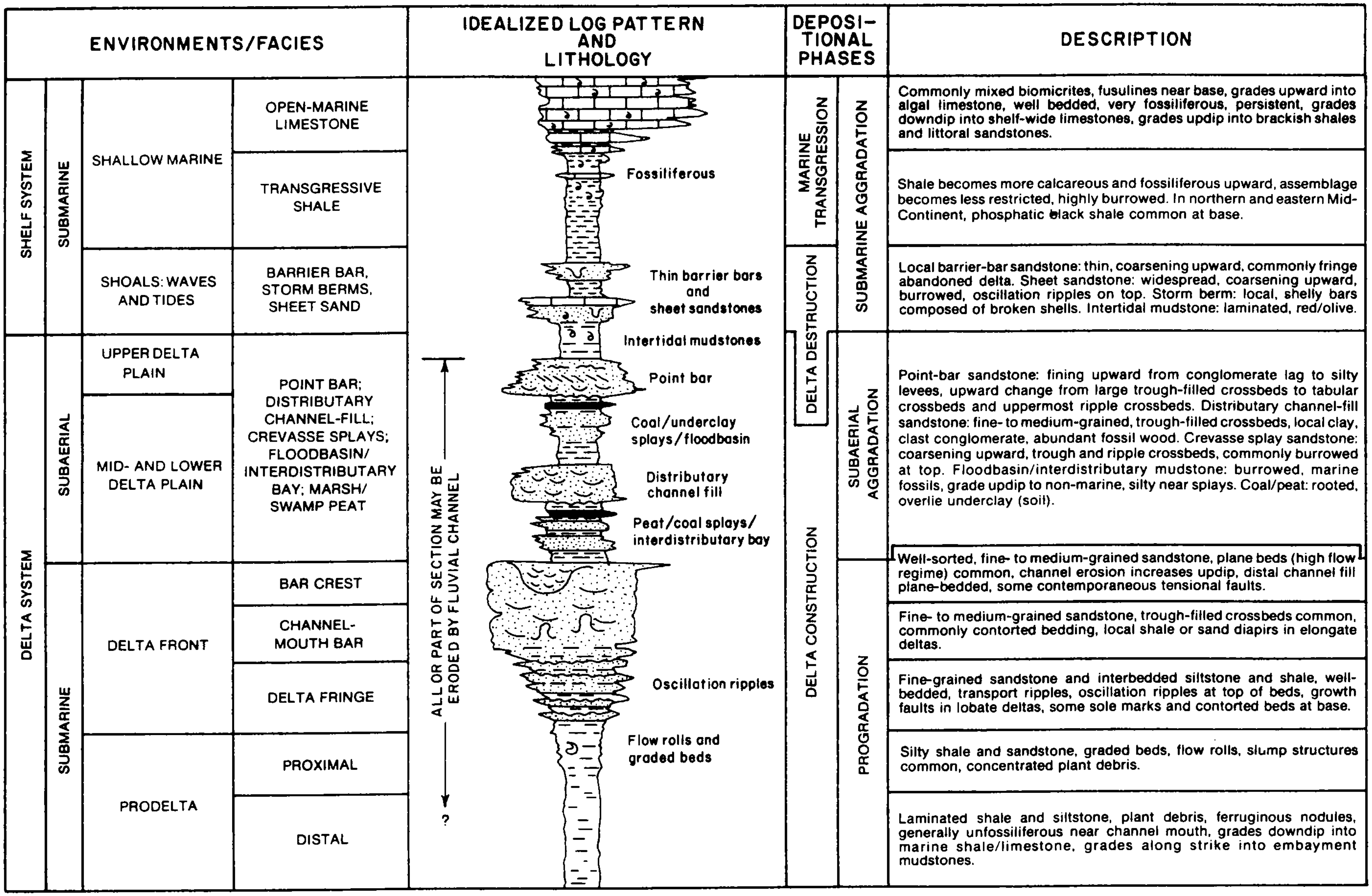


Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

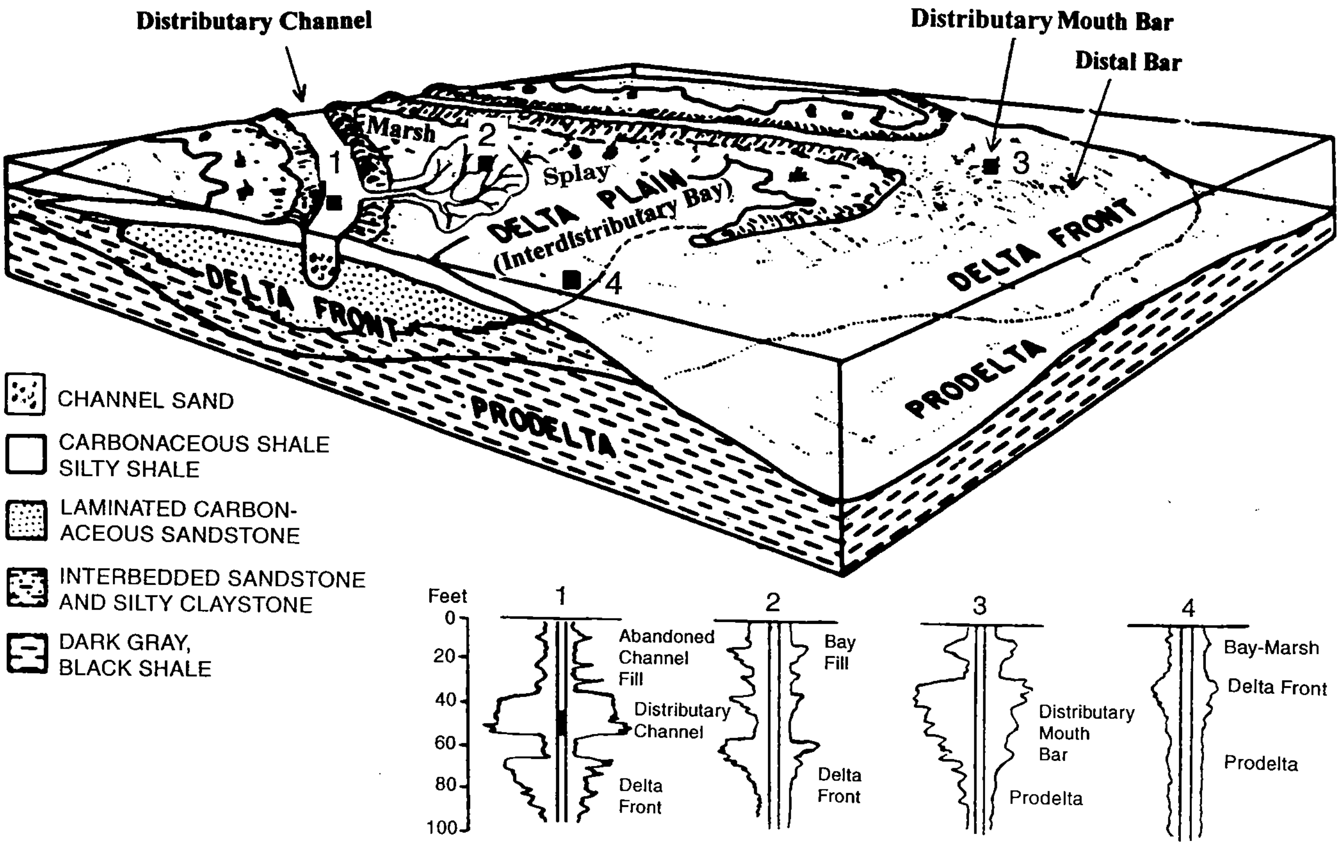


Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

and lateral relationships of rock facies and by faunal content. In the lower delta plain, sediments are influenced highly by marine conditions, which extend from the subaqueous delta front to the landward limit of marine (tidal) influence (Fig. 1). The lower delta plain consists primarily of bay-fill deposits, which occur between or adjacent to major distributaries, and secondarily of distributary-channel deposits. Distributary mouth bars and bar-finger deposits are the principal components of the subaqueous delta front (Fig. 1) and are attached to the lower delta plain. These environments and idealized electric log patterns of associated clastic facies are illustrated in Figure 8.

Lower-delta-plain sediments characteristically overlie delta-front sands and prodelta shale. In the upper reaches of the lower delta plain, coal commonly is associated with marshy areas that are insulated from rapid sedimentation or destructive marine events that typify the lower reaches of the delta plain. Through continued progradation of a delta, the lower delta plain is overlain by upper-delta-plain sediments. Unless the stratigraphic relationship is unconformable, coastal flood-plain sediments commonly are not recognized in succession above delta-plain deposits.

Bay Fill and Splays

Bay-fill sediments originate from several sources including effluent plumes of major distributaries and crevasse splays. Splays, however, are the dominant source of bay-fill sandstone and constitute much of the sediment in fluvial-dominated deltas as shown in Figure 9, which identifies the distribution of principal sand facies in the modern Mississippi River delta. Splays originate during flooding events when sediment is carried through a breach in a distributary levee and distributed into shallow bays through a branching network of smaller channels. The lenticular, fan-shaped deposits (crevasse splays) commonly are 10–40 ft thick and consist of individual sequences of sand and mud that increase in grain size upward. This stratigraphic characteristic is caused by the rapid deposition of suspended sediments ahead of current-induced bed-load transport of coarser sand. However, because splays are driven by fluvial processes, thin distributary-channel deposits also are constituents of every splay. The thickness of a splay deposit commonly is proportional to the depth of the interdistributary bay and the hydraulic advantage between the distributary channel and the receiving area. Thus, splays characteristically are thinner than distributary mouth bars and contain less sand. After abandonment of a crevasse system and subsequent subsidence, the area reverts to a bay environment when marine waters encroach. This entire cycle lasts about 100–150 years (Coleman and Prior, 1982) and may be repeated several times to form a stacked assemblage such as that shown in log signature on Fig-

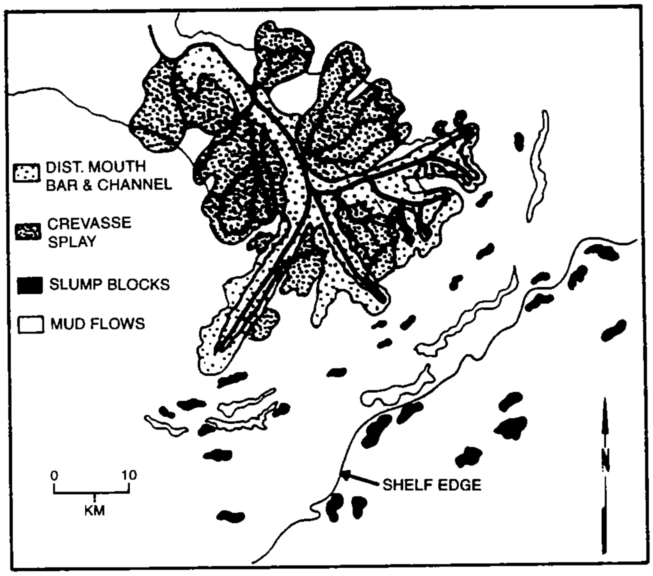


Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

ure 8. Splay deposits are not considered to be good reservoirs because they contain large amounts of detrital clay, which reduce the effective porosity and permeability of the sandstone beds.

Distributary Channels

Distributary channels are responsible for the primary distribution of nearly all sediments within the lower delta plain. Despite their conspicuous presence, however, they account for a relatively small volume of sediment in the delta, as is illustrated in the schematic model of a delta (Fig. 8) and in the sand facies distribution map of the modern Mississippi River delta (Fig. 9).

Distributary channels typically are incised upon preexisting interdistributary or delta-front sediments. Because they occur at the end of a fluvial transport regime, distributary-channel sands commonly are uniformly fine grained and well sorted. As shown in Figure 3, distributary-channel sand bodies commonly are 10–50 ft thick and 100–1,000 ft wide. Sedimentary structures consist of tabular and trough cross-bedding, clay clasts, and contorted beds (Fig. 10).

The extension of distributary channels into the subaqueous marine environment and the concurrent deposition of levee structures help prevent lateral migration of distributary channels. This stabilizing condition inhibits the formation of point bars that characterize coastal flood-plain meander-belt systems. Since distributary channels occur within, or in close proximity to, marine conditions, they may incorporate marine constituents such as shell fragments, fossils, and glauconite.

Distributary Mouth Bars and Bar Fingers

The progradation of a fluvial-dominated system such as the modern Mississippi River delta is sustained by a series of finger-like sand bodies that are deposited ahead of the main river distributaries. These sand bars are the subaqueous extensions of major distributary channels formed because of confined flow and directed transport of suspended sediments into the open gulf. The tendency of distributary channels and accompanying bar-finger sands to be nonbranching seems to be a result of several factors such as sediment load characteristics of the river, water depth and salinity contrasts in the receiving basin, and river discharge rates. Most investigators believe that bar fingers form when river discharge is confined by the development of subaqueous levees and when sediment transport is aided by the buoying effect of saline water. Conversely, non-directed dispersal of river-mouth sediment in shallow, fresher water bays causes multiple branching distributaries

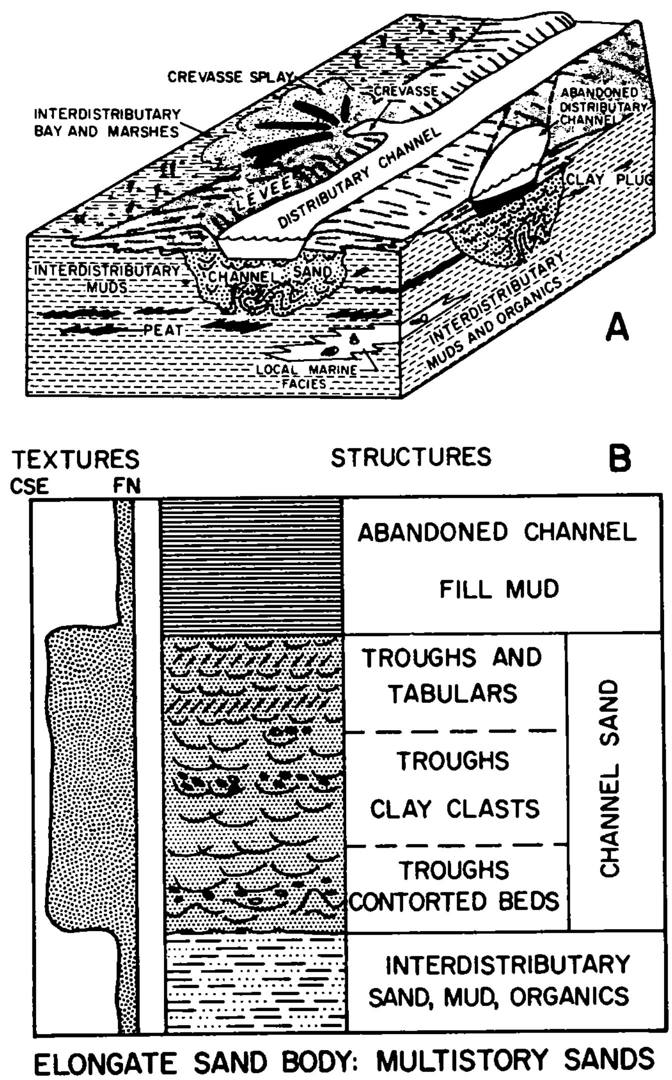


Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

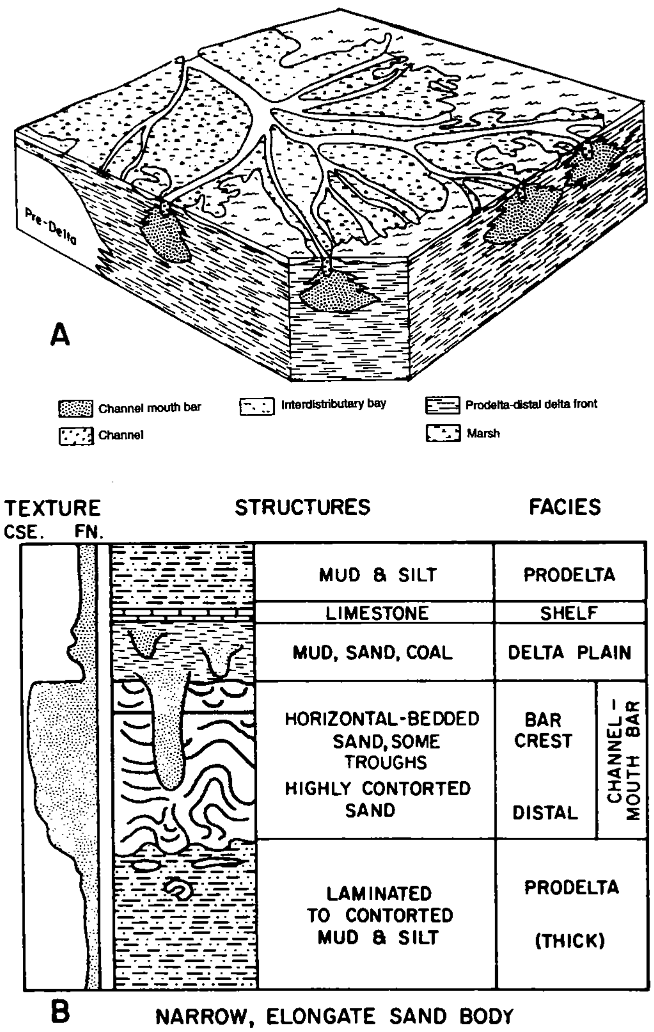


Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

such as those that characterize other parts of the Mississippi River delta. In the latter case, distributary mouth bars are lobate rather than elongate and become progressively finer grained seaward.

Distributary mouth bars have the highest rate of deposition in the subaqueous portion of a delta. They are composed of the same sediments that constitute splays and distributary channels in the lower delta plain but are distinctly different morphologically. In the upper portion of the bar (bar crest), sands are reworked continually by wave and storm currents to produce some of the best and most laterally extensive reservoirs in delta environments. Large-scale sedimentary structures, such as high-angle and trough cross-bedding, are the result of this energy. The rapid clastic buildup also causes soft-sediment instability in the form of mud diapirs and contorted beds. These types of sedimentary structures are illustrated in Figure 11.

Distributary mouth bars make up most of the delta front and may be >200 ft thick, but commonly they are ~100 ft thick. Redistribution of the same sand by marine currents may promote the deposition of distal bars; in the event of eustatic sea level rise (transgression), barrier islands may form. Characteristically, distributary mouth bars have serrated, coarsening-upward logs and textural profiles (Figs. 8,11). In places, the facies are subdivided into a distal bar facies (lower, shaly part of profile) and a proximal bar facies (upper, sandy part of profile). The coarsening-upward stratigraphic profile is caused by the dispersal of buoyed sediment and progressive deposition of coarse-grained sediment on top of previously dispersed fine-grained sediment. Additionally, carbonaceous debris from continental sources commonly is interbedded with the sand. Distributary mouth bars commonly overlie prodelta muds and provide a relatively stable foundation over which delta-plain sediments are deposited during regressive depositional periods.

NOTE TO READERS

Industry participation in the FDD program is heartily encouraged. We welcome any comments that you may have about the content of this publication and about the ongoing needs of industry with respect to information and technology relating to FDD reservoirs. Please contact Charles J. Mankin at the Oklahoma Geological Survey, 100 East Boyd, Room N-131, Norman, OK 73019 with your questions or comments.

PART II

The Red Fork Play

Richard D. Andrews
Geo Information Systems

INTRODUCTION

Oil was discovered in the Middle Pennsylvanian (Desmoinesian) Red Fork sandstone in 1908 in T. 18 N., R. 11 E. near the small town of Red Fork in Creek County, Oklahoma (Hutchison, 1911, in Jordan, 1957). During the early 1900s, the Red Fork was quickly exploited in eastern Oklahoma. In 1921, the giant Burbank oil field in Osage County was discovered. The main production was from the Burbank sandstone, which was later found to be equivalent to the Red Fork (Withrow, 1968). The greatest surge in Red Fork exploration and development occurred during the latter half of the 1900s with the discovery of well-defined sandstone trends such as in the Ceres, Cherokita, Wakita, St. Louis, Putnam, Strong City, and S. Thomas fields. These and many other Red Fork fields were the result of deliberate exploration rather than chance discoveries made in pursuit of deeper targets. Unlike some of the shallower Cherokee sands, such as the Prue and Skinner, the Red Fork is relatively "clean." Therefore, Red Fork oil potential was generally not overlooked because of a shaly or wet appearance on wireline logs.

The Red Fork sandstone is one of the main producers of oil and gas in Oklahoma. About 187 million barrels of oil and >3 trillion cubic feet of gas were produced from 1979 through 1995 (Table 1). Total production for the preceding 71 years was certainly much greater. To illustrate this point, most of the 600 million barrels of oil estimated for the total ultimate recovery for Burbank field (Johnson, 1992) was produced prior to 1979. During each of the 10 years following 1979, more than 10 million barrels of oil were produced from the Red Fork. The highest production volume since 1979 occurred in 1985 when >16 million barrels of oil were produced. Since 1989, oil production has declined steadily (Fig. 12). In 1995, total Red Fork oil production was only about 7 million barrels. The gas production trend is similar, however the peak (223,860 MMCF) occurred in 1988, three years after the peak in oil production (Fig. 12). Annual Red Fork production data is compiled in Table 1 and shown in production curves in Figure 12.

Figure 13 shows the generalized distribution and depositional facies of the Red Fork sandstone. The Red Fork interval is mostly shale and sandstone that lies between the Pink lime and the Inola Limestone. In most places, the entire interval is ~100 ft thick and contains one or two 10- to 50-ft-thick sandstones with an occasional thin limestone or coal bed. Individual sandstones are sometimes much thicker and, in places, are stacked or amalgamated (not separated by shale). Also, in some areas, younger Red Fork channel sandstones are incised into older sandstones. Where the sandstones are stacked, it is difficult to distinguish individual beds, and sandstone can occupy much of the Red Fork interval. The lower sandstone in one field may be the middle or upper sandstone or both in another field.

Sandstones in the Red Fork interval are mostly fine- to very fine grained, with some medium-grained sandstone. In hand sample, they appear to be somewhat cleaner than many of the younger "Cherokee" sandstones. Whole rock analyses indicate that a considerable fraction of the framework constituents are feldspar and rock fragments. Balke (1984) performed several analyses of Red Fork sandstones in north-central Oklahoma and found that they were composed of about 40–60% quartz, 8–15% feldspar, 10–20% rock fragments, 2–7% kaolinite, 2–6% illite, and 1–4% chlorite. Clay, particularly illite, can cause sandstones to appear more shaly on gamma-ray logs and can cause lower resistivity readings; however, the effect of clay on wireline logs of the Red Fork sandstone is not nearly as great as it is on wireline logs of the mica-rich and clay-rich Prue and Skinner sandstones.

STRATIGRAPHY

The Red Fork sandstones are in the interval bound by the Pink limestone above and by the Inola Limestone below. Equivalent subsurface terms for Red Fork include *Burbank* (used mostly in Osage County) and *Earlsboro* (Arkoma basin). As shown in Figure 14, at the surface, the Pink-to-Inola interval corresponds to the interval between the Tiawah Limestone Member of the Senora Formation (Cabaniss Group) and the Inola Limestone Member of the Boggy Formation (Krebs Group). Outside of the Arkoma basin, the top of the Boggy Formation is defined as the base of the Weir-Pittsburg coal bed, which is several tens of feet below the Tiawah (Pink) Limestone (Hemish, 1996). However, the Weir-Pittsburg coal is not sufficiently widespread

TABLE 1. – Annual Oil and Gas Production from the Red Fork Sand in Oklahoma, 1979–95

	Production	
Year	Gas MMCF	Oil MBO
1979	93,768	10,179
1980	110,373	10,841
1981	154,436	13,112
1982	199,526	14,843
1983	170,142	13,747
1984	198,196	15,078
1985	209,587	16,796
1986	213,058	14,821
1987	220,017	11,914
1988	223,860	10,769
1989	208,746	9,057
1990	192,527	8,214
1991	190,051	7,708
1992	169,553	7,246
1993	177,720	7,706
1994	166,789	7,968
1995	151,847	7,018
Total	**3,050,196**	**187,017**

Note: Production data from NRIS.
MBO = 1000 barrels of oil, MMCFG = one million CFG

and/or easy enough to recognize on wireline logs to be useful for subsurface regional mapping. The Tiawah Limestone (Pink lime) at the surface and in cores is underlain by ~10 ft of black, fissile shale, a thin coal (Tebo coal), and shale that contains one or two unnamed discontinuous sandstone beds (Hemish, 1996). Together, the Pink lime and underlying black shale with or without the Tebo coal have a distinctive log signature, especially on resistivity and gamma-ray logs. At the surface, the Inola Limestone consists of up to four thin limestone beds. It is overlain by an unnamed black, fissile shale with abundant black phosphatic nodules and is underlain by black shale and, in places, by a very thin coal bed (Hemish, 1990). Where the Inola Limestone is very thin, or absent, the black shales, which are "hot shales" on gamma-ray logs, mark the base of the Red Fork interval.

The Red Fork sandstone is, for the most part, equivalent to the Taft Sandstone Member in the upper part of the Boggy Formation (Fig. 14). However, some Red Fork sandstone, especially near the top of the Red Fork interval, may be equivalent to the unnamed discontinuous sandstones in the lower part of the Senora Formation. The outcrop of the upper part of the Boggy Formation, which includes the Taft Sandstone Member, is shown on Plates 1 and 2 (in envelope).

Where sandstone occurs in two or more zones separated by shale, they are commonly referred to by posi-

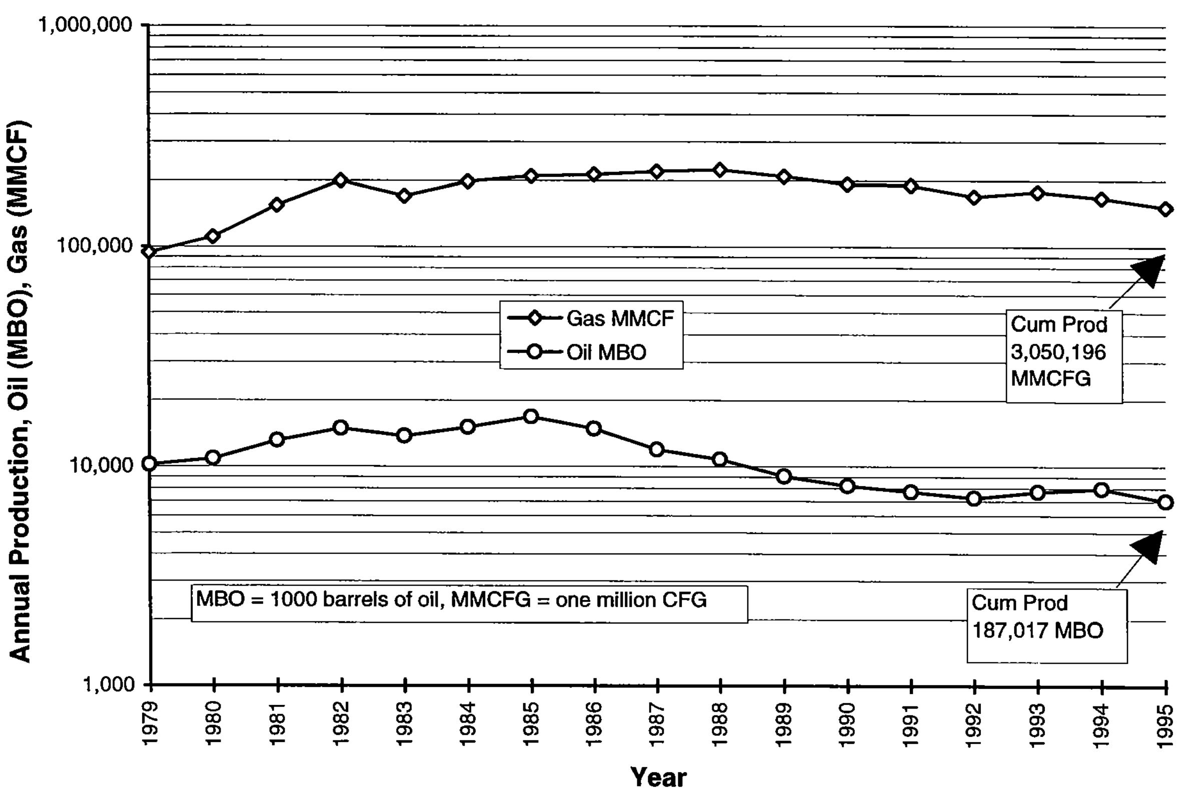


Figure 12. Statewide annual oil and gas production from the Red Fork sandstone.

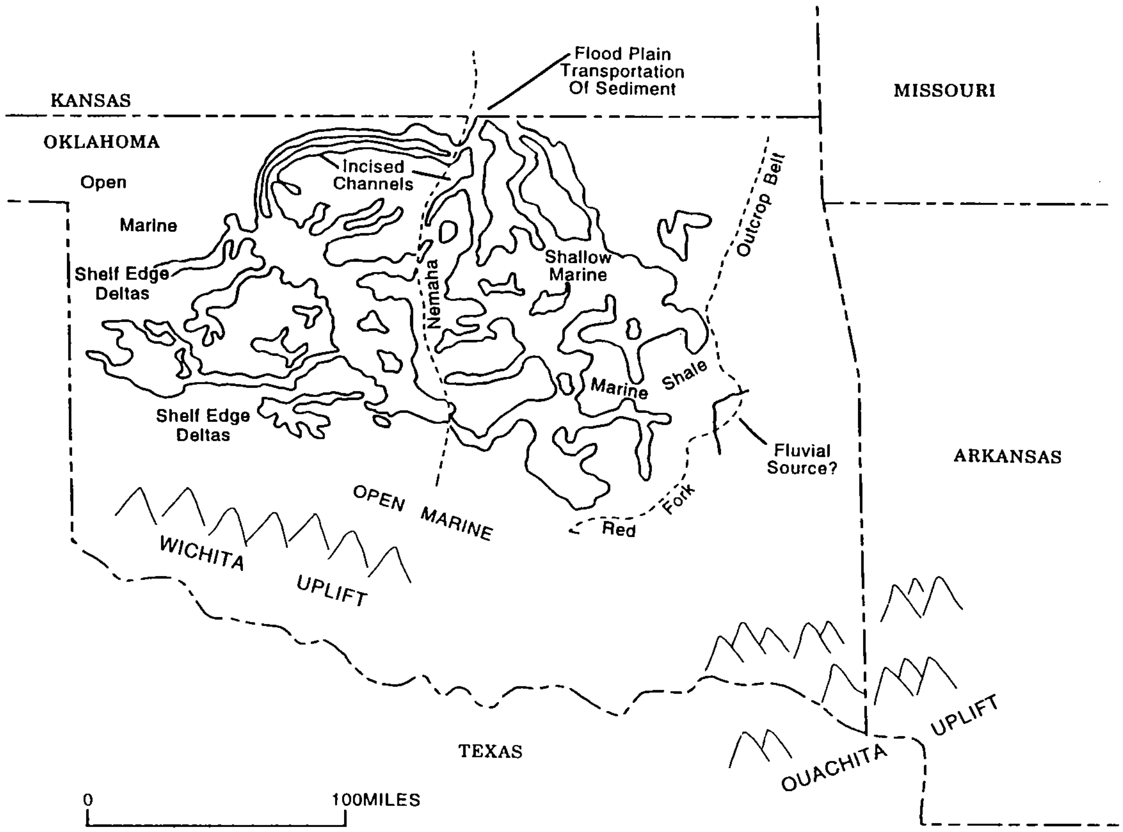


Figure 13. Generalized distribution and depositional environments of the Red Fork sandstone in Oklahoma.

tion (i.e., upper, middle, and lower). However, there are no regionally extensive marker beds, such as a thin limestone or hot shale, that divide the interval into distinct parts. As a result, the terms do not correspond to unique parts of the Red Fork interval that can be correlated regionally. The upper and lower sandstone in one field may be the middle and lower in another field; a sandstone in an incised channel can be lower in the Red Fork interval than an older sandstone in a nearby well.

RED FORK SANDSTONE THICKNESS AND DISTRIBUTION

Regional Thickness of the Red Fork Interval

The Red Fork sandstone is one of the most widespread Cherokee plays in Oklahoma. A regional isopach map of the interval from the top of the Pink lime to the top of the Inola Limestone reflects the location and geometry of basins and platform areas that existed during deposition of the Red Fork sandstone (Fig. 15). The thickness of the Red Fork interval was apparently controlled mostly by the configuration of the Cherokee platform, the Nemaha fault zone and central Oklahoma uplift, and the Anadarko basin. The Red Fork interval is thin (≤100 ft thick) and relatively uniform in thickness throughout much of central and northeastern Oklahoma. This indicates that Red Fork deposition was significantly attenuated along the Nemaha uplift and possibly eroded. The relatively uniform thickness of the Red Fork interval also suggests that the depositional gradient was relatively low on the Anadarko shelf and the Cherokee platform. This is in sharp contrast to the Anadarko basin, where the Red Fork interval thickens considerably over a relatively short distance. Subsidence of the Anadarko basin permitted the accumulation and preservation of Red Fork deltaic sediments.

The current structure of middle "Cherokee" in the same area is shown in Figure 16, which is a structure map contoured on the top of the Pink lime. Structural elements that affected the Red Fork interval thickness (such as the Nemaha fault zone and central Oklahoma uplift, and the Seminole structure in south-central Oklahoma) are poorly defined or not evident on this map. Instead, only gentle dip to the west that changes gradually to southwest in the Anadarko basin is shown.

Red Fork Sandstone Distribution

The regional distribution of sandstone in the Red Fork interval and interpretation of depositional facies is shown on Plates 1 and 2. The sand distribution shown on these plates was compiled from all available published and unpublished sources of information, including theses, articles in *Shale Shaker*, consultants, and investigations by the author. The references are listed alphabetically and keyed by number to an index map of the State (Pl. 6, in envelope). The depositional

SYSTEM	SERIES	GROUP		FORMATION	SURFACE NAMES (Members & Fms.)	PRIMARY SUBSURFACE NAMES	SECONDARY SUBSURFACE NAMES
PENNSYLVANIAN	DESMOINESIAN	MARMATON		FT. SCOTT	Ft. Scott Limestone (Wetumka Shale in Arkoma basin)	Oswego lime	Oswego lime
		"CHEROKEE"	CABANISS	SENORA	Lagonda Sandstone (Calvin Fm. in Arkoma Basin)	Prue sand	Squirrel, Perryman, Gibson, Bixler, 2nd & 3rd Deese, Wanette
					Verdigris Limestone	Verdigris Limestone	Ardmore lime
					Croweburg coal	Henryetta coal (Senora lime)	Croweburg coal (Senora lime)
					Oowala Sandstone	Upper Skinner sand (Cherokee Platform)	Verdigris, Senora, Allen sand, Cattleman sandstone
					Mineral coal	Morris coal	Morris coal
						Middle skinner sand	Allen, Olympic, Senora sand
					Chelsea Sandstone	Lower Skinner sand	Upper Hart zone (?), Senora Thurman, Fourth deese sand
					Tiawah Limestone	Pink lime	Pink lime, lower Senora lime
					-Weir-Pittsburg coal bed- (Senora base when Stuart & Thurman are absent)		
				STUART	Stuart Shale only present in Arkoma basin	Stuart Shale only present in Arkoma basin	Stuart Shale only present in Arkoma basin
				THURMAN	Thurman Ss. only present in Arkoma basin	Thurman Ss. only present in Arkoma basin	Thurman Ss. only present in Arkoma basin
			KREBS	BOGGY	Taft Sandstone	Red Fork sand	Earlsboro, Burbank, Dora Osborn Peach Orchard, Chicken Farm sand
					Inola Limestone	Inola Limestone	Inola Limestone
					Bluejacket Sandstone	Bartlesville sand	Glenn sand, Burgess sand
				SAVANNA	Doneley Limestone	Upper Brown lime	Brown lime
					Sam Creek Limestone	Middle Brown lime	Brown lime
					Spaniard Limestone	Lower Brown lime	Brown lime
				McALESTER	Tamaha Limestone	Upper Booch sand	
					Upper Warner (Lequire) Ss.		Booch sand
					Lower Warner Sandstone	Lower Booch sand	

Figure 14. Stratigraphic nomenclature chart of the "Cherokee" Group in northeastern, central, and western Oklahoma. Modified from Bennison, 1979; Chandler, 1977; Hemish, 1995 (personal communication); Jordan, 1957; and Lojek, 1984.

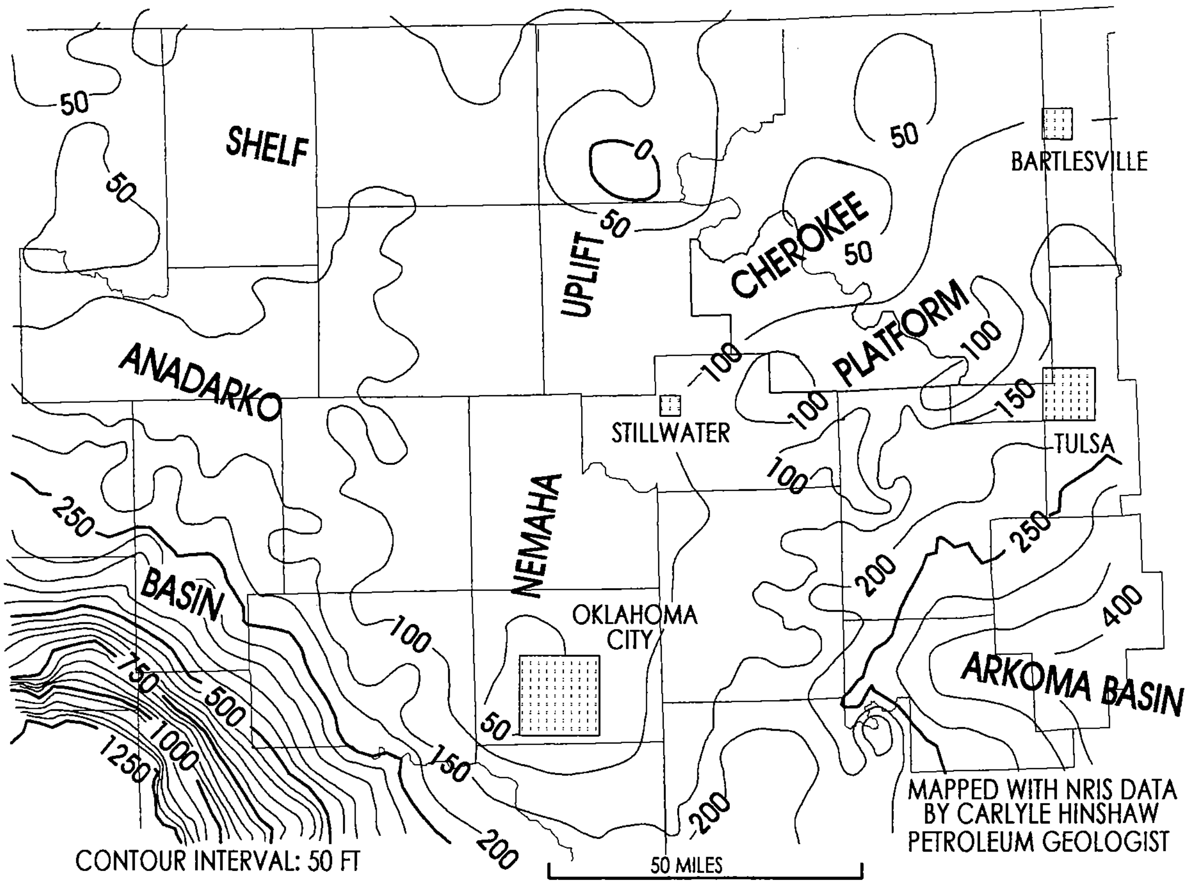


Figure 15. Regional isopach map of the interval from the top of the Pink lime to the top of the Inola Limestone (Red Fork interval plus the Pink lime), Oklahoma. Contour interval is 50 ft.

environments shown on these plates were interpreted from the sand distribution pattern (i.e., shape of the sand body in map view) and from the vertical sequence of lithologies as interpreted from wireline logs. The outcrop of the upper part of the Boggy Formation (which includes the Taft Sandstone, surface equivalent to the Red Fork) is also shown on Plates 1 and 2. The only good exposures of the Taft Sandstone were found in the southern part of the outcrop belt along the western shores of Lake Eufaula. At this location, the depositional environment of the Red Fork is fluvial, and the sand section is highly conglomeratic. This may indicate a middle Pennsylvanian source reversal in a manner similar to other upper Cherokee FDD plays.

East of the Nemaha fault zone, all sandstone in the Red Fork interval is shown on Plate 1. West of the Nemaha fault zone, on the Anadarko shelf and in the Anadarko basin, the Red Fork sandstone is shown on two plates. In the Anadarko basin, the Red Fork interval is considerably thicker than it is on the shelf and contains two to four sandstones instead of one or two. Sandstone in the upper part of the Red Fork interval is mapped on Plate 2, and sandstone in the lower part is mapped on Plate 1. The outcrop of the upper part of the Boggy Formation, which includes the Taft Sandstone Member (Red Fork equivalent), is shown on Plates 1 and 2.

Regional Cross Sections

Regional stratigraphy of the Red Fork interval is shown on three regional stratigraphic cross sections accompanying this report (Pl. 4, in envelope). The cross-section locations, which are also shown on Plates 1 and 2, were chosen to illustrate the regional stratigraphic relationships and also the character of the Red Fork sandstone in fields where it produces.

East-west cross-section A–A′ (Pl. 4) extends from the western Anadarko basin, across the Nemaha fault zone and central Oklahoma uplift, to the Cherokee platform. The Red Fork interval thins eastward from ~220 ft (well 2, A–A′) to ~120 ft in well 4. Wells 1–3 are near the hinge line of the Anadarko basin (just north of the 250′ contour line in west part of the isopach map in Fig. 16). The Red Fork interval in wells 1–3 is divided into upper and lower parts. The lower interval in wells 2 and 3 is characterized by shale that becomes siltier or sandier upward and is overlain by sandstone. This sequence is interpreted to have been deposited in the delta front environment of a prograding delta. The Red Fork interval in well 1 is believed to have been deposited in a shallow

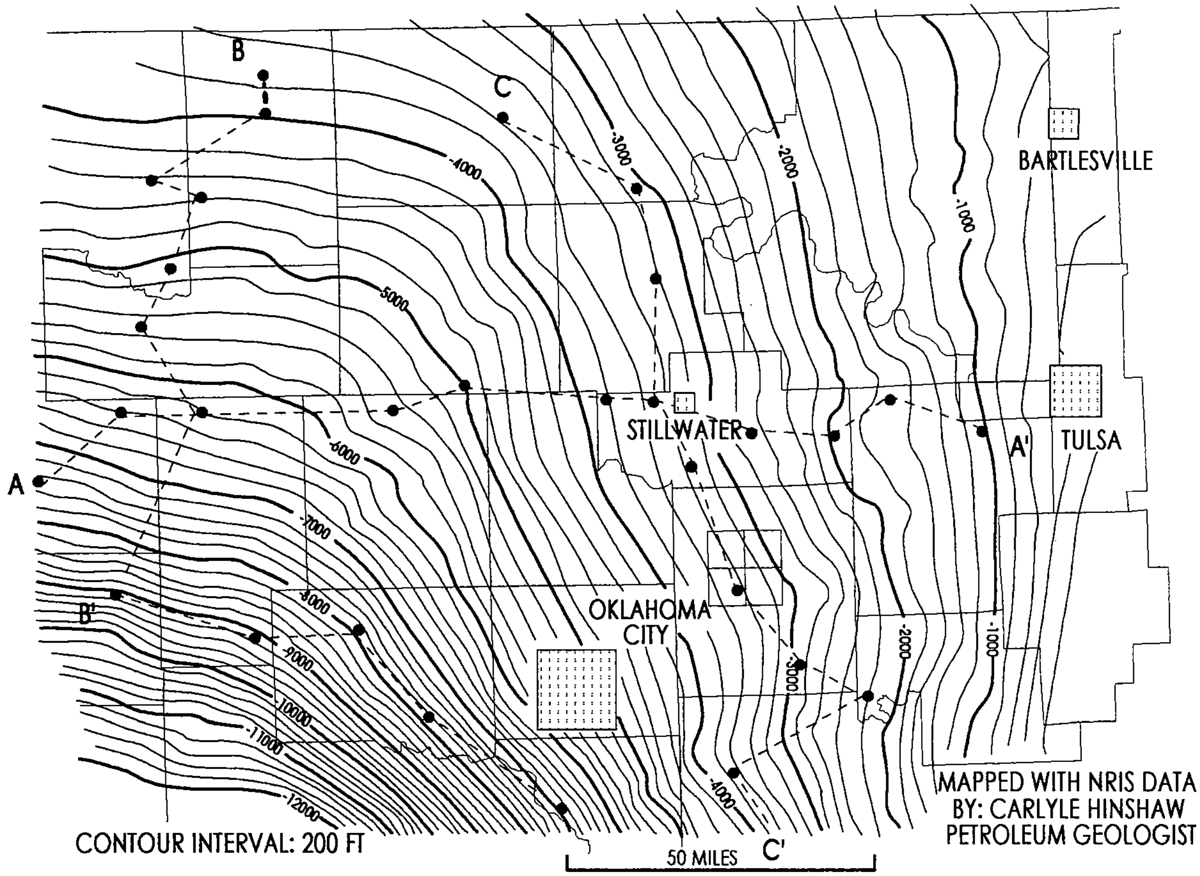


Figure 16. Generalized regional structure map of the top of the Pink lime, Oklahoma. Contour interval is 200 ft.

marine or delta front environment. Sandstones in the lower interval are shown on Plate 1. Sandstones in the upper interval in wells 2 and 3 (A–A′) are interpreted to be fluvial channel deposits and are plotted on Plate 2.

The Red Fork interval lies unconformably on Mississippian rocks in wells 6 and 7 (A–A′) and is thin in wells 5–7 over much of the central Oklahoma uplift. The thin Red Fork interval in central and northeastern Oklahoma indicates that during Red Fork deposition the area was structurally active (uplifted) or perhaps stable, while the Anadarko basin to the west-southwest and the Arkoma basin to the southeast subsided. The resulting lack of accommodation space favored the formation of incised channels (see wells 4 and 5, A–A′) and relatively thin shallow marine deposits and poorly developed progradational sequences (see wells 6–10, A–A′). Much of the sandstone in eastern Oklahoma appears to have been deposited in shallow marine or delta front environments. The Red Fork interval thickens from 60 ft in well 7 to ~140 ft in well 12.

Regional cross-section B–B′ (Pl. 4) runs southward from the Anadarko shelf into the Anadarko basin (wells 1–8, B–B′), then southeastward out of the Anadarko basin to the central Oklahoma uplift (wells 8–12). Southward, the Red Fork interval thickens from ~70 ft on the Anadarko shelf (well 1), to ~90 ft at the north edge of the Anadarko basin (well 6), to ~350 ft in the Anadarko basin. The Red Fork interval on the Anadarko shelf (wells 1–6, B–B′) is mostly sandstone interpreted to have been deposited primarily as fluvial point bars in incised channels (Pl. 1). The sandstone in well 2, which is in the Cherokita trend, is not clearly understood. In this well, a shale bed, almost 10 ft thick, separates the sandstone into upper and lower parts, and the gamma-ray and resistivity logs suggest that the lower part consists of two, perhaps three, beds of sandstone with slightly different characteristics.

The cross section from well 8 to well 10 runs southeastward, roughly parallel to strike of the basin, to the eastern edge of the basin (well 11), and ends on the central Oklahoma uplift (well 12). In wells 8–10, the Red Fork interval is about 350–220 ft thick and contains two or more progradational sequences (i.e., sequences that coarsen upward from shale to sandstone). Farther southeast, in well 11, the Red Fork interval is only ~100 ft thick, and it rests unconformably on the Woodford Shale. The Red Fork sandstone in this well is interpreted to be a point bar sandstone in an incised channel. In well 12, east of the central Oklahoma fault zone, the Red Fork interval is only ~90 ft thick and is a poorly developed progradational sequence consisting of a channel sand overlying a delta front sand.

Regional cross-section C–C′ (Pl. 4) is a north-south line illustrating stratigraphic changes that occur within the Red Fork interval on the Cherokee platform and platform margin. Over the entire length of the cross section, the Red Fork interval thickens southward from 80 ft (well 1) to ~210 ft (well 12). The regional thickening is interrupted by the Seminole uplift, where the Red Fork interval is somewhat thinner (125 and 100 ft thick in wells 10 and 11). The Red Fork interval in the southernmost well, which is only a few miles northwest of the Arkoma basin, is mostly shale. Log signatures of wells 1–6 suggest that the sandstone is fluvial and was probably deposited in point bars of a flood plain in a coastal environment. Farther south, in well 7, the Red Fork interval is predominantly marine shale. At well location 9 in southwest Okfuskee County, the Red Fork interval gradually thickens and is interpreted to consist of delta front sands overlain by channel sands (prograding deltaic sequence). Farther to the south, cross-section C–C′ crosses the Seminole structure, and the resulting uplift has caused considerable thinning of all lower "Cherokee" FDD intervals, including the Bartlesville, Red Fork, and even the middle "Cherokee" Skinner interval.

DEPOSITIONAL MODEL

In general, the Red Fork FDD system has a northerly source and advanced to the south and west (Fig. 13). Sandstone in the Red Fork interval originated from a major fluvial system that advanced across much of the Cherokee platform in a southerly direction (Fig. 13). Based on the prevalent patterns of sand distribution and the fine grain size of the sand, the source area was probably cratonic areas far to the northeast or possibly structurally positive areas in northern Kansas and southern Nebraska (Table Rock Arch—part of the Nemaha fault zone). Sediment was transported southward in rivers and streams that carried large amounts of clay, silt, and very fine grained sand in suspension, and fine- to medium-grained sand (quartz, rock fragments, and feldspars) as bedload. Large amounts of organic material, such as leaves and wood fragments, are also present in both the fluvial and marginal marine sandstones.

The configuration of the Cherokee platform, the western edge of which is the Nemaha fault zone, had an enormous influence of the depositional patterns of Red Fork sandstone in Oklahoma. Fluvial systems entered Oklahoma from the north (Kansas) on the east side of the Nemaha uplift, since this feature consisted of structural elements that were largely positive during much of Red Fork time. Fluvial systems were directed primarily to the south and dispersed sediment over a large area in northeast Oklahoma. On the Cherokee platform, in a southward direction, fluvial deposits give way to sandstone and shale deposited in a variety of shallow marine environments. Minimal subsidence (i.e., inadequate sediment accommodation space) prevented the formation of thick deltaic sequences and restricted the total accumulation to not much more than ~100 ft. Many of the fluvial channel deposits on the Cherokee platform were incised into older Red Fork marine deposits during periods of lower sea level. These channels were directed farther to the south and then west, where structural uplift along the central Oklahoma fault zone was not appreciable. This contributed to the development of a west-trending Red Fork channel in southern Oklahoma and Canadian Counties that was later the site of a major Prue-Skinner channel complex known as the Airport trend.

Red Fork deposits in western Oklahoma are very different, consisting mostly of incised channels trending west and southwest at a high angle to the uplift in central Oklahoma. These channel systems probably also formed in response to lowering of eustatic sea level. Many of the channels in western Oklahoma are parallel to subparallel and persist for 25–100 mi. Due to the parallelism of two prominent channel systems, the Cherokita and Wakita trends, many geologists (Withrow, 1968; O'Reilly, 1986) interpret them as shoreline deposits. The sharp base and fining-upward texture of sand bodies as interpreted from gamma-ray log profiles and local scouring strongly indicate that these sands were deposited in a fluvial channel complex. All of the channel trends mapped in Plates 1 and 2 pass basinward into deltaic sandstones which have distribution patterns and log characteristics that are very different from the fluvial channel sandstones.

In a simplified depositional model, the Red Fork sandstone is predominantly fluvial in the north and passes southward into deltaic and shallow marine sandstones. In central and northern Oklahoma, much of the Red Fork sandstone was deposited in channels incised directly into shale. Progradational sequences, consisting of delta front shale and sandstone overlain by channel sands, are not common in the north, possibly because of the lack of sediment accommodation space. West of the Nemaha and central Oklahoma fault zones, subsidence of the Anadarko basin allowed the accumulation and preservation of thick deltaic sequences. The Red Fork sandstones in the deep Anadarko basin (Pl. 2) are interpreted to have been deposited during a sea level lowstand. After a substantial drop in sea level, fluvial channels incised into older marine deposits delivered sand directly to the old shelf edge where the shelf-edge delta forms. The low-stand delta, also called a shelf-edge delta model, is shown in the lower half of Figure 17.

FDD RED FORK RESERVOIRS

Red Fork production is distributed throughout much of Oklahoma. This is illustrated on Plate 3, which is a map showing "locations" (actually one or more wells per spot on the map) with Red Fork oil and gas production. In some cases, Red Fork production is not identified because the designation of production was not specific, such as in the use of "Cherokee sand." The production map can be compared to Plate 5 (in envelope) which shows oil and gas fields that produced at least 5,000 barrels of oil or at least 3 billion cubic feet of gas from the Red Fork from 1979 through 1993. Field names and boundaries are consistent with field designations by the Oklahoma Nomenclature Committee of the Mid-Continent Oil and Gas Association. In some fields, Red Fork production is found only in part of the field. Red Fork wells also are located outside of the field boundaries shown on Plate 5 because the effort by the Oklahoma Nomenclature Committee to formally extend field boundaries lags behind the extension of producing areas.

Both oil and nonassociated gas wells produce even from different areas within the same trend. However,

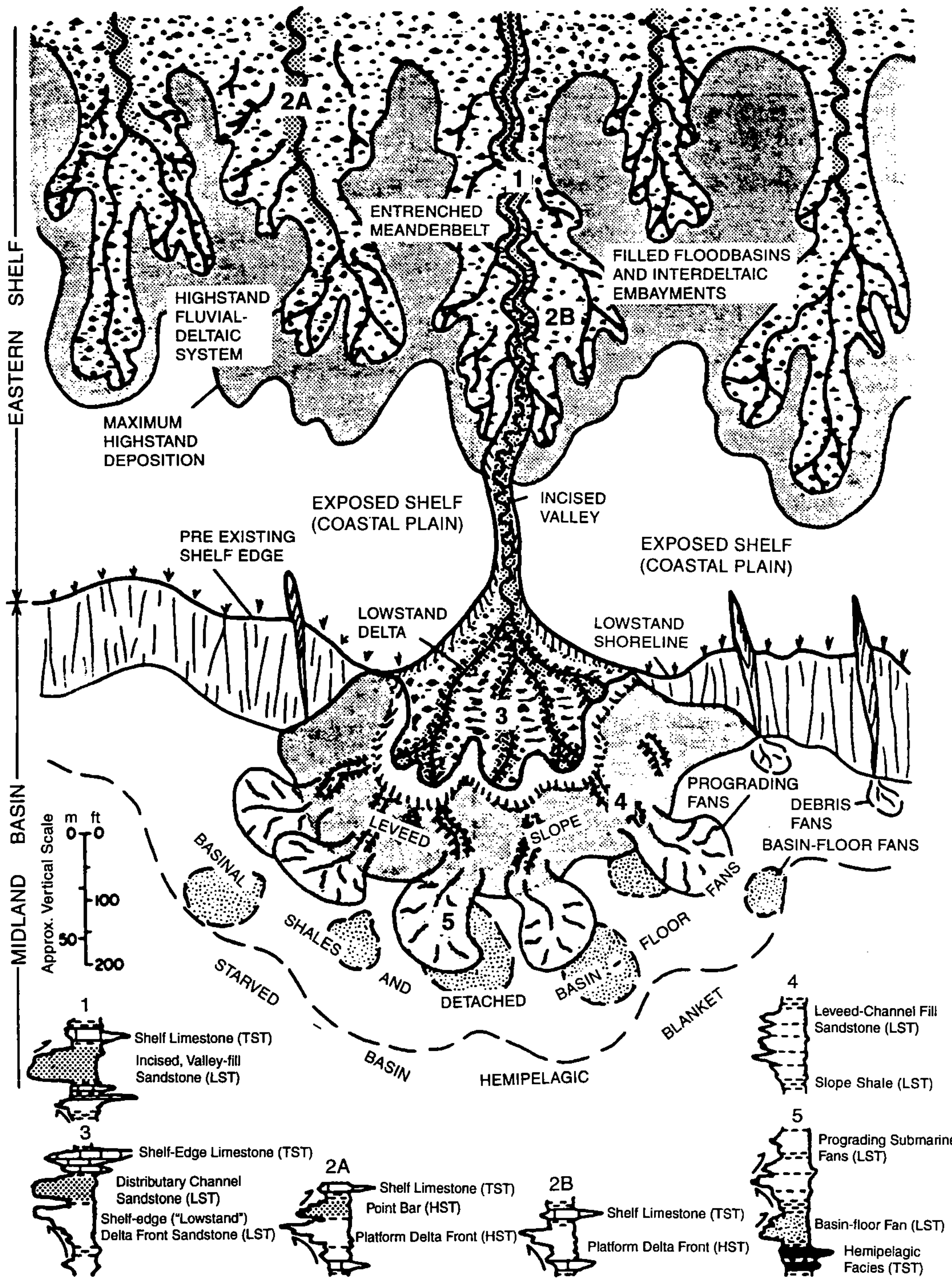


Figure 17. Deltaic depositional systems tracts. Upper part of the figure shows a depositional facies model for a sea-level highstand delta. The lower part of the figure shows a depositional facies model for a lowstand delta, also known as shelf-edge deltas. HST = highstand system tract, LST = lowstand system tract, TST = transgressive system tract (TST). Representative logs illustrate facies within various parts of the two deltas. From Brown (1989).

hydrocarbon production is entirely gas in parts of the Anadarko basin (see Pls. 1–3). In eastern Oklahoma, only about half of the completions are classified as oil wells (Pl. 3). Many Red Fork wells in eastern Oklahoma produce from sandstones other than channel sandstones, such as distributary mouth bars and marine shelf sands. Red Fork channel sands commonly have a high degree of porosity and permeability and make excellent reservoirs. On Plate 3, production appears to be continuous over relatively large segments of some of the channel trends when, in fact, production is from a series of fields along the length of the channel system. Some channel systems contain water and produce only where they are above a well-defined oil/water contact.

The gas-saturation is moderate to high in most Red Fork oil reservoirs, which generally produce significant amounts of associated gas throughout the life of a field. The main drive mechanism of many Red Fork reservoirs is solution gas. Therefore, producing the gas depletes the reservoir energy, leaving much of the oil behind. Red Fork oil commonly has a high shrinkage factor, which should be considered in waterflood operations when calculating the amount of water that must be injected to replace the volume of oil produced and the oil production response time.

Throughout this paper, references are made regarding various sand size grades in the description of certain rock units. For those not remembering the correct values, they are listed in Appendix 1 of this report. Similarly, various abbreviations and terms that are used in this paper are defined in Appendixes 2 and 3, respectively. All well symbols are illustrated and defined in Appendix 4. Three cores are provided for examination by workshop attendees. One core is an incised channel sandstone, one is a shallow marine detached bar, and one, from the Cherokita trend, is thought to be a reworked channel sandstone. A brief core description and facies interpretation is provided along with well logs and select computer-scanned images in Appendix 5.

N. Carmen Field

(Red Fork oil pool in secs. 34 and 35, T. 25 N., R. 12 W., and secs. 2 and 3, T. 24 N., R. 12 W., Alfalfa County, Oklahoma)

by Richard D. Andrews

Introduction: N. Carmen field is located in southwestern Alfalfa County in northwestern Oklahoma (Fig. 18). The field area is about 60 mi west of the Nemaha uplift, in an area commonly referred to as the Anadarko Shelf Province (Plate 1). N. Carmen produces oil and gas from fluvial point bar deposits in the Red Fork sandstone. A map identifying operators, well locations, well numbers, and principal leases within the field area is shown in Figure 19.

Oil production was first established in the N. Carmen study area in 1965 with the completion of the Union Texas No. 1 Pruett well located in the SW¼SE¼NW¼ sec. 3, T. 24 N., R. 12 W. The well was completed in the Mississippi lime for 114 BOPD and 25 BWPD. In 1980, this well was offset ~1,000 ft to the northwest by Magic Circles's No. 1 Pruett. This well also was completed in the Mississippi lime. The Red Fork in both of these wells was shaly. In 1983, Pan Western drilled the No. 1 Curry in the N½SW¼ sec. 34, T. 25 N., R. 12 W. This well was also dry and encountered only shale in the Red Fork interval. It was only ~1,200 ft northeast of the Red Fork discovery well. The next well in the study area wasn't drilled until December 1984, when Duncan Oil drilled the field-opener for the Red Fork oil pool. The No. 1 Zoa (SW¼NW¼SW¼ sec. 34) had an initial potential flowing 108 BOPD, 344 MCFGPD, and no water from 14 ft of Red Fork sandstone. During the next year, nine additional Red Fork wells were drilled in the area east of the discovery well. By mid-1986, 14 wells had been completed in the Red Fork. The Red Fork has an oil gravity ranging from 40° to 45° API. The lighter oil is found structurally lower in the reservoir, and the heaviest oil is found structurally high within the reservoir. No gas cap was encountered. Only one well found additional pay above the Red Fork: the No. 1-A Horn, which was recompleted in the Oswego for 195 MCFGPD.

N. Carmen is fully developed on 40-acre spacing. Most of the wells were shut-in during the early 1990s, when individual well production fell to only a few barrels of oil per day. In late 1995, the field was unitized by Ensign Oil and Gas (Oklahoma City) and a waterflood was initiated. In early 1996, a response in oil production was measured.

Stratigraphy: A typical log from the N. Carmen field and the stratigraphic nomenclature are shown in Figure 20. The Red Fork interval is immediately overlain by ~7 ft of hot shale, which is overlain by the Pink lime. (The Pink lime in this well and elsewhere in this field is very thin and the resistivity is uncharacteristically low.) The base of the Red Fork interval is the top of the Inola limestone. The Red Fork sandstone, which lies in about the upper two-thirds of the Red Fork interval, is underlain by 15–20 ft of shale. The "bell-shaped" SP log profile and the upward-increasing gamma-ray profile are interpreted to reflect a fining-upward in grain size, which is characteristic of point bar deposits.

Stratigraphy of the Red Fork interval is shown by detailed structural-stratigraphic cross-sections A–A′ (Fig. 21, in envelope) through the western half of the field, and B–B′ (Fig. 22, in envelope) through the eastern half of the field. Wells 2–4, cross-section A–A′, produced oil and gas from the Red Fork. Based on the "bell-shaped" gamma-ray and SP log profiles, the sandstone in these wells is interpreted to be a point bar deposit. Thin shale beds in the sandstone, as inter-

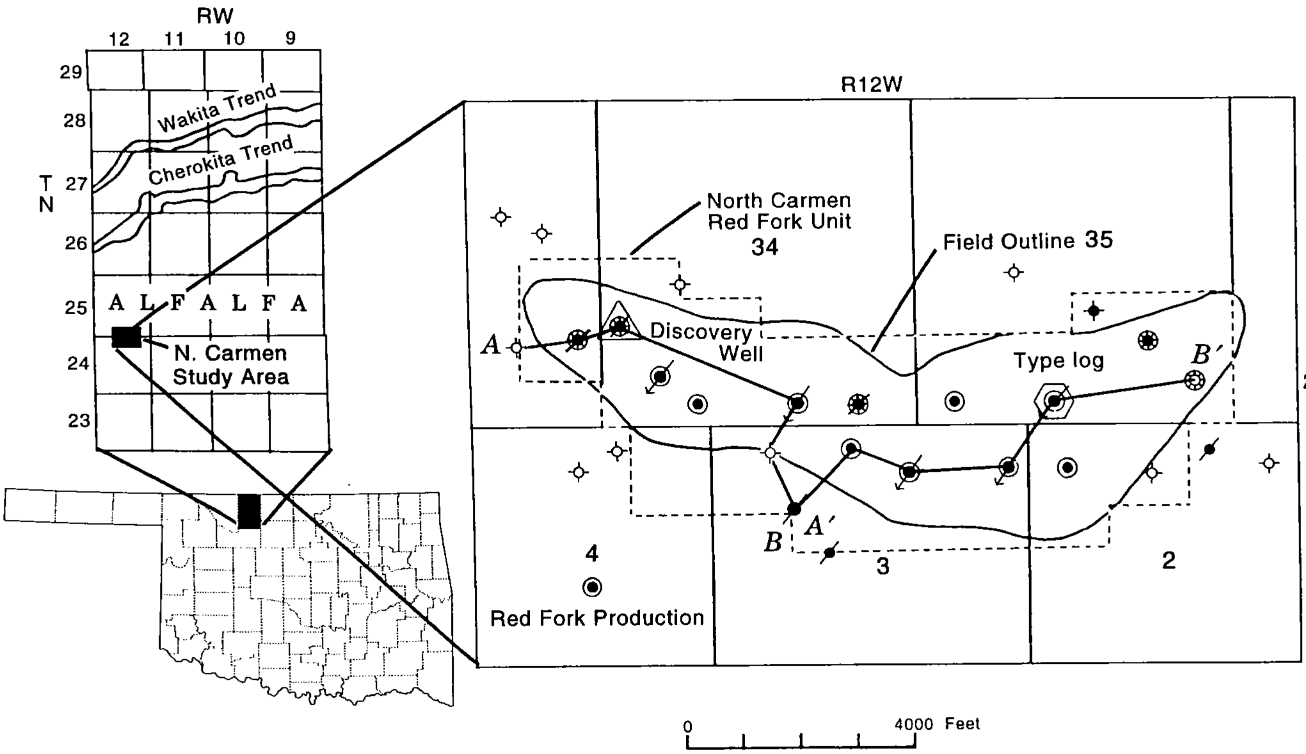


Figure 18. Map showing location of the N. Carmen Field in southwestern Alfalfa County, Oklahoma. The field boundary is shown by the solid line; the N. Carmen Red Fork Unit boundary is shown by the dashed line. The Cherokita and Wakita trends also produce from the Red Fork sand.

preted from the serrated gamma-ray log profile in wells 3 and 4, are probably "shale drapes." Shale drapes are relatively thin layers of mud deposited on top of point bars during periods of low stream discharge. Unless the mud is eroded when higher flow rates resume, the shale drapes become interbedded with the point bar sandstone. Most of the shale interbeds are only ~1 ft thick, but probably form effective barriers to fluid flow.

Shaly sandstone or silty shale in the upper part of the Red Fork interval in wells 2 and 5, which is laterally equivalent to the upper part of the point bar sandstone in wells 3 and 4, is interpreted to be a shaly channel-fill (i.e., channel margin facies). The clean sandstone thins appreciably between wells 3 and 2.

The Red Fork interval in wells 1 and 6 in cross-section A–A′ is distinctly different than it is in the other wells in the cross section. It is mostly shale, but more importantly, beds within the shale section of well 6 cannot be correlated with beds in the shale of well 5. Based in large part on the gamma-ray log of well 1, which contains one, perhaps two, coarsening-upward sequences (i.e., the gamma-ray decreases upward and the resistivity increases upward), the Red Fork interval in wells 1 and 6 is interpreted to have been deposited in a marine environment. Because of the differences in details of bedding/lithology, the marine shale can be distinguished from the shaley channel fill. In well 5 (near southeast end of A–A′), the Red Fork interval consists of very thin sandstone beds interbedded with shale and siltstone. The Red Fork in this well is interpreted to be a channel margin deposit. In well 2, clean sandstone is overlain by shalier channel margin deposits. The fact that the marine deposits are adjacent to the channel deposits and the channel deposits are not overlain by marine sands indicates that point bar sandstone was deposited in a channel incised into the older marine deposits.

Cross-section B–B′ (Fig. 22) is a cross section across the eastern half of the field. Most apparent in the logs in this cross section is the presence of a distinct lower section of the sandstone with distinctly different log characteristics. The sandstone in the lower 10–15 ft has the following log characteristics: a sharp basal contact with shale, the cleanest (i.e., lowest) gamma-ray response, separation of the short and deep resistivity curves, and a positive SP deflection. This is the primary producing portion of the point bar and probably has the greatest porosity and permeability. The remainder of the Red Fork interval in these wells consists of alternating thin beds of sandstone and shale. The gamma-ray profile clearly indicates that vertically, this interval is not one continuous depositional sequence and is probably not a single, simple point bar.

Well 1 in cross-section B–B′ (well 6 in A–A′) is in the marine facies, outside the channel. The marine facies in well 1 is incised by the channel represented in well 2. In this well, the channel sands pinch out to the southwest and occur in three intervals separated by shale. Between wells 5 and 6 at the eastern end of cross-sec-

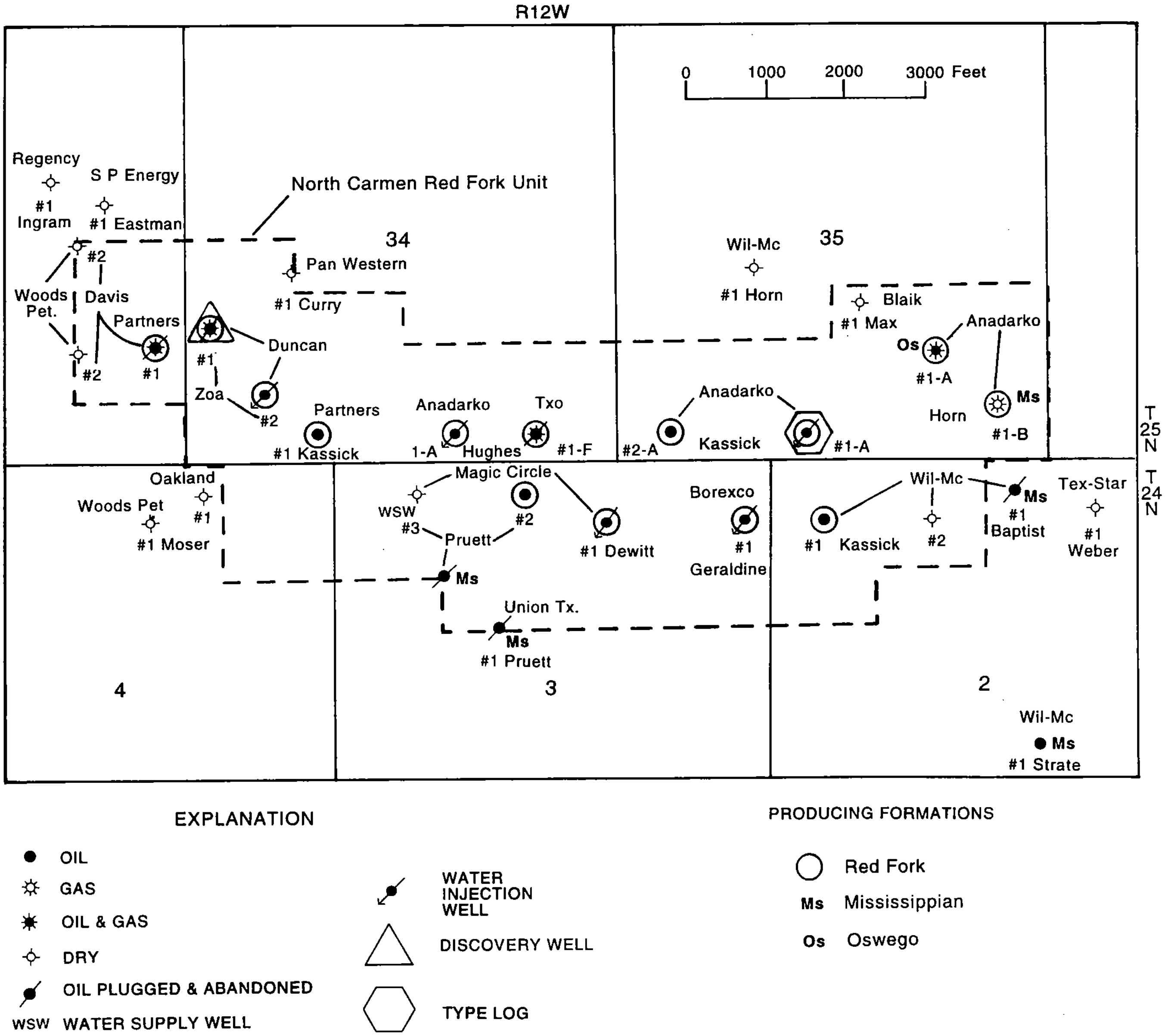


Figure 19. Well information map showing operator, lease name, well number, and producing reservoir(s) for wells in the N. Carmen study area.

tion B–B′, the main point bar sequence thins from 23 ft in well 5 to only 6 ft in well 6. The sandstone in well 6 is overlain by interbedded shale and thin sandstone beds interpreted to be channel margin deposits. The channel sandstone pinches out in the southeast corner of sec. 35. However, shaly channel deposits (channel margin deposits) continue to the northeast, and in sec. 24 the channel sand is again well developed. Core analysis data from a well in sec. 24 is presented later in this paper.

Structure: Regional dip of the Pink lime in the study area is to the south at ~50 ft/mi (Fig. 16). A structure map of the study area contoured on the top of the Red Fork sand zone (base of the "hot" shale below the Pink lime, see Fig. 20) shows dip to the south at ~100 ft/mi or 1° (Fig. 23). The regional southward dip is interrupted by a pronounced northeast-trending trough that plunges to the south in the eastern part of the study area and a smaller northwest-trending trough in the western part of the field (Fig. 23). These deviations from the regional structure are probably the effects of small-scale basement faulting. There are no exceptional sediment buildups beneath the Red Fork in the study area that could have caused local drape folding. The field is oriented subparallel to the regional structure; the highest part of the field is at the far west end in the SE¼ of sec. 33. Because there is no dominant structural feature as an incentive for exploratory drilling,

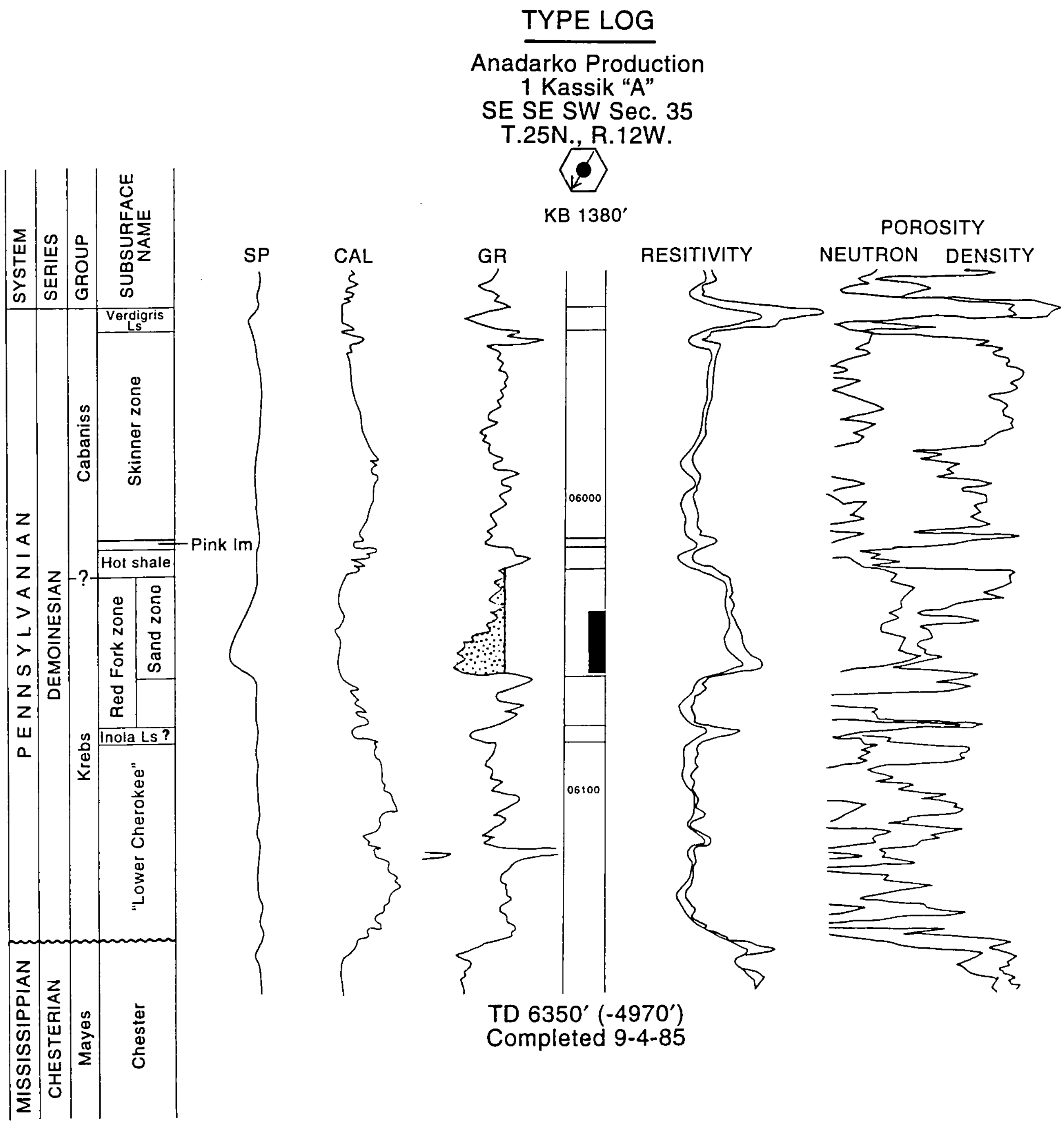


Figure 20. N. Carmen Field Red Fork type log showing the stratigraphic section, nomenclature, and typical log signature of the Red Fork channel sand. In this paper, the "Red Fork zone" is the interval from the base of the hot shale below the Pink lime to the top of the Inola Limestone. The "Red Fork interval" is the interval from the base of the Pink lime to the top of the Inola. SP = spontaneous potential, GR = gamma-ray.

this field was discovered by extending the known geologic trend of the Red Fork channel that was delineated further to the west in the early 1980s.

As in many areas within the Anadarko Shelf and Platform areas, fracturing may have a significant effect on fluid flow, especially during water injection. The dominant fracture pattern in this area is interpreted to occur in a northeast-southwest direction, although fracturing is not positively identified in the field. Nevertheless, the location of injector and producing wells within N.

Carmen field was accomplished by avoiding the placement of injection wells at an orientation of about N. 70° E. to production wells.

Red Fork Sandstone Distribution and Depositional Environment: Figure 24 shows the gross thickness of the Red Fork sandstone for all the wells in the study area. The gross sand thickness is the total thickness of the sandstone, regardless of porosity, determined from the gamma-ray and resistivity logs. The zero-thickness line is the limit of sandstone deposition within the channel. The channel is about 0.3–0.5 mi wide. Within the general area, the course of the channel is U-shaped and extends beyond the area mapped to the northeast and northwest. The channel sandstone pinches out near the eastern edge of the study area but reappears farther north, in sec. 24. West-northwest of the study area, the channel sandstones are not continuous but occur in a series of fields (a "trend") that intersects the south-trending part of the Cherokita trend. The fields in this trend are prone to gas rather than oil production.

The gross sandstone thickness ranges from 4 to 30 ft. The gross thickness in most of the wells (9 out of 14) is from 18 to 25 ft thick. However, the sands do not occur everywhere within the channel. In many places such as at the ends of the field, channel deposits are predominantly shale rather than sand, since they occur along the channel margin or in places within the channel where little sand was deposited. These shaly intervals form the stratigraphic barriers that isolate hydrocarbons along the course of the channel. The thin sandstones north and south of the channel belong to the regionally extensive marine shelf deposits that existed prior to deposition of the Red Fork channels. These marine sandstones do not produce anywhere near the study area.

The net sandstone isopach map shows the thickness of sandstone with porosity ≥10%. The net sand thickness ranges from 4 to 20 ft, the average thickness is ~12 ft. (Gross sand thickness ranges from 6 to 30 ft.) The net sand map (Fig. 25) is very similar in overall appearance to the gross sand map (Fig. 24) and clearly shows that much of the sandstone identified in the gross sand isopach map has good porosity. The main differences between the two occurs in the upper portion of the point bar, causing a reduction of (net) sand thickness of several feet. Although much of the sandstone had porosity considerably greater than the 10% cutoff value, a higher cutoff value, such as 12% or 14%, would have significantly changed the appearance of the net sand map because the upper half of the sandstone in many wells is "dirty."

There is no water leg in the field so the reservoir includes the entire area with >0 ft of net sand (Fig. 25). Both the gross and net sand thin appreciably in the center of the northern part of sec. 3, which suggests the possibility of reservoir compartmentalization.

The thickest sandstone in the study area is found in point bars in fluvial channels (as opposed to distributary channels). The direction of flow has not been determined, but is inferred to be from east to west. The sand body is elongate with a width of about 0.3–0.5 mi and is slightly more than 2 mi long. As seen in field wells, the point bars have a sharp basal contact with shale and a fining-upward textural profile that eventually becomes entirely shale. The reservoir occurs only in fluvial sandstones. The thin marine shelf sands (see well 1, cross-section B–B′) are not part of the reservoir. Marine deposits were probably incised by fluvial channels during lowering of eustatic sea level.

Facies Mapping: Depositional environments were interpreted from the wireline log signatures, particularly the gamma-ray and resistivity logs (Fig. 26). Two distinctly different depositional environments are interpreted in the N. Carmen field area and include fluvial and shallow marine deposits.

Fluvial (Channel) Facies: The depositional origin of these sediments appears to be a simple meandering stream contained within a flood plain (rather than delta plain). This distinction is important for exploration purposes since there is no delta front underlying the channel facies and, therefore, no progradation, i.e., no deposition extending basinward into a marine environment (definition of a delta!). Within the fluvial (channel) facies, sediments are either predominantly sandstone, or shale with thin interbedded sand layers. Because of the morphology of the sandstone body, it is interpreted to be a point bar "smeared" or extended with longitudinal bar growth. The reasons for this interpretation include: (1) sharp basal contact, (2) fining-upward textural profile on gamma-ray logs, (3) distinct shale breaks in the upper half (clay drapes), and (4) elongate to almond-shaped map outline. Channel deposits that are predominantly shale are interpreted to be channel margin or abandoned channel deposits and are not part of the reservoir.

Shoreface or Shallow Marine Shelf Facies: The shale with thin interbedded sandstones that occurs adjacent to the fluvial channel deposits are interpreted to be shallow marine shelf deposits (see well 1, cross-section A–A′). Although they do not produce in or anywhere near the study area, their identification is very important in managing exploration and development drilling using facies recognition. The marine facies are impervious to hydrocarbons and probably contribute to hydrocarbon entrapment in areas adjacent to the main channel reservoir. Recognition of the marine facies can be used effectively to direct "step-out" drilling in the development of fluvial trends such as N. Carmen.

Core Analysis: None of the wells in N. Carmen field was cored. However, the core analysis report on sidewall cores from the bottom 10 ft of the Red Fork sand in the Anadarko Petroleum No. 1-24 Means "E" well, NW¼ NE¼SE¼ sec. 24, T. 25 N., R. 12 W., was obtained. This well lies ~2 mi northeast of the N. Carmen field. The

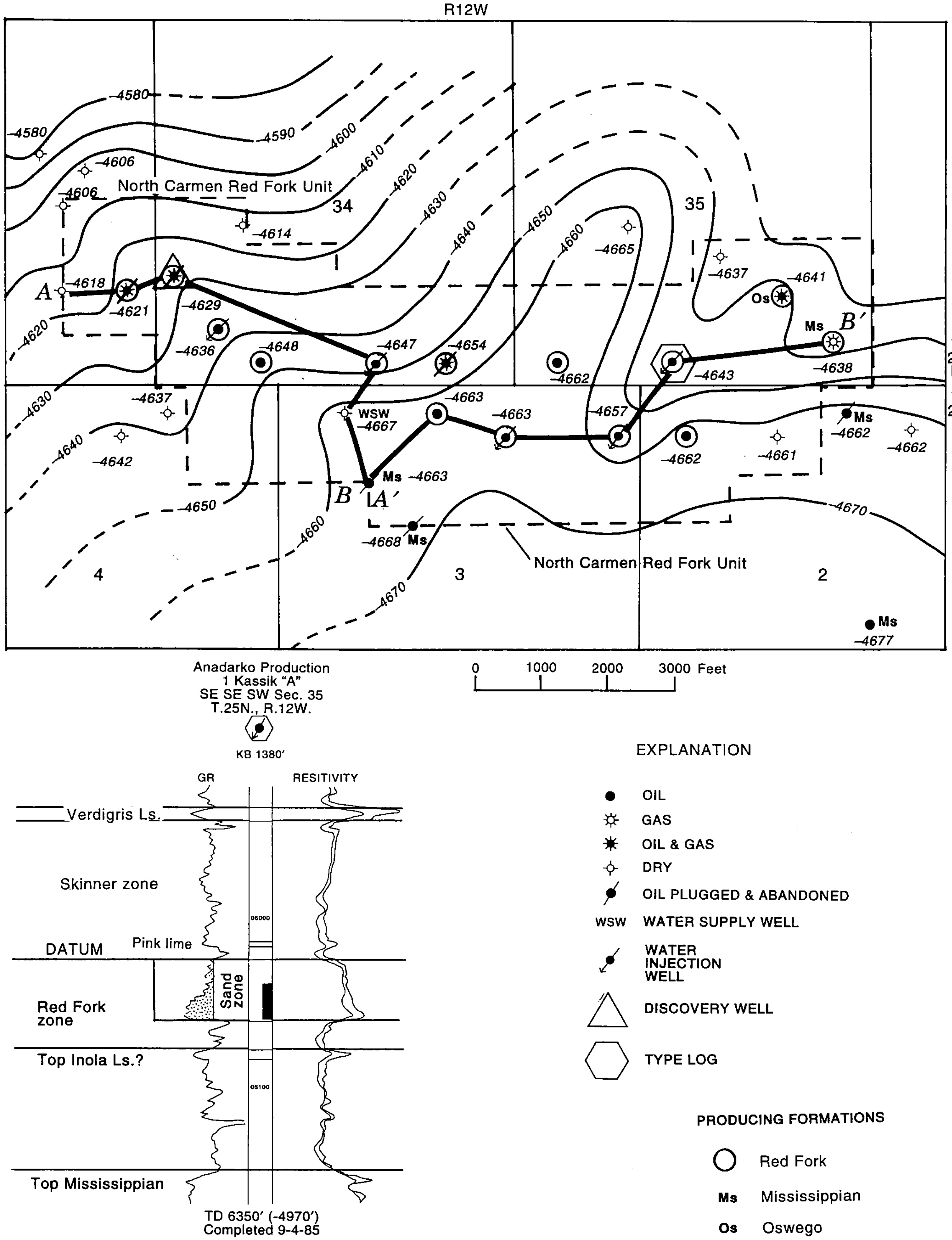


Figure 23. Structure map of the top of the Red Fork zone in the N. Carmen study area. The top of the Red Fork zone is also the base of the black shale below the Pink lime. Contour interval is 10 ft; contours are dashed where inferred. See Figure 19 for well names.

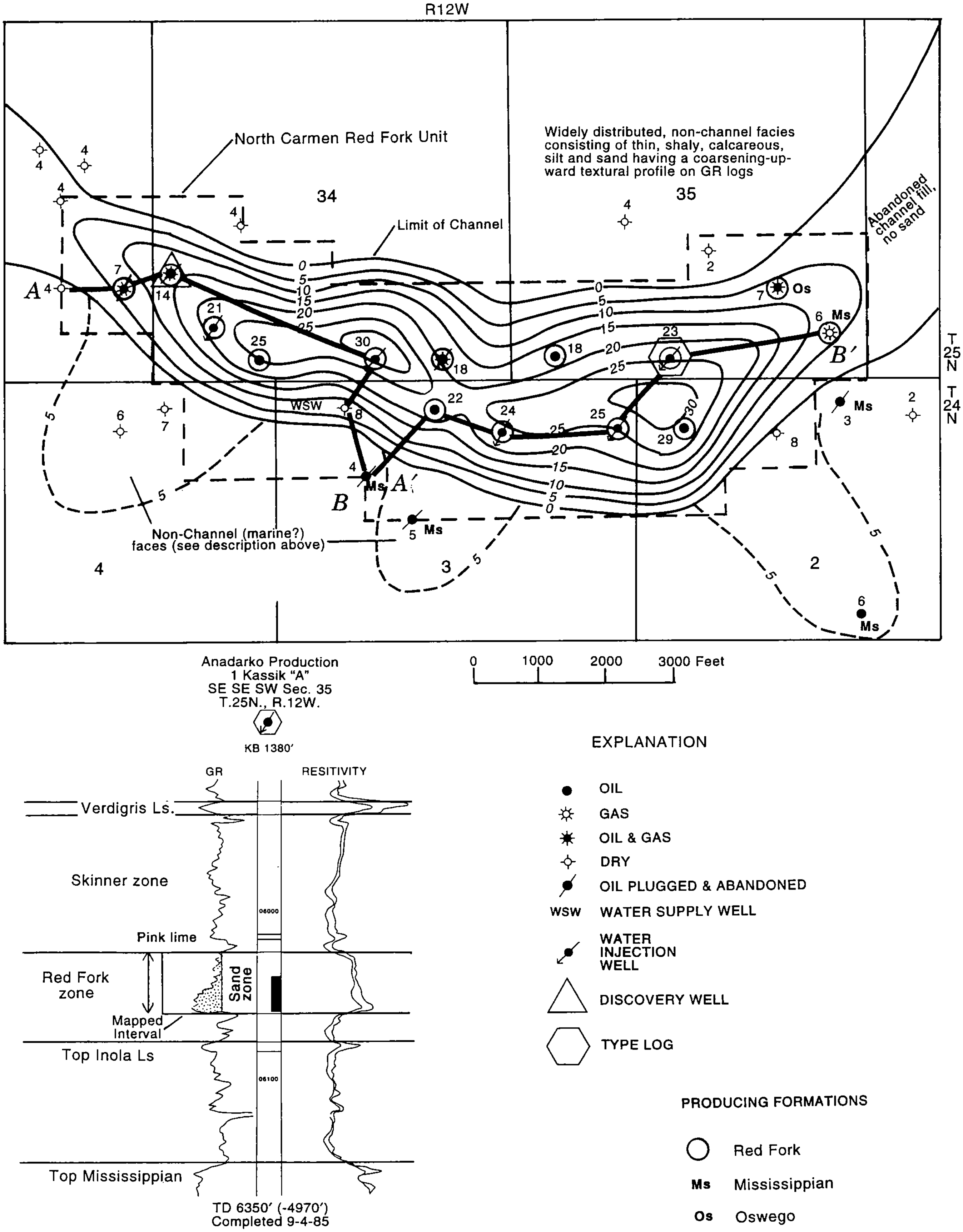


Figure 24. Gross sand isopach map of the Red Fork sandstone in N. Carmen field. Gross sand includes all sandstone in the interval from the top of the Red Fork zone to the base of the Red Fork sandstone (see index log). Non-channel marine bar sandstone also occurs in this interval. Contour interval is 5 ft. See Figure 19 for well names.

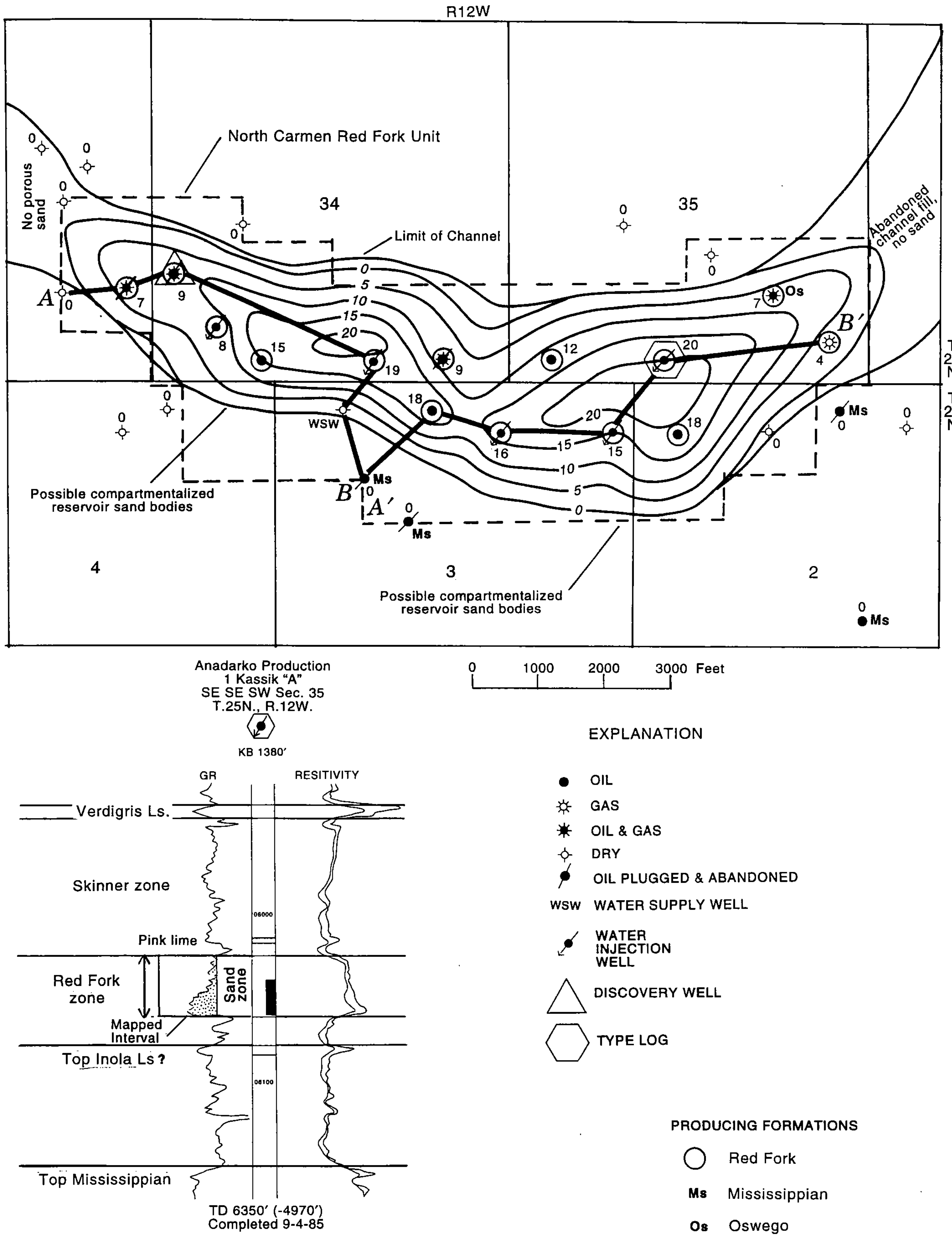


Figure 25. Net sand isopach map of the Red Fork sandstone in N. Carmen field. Net sand = sand with log porosity ≥10%. "Limit of channel deposits" is the zero-thickness line on the gross sand map. Contour interval is 5 ft. See Figure 19 for well names.

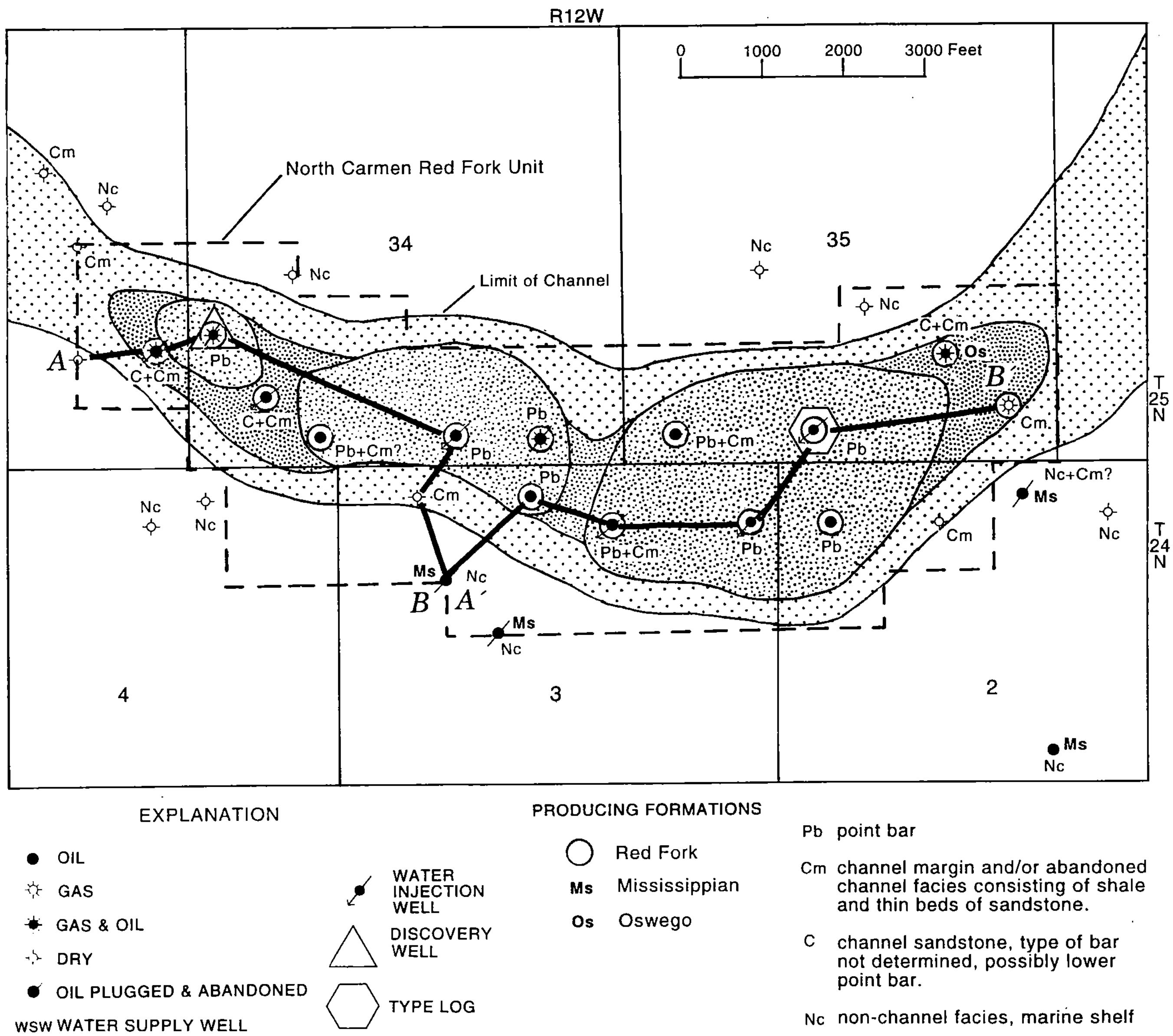


Figure 26. Depositional facies map of the Red Fork sand interval in the N. Carmen study area.

samples were described as being very fine to medium-grained sand, greenish gray, subangular to subrounded, well sorted and well cemented, with a trace of pyrite. The grain size increased with depth from very fine to medium grained. The grain density ranged from about 2.68–2.72 and averaged ~2.69. Porosity and permeability measurements are listed and plotted in Figure 27. The porosity ranges from 12.1% to 17.3%. Permeability measurements range from 1.8 to 27.7 md; most are between 3.4 and 8.8 md. The porosity-permeability curve shows that for ~10% porosity, the permeability should be slightly more than 1 md, which is considered to be the minimum permeability for oil production. For a sandstone with average porosity (15–16%), the permeability should be ~10 md. In this well, core porosity is identical to the porosity determined from the density log run with a 2.68 matrix density. The decrease in porosity and permeability at the bottom 4–5 ft of core is due to carbonate cementation.

Reservoir Characteristics: EOG analyzed all available cuttings of the Red Fork sand in N. Carmen field. Based on lithology (framework grains, authigenic minerals, and texture), they identified three distinct zones. These are described in stratigraphic order starting from the top of the sand section:

1. The upper channel facies consists of interbedded shale and thin, silty sandstone. The sandstone is very fine grained and contains abundant clay ("dirty" sandstone). This lithology, which commonly occupies the

upper half of the Red Fork sand zone, is generally not part of the reservoir.

2. Local tight streaks consist of calcite-cemented subarkose (mostly quartz with some feldspar). Trace amounts of pore-filling barite and iron-rich dolomite are also present. Authigenic or detrital clay is generally absent in this zone. The best development of this zone is in the SE¼SE¼ sec. 35 (see well 6, B–B′, Fig. 22) in the far eastern part of the field and in the SW¼SE¼SE¼ sec. 34 near the center of the field.

3. The basal zone (lower channel or point bar facies) is the main producing interval. It is composed of fine-grained, porous, sandstone with zones of lithic arkose having abundant feldspars and rock fragments. Pore linings contain relatively large amounts of chlorite.

TABLE 2. – Reservoir/Engineering Data for the Red Fork Sandstone, N. Carmen Field, Alfalfa County, Oklahoma

Reservoir size	~635 acres
Depth	~6,000 ft
Spacing (oil)	40 acres, irregular
Oil/water contact	none
Gas/oil contact	none
Porosity (in net sand)	12–23%, (avg. about 15–16%)
Permeability[1]	3–28 md (avg. about 6–10 md)
Water saturation (calculated)	28% (range 20–31%)
Thickness (net sand $\phi \geq 10\%$)	5–20 ft (avg. about 10–12 ft)
Reservoir temperature	135°F
Oil gravity	40–45° API
Initial reservoir pressure[2]	2,383 PSI
Initial formation volume factor[2]	1.29 RB/STB
Current formation volume factor[2]	1.1 RB/STB
Original average GOR	1,725 SCF/BBL (range, 618 to >2,000)
Final average GOR	5,579 (SCF/BBL)
OOIP (volumetric)	4,152,000 STBO
Primary oil production (through 10/95)	412,246 BO
Primary oil recovery efficiency	10.0%
Primary recovery per acre-foot	~65 BO/acre-ft
Secondary oil recovery (11/95–6/96)	2,836 BO
Primary plus secondary oil production	415,082 BO
Cumulative gas production	2,315,685 MCF

[1]Measured in core from the Anadarko No. 1-24 Means "E," NW¼NE¼SE¼ sec. 24, T. 25 N., R. 12 W., 2 mi northeast of N. Carmen field.

[2]Data provided by Ensign Oil and Gas.

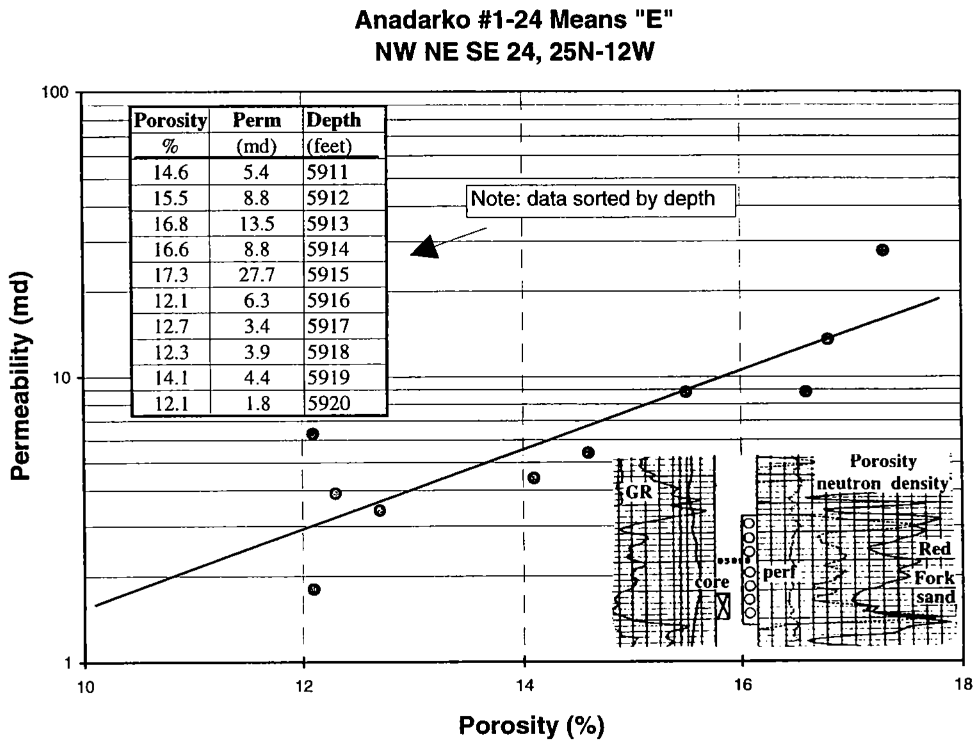
Reservoir characteristics are summarized in Table 2. Porosity (from density logs) in the lower part of the channel sandstone, which is the main part of reservoir, ranges from about 12% to 23% and in most wells is 14–17%. There are no permeability measurements of the Red Fork in the study area. However, core analysis in the channel sand in the nearby Anadarko No. 1-24 Means well shows the permeability to vary from about 3 to 28 md, averaging about 6–10 md. This relatively low average permeability is due mainly to interstitial clay originating from detrital sources as well as authigenic alterations of framework constituents such as rock fragments and feldspar. Chlorite has been identified as being one of the main authigenic clays. The relationship of porosity and permeability in the Red Fork channel sandstone in N. Carmen field is shown in Figure 27. This graph shows that when log porosity reaches ~10%, the sand should have slightly more than 1 md permeability, which is considered mininal for oil production. However, most of the sandstone within the lower to middle point bar has porosity between 14% and 17%, which would indicate an average permeability of about 6–10 md.

Within the point bar sequence of N. Carmen field, fluid flow and reservoir properties (permeability) are expected to be most favorable parallel to the axis of the channel (east to west) and least favorable vertically and across the channel (north to south).

Formation Evaluation: The identification and evaluation of Red Fork sandstone in N. Carmen field is very straightforward. The productive sandstone is relatively clean (i.e., gamma-ray and resistivity logs are not significantly affected by interstitial clay or mica). For the cored well (No. 1-24 Means "E," sec. 24, T. 25 N., R. 12 W.), porosity calculations from the density-neutron log using a standard 2.68 matrix density were identical to the porosities measured in the core.

The deep or "true" resistivity of productive intervals ranges from about 15 to 30 ohm-meters. The higher resistivities are caused by higher oil saturation in the lower channel facies. A relatively strong separation of about 10–20 ohm-meters exists between the shallow and deep resistivity readings in the producing interval. However, the separation is not readily apparent on many of the logs because the deep and shallow curves both fall on the part of the logarithmic scale that has closely spaced lines. The separation of the shallow and deep resistivity curves indicates the presence of permeability. Notice that in the upper part of the sand zone, there is virtually no separation of the short and deep curves.

Water saturation (S_w) calculations for the Red Fork sandstone ranged from about 20% to 39%. The S_w in most of the lower (productive) part of the sandstone was about 28%. Calculations were made using the formula $S_w = \sqrt{F \times R_w / R_t}$. The formation water resistivity (R_w) was assumed to be 0.04 ohm-meters at formation temperature. The Archie equation for formation factor ($F = 1/\phi^2$) was used to reflect the average reservoir lithology (consolidated sand with relatively high grain density). R_t, true resistivity, was taken directly from the deep resistivity log. Porosity values were also taken directly from density logs.



Porosity %	Perm (md)	Depth (feet)
14.6	5.4	5911
15.5	8.8	5912
16.8	13.5	5913
16.6	8.8	5914
17.3	27.7	5915
12.1	6.3	5916
12.7	3.4	5917
12.3	3.9	5918
14.1	4.4	5919
12.1	1.8	5920

Figure 27. Core porosity and permeability data from the Red Fork sand in a well 2 mi northeast of N. Carmen field.

Oil and Gas Production: The estimated cumulative oil and gas production from the Red Fork in N. Carmen field from December 1984 through June 1996 is 415,082 BO and 2,315,685 MCFG (Table 3). Table 3 also shows annual oil and gas production, average monthly production, and average daily production per well. The peak in annual oil production was in 1985 when 10 wells produced 166,375 BO; average daily production was 46 BOPD per well. In 1988, 12 wells were producing; annual production was only 17,931 BO and average daily production had fallen to 4 BOPD per well. The rapid decline in oil production is illustrated by the production decline curve in Figure 28. Oil production fell 78% in 1986; by 1990, the decline rate had decreased to 5%.

The annual oil and gas production history for individual wells is shown in Table 4 (oil) and Table 5 (gas). Additionally, Table 4 shows amount of oil production attributed to primary recovery (412,246 BO) as well as the amount attributed to secondary recovery (2,836 BO). The cumulative oil production map in Figure 29 shows the cumulative production and date of first production for each well in the field. High production values on this map correspond to wells having the thickest net sandstone (Fig. 25). Cumulative production does not appear to be related to the date of first production (most wells were completed in mid-1985).

Half of the wells in the field produced >36 MBO from the Red Fork. Two wells, the No. 1 Kassick (sec. 2, T. 24 N., R. 12 W.) and the No. 1 DeWitt (CNW¼NE¼ sec. 3, T. 24 N., R. 12 W.), both in the east half of the field, produced >60 MBO (Table 4; Fig. 29). The poorest producers, those with cumulative production <15,000 BO, were at the east and west ends of the field and a well in sec. 34, SW¼SE¼SE¼ (Fig. 29).

Initial oil production rates ranged from 30 to 600 BOPD; most of the wells in the field flowed 200–300 BOPD. Three wells in the west half of the field (sec. 34) had initial flow rates from about 400 to 600 BOPD (Fig. 30). One of these wells (S½SW¼SE¼ sec. 34) was only a quarter of a mile away from two wells that had been completed six months earlier, which indicates some degree of reservoir compartmentalization. Another possible indication of reservoir compartmentalization is the fact that the initial shut-pressure of some wells was greater than initial shut-pressures reported for some older wells. Flowing tubing pressures ranged from 50 to 900 PSI and was ≥450 PSI in five of the 11 wells reporting (Fig. 30). The wells with higher flowing pressures were some of best producers, which may indicate that the permeability in these wells is higher than the permeability measured in the No. 1-24 Means "E" core (see Fig. 27).

The API gravity measured in oil from two wells in the west half was 40° API and 41° API. The API gravity of oil from two wells in the east half of the field was 43° API and 45° API (Fig. 30). The heavier oil (lower API gravity) was produced from the structurally higher part of the reservoir and the lighter oil (higher API gravity) was produced from the structurally lower part of the reservoir. This relationship indicates the possibility of reservoir compartmentalization between the west and east halves of the field. Most wells produced a significant

TABLE 3. – Oil and Gas Production Statistics for the Red Fork Sand in the N. Carmen Red Fork Unit, Alfalfa County, Oklahoma

Year	Number of Wells Oil	Number of Wells Gas	Annual Production Oil BBLS	Annual Production Gas MCF	Average Monthly Production Oil BBLS	Average Monthly Production Gas MCF	Average Daily Production Per Well Oil BBLS	Average Daily Production Per Well Gas MCF	Cumulative Production Oil BBLS	Cumulative Production Gas MCF
[1] 1984	1	0	645	0	645	0	22	0	645	0
1985	10	7	166,375	301,317	13,865	25,110	46	120	167,020	301,317
1986	14	12	155,077	1,132,142	12,923	94,345	31	262	322,097	1,433,459
1987	14	12	34,238	390,849	2,853	32,571	7	90	356,335	1,824,308
1988	12	11	17,931	183,444	1,494	15,287	4	46	374,266	2,007,752
1989	11	10	9,288	101,675	774	8,473	2	28	383,554	2,109,427
1990	11	9	8,831	67,971	736	5,664	2	21	392,385	2,177,398
1991	10	9	5,820	50,196	485	4,183	2	15	398,205	2,227,594
1992	10	8	5,576	26,383	465	2,199	2	9	403,781	2,253,977
1993	9	9	3,253	25,577	271	2,131	1	8	407,034	2,279,554
1994	7	9	3,328	14,206	277	1,184	1	4	410,362	2,293,760
1995	6	5	2,447	6,132	204	511	1	3	412,809	2,299,892
[2] 1996	6	5	2,273	3,793	379	632	2	4	415,082	2,315,685

[1] one month oil production [2] for first six months production

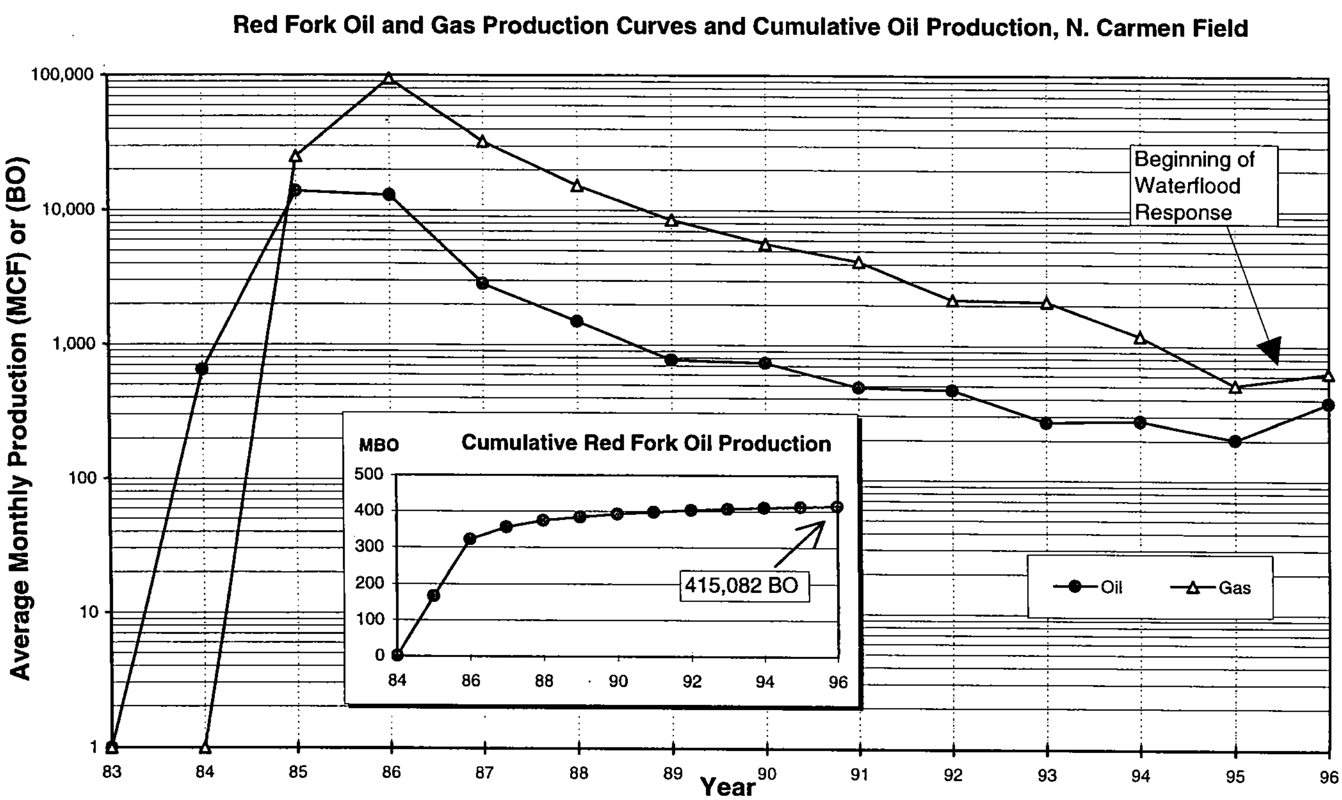


Figure 28. Red Fork oil and gas production decline curves show average monthly production from N. Carmen field through June 1996. Inset shows cumulative oil production through June 1996. Water injection began in September 1995. Cumulative oil production through June 1996 was 415,082 BO; of that, 2,937 BO is considered to be secondary production.

TABLE 4. – Annual Red Fork Oil Production from Wells in N. Carmen Field

Well Information							Primary Oil Production in barrels												Secondary [3]	
S3	S2	S1	SEC	Lease name	Well	Oil Prod Date	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996 6 months	Cum Prod (to 6-96)
T. 24 N., R. 12 W.																				
	Nw	Nw	2	Kassick	1	6/85-6/95	0	35,553	14,176	4,398	2,310	1,088	1,106	741	766	159	770	384		61,451
	Nw	Ne	3	DeWitt (Inj)	1	5/85-9/94	0	43,405	12,637	2,984	1,987	586	1,062	502	495	184	484	0	0	64,326
E/2	Ne	Ne	3	Geraldine (Inj)	1	8/85-2/95	0	23,990	7,867	1,761	857	473	462	282	147	143	158	157	0	36,297
Ne	Ne	Nw	3	Pruett	2	9/85-8/94	0	15,977	15,264	2,556	2,494	1,070	1,044	659	503	349	63	0		39,979
T. 25 N., R. 12 W.													unitized production attributed to 5 wells							
E/2	E/2	Se	33	Davis (Abnd)	1	6/86-6/96	0	0	1,920	506	193	806	190	0	0	0	0	1,262	2273	7,150
S/2	Sw	Se	34	Hughes (Inj)	1-A	2/86-4/95	0	0	14,162	3,298	1,589	1,024	657	437	437	276	94	32	0	22,006
Sw	Se	Se	34	Hughes (Abnd)	1-F	8/85-3/88	0	4,080	2,857	550	114	0	0	0	0	0	0	0	0	7,601
Sw	Se	Sw	34	Kassik	1	8/85-1/94	0	5,628	28,940	4,263	1,805	392	966	344	370	0	0	0		42,708
Sw	Nw	Sw	34	Zoa (Abnd)	1	12/84-8/87	645	8,401	4,256	310	0	0	0	0	0	0	0	0	0	13,612
Ne	Sw	Sw	34	Zoa (Inj)	2	4/86-3/95	0	0	20,603	6,042	3,267	1,563	1,449	923	954	882	903	188	0	36,774
E/2	W/2	Se	[1] 35	Horn	1-A	6/85-4/95	0	2,867	2,893	1,808	1,028	762	1,084	1,044	1,021	674	856	424		14,461
C	Se	Se	[2] 35	Horn	1-B	2/86-2/87	0	0	1,559	54	0	0	0	0	0	0	0	0		1,613
Se	Se	Sw	35	Kassik (Inj)	1-A	8/85-9/93	0	21,618	14,845	2,866	1,229	691	382	444	446	275	0	0	0	42,796
S/2	Sw	Sw	35	Kassik	2-A	11/85-4/93	0	4,856	13,098	2,842	1,058	833	429	444	437	311	0	0		24,308
Cumulative Annual Production (BO) →							645	166,375	155,077	34,238	17,931	9,288	8,831	5,820	5,576	3,253	3,328	2,447	2,273	
Number of producing oil wells →							1	10	14	14	12	11	11	10	10	9	7	6	6	

Cumulative primary oil production for field 12/84 through 10/95 → **412,246**

Cumulative secondary oil production for field 11/95 through 6/96 → **2,836**

Total field production, primary plus secondary → **415,082**

[1] Recompleted in Oswego Ls (5787' - 5847') on 7-11-85 with IPF of 195 MCFGPD, and 72 BWPD

[2] Recompleted in Miss Chester Ls (6200' - 16') on 9-23-87 with IPF of 2 BOPD, 381 MCFGPD, no water

[3] Waterflood water injection started 9-7-95, response interpreted in 11-95

TABLE 5. – Annual Red Fork Gas Production from Wells in N. Carmen Field

Well Information							Gas Production during Primary (MCF)											Secondary[3]	
S3	S2	S1	SEC	Lease name	Well	Gas Prod Date	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996 5 months	Cum Prod (to 4-96)
T. 24 N., R. 12 W.																			
	Nw	Nw	2	Kassick	1	7/85-11/93	80,865	139,570	49,675	11,670	204	0	0	0	852	1	0	0	282,837
	Nw	Ne	3	DeWitt (Inj)	1	6/85-7/94	70,931	95,909	28,860	20,572	8,170	6,970	4,701	2,608	2,487	735	0	0	241,943
E/2	Ne	Ne	3	Geraldine (Inj)	1	8/85-3/95	39,808	61,319	17,248	7,993	5,335	2,708	2,391	1,134	281	919	158	0	139,294
Ne	Ne	Nw	3	Pruett	2	10/85-7/94	39,191	93,332	20,817	27,187	14,549	10,148	7,031	3,449	2,810	681	0	0	219,195
T. 25 N., R. 12 W.													unitized production attributed to about 5 wells						
E/2	E/2	Se	33	Davis	1	7/86-5/96	0	15,647	10,579	4,275	11,259	3,354	409	6	0	0	2,647	3,793	51,969
S/2	Sw	Se	34	Hughes (Inj)	1-A	4/86-4/95	0	94,992	53,479	27,187	18,270	13,339	10,092	7,356	5,216	3,351	787	0	234,069
Sw	Se	Se	34	Hughes (Abnd)	1-F	3/86-2/88	0	15,188	7,207	503	0	0	0	0	0	0	0	0	22,898
Sw	Se	Sw	34	Kassik	1	12/85-11/92	0	91,379	42,251	13,503	7,667	4,273	7,965	2,850	2,026	963	123	0	173,000
Sw	Nw	Sw	34	Zoa (Abnd)	1	2/85-8/87	25,787	16,170	7,609	0	0	0	0	0	0	0	0	0	49,566
Ne	Sw	Sw	34	Zoa (Inj)	2	5/86-5/95	0	90,385	49,945	34,429	17,786	16,736	10,467	3,855	7,730	7,240	2,417	0	240,990
E/2	W/2	Se	[1] 35	Horn	1-A	10/85-5/96										estimated production =			12,000
C	Se	Se	[2] 35	Horn	1-B		0	0	0	0	0	0	0	0	0	0	0	0	0
Se	Se	Sw	35	Kassik (Inj)	1-A	10/85-2/94	40,525	233,013	64,674	26,373	13,506	7,988	5,201	4,716	1,810	55	0	0	397,861
S/2	Sw	Sw	35	Kassik	2-A	12/85-2/94	4,210	185,238	38,505	9,752	4,929	2,455	1,939	409	2,365	261	0	0	250,063
Cumulative Annual Production (MCF) →							301,317	1,132,142	390,849	183,444	101,675	67,971	50,196	26,383	25,577	14,206	6,132	3,793	
Number of producing gas wells →							7	12	12	11	10	9	9	8	9	9	5		
							Cumulative Associated Gas Production (MCF) for field 2/85 through 6/95 →												**2,315,685**

[1] Recompleted in Oswego Ls (5787' - 5847') on 7-11-85 with IPF of 195 MCFGPD, and 72 BWPD

[2] Recompleted in Miss Chester Ls (6200' - 16') on 9-23-87 with IPF of 2 BOPD, 381 MCFGPD, no water

[3] Waterflood water injection started 9-7-95, response interpreted in 11-95

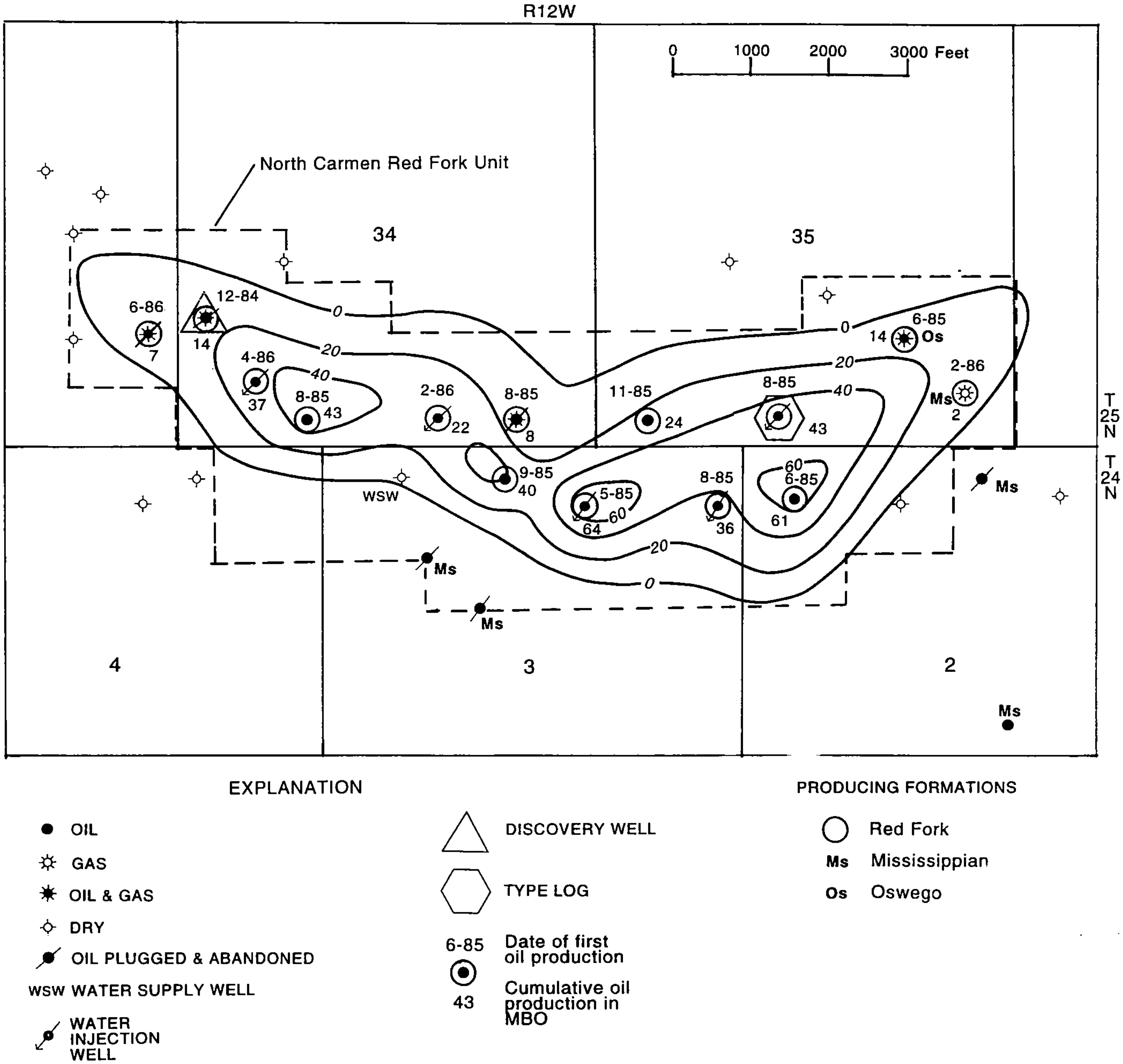


Figure 29. Red Fork cumulative oil production contour map. Cumulative oil production in thousands of barrels (MBO) and date of first production are shown for each well. Contour interval is 20 MBO.

amount of gas regardless of structural position (see Figs. 23,30). Most of the wells in the field reported initial gas/oil ratios (IGORs) <2,000 SCF/BBL. The four wells that had IGORs >2,000 SCF/BBL also had the lowest amount of cumulative oil and gas production (Fig. 30).

Well Completion: Most operators set 4.5-in. production casing at or very near the bottom of the hole (some operators used 5.5-in. production casing). In most wells, the bottom 15–20 ft of the Red Fork was perforated, avoiding much of the shalier upper part of the Red Fork zone. The wells were acidized and then stimulated with a fracture treatment. Because there is no water leg in this field, any sand that had porosity was perforated, and the porosity is in the bottom part of the sandstone. Most fracture treatments used water or cross-linked gel as the mobilizing agent; typically 35,000–66,000 gallons of water and something on the order of 35,000 pounds of sand was used. A few wells were fractured with oil.

Secondary Recovery: N. Carmen was unitized for purposes of waterflooding in 1995. The water supply well for the field is completed in the Tonkawa sandstone and is located in the NW¼NW¼ sec. 3. The "staggered"

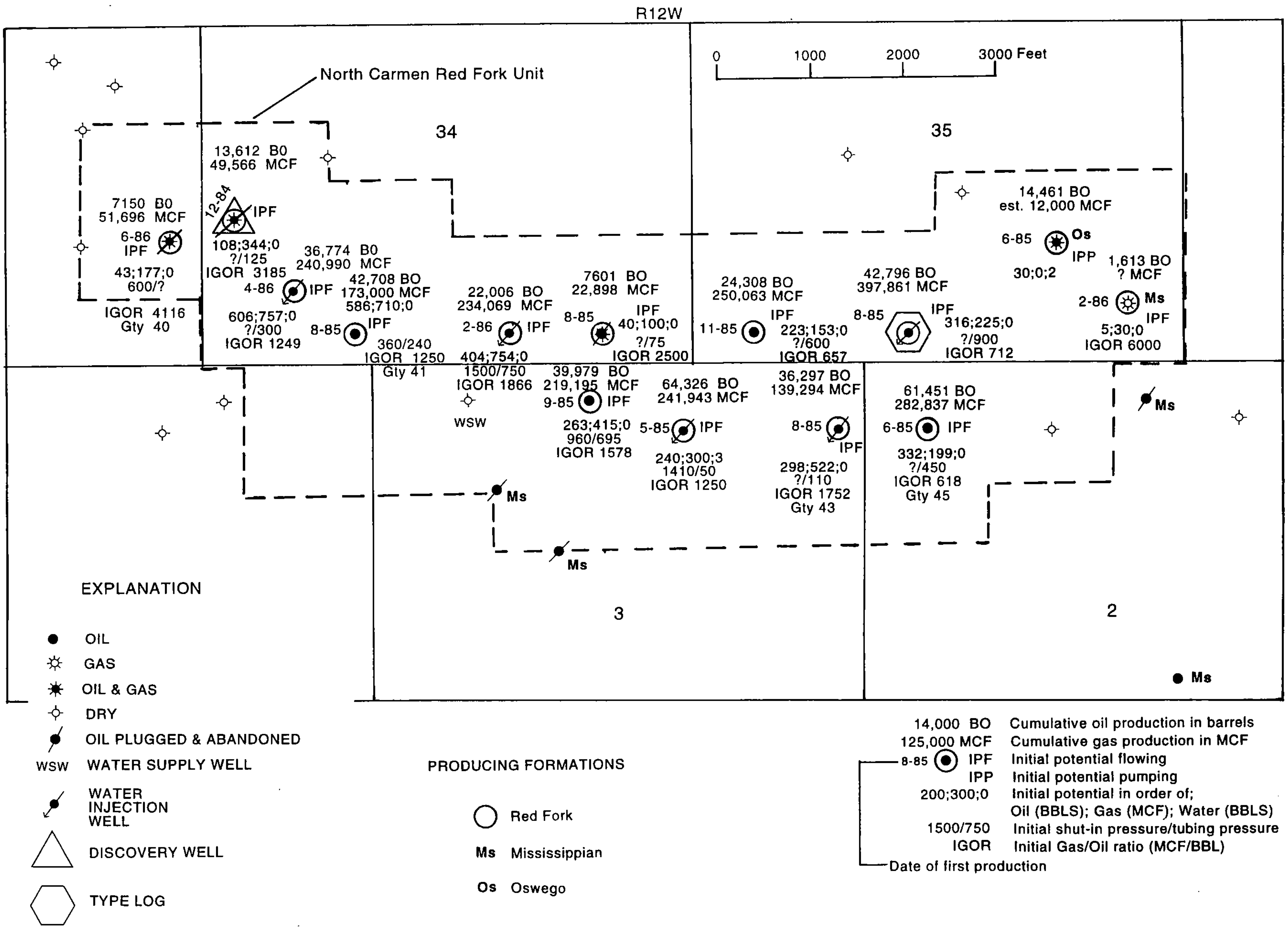


Figure 30. Map showing cumulative oil and gas production, date of first production, initial potential, shut-in and tubing pressure, initial gas/oil ratio, and API gravity for wells in N. Carmen field. See Figure 19 for well names.

injection pattern with five injection wells and five producers was planned so that injection wells and producers were not located along a line trending approximately N70°, which is the predicted orientation of fractures. This well pattern also provides for longitudinal sweep (lengthwise) since transverse mobility across the channel may be attenuated by stratigraphic barriers within the point bars. Water injection began with about 75–80,000 BW per month (~500 BWPD per well) in September 1995. A small increase in oil production was noticed in November 1995. Production climbed steadily over the next seven months. Total oil production for the field in June 1996 was 685 BO, all secondary oil. By August, production had increased to 966 BOPM. In October 1996, EOG was injecting about 60–70,000 BWPM; fill-up was about 70–80%. As of December 1996, five wells had responded, four of which were producing 12–19 BOPD. The best responses came from the No. 1-34 Kassick located in the far western half of the field; and in the No. 2-35 Kassick A, the No. 1-35 Horn A, and the No. 1 Kassick (sec. 34) located in the eastern half of the field. The response in the No. 2 Pruett located in the western part of the field was weak at only 3 BOPD even though the well had a net sandstone thickness of 18 ft. Prior to waterflooding in 1993, the average daily oil production from all of these wells was <2 BOPD.

Otoe City South Red Fork Sand Unit

(Red Fork oil pool in secs. 16, 20, 21, and 29, T. 22 N., R. 1 E., Noble County, Oklahoma)

by Kurt Rottmann

Introduction: The Otoe City South Red Fork sand unit is located in central Noble County in north-central Oklahoma (Fig. 31). The Otoe City South study area lies about three townships east of the Nemaha fault zone and in an area referred to as the Cherokee platform province (Pl. 1). Production from the Otoe City South Red Fork sand reservoir was established on September 22, 1972, with the discovery of oil and gas in the Wil-Mc Oil Corporation No. 1 Loula well in the NW¼SW¼ sec. 21, T. 22 N., R. 1 E. (Fig. 32). This well was completed with an initial potential flow of 840 BOPD. Within two years the field was developed with the completion of 18 additional Red Fork oil producers.

Production from wells in the Otoe City South Red Fork Sand Unit is from the Red Fork sandstone, however several other formations also produce in the study area. A map identifying operators, well locations, well numbers, principle leases, and producing formations is shown in Figure 32. For clarity, only wells that penetrated the Red Fork are posted; a large number of Osage-Layton and Layton wells have been omitted on this and the other maps in this field study. Sincere appreciation is extended to Mr. Gary Foster, president of Blackjack Oil and Gas Company, for his support in supplying data for this field study.

Stratigraphy: The stratigraphic section in the Otoe City South Red Fork sand unit is illustrated by logs from the Wil-Mc Oil Company No. 1-A Dent, S½NE¼NW¼, sec. 21, T. 22 N., R. 1 E. (Fig. 33). The Red Fork interval is described as that section occurring below the Pink lime and above the Inola Limestone. However, in this well and elsewhere in the study area, the Inola Limestone has been eroded and the Red Fork sandstone lies directly on shale near the top of the Bartlesville zone. The upper limit of the Red Fork zone can be determined easily from the gamma ray and SP curves. The upper boundary of the Red Fork zone is transitional, from sandstone or siltstone to shale.

Stratigraphy of the Red Fork interval can best be shown by detailed cross sections of the field. Cross-section A–A′ (Fig. 34, in envelope) is oriented southwest-northeast. The upper part of Figure 34 is a stratigraphic section hung on the base of the Pink lime and represents a dip section at time of Red Fork deposition. The wells are spaced to scale horizontally with stratigraphic interpretations inferred between the wells.

Cross-section A–A′ shows the log character of the Red Fork sand along the axis of the Otoe City South field channel deposit. The gamma-ray curves indicate a sharp basal contact for the Red Fork sandstone in all of the wells in cross-section A–A′. The basal Red Fork in the No. 1 John Streller and the No. 1 Loula (wells 1 and 2) appears to be lying on the top of the Bartlesville zone. The Inola Limestone may be present locally only as a thin layer and has not been ascertained in any of the wells in the field study. The Red Fork sand appears to have scoured a short distance into the upper part of the Bartlesville zone in the No. 1-A Dent (well 3). The Red Fork sand has a blocky gamma-ray profile and is interpreted to have been deposited as a channel-fill sandstone. The sand was probably deposited by vertical aggradation in a subaerial coastal floodplain environment. The upper limit of the Red Fork sand zone can easily be determined from the gamma ray and SP curves. The upper boundary of the Red Fork zone is transitional from sandstone or siltstone to shale. Shale deposits, possibly of flood-plain origin, overlie the Red Fork sand zone. Transgression of the Cherokee sea, which inundated the region, ended deposition of Red Fork fluvial deposits. During this time period, the marine Pink lime was deposited.

The lower portion of cross-section A–A′ is a structural section that shows the present-day structural configuration of the field. There is a fault between wells 3 and 4 (No. 1-A Dent and No. 2-16 Yahn). Throw on the fault at the Red Fork horizon is ~50 ft. The cross section illustrates the effect of fault drag on the Red Fork sand interval. Discounting the effect, throw at the Red Fork horizon probably approaches 125–150 ft. An oil/water contact is present at approximately –3,410 ft in well 1. In the down-thrown block, a gas/oil contact

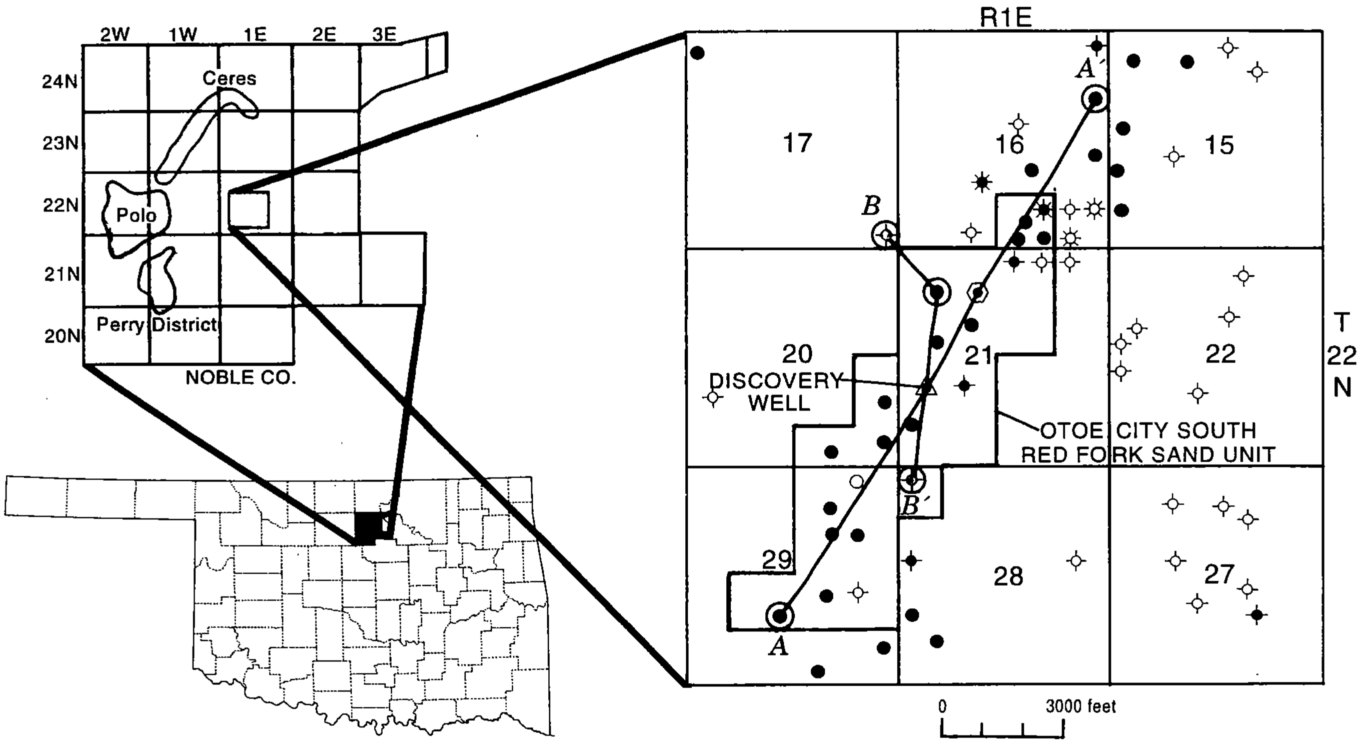


Figure 31. Generalized location map of Otoe City South Red Fork study area, Noble County, Oklahoma. Solid black line is the outline of the Otoe City South Red Fork Sand Unit.

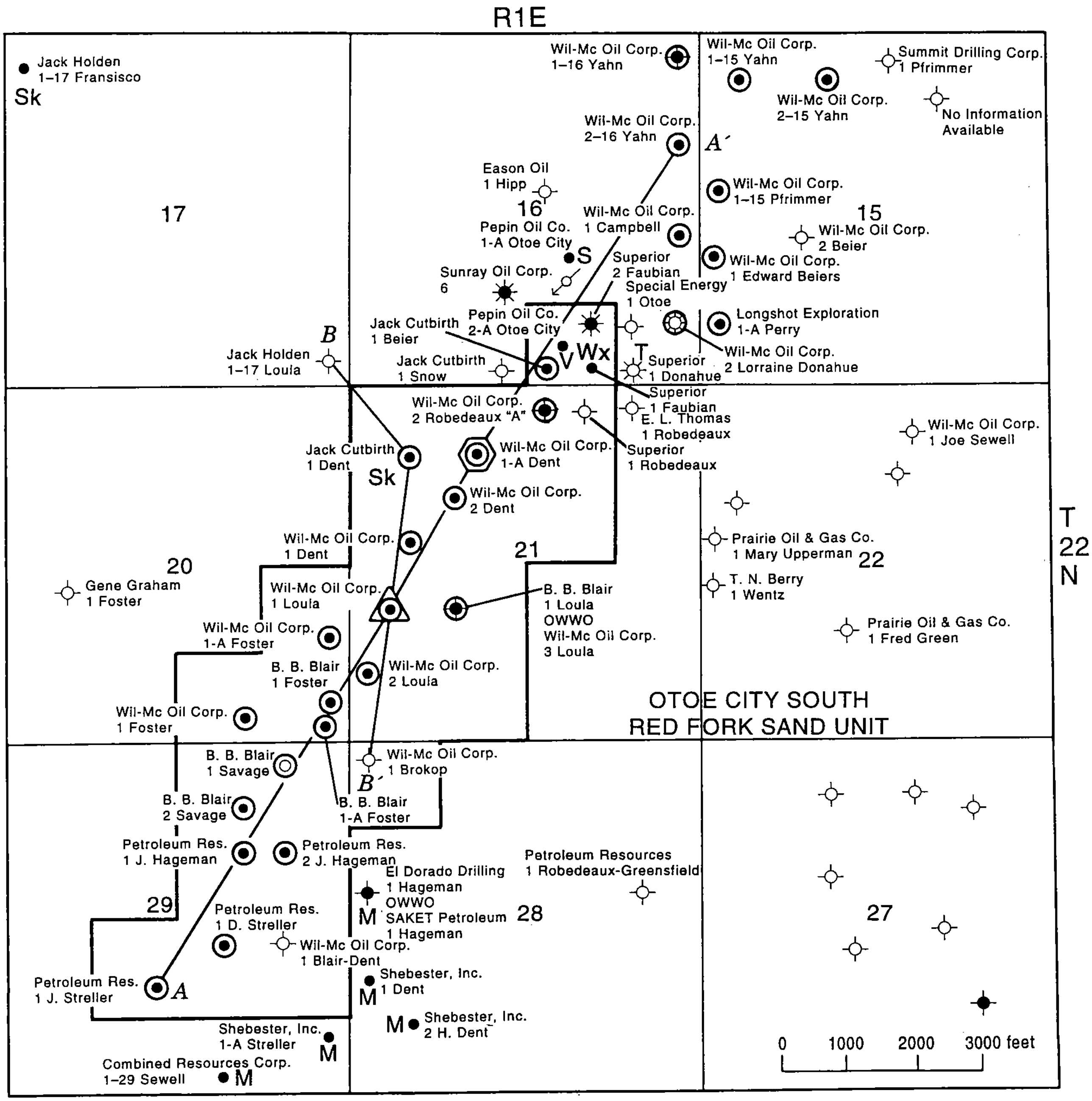
at approximately –3,345 ft is shown between wells 3 and 4.

Cross-section B–B′ (Fig. 35, in envelope) is a northwest-to-south section. The northern segment (well 1 to 2) is oriented approximately parallel to strike at the time of Red Fork deposition. The stratigraphic cross section in the upper portion of Figure 35 is hung on the base of the Pink lime and illustrates the lateral facies changes that occur diagonally across the channel. The tie well for cross-sections A–A′ and B–B′ is the No. 1 Loula (well 3 in B–B′) and the discovery well for the field. Northward, from well 3 to well 2, the channel sandstone thins appreciably and changes character as shown in the well log profiles. This may indicate a transition from channel facies to flood plain or marginal marine facies. Further to the northwest at well 1, the Red Fork interval is entirely shale. Southward from well 3, the channel sandstone thins rapidly and is absent in well 4, which is only ~0.5 mi away from well 3. The lower portion of cross-section B–B′ was constructed using micro-logs and a porosity log hung structurally to show present day structural relationships. This cross section is essentially parallel to present day structural strike, so there is very little structural relief indicated.

Structure: A structure map of the study area is contoured on the base of the Pink lime (Fig. 36). Regionally, dip is to the southwest at approximately 80–100 ft/mi. A northwest-southeast–trending normal fault, down-to-the-north, is present in sec. 16 and sec. 22. The fault has a throw of ~50 ft. Drag is evident by the geometry of the structural contours. This effect of the drag is a narrow structural high parallel to the fault and on the downthrown side of the fault. This is evident by the initial potential of Wil-Mc Oil Corporation's No. 2 Lorraine Donahue Campbell located in the NE¼SE¼ SE¼ of sec. 16. This well had an initial potential of 10 BOPD and 500 MCFGPD with no water reported. The resulting GOR of 50,000:1 indicates the presence of a gas cap as compared to the GORs of approximately 350:1 for wells within the same reservoir in the NE¼ of sec. 16 and W½ of sec. 15 and further to the north.

Two closures are present on the structure map (Fig. 36). The first is a fault closure against the upthrown block in the SE¼ of sec. 16, NE¼ of sec. 21, and the NW¼ and SE¼ of sec. 22. This fault closure is also responsible for the trapping of hydrocarbons in the Osage-Layton, Layton, and Simpson sandstones. (However, only wells that penetrate the Red Fork are shown on Fig. 36). The second closure is located in the NW¼ of sec. 27 and the NE¼ of sec. 28. An oil/water contact at –3,410 ft in the Red Fork sand is shown on the structural cross section in Figure 34. This oil/water contact is mapped at –3,343 in Figure 36 and represents the intersection of the oil/water datum with the base of the sandstone (rather than the top).

Isopach Maps: Figure 37 is a Red Fork gross sand isopach. Gross sand was determined primarily by tabulating the amount of sand present [below the 50% point]



EXPLANATION

T	TONKAWA	S	SIMPSON
Sk	SKINNER	Wx	WILCOX
○	RED FORK		INJECTION WELL
M	MISSISSIPPIAN		TYPE LOG
V	VIOLA		DISCOVERY WELL

Figure 32. Well information map showing operator, lease, well number, and producing formation for wells in the Otoe City South Red Fork study area, Noble County, Oklahoma. Only Red Fork penetrations are included on this base map.

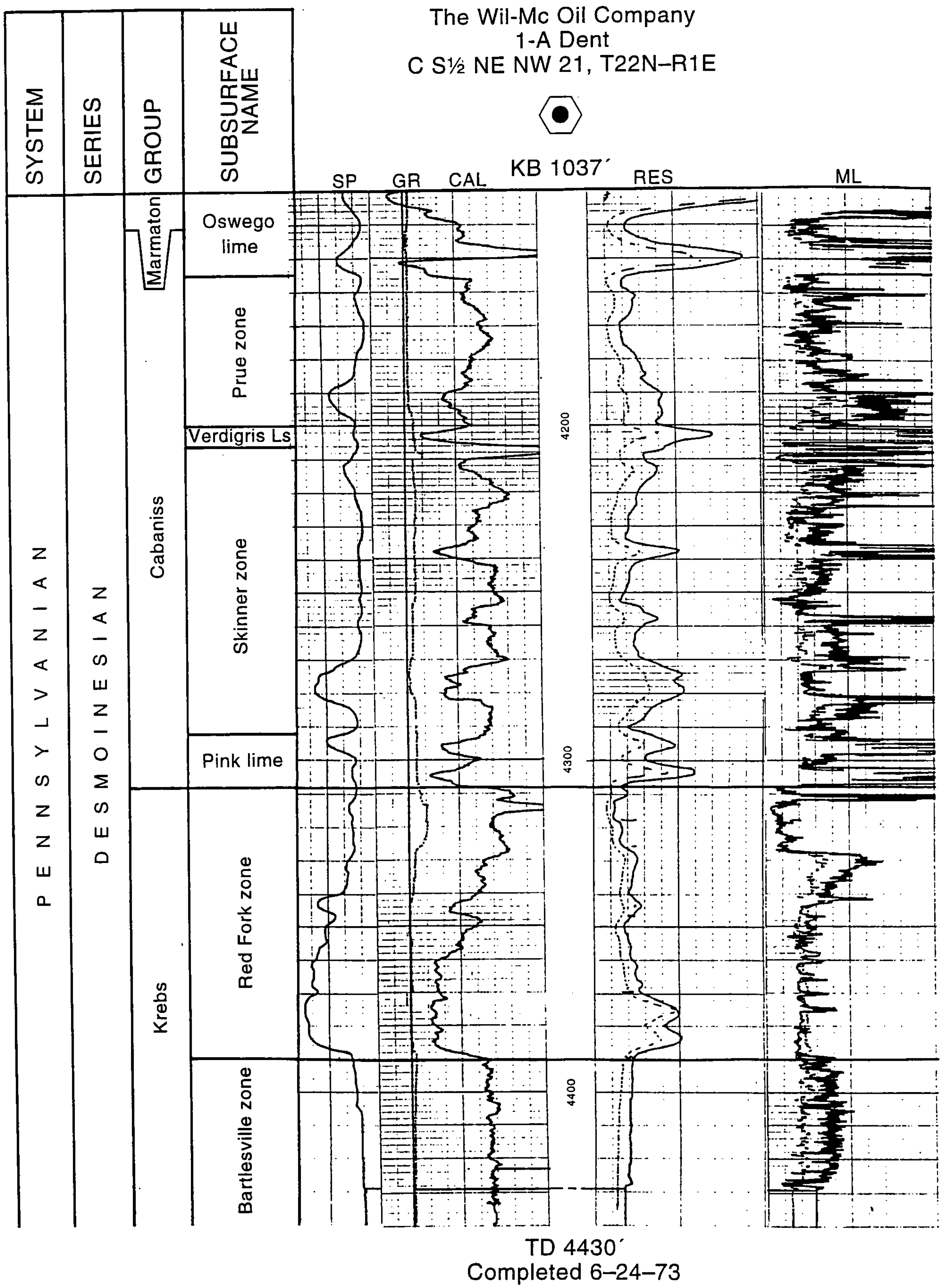


Figure 33. Otoe City South Red Fork reservoir type log showing stratigraphic intervals and characteristic log signatures. SP = spontaneous potential, GR = gamma ray, CAL = caliper, ML = Micro Log.

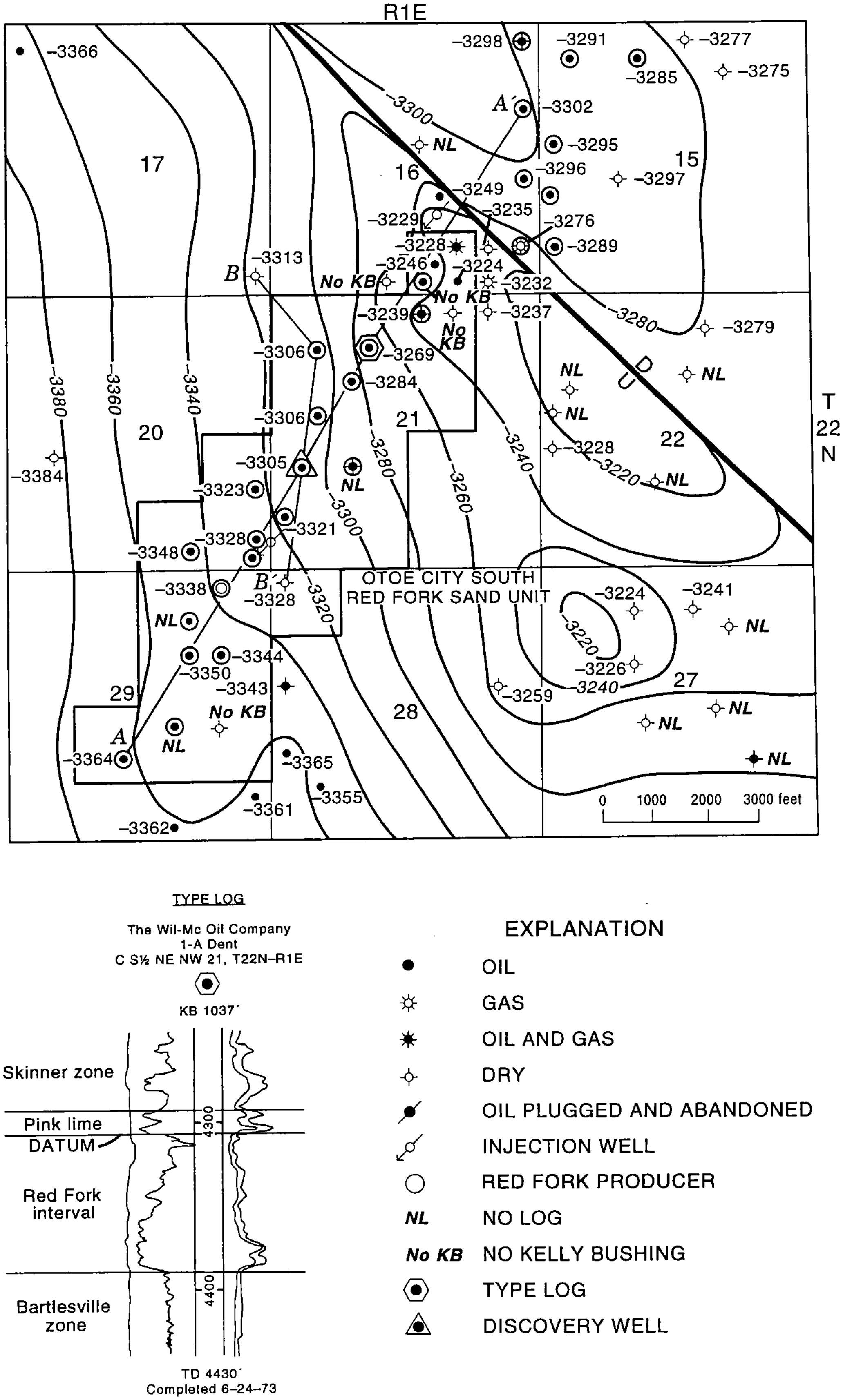


Figure 36. Structure contour map on the base of the Pink lime, Otoe City South Red Fork field, Noble County, Oklahoma. Dashed lines indicate the position of the oil/water and gas/oil contacts. Contour interval = 20 ft. See Figure 32 for well names.

as determined by comparing the clean gamma ray to the shale base line. The SP log curve of the clean reservoir interval was used as a "type" SP for gross sandstone. By comparing SP logs with the "type" SP log, gross sand thickness was estimated for wells without gamma-ray logs. Gross sand ranges in thickness from 0 to almost 50 ft. The sand body indicated by the gross sand map trends northeast-southwest and is approximately one-third of a mile wide (Fig. 37). The long, narrow shape of the sand body combined with the log characteristics of the Red Fork sand as seen in Fig. 34 (i.e., sharp base, fining-upward profile, grading upward to shale) indicate that the sandstone was deposited in a fluvial channel environment. The sand appears to have been deposited in three "pods": the first one in the NW¼ of sec. 15, the second one in the SE¼ of sec. 16 and the W½ of sec. 21, and the third one in sec. 29.

Two fluid contacts are present in the Otoe City South field study area. The first is a gas/oil contact located in the SE¼ of sec. 16. As described previously, this contact is the result of fluid segregation on the downthrown block where gas has been trapped in the structurally high Red Fork sand reservoir produced by fault drag. The second is an oil/water contact located in the SE¼ of sec. 20 and the NE¼ of sec. 29. This contact can also be seen on the structural cross-section A–A′ (Fig. 34). The oil/water contact occurs at approximately –3,410. Water was produced from all of the oil wells downdip from this contact. The fact that water production is not significant on the downthrown side of the fault and the presence of a water contact in the S½ of sec. 29, indicates that the age of the fault (as seen at Red Fork age) may postdate the migration and entrapment of hydrocarbons in the Otoe City field.

Figure 38 is an isopach map of the net Red Fork sand. The net sand is sandstone with porosity ≥8%. Porosity was interpreted to be ≥8% for sandstone with micro log permeability separation or mud filter cake thicknesses. Application of the net porosity cuttoff further defines the three sand "pods" that are evident on the gross sand isopach map (Fig. 37). The gross and net sand values are not particularly close, which suggests that a fairly significant percentage of the gross sand is not reservoir quality.

Reservoir Characteristics: Reservoir characteristics for the Otoe City South Red Fork sand unit are summarized in Table 6. The GOR is ~350 SCF/BBL based upon the average initial potentials for those wells reporting gas production. The presence of a gas cap in the downthrown block's closure probably indicates the saturated conditions of the oil. Calculated water saturations average 30%. The oil gravity is approximately 41° API based on the average of 14 well measurements. Average porosity and permeability are taken primarily from the two cores described in the next section.

Core Analysis: At least three wells were cored in the Otoe City South field. The first was the B. B. Blair No. 1 Savage NW¼NE¼NE¼ sec. 29 with no description reported. The second was B. B. Blair's No. 1 Loula W½ NE¼SW¼ sec. 21. The cored interval was 4,355–4,405 ft. Sand with shows of oil and gas was recovered in this core. The third core was Wil-Mc Oil Corporation's No. 1 Brokop NW¼NW¼NW¼ sec. 28, which was described as 4 ft of sandy shale and 10 ft of shale (see log, Fig. 35). As of this writing, core analysis results for these three wells is not available. However, core analysis reports from two wells in the immediate vicinity were available for this study. These cores are the No. 1 Adele Fullenkamp NE¼SW¼NW¼ sec. 10, T. 22 N., R. 1 E., and the No. 1 Elizabeth Rissman NE¼SE¼SW¼ sec. 3, T. 22 N., R. 1 E. Both cores are from the same reservoir as Otoe City South and are probably representative of Otoe City's reservoir characteristics.

The No. 1 Adele Fullenkamp (Table 7A) was cored from 4,345 to 4,368 ft. Almost the entire core was sandstone. Porosity averaged ~12.0%. The average permeability was very low at 0.2 md. As can be seen in Table 7A, there appears to be a break in the residual oil saturation values at 4,359 ft. The values above 4,359 ft probably represent oil saturation at or near a gas cap and the values below 4,359 ft probably represent saturations in the oil leg. The No. 1 Elizabeth Rissman (Table 7B) was cored from 4,376 to 4,410 ft. The average porosity was 15.2% and the average permeability was 1.5 md (Table 7B). The average oil saturation for the core is 12.1%, which probably indicates that the sandstone is in the oil leg. Figure 39A,B are scatter plots of porosity and permeability values for the No. 1 Fullenkamp and No. 1 Rissmann cores. Both cores exhibit good porosities, however the corresponding permeabilities are very low.

Production History: Red Fork production had been established in 1968 from the North Otoe Field, which is the Red Fork production on the north side of the fault and which extends northward into secs. 10 and 3 of T. 22 N., R. 1 E. Expansion of production on the south side of the fault, however, was limited by acreage that was held by shallow Layton production. In September 1972, Wil-Mc Oil Corporation drilled and completed the No. 1 Loula for an initial potential flow of 840 BOPD. This well was the first Red Fork completion south of the acreage held by shallow production. In two years, 18 more wells were drilled and completed in the delineation of the Red Fork field.

By January 1, 1977, primary oil production from the Otoe City South Red Fork field was ~586,755 BO. This equates to an average of >32,000 BO per well for the field. On January 1, 1977, the field was unitized for secondary production, therefore individual lease production ceased and unit production started. Details of unitization and secondary recovery will be discussed in the next section.

Figure 40 is the production decline curve for the Otoe City South Red Fork Sand Unit. As described in the previous section, the permeabilities for the field are

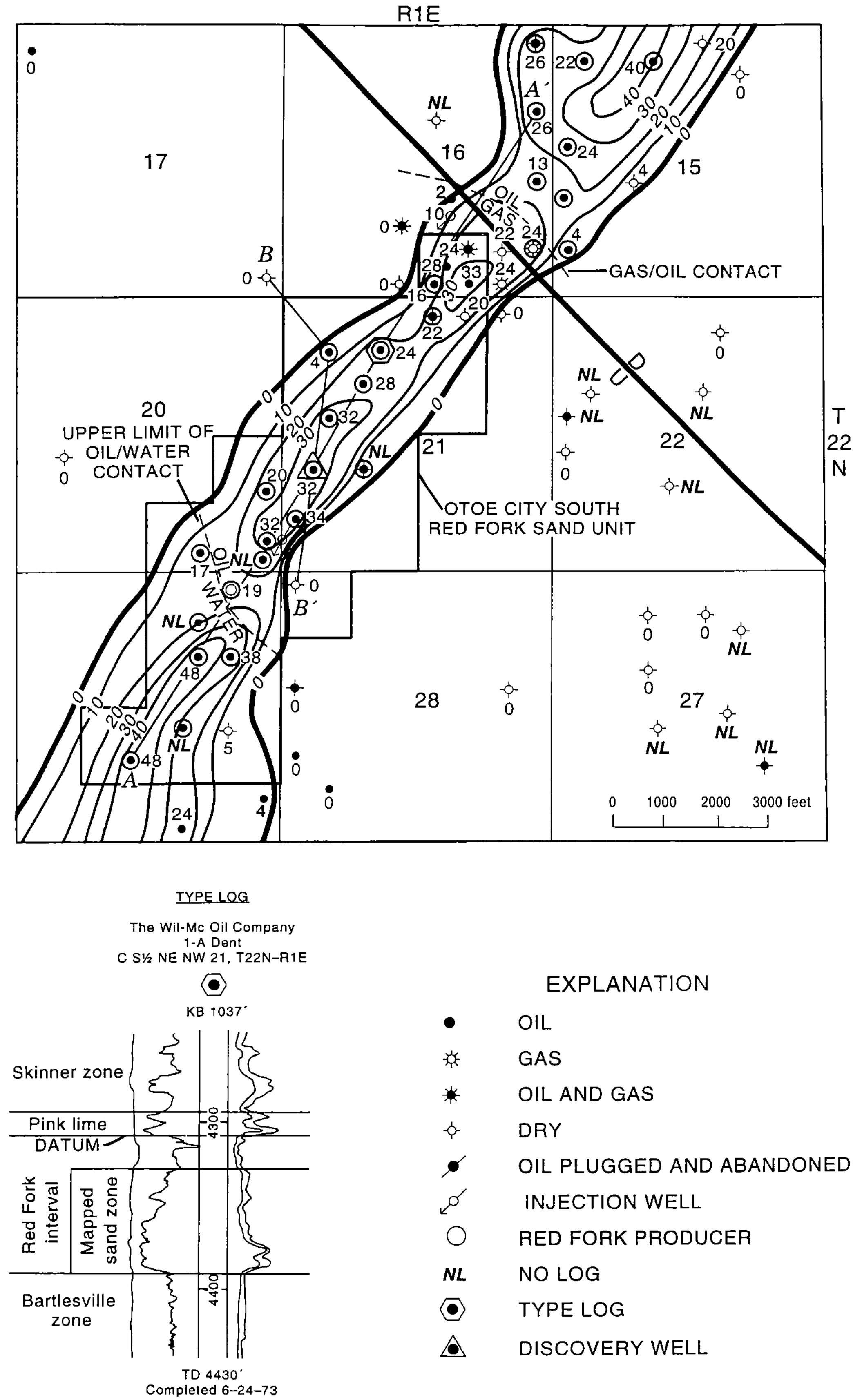


Figure 37. Gross sandstone isopach map of the Red Fork sandstone, Otoe City South Red Fork field, Noble County, Oklahoma. Contour interval = 10 ft. See Figure 32 for well names.

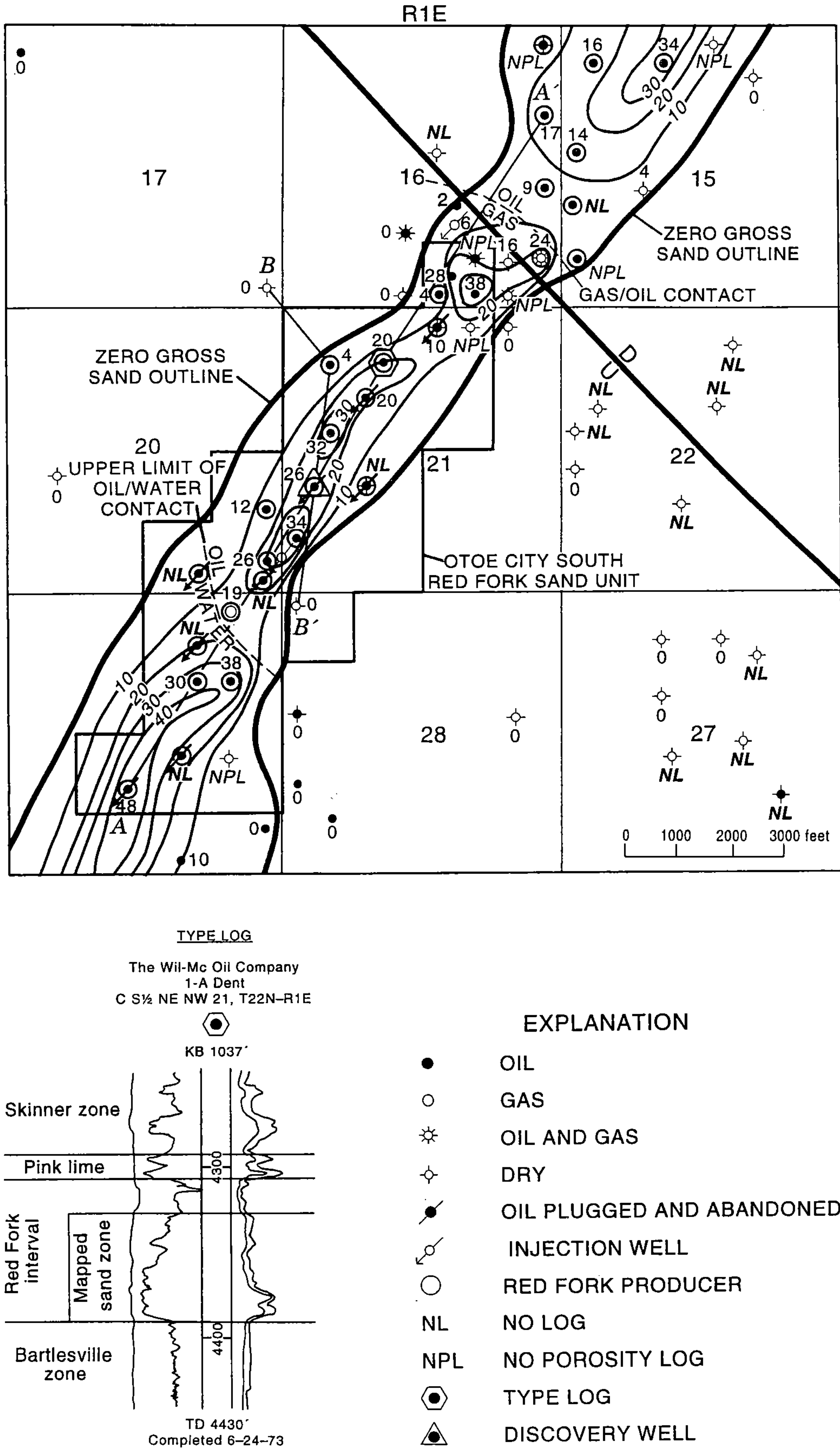


Figure 38. Net sandstone isopach of the Red Fork sandstone, Otoe City South Red Fork field, Noble County, Oklahoma. Net sand = sand with log porosity ≥8%. The locations of injector wells for the waterflood that was implemented in January 1977 is shown. Contour interval = 10 ft. See Figure 32 for well names.

TABLE 6. – Reservoir/Engineering Data for the Red Fork Sandstone in Otoe City South Red Fork Sand Unit, Noble County, Oklahoma

Reservoir size	~6,750 acres
Depth	~4,350 ft
Spacing (oil)	40 acres
Oil/water contact	~3,410
Gas/oil contact	NA
Porosity	13.5%
Permeability	2 md average
Water saturation (calculated)	30%
Gas to Oil Ratio	350:1 SCF/BBL
Thickness (net sand $\phi \geq 8\%$)	9.8 ft
Reservoir temperature	115°F
Oil gravity	41° API
Initial reservoir pressure	~1,900 PSI
Initial formation volume factor	1.25 RB/STB
Original oil in place	3,845 MSTBO
Cumulative primary oil	~586 MSTBO
Primary recovery efficiency (oil)	~15.2%
Primary recovery BO/acre-ft	~87 BO/acre-ft
Cumulative gas	Unknown

very low, which necessitates fracture treatment of all the wells in order to establish production. Completion techniques varied, but generally consisted of drilling through the pay zone, setting casing, acidizing, and fracturing. Fracture treatments for some of the wells are shown below the well logs on Fig. 34. Peak production for the field occurred in the summer of 1973 at ~26,000 BOPM. Table 8 summarizes the oil production statistics for the Otoe City South Red Fork Sand Unit. The table lists the year of production, the number of oil producers, annual oil production, average monthly oil production, average daily oil production, and cumulative oil production.

Figure 41 is a map of initial potential for the Otoe City South Red Fork field. The initial oil potential isopach has a 200 BOPD contour interval. Notice that the contours indicate two pods of initial potential that coincide with the pods of gross and net Red Fork sand (Figs. 37 and 38). The southern most pod located in the NE¼ of sec. 29 is not as large as the pod located in sec. 21 because of its proximity to the oil/water contact. In sec. 29, water cuts increase southward until finally in the S½S½ of sec. 29, only water production is found.

TABLE 7. – Core Results for the Otoe City Field Area

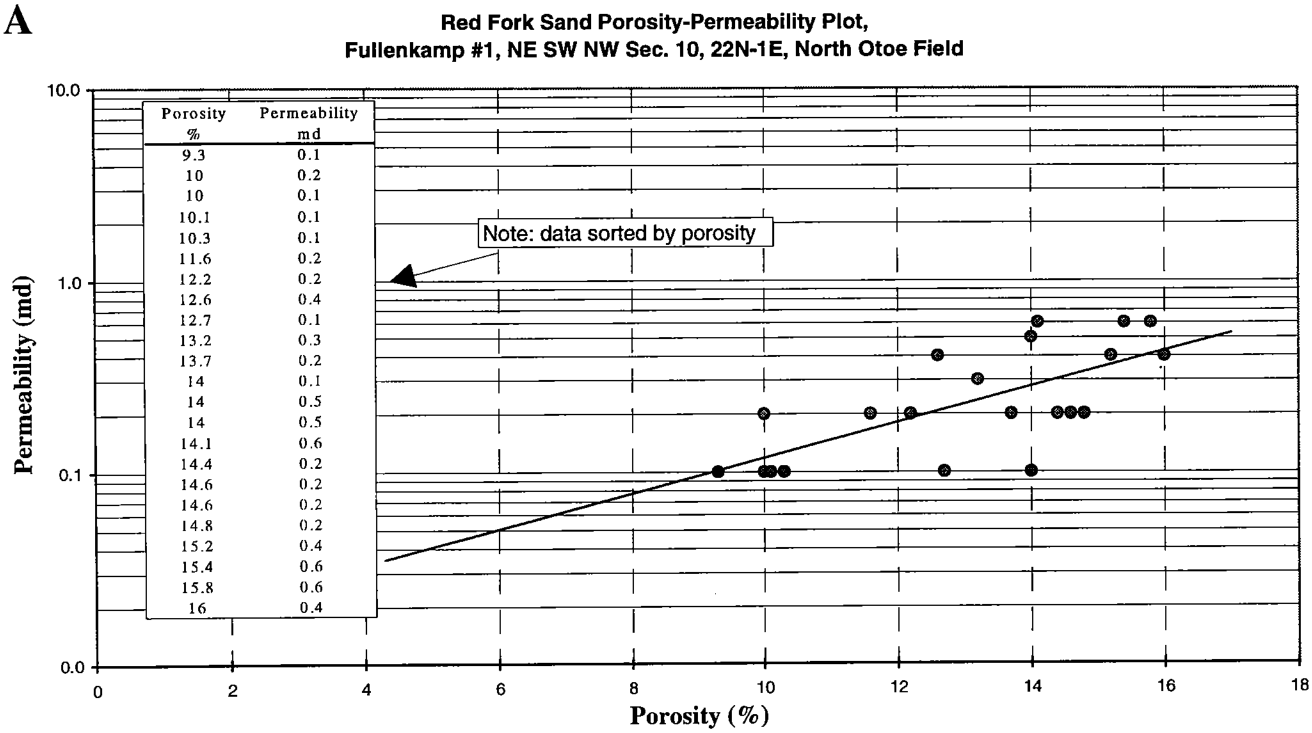
Table 7A. - Core Analysis Results, Red Fork Sand
Wil-Mc Oil Corporation #1 Adele Fullenkamp
NE SW NW Section 10 T22N-R1E, Noble County, Oklahoma

Sample Number	Depth ft.	Permeability md	Porosity %	Residual Saturation Percent Pore Space		
				Oil	Water	Total
1	4345-46	0.2	10.0	0.0	82.0	82.0
2	46-47	0.1	9.3	0.0	79.6	79.6
3	47-48	0.1	10.0	Tr	71.0	71.0
4	48-49	0.1	14.0	Tr	80.3	80.3
5	49-50	0.1	10.1	0.0	69.4	69.4
6	50-51	0.3	13.2	0.0	59.1	59.1
7	51-52	0.2	12.2	0.0	56.5	56.5
8	52-53	0.4	16.0	1.3	53.2	54.5
9	53-54	0.1	10.3	1.9	76.7	78.6
10	54-55	0.1	12.7	1.6	67.0	68.6
11	55-56	0.2	14.4	4.2	56.2	60.4
12	56-57	0.2	14.6	4.1	56.1	60.2
13	57-58	0.4	15.2	5.3	50.6	55.9
14	58-59	0.2	11.6	7.7	62.8	70.5
15	59-60	0.2	14.6	5.5	50.7	56.2
16	60-61	0.2	14.8	9.5	48.6	58.1
17	61-62	0.6	15.4	9.1	49.3	58.4
18	62-63	0.6	15.8	10.7	45.5	56.2
19	63-64	0.40	12.60	Tr	47.60	47.6
20	64-65	0.20	13.70	13.90	49.60	63.5
21	65-66	0.60	14.10	14.90	47.50	62.4
22	66-67	0.50	14.00	13.60	35.10	48.7
23	67-68	0.50	14.00	14.30	44.30	58.6

Table 7B. - Core Analysis Results, Red Fork Sand
Wil-Mc Oil Corporation #1 Elizabeth Rissman
NE SE SW Section 3 T22N-R1E, Noble County, Oklahoma

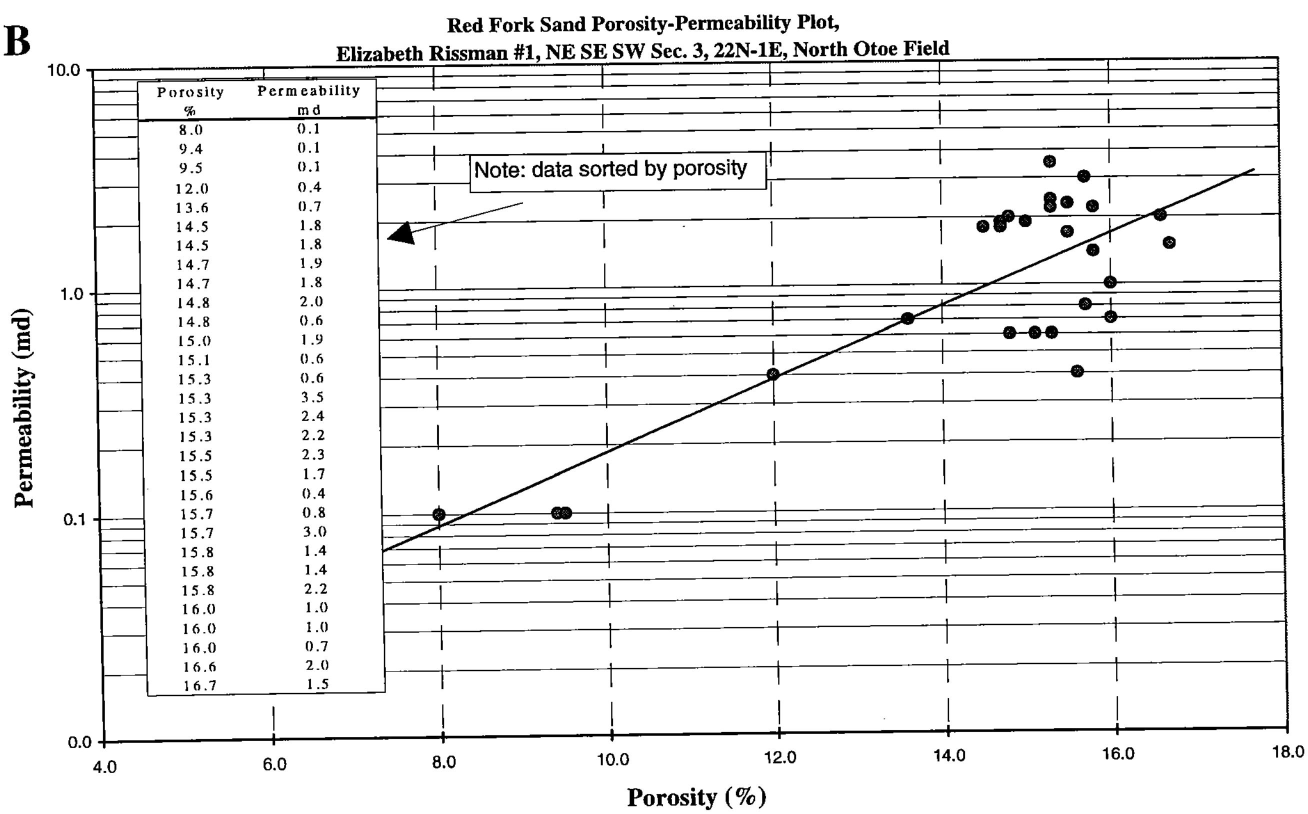
Sample Number	Depth ft.	Permeability md	Porosity %	Residual Saturation Percent Pore Space		
				Oil	Water	Total
1	4377-78	0.4	12.0	5.4	52.2	57.6
2	4378-79	0.8	15.7	5.3	49.6	54.9
3	4379-80	0.6	15.1	11.1	47.4	58.5
4	4380-81	1.0	16.0	8.8	45.7	54.5
5	4381-82	1.4	15.8	12.0	45.0	57.0
6	4382-83	1.0	16.0	11.9	44.6	56.5
7	4383-84	1.5	16.7	15.5	42.3	57.8
8	4384-85	2.3	15.5	13.6	42.4	56.0
9	4385-86	0.6	15.3	11.0	51.8	62.8
10	4386-87	0.7	16.0	11.8	48.9	60.7
11	4387-88	3.5	15.3	14.0	41.9	55.9
12	4388-89	2.0	14.8	12.9	45.2	58.1
13	4389-90	1.4	15.8	13.6	43.7	57.3
14	4390-91	1.8	14.5	13.2	44.5	57.7
15	4391-92	1.7	15.5	12.3	44.6	56.9
16	4392-93	2.2	15.8	12.0	45.2	57.2
17	4393-94	2.4	15.3	12.4	41.9	54.3
18	4394-95	3.0	15.7	13.6	42.5	56.1
19	4395-96	2.2	15.3	14.0	43.6	57.6
20	4396-97	0.4	15.6	12.5	46.6	59.1
21	4397-98	0.6	14.8	11.8	45.6	57.4
22	4398-99	1.9	14.7	14.7	42.5	57.2
23	4399-4400	1.9	15.0	14.4	43.2	57.6
24	4000-01	1.8	14.7	14.7	39.3	54.0
25	4001-02	1.8	14.5	14.9	39.9	54.8
26	4002-03	2.0	16.6	13.9	43.2	57.1
27	4003-04	0.7	13.6	12.5	42.7	55.2
28	4004-05	0.1	9.5	9.3	47.9	57.2
29	4005-06	0.1	9.4	9.5	43.5	53.0
30	4006-07	0.1	8.0	11.2	47.9	59.1

A



Porosity %	Permeability md
9.3	0.1
10	0.2
10	0.1
10.1	0.1
10.3	0.1
11.6	0.2
12.2	0.2
12.6	0.4
12.7	0.1
13.2	0.3
13.7	0.2
14	0.1
14	0.5
14	0.5
14.1	0.6
14.4	0.2
14.6	0.2
14.6	0.2
14.8	0.2
15.2	0.4
15.4	0.6
15.8	0.6
16	0.4

B



Porosity %	Permeability md
8.0	0.1
9.4	0.1
9.5	0.1
12.0	0.4
13.6	0.7
14.5	1.8
14.5	1.8
14.7	1.9
14.7	1.8
14.8	2.0
14.8	0.6
15.0	1.9
15.1	0.6
15.3	0.6
15.3	3.5
15.3	2.4
15.3	2.2
15.5	2.3
15.5	1.7
15.6	0.4
15.7	0.8
15.7	3.0
15.8	1.4
15.8	1.4
15.8	2.2
16.0	1.0
16.0	1.0
16.0	0.7
16.6	2.0
16.7	1.5

Figure 39. Porosity and permeability data from Red Fork cores of two wells near the Otoe City South field. Both wells are in the North Otoe field, Noble County, Oklahoma.

TABLE 8. – Oil Production Statistics for the Otoe City South Red Fork Sand Unit, Noble County, Oklahoma

Year	Number of Oil Wells	Annual Oil Production (Barrels)	Average Monthly Oil Production (Barrels)	Average Daily Oil Production Per Well (BOPD)	Cumulative Oil Production (Barrels)
1972	7	63,364	20,769	99	63,364
1973	17	287,209	24,666	48	350,573
1974	18	140,047	11,699	22	490,620
1975	18	60,932	5,078	9	551,552
1976	18	35,203	2,934	5	586,755
1977 [1]	9 [2]	20,052	1,671	6	606,807
1978	9	25,562	2,130	8	632,369
1979	9	62,843	5,237	19	695,212
1980	9	48,692	4,058	15	743,904
1981	9	36,284	3,024	11	780,188
1982	9	34,264	2,855	11	814,452
1983	9	23,827	1,986	7	838,279
1984	9	14,230	1,186	4	852,509
1985	9	12,160	1,013	4	864,669
1986	9	13,354	1,113	4	878,023
1987	9	12,467	1,039	4	890,490
1988	9	8,600	717	3	899,090
1989	9	8,030	669	2	907,120
1990	9	5,002	417	2	912,122
1991	9	4,631	386	1	916,753
1992	9	3,430	286	1	920,183
1993	9	2,176	181	1	922,359
1994	9	366	31	0	922,725
1995	0	0	0	0	922,725

[1] Otoe City South unitized 1/1/77

[2] Denotes number of oil producers only

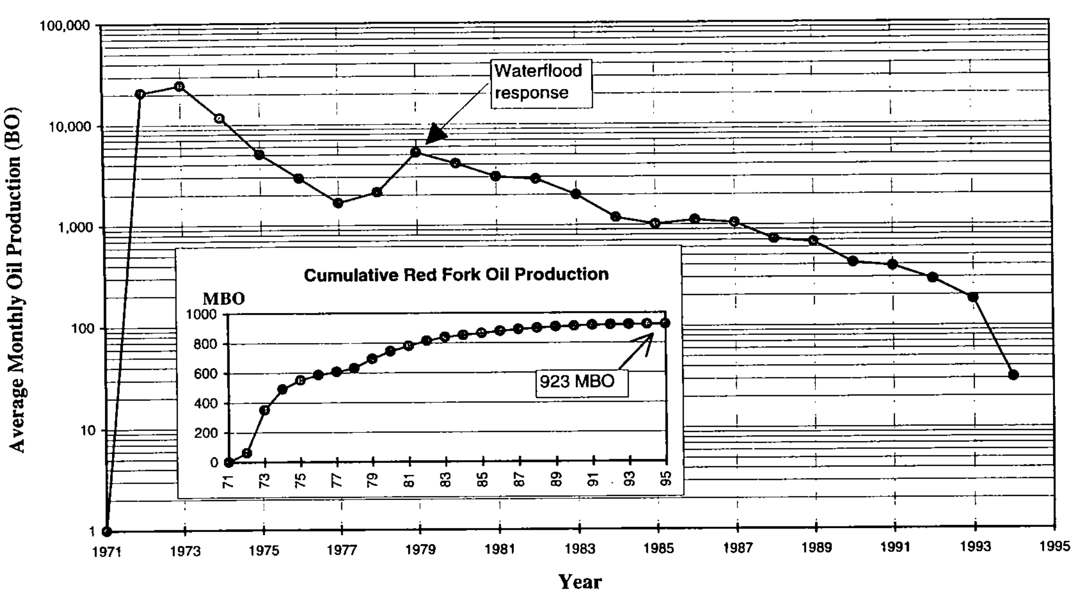


Figure 40. Oil production decline curve and cumulative oil production from the Otoe City South Red Fork Sand Unit, Noble County, Oklahoma.

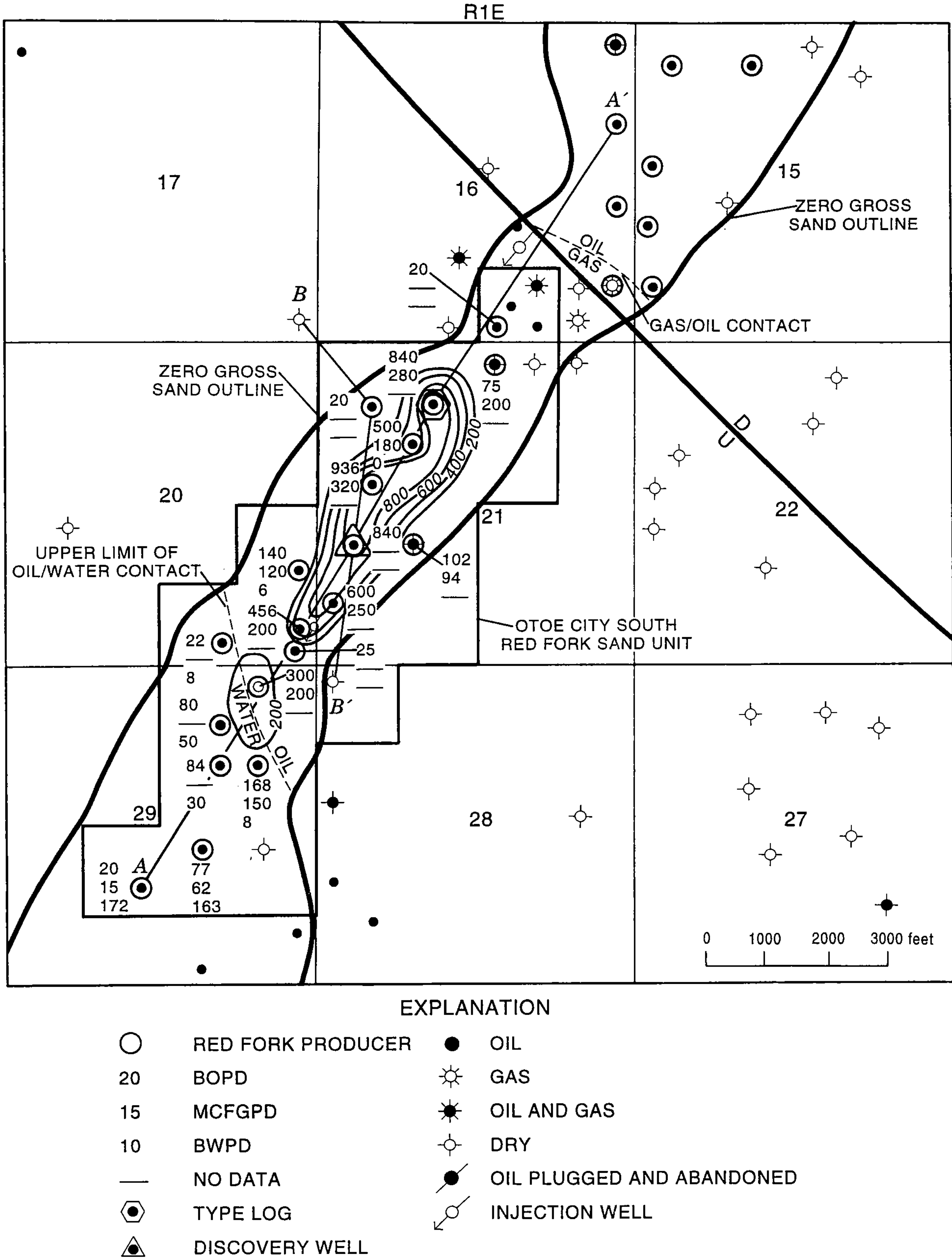


Figure 41. Initial potential production data for wells in the Otoe City South Red Fork Sand Unit, Noble County, Oklahoma. Contour interval is 200 BOPD. See Figure 32 for well names.

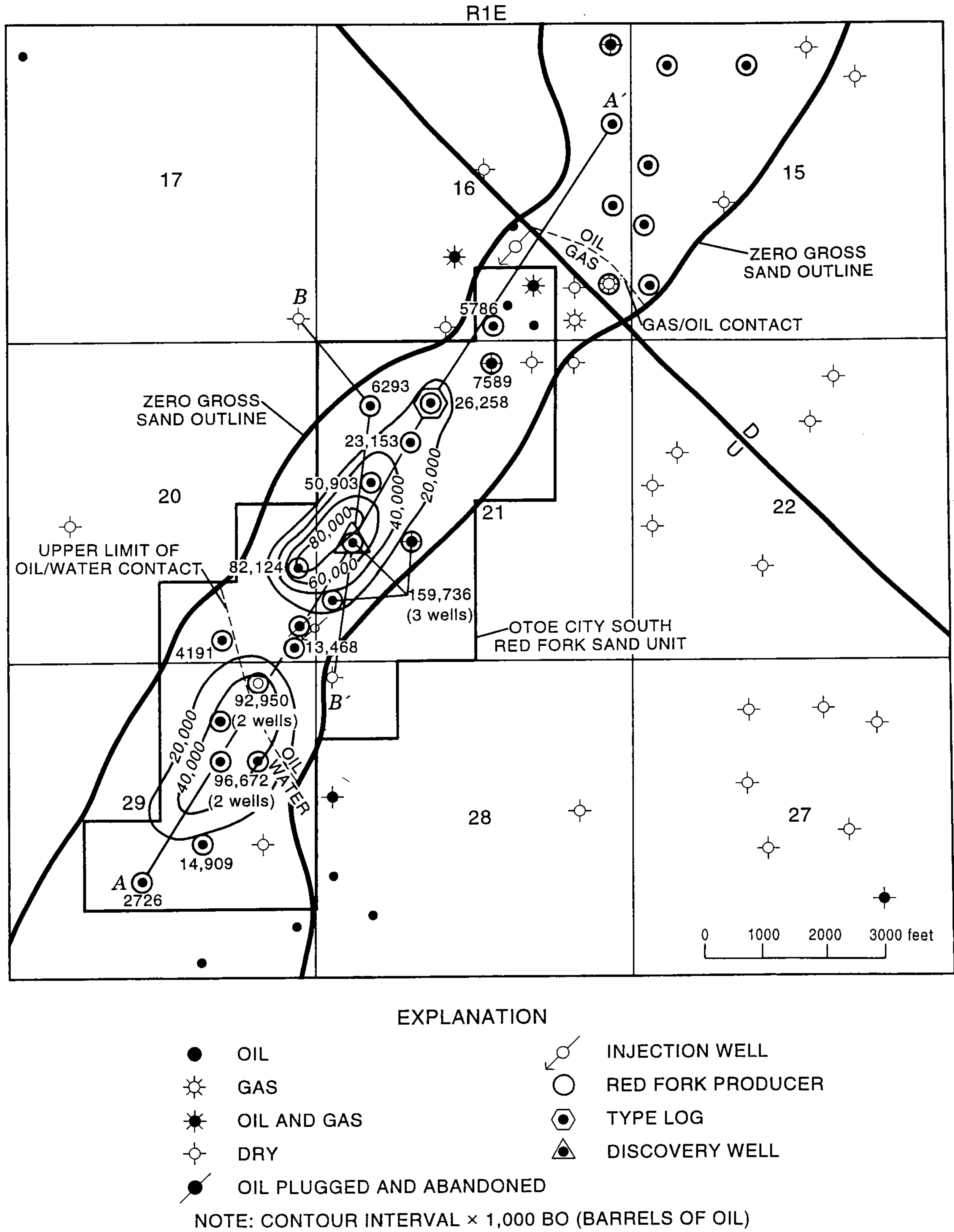


Figure 42. Cumulative oil production for the Otoe City South Red Fork study area, Noble County, Oklahoma. Contour interval is 20,000 BO. See Figure 32 for well names.

Figure 42 is an isopach of cumulative oil production contoured in 20,000 BO increments. As seen on the initial potential isopach (Fig. 41), the greatest amount of primary production occurred in the proximity of the highest initial potential and the thickest net sand (Fig. 38).

Secondary Recovery: The Otoe City South Red Fork field area was unitized on January 1, 1977, by Edinger, Inc. The net sandstone isopach map (Fig. 38) shows the wells that were converted to injectors for the field. As of this writing, specifics such as water injection per well and lease production information is not available. However, Edinger, Inc. (personal communication) did shed some insight as to the performance of the Otoe City South Red Fork sand unit. As of June 1977, no water had been injected, yet it produced ~20,000 bbl of formation water, which is equivalent to ~110 BWPD for the field. Edinger, Inc. suggested that most of the water had come from wells south of the Blair No. 1 Savage NW¼NE¼ sec. 29. This is also approximately the same position as the oil/water contact as seen from Figures 37 and 38. Edinger also reported that ~15% of secondary oil came from producing wells below the oil/water contact, however, 30% of the primary oil came from those wells downdip of the oil/water contact.

The pattern set up by Edinger, Inc. was probably a modified 5-spot (Fig. 38). In sec. 21 and sec. 16, the pattern could be described as an alternate injector producer. However, in sec. 20 and sec. 29 it was more typical of a 5-spot pattern. Two of the injectors proved to be too tight for injection: the No. 3 Beier SW¼SW¼ SW¼ sec. 16 and the No. 3 Foster SE¼SW¼SE¼ sec. 20. Water break-through occurred almost immediately in the No. 2 Hageman NW¼SE¼NE¼ sec. 29. This well produced 80–90% SW from the beginning, and the origin of the water is unknown. At the end of June 1994, the cumulative injection volume was 5,192,401 BW and the cumulative water production was 2,491,890 BW. The peak in secondary oil production occurred during 1979 with an average monthly production rate of 5,237 BO. Cumulative secondary oil for the Otoe City South field was ~336,000 BO as of December 1994. This represents a secondary-to-primary recovery ratio of 57%. Primary recovery efficiency for the field was ~15%. Total recovery efficiency was 24%.

Long Branch Field

(Red Fork oil pool in secs. 9 and 10, T. 18 N., R. 4 E., Payne County, Oklahoma)

by Richard Andrews

Introduction: Long Branch field is located in east-central Payne County in north-central Oklahoma (Fig. 43). The field area is ~45 mi east of the Nemaha fault zone and in an area often referred to as the Cherokee platform province (Pl. 1). A map identifying operators, well locations, well numbers, and principal leases in the field area is show in Figure 44.

Oil production was first established in the Long Branch field area in 1926 with the completion of Deep Rock's No. 1 Cole well in the NW¼SE¼NE¼ sec. 10, T. 18 N., R 4 E. (Fig. 44). This well produced only a few thousand barrels of oil from the Misener sand before being abandoned. Several more wells nearby in sec. 10 were drilled prior to 1960. Although they penetrated the Red Fork interval, no commercial production was found. The first commercial Red Fork well in the area was the Statex Petroleum No. 1 Snyder, NE¼SW¼ sec. 10, T. 18 N., R 4 E., which was completed in November 1983. The well was completed in about 6 ft of net Red Fork sand and had an initial flowing potential of 238 BOPD, 100 MCFGPD, and no water. The relatively thin sandstone had excellent porosity at the top of a coarsening-upward clastic sequence interpreted to be a marine shoreface or shelf bar. During the next year, development in the area progressed to the northwest where a much thicker Red Fork sand was encountered. As of April 1996, nine wells had been completed in the Red Fork and, except for location exceptions, the Red Fork pool is fully developed in secs. 9 and 10. Additional reservoirs in the Skinner and Bartlesville sands have been discovered in secs. 9 and 10. However, as of April 1996, the only two Red Fork wells still active were making only a few barrels of oil per day. Because of the shallow depth and well spacing patterns, this field appears to be an excellent candidate for a waterflood.

Stratigraphy: The stratigraphic section in the Long Branch field area is illustrated in Figure 45 by the log from the Garfield Resources No. 1 Mighty Mouse (SE¼ SE¼NE¼, sec. 9, T. 18 N., R. 4 E.). This log shows that the Red Fork sand lies in the middle of the Red Fork interval and has an equal thickness of shale both above and beneath it. About a mile south of this field in the SE¼ sec. 16, the Red Fork sand is considerably thicker and occupies about the lower three-fourths of the Red Fork interval.

The Red Fork interval is from the base of the Pink limestone to the top of the Inola Limestone. The Red Fork sandstone zone is from the base of the hot shale below the Pink lime to the top of the Inola Limestone. Although the resistivity of the Inola is uncharacteristically low for limestone, its identification is possible based on correlations of the package of strata that consists of the Inola plus the thin shale above and below. The shale beds are each about 3–5 ft thick and have resistivities that are lower than the surrounding shale (see Fig. 45 and well 9 in A–A′, Plate 4). In many wells, these thin shales are also "hotter" than the surrounding shale. This log also illustrates the "bell-shaped" SP and gamma-ray log profiles which are interpreted to reflect the fining-upward grain size from clean sandstone (lower point bar) to shaly sandstone (upper point bar) to shale (channel margin or abandoned channel fill.

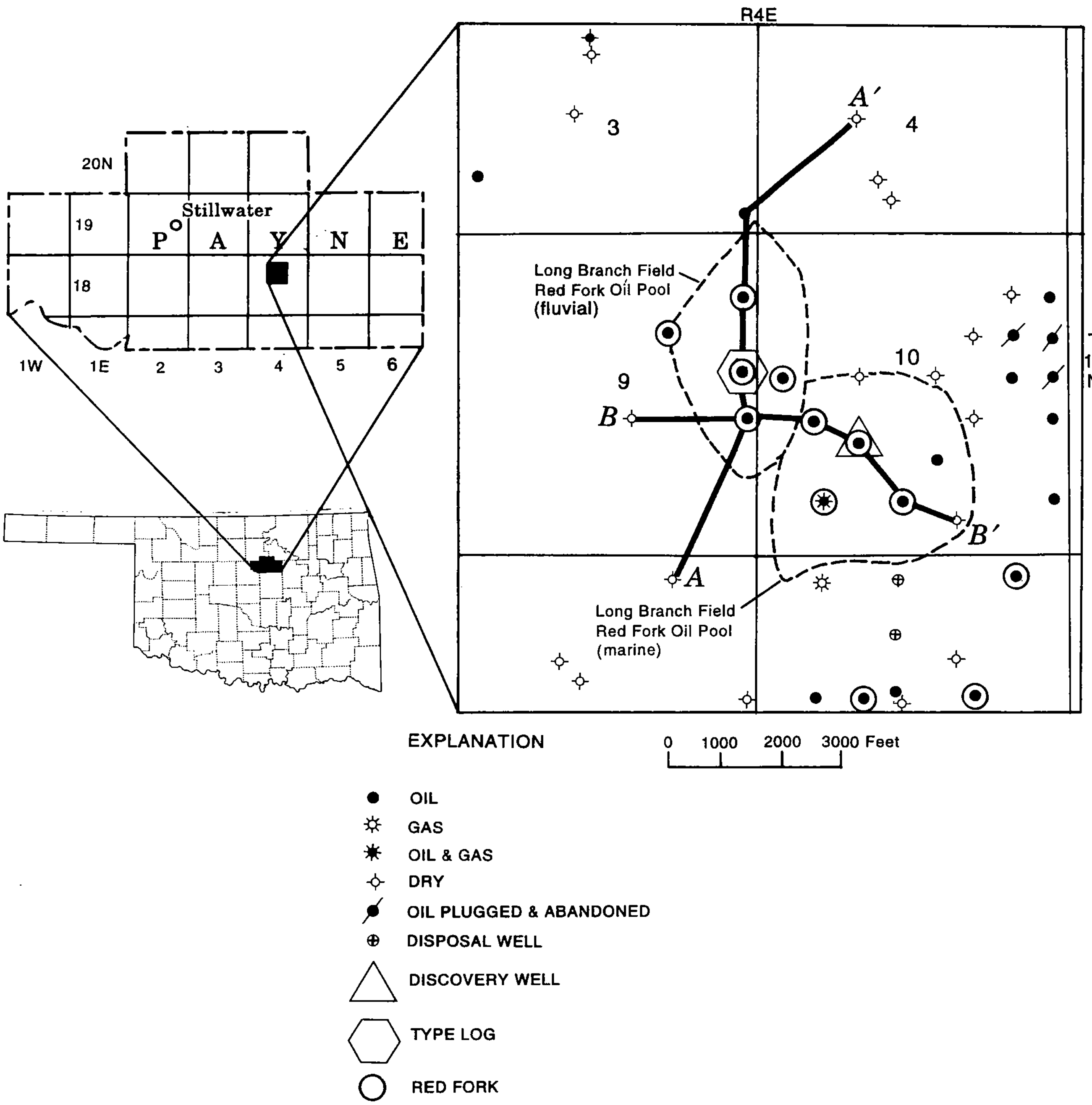


Figure 43. Generalized location map of the Long Branch study area in east-central Payne County, Oklahoma. The field outline is differentiated between fluvial and marine reservoir facies as determined from well logs.

Stratigraphy of the Red Fork interval is best shown in the detailed structural-stratigraphic cross sections of the field. Cross-section A–A′ (Fig. 46, in envelope) is a north-south cross section that includes the type log (Fig. 45). The sandstone in wells 2, 3, and 4 (A–A′) has the "bell-shaped" gamma-ray log profile that is characteristic of point bar deposits. The sandstone in these wells grades upward into shale or silty shale that is also part of the channel-fill and is labeled "shaly channel margin or abandoned channel fill" in Fig. 46. Shale breaks within the sandstone in wells 3 and 4 (see serrated gamma-ray log profile) are probably clay drapes deposited during periods of low stream discharge rates that become interbedded with the point bar sandstone. The shale interbeds which are only about 1 ft thick can be effective vertical and lateral barriers to flow. Northward from well 4, the sandstone thins appreciably and is replaced by shaly channel margin deposits. Based on the similarity in the log character of the shale in well 6 to that of the shaly channel-fill in wells 4 and 5, the

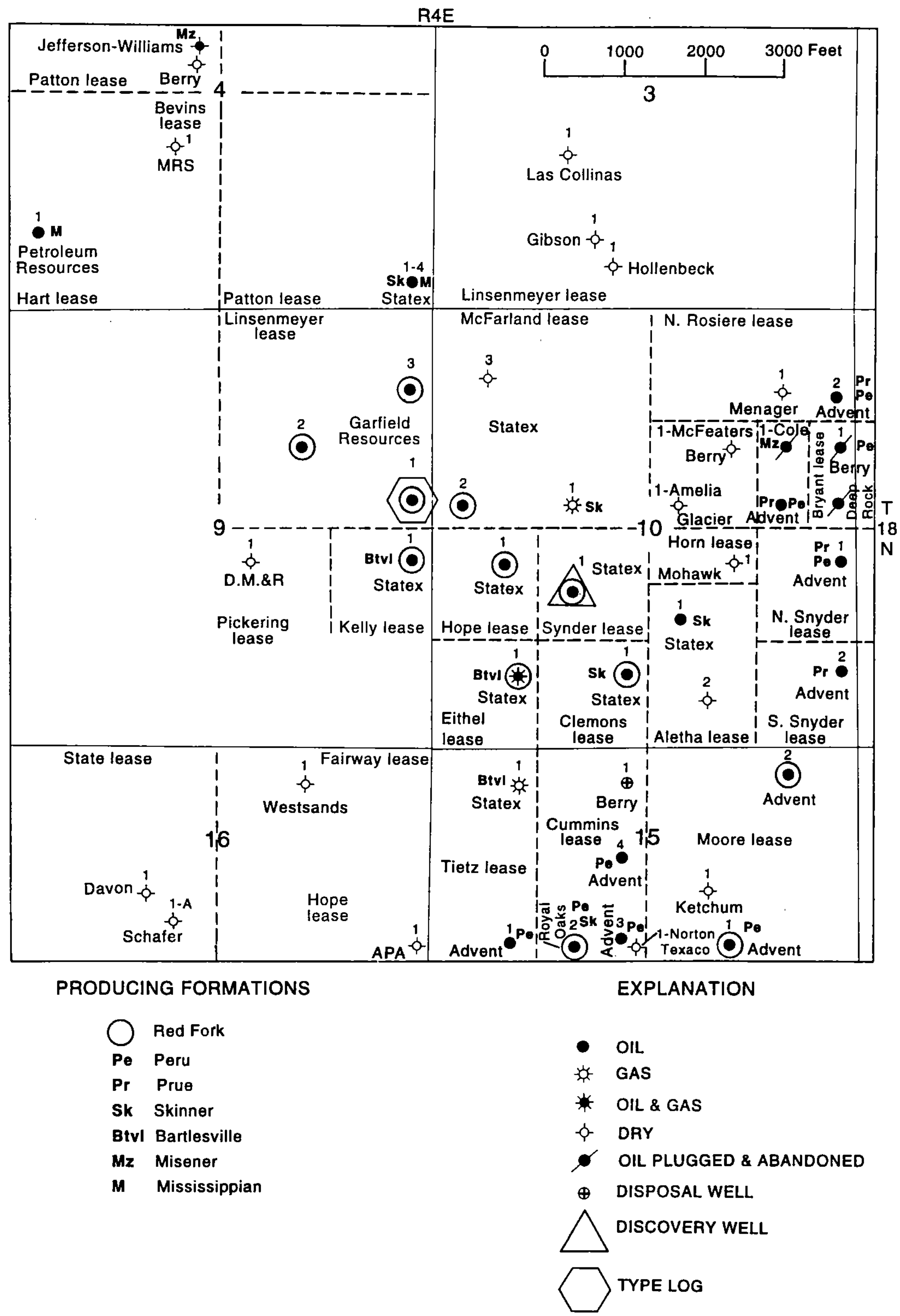


Figure 44. Well information map showing operator, lease name, well number, and producing reservoir(s) for wells in the Long Branch study area.

shaly interval in well 6 can be identified as part of the channel fill. At the south end of the cross section, the Red Fork interval in well 1 is dominantly shale in the bottom half and dirty sandstone in the upper half. The sandy section has at least two 6–8-ft intervals that appear to have a coarsening upward textural profile that, together, closely resemble well logs of sandstone identified in the marine bar trend mapped in the N½ sec.

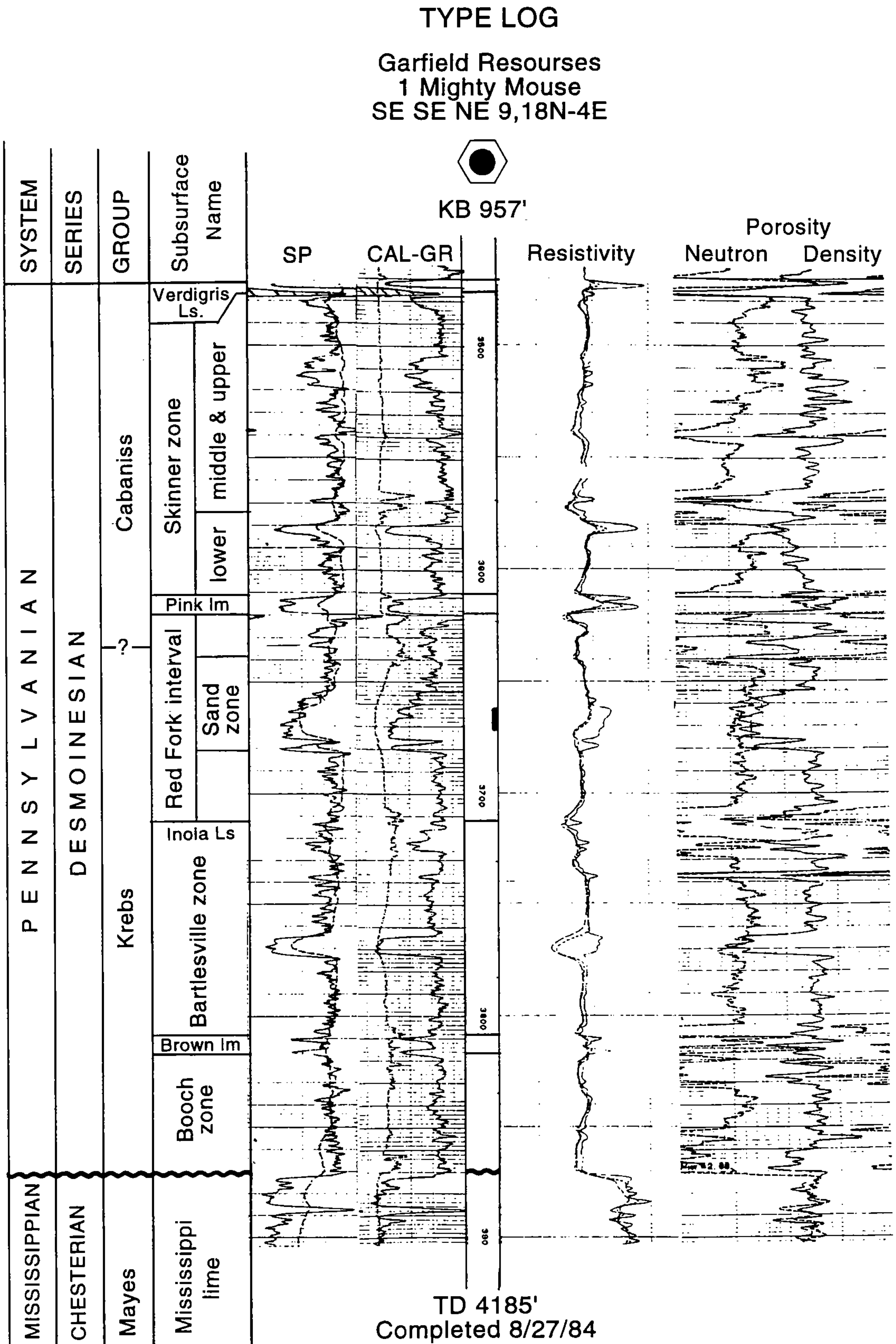


Figure 45. Long Branch Field Red Fork type log showing stratigraphic markers and characteristic log signature of the Red Fork fluvial point bar sandstone. This log also appears in regional cross-section A–A′ (Pl. 4, in envelope). SP = spontaneous potential, CAL = caliper, GR = gamma-ray.

15, T. 18 N., R. 4 E. The overall Red Fork interval of shale and dirty sandstone in well 1 appears to coarsen upward as indicated on the cross section. Therefore, well 1 is interpreted to be outside of the channel. Even where the channel sandstone is absent, channel-fill can be distinguished from non-channel facies based on the log characteristics.

Cross-section B-B′ (Fig. 47, in envelope) is an east-west section across the field. In this B–B′, the point bar sandstone is only present in well 2 and it is stratigraphically lower than the sandstone in wells 3–6. The sandstone in wells 3–6 is interpreted to be a marine shelf bar or marine shoreface sandstone based on the log profile that reflects an upward-coarsening from shale to sandstone. This profile is best displayed by well 4 (B–B′). Westward, the channel sandstone thins and pinches out between wells 2 and 1. The Red Fork interval in well 1 is marine shale.

Differences in color and gravity between oil from the point bar sandstone and oil from the marine sandstone support the interpretation that the two sandstones are indeed separate sand bodies. (Oil from the marine sandstone is black, 36° API oil; oil from the fluvial sandstone is green, 41° API oil. Furthermore, the marine sandstone does not overlie the channel-fill in well 2 (B–B′), or in any other wells in the field, therefore the point bar sandstone in well 2 is interpreted to have been deposited in a channel that was incised into the surrounding sequence of marine shale and sandstone.

Structure: Regional dip in the area surrounding Long Branch Field is to the west-southwest toward the Anadarko basin at ~50 ft/mi (Fig. 16). Within the study area, however, regional dip is interrupted by a small but pronounced structural nose in secs. 9 and 10, T. 18 N., R. 4 E. that plunges to the west-southwest at about 100 ft/mi (~1° dip). This is shown in Figure 48, which is a structure contour map of the top of the Pink limestone. The most pronounced part of the structure is in the northeast part of sec. 10, which is east of the Red Fork oil pool in the study area. This structure map probably reflects the effects of small-scale basement faulting and was probably the incentive for many of the early wells drilled in the study area. The structure of shallower formations, such as the Oswego lime, sec. 10, is strongly influenced by the underlying locally thick Prue channel sands.

Red Fork Sandstone Thickness and Distribution: Figure 49 is an isopach map of the Red Fork gross sandstone thickness with separate contours for the channel and marine sandstones. As it is elsewhere in northeastern Oklahoma, the Red Fork sandstone is relatively clean, so the distinction between sandstone and shale on gamma-ray logs is quite clear. The point bar sandstones have a sharp basal contact with shale and grade upward into the overlying shale, which results in the distictive "bell-shaped" fining-upward textural profile. The channel, which is one-quarter to one-half mile wide, approaches the study area from the northeast, runs westward in the south half of secs. 2 and 3 in the northeast corner of the study area, then straight south along the line between secs. 9 and 10. The gross sand thickness in the channel ranges from 4 to 26 ft. In many places such as in sec. 3, the channel-fill is predominantly shale. The point bar sandstone in productive wells is 11–26 ft thick.

The marine sandstones were identified by their distinctive coarsening-upward textural profile on logs. The marine sand body in Long Branch field (SW¼ sec. 10) is a thin, elongate bar oriented at a high angle to the trend of the fluvial channel. The marine sandstone was interpreted to have been deposited in a shoreface environment, or comparable water depths on the marine shelf.

Within Long Branch field, the marine sandstone gross thickness is 2–14 ft and 8–14 ft in the wells that produce from it in the SW¼ sec. 10. The productive marine sandbody is truncated by the channel deposits along the west line of sec. 10. Marine sandstone (apparently wet) is also present in a well immediately west of the channel (NW¼NE¼ sec. 16). To the east, the sandstone becomes thin, shaly, and discontinuous (see the east end of B–B′, Fig. 47). The thick sandstone, which is interpreted to be another marine bar sandstone, in the southeast corner of the map (Fig. 49) produces oil from the Red Fork, but is separated from the marine sandstone in Long Branch field by marine shale.

The net sandstone isopach map, Figure 50, shows the thickness of sandstone with ≥10% porosity. The net sandstone map is very similar to the gross sandstone map in Figure 49 and clearly shows that much of the sandstone identified in the gross sand isopach map has good porosity. The main differences in net and gross sand thickness are in the channel margin areas and transitional areas surrounding the marine sandstones. A higher porosity cutoff value such as 12% or 14% would have significantly changed the net thickness, because much of the sandstone is relatively "dirty" and has only a little more than 10% porosity.

Application of the 10% net cutoff clearly shows the configuration of both reservoirs. The reservoir in the fluvial sandstone corresponds to the area having more than about 2 ft of net sand above the oil/water contact. The oil/water contact which is at about –2,716 ft below sea level is shown on cross-section A–A′ (Fig. 46, in envelope). West of the oil/water contact line (Fig. 50), all of the net sand is below the oil/water contact. Point bar sandstone above the oil/water contact at the eastern edge of sec. 4 and in the western part of sec. 3, T. 18 N., R 4 E. has not been tested.

The Long Branch field marine sandstone reservoir is defined by the area having more than about 2 ft of net sand and is mostly in the SW¼ of sec. 10 (Fig. 50). The net sand thickness in the marine sandstone wells of 6–9 ft is very close to the gross thickness of 8–10 ft. The marine sandstone part of the field has no clearly defined oil/water contact, and oil entrapment is entirely

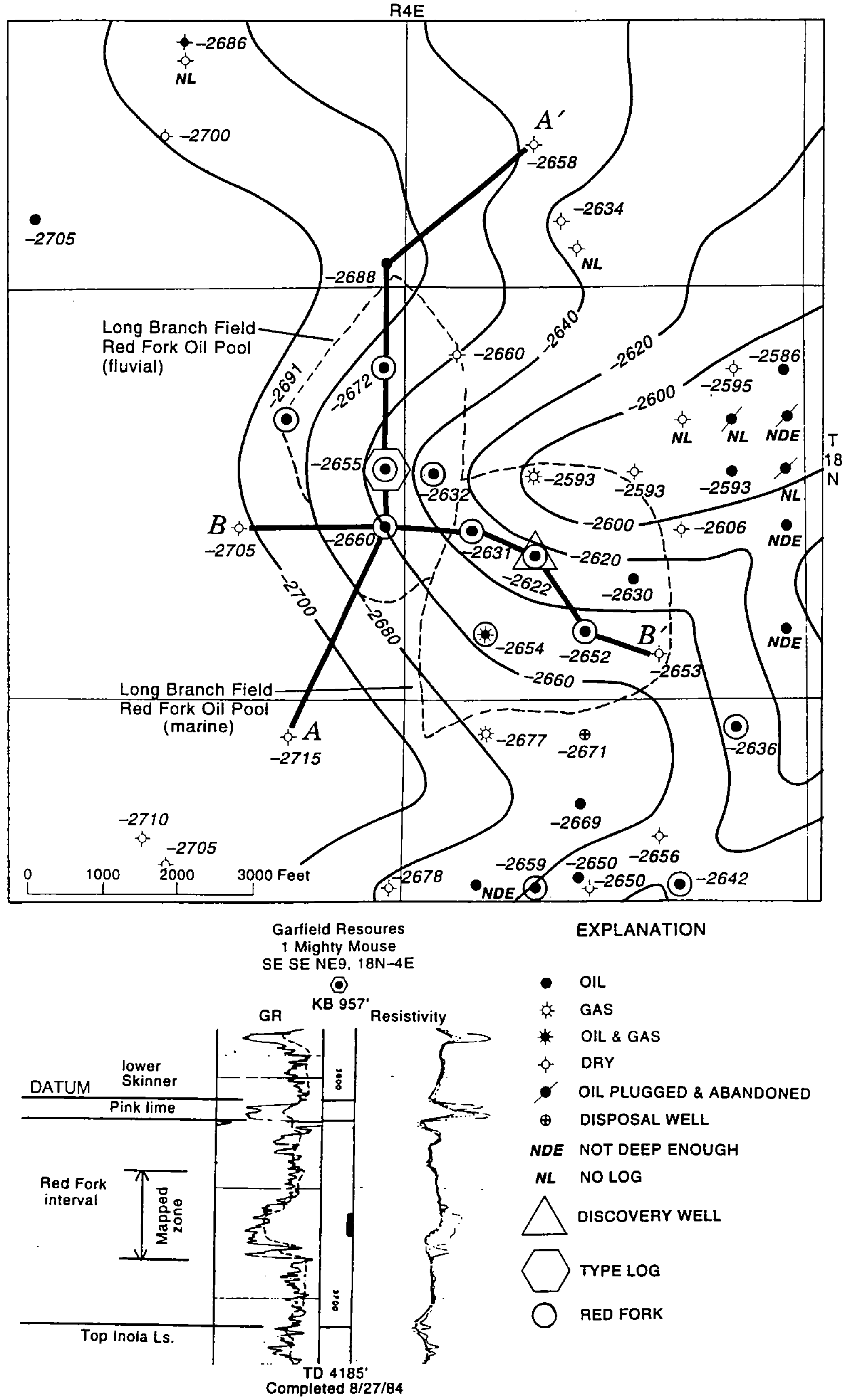


Figure 48. Structure map of the top of the Pink limestone, Long Branch field. Contour interval is 20 ft. See Figure 44 for well names.

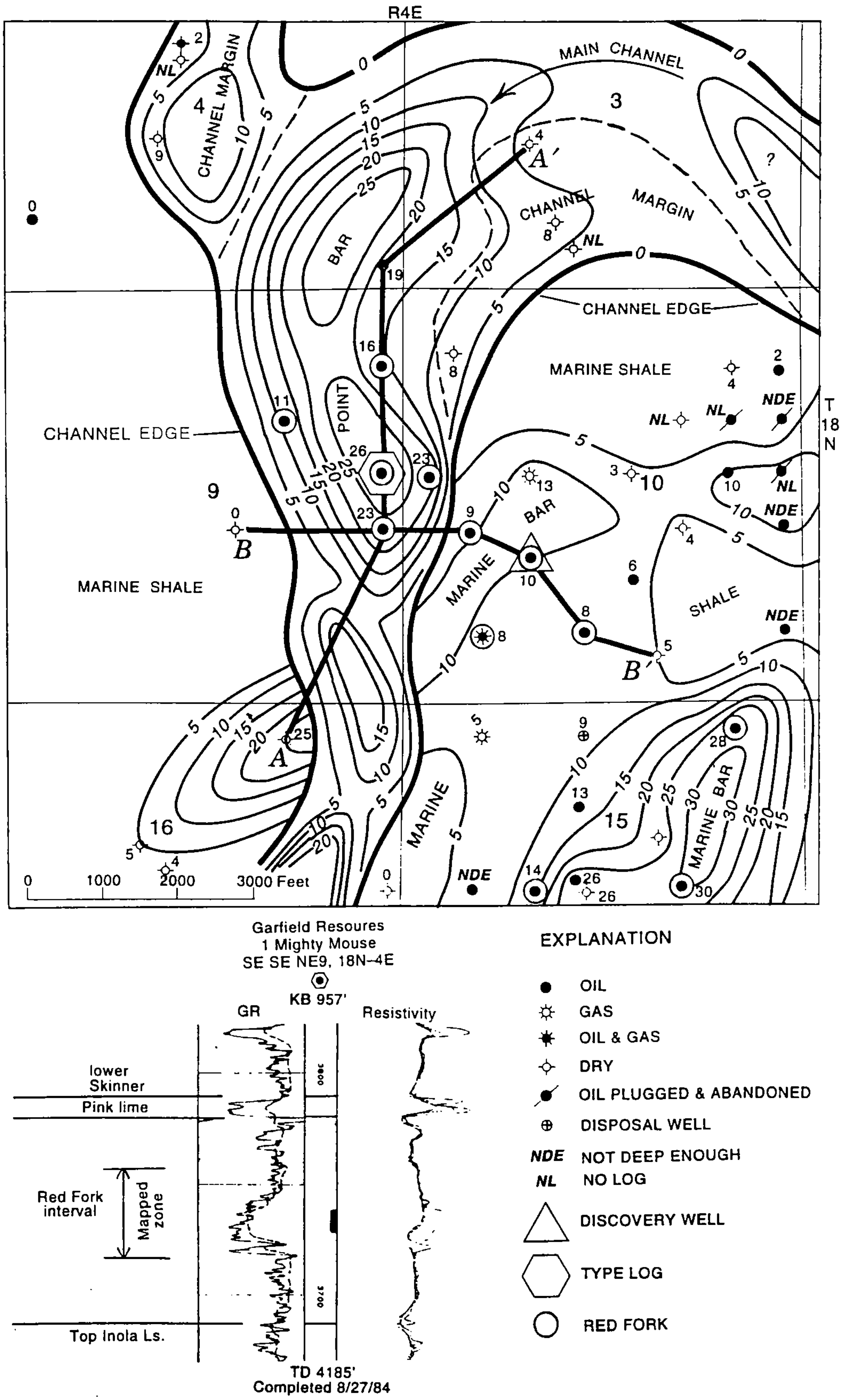


Figure 49. Gross sand isopach map of the Red Fork sandstone, Long Branch field. Contour interval is 5 ft. See Figure 44 for well names.

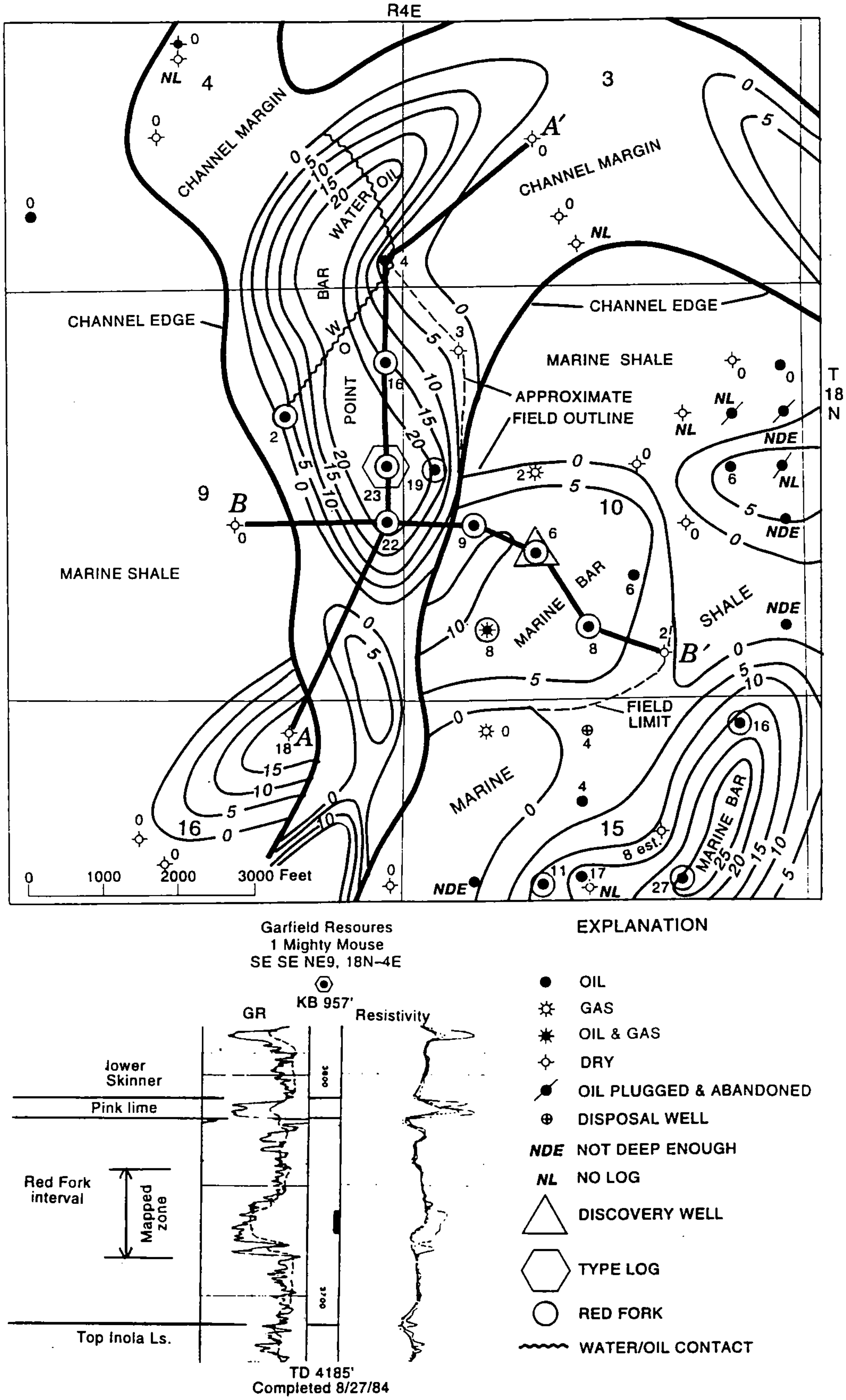


Figure 50. Net sand isopach map of the Red Fork sandstone, Long Branch field. Net sand = sandstone with density log porosity ≥10%. Location of the oil/water contact is shown at –2,716. Contour interval is 5 ft. See Figure 44 for well names.

stratigraphic. Downdip, the sandstone is truncated on the west by the Red Fork channel; updip the sandstone becomes tight and shaly.

Because of the differences in the fluvial and marine depositional processes, the marine sandstone is expected to be less heterogeneous than the point bar sandstone. The marine sandstone is predicted to have very good lateral continuity which should result in efficient drainage. The point bar sandstone, on the other hand, is expected to have some degree of compartmentalization. Only four wells produce from the marine sandstone; however, the No. 1 and No. 2 Aletha wells (W½SE¼ sec. 10) and the No. 1 McFarland (SE¼ NW¼ sec. 10) might be capable of producing minor amounts of oil from the Red Fork marine sandstone. These three wells each have 2–6 ft of porous sandstone but were not completed in the Red Fork because of "shaliness" or poor test results; the No. 1 Aletha well had greater potential in the Skinner sandstone.

Depositional Facies Map: Depositional facies interpretations were based mostly on the gamma-ray log signatures and also on the resistivity log signature. Figure 51 shows the distribution of the various fluvial and shallow marine facies.

Fluvial Channel Deposits: The Red Fork channel sandstone that is productive in Long Branch field is interpreted to be a point bar deposited within a meandering river of a flood plain rather than in a distributary channel of a delta plain. The distinction between fluvial versus distributary is important for exploration purposes because there are no delta front sandstones underlying the fluvial channel and, therefore, no progradation, i.e., no deposition extending basinward into a marine environment (definition of a delta!). Within the fluvial (channel) facies, sediments are either predominantly sandstone, or shale with thin interbedded sand layers. The point bar sandstone was interpreted mainly from the character of the gamma-ray and resistivity logs. The sandstone had a sharp basal contact with shale and a fining-upward textural profile that included shale breaks in the upper half of the sandstone. The point bar sands contain a major portion of the oil within the Red Fork oil pool in Long Branch field. The shaly channel fill is not part of the reservoir.

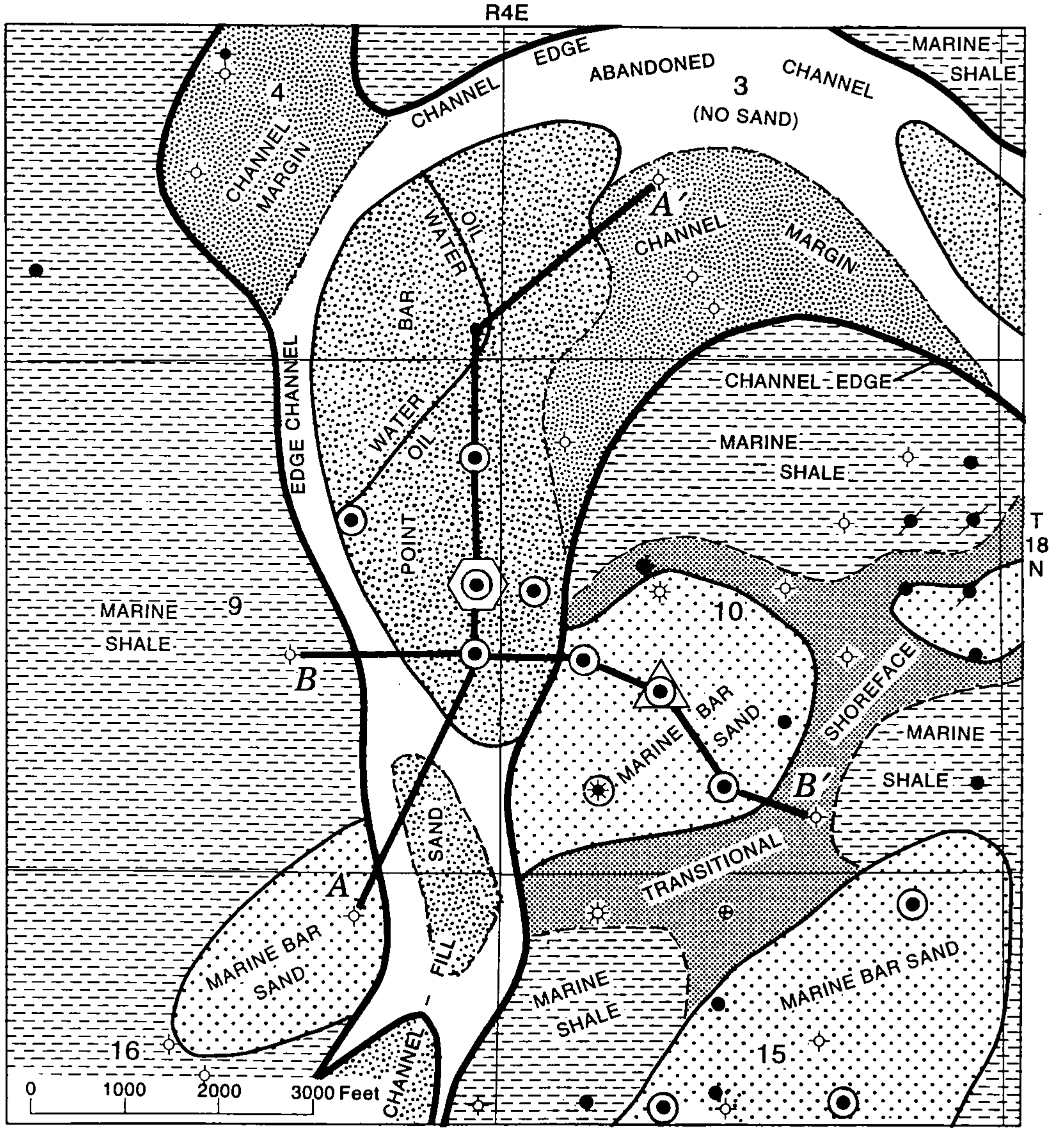
Shallow Marine Facies: Marine sandstone that is productive in Long Branch field is interpreted to have been deposited on a shallow marine shelf, as bars (or sand ridges), or as a poorly developed shoreface. The marine sandstone reservoir is probably not deltaic since it does not occur in a stratigraphic succession typical of most deltas as shown in Figures 7 and 17. The marine sandstones have a distinct coarsening-upward textural profile, are oriented at a high angle to the fluvial channel previously described, and have shaly transition zones that are characterized by significant amounts of interbedded shale and sandstone beneath the main bar sand. When not incised by the Red Fork channel, the marine sandstone is surrounded laterally by shallow marine shale.

Core Analysis: The Statex Petroleum No. 1 Kelley NE¼ NE¼SE¼ sec. 9, T. 18 N., R. 4 E. is the only well in Long Branch field that was cored. The entire Red Fork sandstone section was recovered and is interpreted to be a point bar. The core analysis report describes it as tan, fine grained, slightly calcareous/dolomitic?, and micaceous with numerous thin carbonaceous laminations, particularly near the top. Core photographs provided by Mid-Continent Energy (Tulsa) showed faint shale laminae in the upper part of the sandstone, otherwise, the core appeared to have few shaly zones and was mostly sandstone. Bedding was horizontal to moderately inclined (cross bedded?) near the top. Near the bottom of the sandstone, bedding was horizontal to moderately inclined and contained zones of what appeared to be larger clasts. X-ray analysis was not performed but, inferring from other Red Fork cores and log analysis, it probably consists of mostly quartz with a fair amount of rock fragments, feldspar, and authigenic clay (but not nearly as much clay as in the Prue channel sands).

The grain density of sandstones with 15–18% porosity ranges from 2.66 to 2.69, although most core samples of sandstone have a gram density of 2.69. The permeability values range from 11 to 81 md; the average is ~30 md. The porosity measured in samples from the main sand interval, which is about 3,672–3,691 ft, ranges from about 14.8% to 18.2% and is identical to the porosities derived from the density log using a 2.68 matrix density. The porosity and permeability measurements are plotted in Figure 52.

Reservoir Characteristics: Red Fork sands are often noticeably cleaner than many of the other sands in the upper Cherokee section such as the Prue or Skinner. For purposes of this field study, however, no hand samples were available for examination and reservoir evaluations were based entirely upon wireline log and core analysis, production data, and isopach maps. From these data sources, it is apparent that differences do exist between the fluvial and marine facies, primarily in sandstone thickness, porosity, water saturation, and possibly in permeability.

The porosity in channel sands ranges from about 12% to 18%, averaging ~15%. Permeability generally varies from about 11 md to 81 md and averages ~30 md. This is relatively good in comparison to most other Cherokee sands of similar depositional origin; the permeability, however, is probably suppressed by authigenic clays. The relationship of porosity and permeability in the Red Fork channel sandstone in Long Branch field is shown in Figure 52. This graph shows that when log porosity reaches ~10%, the sand should have slightly more than 1 md permeability, which is considered minimal for oil production. However, most of the sandstone within the lower to middle point bar has porosity of ~15%, which would indicate an average



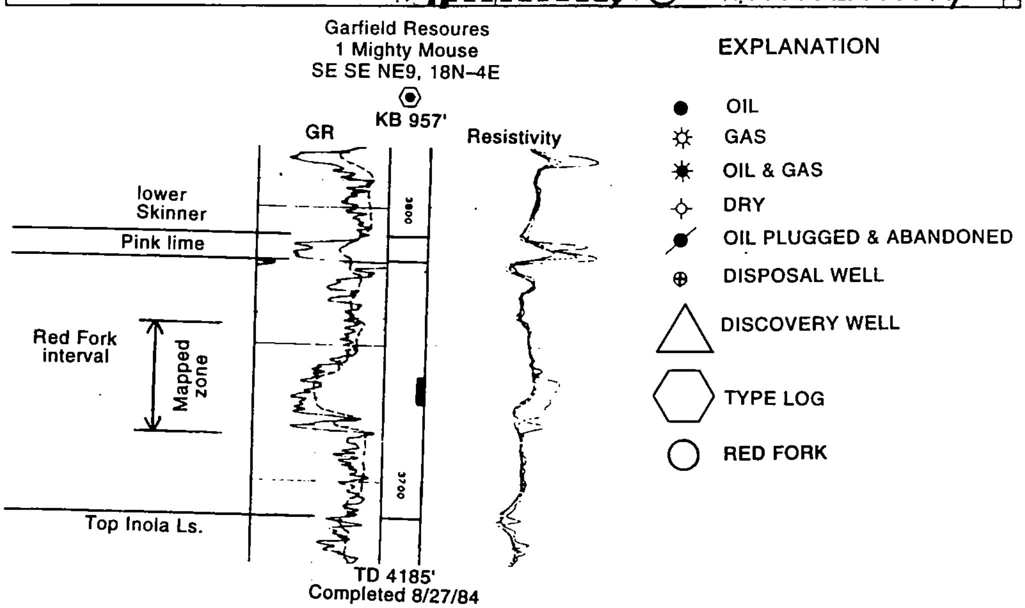


Figure 51. Red Fork sandstone facies map, Long Branch field.

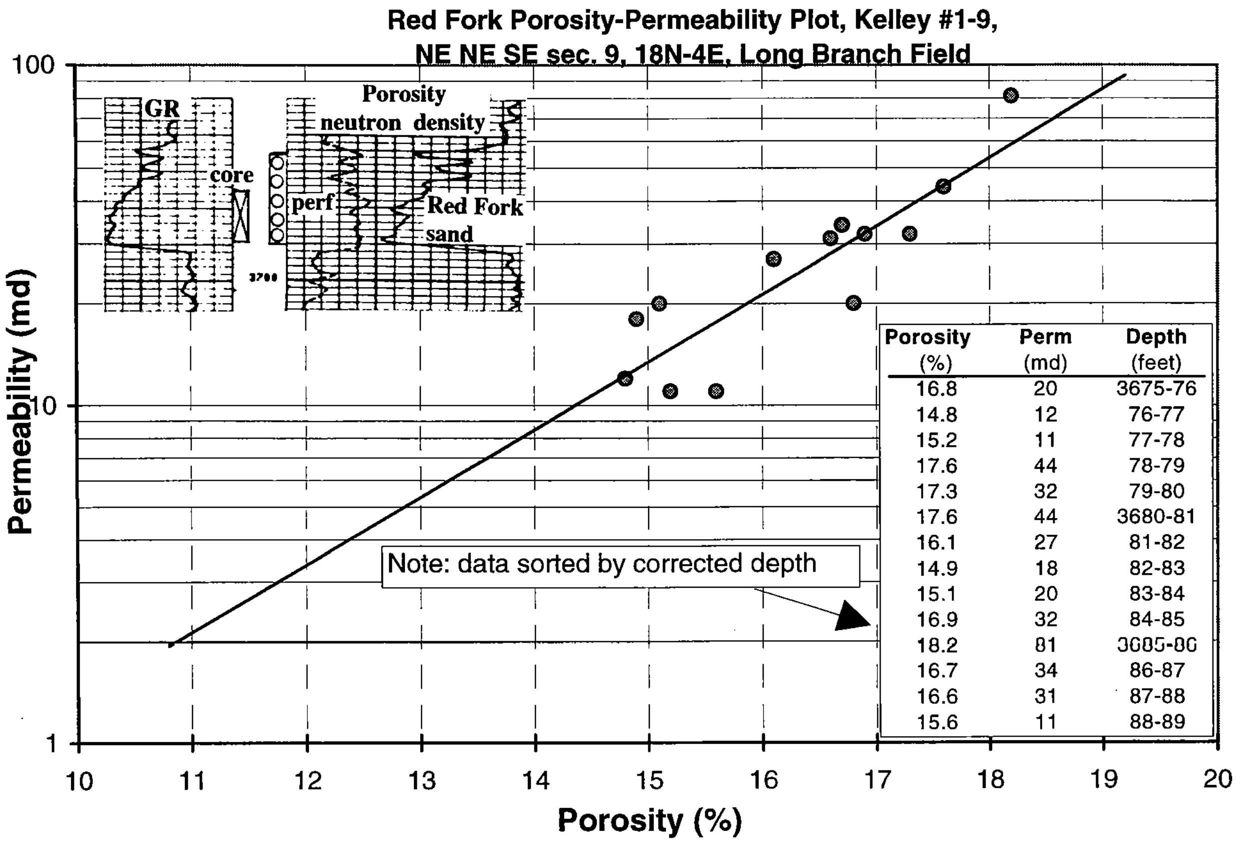


Figure 52. Porosity and permeability data from a Red Fork (point bar) sandstone core in Long Branch field, Payne County, Oklahoma.

permeability of ~12 md on Figure 52. Core analysis indicates that the Red Fork channel sandstone is slightly calcareous/dolomitic and contains numerous thin carbonaceous laminations. Thin shaly zones are particularly common in the upper part of the point bar sequence, as shown on gamma ray logs and is seen on core photographs.

Sandstone beds in the upper portion of the point bar sequence tend to be thinner with increasing amounts of interbedded shale making this portion of the reservoir much more discontinuous, although reservoir quality within thin bed sets may be very good. Unfortunately, the upper channel facies in Long Branch field is often the only portion of the Red Fork sand zone that lies about the oil/water contact and this situation leads to compartmentalization, low sweep efficiency, and attenuated hydrocarbon recovery efficiency. In wells containing an oil column extending into the lower point bar facies (well No. 3, cross-section A–A′, Fig. 46), production may be attributed to intervals having paths of really exceptional permeability and porosity that are continuous laterally over a relatively large areal extent as compared to the thinner sandstone beds comprising the upper point bar. Therefore, because of the continuity of sandstone in the lower part of a point bar in addition to good reservoir quality, this zone commonly accounts for a disproportionally larger amount of recoverable oil in relation to the overall thickness of the point bar. Within the point bar sequence, fluid flow and reservoir properties (permeability) are expected to be most favorable parallel to the axis of the channel and least favorable vertically and across the channel.

The marine shoreface sands that are productive in Long Branch field are considerably thinner than the channel sands but are locally a much better reservoir. In the four wells that produce from this facies, porosity is 14–21% and averages ~17%. The marine sandstone has not been cored. However, clean Skinner sandstone having comparable appearances on gamma-ray and resistivity logs and comparable porosities can have permeabilities >50 md. Permeability in the marine reservoir is expected to be higher in an east-west direction parallel to depositional strike. However, permeability in the north-south direction and vertically should also be good due to the diminishing effects of flow impediments that characterize fluvial deposits such as shale laminae in cross bedding and erratic sand distribution. As a rule, marine shelf and shoreface sandstones are much less heterogeneous than point bar sandstones. Point bars, which accumulate and grow laterally across the channel and downstream (the process of lateral accretion) commonly have lateral accretion surfaces blanketed with mud (shale drapes), which, if preserved, will be a barrier to both vertical and lateral flow. Because marine shelf and shoreface sandstones are typically cleaner and more uniform in sandstone distribution patterns than point bar sandstones, they can be expected to have higher recovery efficiencies. However, the oil recovery efficiency for the marine reservoir was only 9.8%, compared to 12.1% for the channel sandstone reservoir (Table 9). Several reasons might explain the low recovery efficiency: inaccurate reserve estimates, inaccurate estimates of Red Fork production from wells that are commingled with Skinner or Bartlesville production, and locally high clay content in the marine sandstone.

TABLE 9. – Reservoir/Engineering Data for the Red Fork Sandstone in Long Branch Field, Payne County, Oklahoma

	Red Fork sand	
	Fluvial	*Marine*
Reservoir size	~159 acres	~216 acres
Depth	~3,600 ft	~3,600 ft
Spacing (oil)	40 acres, irregular	40 acres, irregular
Oil/water contact	about –2,716	none observed
Gas/oil contact	none observed	none observed
Porosity (in net sand)	12–18% (avg. ~15%)	14–21% (avg. ~17%)
Permeability	11–81 md (avg. ~30 md)	unknown
Water saturation (calculated)	29–53% (avg. ~40%)	22–44% (avg. ~30%)
Thickness (net sand $\phi \geq 10\%$)	15–25 ft (avg. ~15 ft)	6–10 ft (avg. ~7.5 ft)
Reservoir temperature	115° F	115° F
Oil gravity	40–41° API	36° API
Initial reservoir pressure	not known	not known
Initial formation volume factor (est.)	1.24 RB/STB	1.24 RB/STB
Original average GOR (SCF/BBL)	0–2,000 (avg. ~1,000)	0–2,500 (avg. ~1,000)
Final average GOR	1,006 (SCF/BBL)	1,064 (SCF/BBL)
OOIP (volumetric)	1,226 MSTBO	1,008 MSTBO
Cumulative primary oil (to 10/95)	148,561 BO	98,645 BO
Primary recovery efficiency (oil)	12.1%	9.8%[1]
Primary recovery	~62 BO/acre-ft	~61 BO/acre-ft
Cumulative gas	51,898 MCF[2]	106,951 MCF

[1]Value may be slightly suppressed due to cumulative production estimates in commingled wells.

[2]Figure does not include cumulative gas production from Linsenmeyer No. 1 & No. 3, which was not reported.

Formation Evaluation: The identification of Red Fork sandstone in Long Branch field is very straightforward. There are no correlation problems associated with deeply incised channel deposits, which can lead to confusion in differentiating the Red Fork with the underlying Bartlesville sand. The gamma-ray and resistivity logs are not significantly affected by the presence of interstitial clay or interbedded mica in the sandstone. For the point bar sandstone in the No. 1-9 Kelley (NE¼ NE¼SE¼ sec. 9, T. 18 N., R. 4 E.), porosities calculated from the density-neutron log using a standard 2.68 matrix density were identical to the porosities measured in core. The sandstone core also had a matrix density of 2.68–2.69.

"Deep" or "true" resistivity readings in productive zones in the Red Fork have about 8–15 ohm-meters (the higher resistivity is from the marine sandstone, which has a higher oil saturation). The separation between the shallow and deep resistivity curves is ~10 ohm-meters in the oil column and ~15 ohm-meters in the water column. The separation of the two curves indicates the presence of relative permeability and the decrease in the deep resistivity curve in the water column clearly marks the oil/water contact in the thick channel sands in the northwest part of the field.

Water saturations were calculated using the equation ($S_w = \sqrt{F \times R_w/R_t}$). The resistivity of formation water (R_w) was assumed to be 0.04 ohm-meters at formation temperature. The modified equation for formation factor ($F = 0.81/\phi^2$) was used to reflect the average reservoir lithology (consolidated sand). R_t (true resistivity) was from the deep resistivity log curve and porosity ϕ was read directly from density logs.

Water saturation in the point bar reservoir ranges from about 29% to 53% and averages ~40%. Water saturation of the marine sandstone ranges from 22% to 44% and averages ~30%. The difference in water saturations between the two reservoirs is due to the encroachment of an oil/water contact in the fluvial sandstone, whereas the marine sandstone has no free water.

Oil and Gas Production: Estimated cumulative oil and gas production from the Red Fork in Long Branch field from November 1983 through April 1996 was 247,206 BO and 158,849 MCFG. Production statistics for the field—annual oil and gas production, average monthly production, and average daily production per well—are compiled in Table 10. From this table, it is apparent that the wells in this field were diminished to strippers by the late 1980s when the average daily oil production was only 2–3 BOPD. The rapid decline in oil production is illustrated in Figure 53, which is the decline and cumulative production curves for the Red Fork pool in Long Branch field. The annual oil production decline

TABLE 10. — Oil and Gas Production Statistics for the Red Fork Sand in Long Branch Field, Payne County, Oklahoma

Year	Number of Wells		Annual Field Production		Average Monthly Field Production		Average Daily Production Per Well		Cumulative Production	
	Oil	Gas	Oil BBLS	Gas MCF	Oil BBLS	Gas MCF	Oil BBLS	Gas MCF	Oil BBLS	Gas MCF
[1] 1983	1	0	7,341	0	3,671	0	122	0	7,341	0
[1] 1984	7	1	86,517	2,577	13,518	2,577	64	86	93,858	2577
[1] 1985	9	7	66,500	68,864	5,542	11,477	21	55	160,358	71,441
1986	9	7	28,522	42,845	2,377	3,570	9	17	188,880	114,286
1987	9	4	16,281	23,234	1,357	1,936	5	16	205,161	137,520
1988	9	3	9,527	14,334	794	1,195	3	13	214,688	151,854
1989	9	3	7,889	6,995	657	583	2	6	222,577	158,849
1990	9	0	6,720	0	560	0	2	0	229,297	158,849
1991	9	0	7,897	0	658	0	2	0	237,194	158,849
1992	8	0	4,449	0	371	0	2	0	241,643	158,849
1993	6	0	2,279	0	190	0	1	0	243,922	158,849
1994	6	0	1,684	0	140	0	1	0	245,606	158,849
1995	3	0	1,244	0	104	0	1	0	246,850	158,849
[2] 1996	2	0	356	0	89	0	1	0	**247,206**	**158,849**

[1] partial year's production for some wells [2] 4 months production

rate, which was 57% in 1985, had decreased to 17% by 1989. Annual and cumulative oil production by well or lease are shown in Table 11; the same figures for gas are shown in Table 12.

About 60% of the Red Fork oil produced from Long Branch field was from wells in the point bar channel facies (see wells in secs. 4, 9, and NW¼ sec. 10). These wells originally produced little water, with the exception of the No. 1 Kelly, NE¼NE¼SE¼ sec. 9, which had perforations that extended below the oil/water contact (see well No. 2, A–A′, Fig. 46). In the point bar reservoir, oil production is highly influenced by structural position. The two best wells were high enough so that at least part of the lower channel facies (i.e., the clean sandstone in the lower part of the point bar sandstone) was in the oil column. The two best wells—the No. 1 Linsenmeyer (SE¼NE¼ sec. 9) and the No. 2 McFarland (SW¼NW¼ sec. 10)—had the highest initial flowing potentials (IPFs) of 700 and 400 BOPD, respectively (Fig. 54). They were also structurally higher than the other wells in the field (Fig. 46). The cumulative production (estimated) from the No. 1 Linsenmeyer was 40,000 BO; cumulative production from the No. 2 McFarland was 68,000 MBO (Figs. 54,55; Table 11). These two wells also had the highest flowing tubing pressures (350 PSI and 315 PSI, respectively; Fig 54). Wells that are structurally lower had considerably lower initial production rates and lower cumulative production. In spite of the presence of water in the lower part of the point bar sandstone, relatively little water was produced during the 12-year production history of the field (as indicated by royalty interest owners). Therefore, the principal drive mechanism is interpreted to be solution gas expansion rather than a water drive. As mentioned previously, the channel sands produced green oil with a gravity of 41° API.

About 40% of the Red Fork oil produced from Long Branch field was produced from wells in the marine sandstone in spite of the fact that the marine sandstone is only about half as thick as the channel sandstone. Wells in this part of the field did not produce any significant amount of water and there is no oil/water contact. Therefore the principal drive mechanism is interpreted to be solution gas expansion.

Initial production rates from wells in the marine sandstone were relatively uniform and ranged from 79 to 238 BOPD; typical well came in at about 160 BOPD. Flowing tubing pressure ranged from 105 PSI to 260 PSI. Three of the four wells each produced about 14,000–20,000 BO; the field discovery well (No. 1 Snyder, W½NE¼SW¼ sec. 10) produced ~47 MBO (Table 11). The marine sandstone produced black oil with a gravity of 36° API.

Lease production can include production from more than one well and production from one well can come from more than one reservoir (commingled). Estimates of the performance of individual wells were based on the performance of single well–single zone completions and adjusted for differences in reservoir quality, thickness, and structural position. The estimated cumulative production and date of first production for each well are shown in Figure 55. A more detailed summary of well performance data is shown in Figure 54 and includes cumulative oil and gas production, initial production, important test data, tubing pressure, and oil gravity.

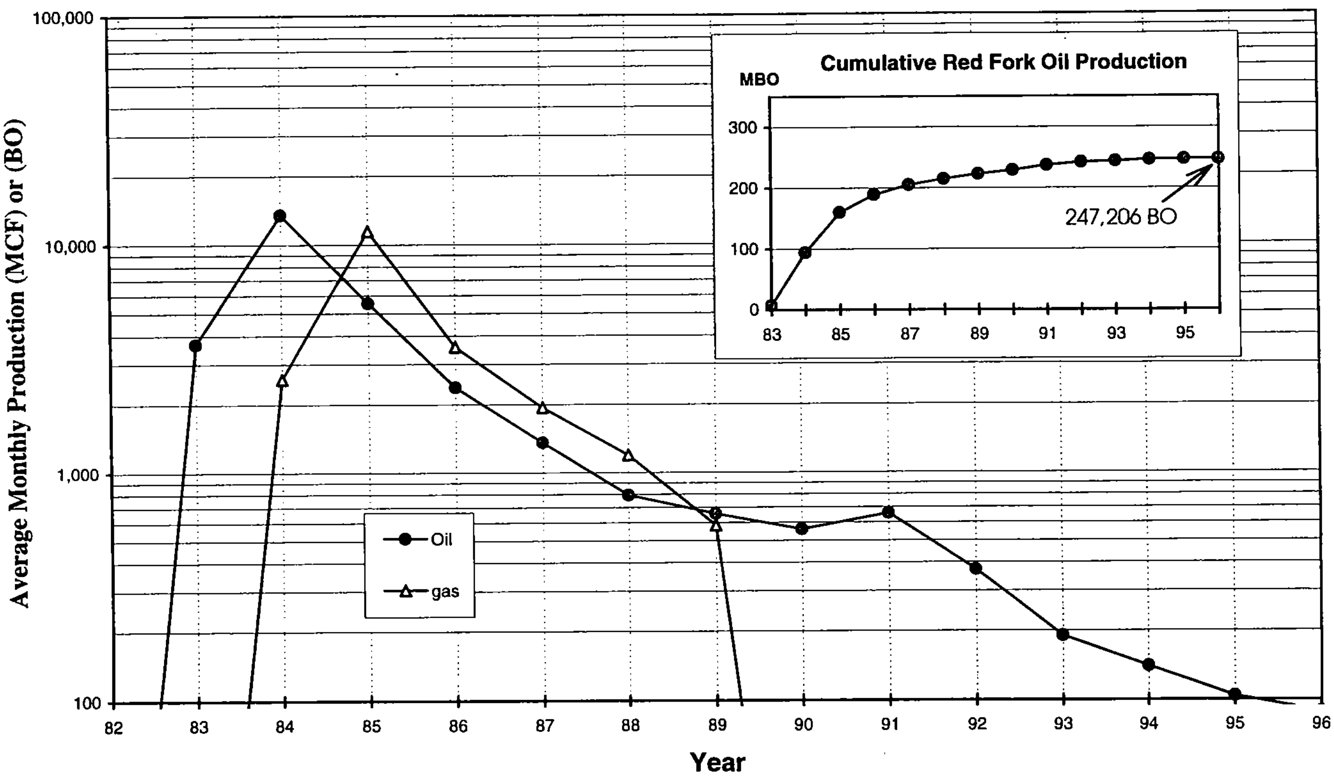


Figure 53. Red Fork oil and gas production decline curves, Long Branch field. Inset plot shows cumulative oil production from the Red Fork sand.

Well Completion: Wells completed in the Red Fork were acidized and stimulated with a fracture treatment that was proportional to the thickness of the perforated interval. As such, the entire sand interval may be perforated and fractured, which was common in the shoreface sands, but usually only the upper portion of the channel sequence was fractured because of the danger of inducing water production from the underlying water saturated zone.

Most wells were perforated through 5.5-in. production casing that was set at or very near bottom of the hole (a few wells used 4.5-in. casing). The wells were then acidized (to clean up the well bore) and fractured. Typical fracture treatments used 14,000–25,000 gal of water or cross-linked gel and as much as 36,000 lb of sand to assist in the initial response following stimulation. Initial production tests (flowing) were in the range of 79–238 BOPD from the marine sandstone reservoir and 15–700 BOPD from the point bar reservoir (Fig. 54). "Channel" wells initially produced small amounts of water when fractured above the oil/water column, whereas the marine sandstone wells were essentially water-free. Flowing tubing pressure generally ranged from 100 to 350 PSI, which indicates the relative tightness of the Red Fork sandstone.

ACKNOWLEDGMENTS

Completion of this study would not have been possible without funding from the U.S. Department of Energy and the combined efforts of many people from the Oklahoma Geological Survey and the Geo Information Systems Department and the School of Petroleum and Geological Engineering at the University of Oklahoma. Special recognition is given to Dr. Charles Mankin, Director of the Oklahoma Geological Survey (OGS), and Mary Banken, Director of Geo Information Systems (GeoSystems), who originated concepts for this program and provided overall leadership. Both the OGS and GeoSystems also provided funding for this cooperative project.

Several companies and consulting geologists contributed greatly to this project by providing technical information—field and well log data, core data, and geological interpretations. These include Ensign Oil and Gas (Oklahoma) and James Fowler for providing geological interpretations and reservoir, production, and waterflood information for N. Carmen field; Anadarko Petroleum (Houston) for providing core data from the N. Carmen field area; Mid-Continent Energy (Tulsa) and Mickey Canaday for providing core data for the Long Branch field study; and Greg Riepl for providing geological interpretations and oil samples for the Long Branch field study. Kurt Rottmann performed the S. Otoe field study. Reservoir simulation and waterflood modeling was completed by Dr. Roy Knapp and X. H. Yang.

Much of the technical support for computer map preparation, core preparation, technical editing, and

TABLE 11. – Annual Red Fork Oil Production for Wells in Long Branch Field

Well information							Annual Oil Production (in barrels)														Cum Prod
S3	S2	S1	SEC	Lease name	Well	Prod date	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	(to 4-96)
T.18N., R.4E.																					
Se	Se	Ne	9	Linsenmeyer	1	8/84-?		30,617	16,404	9,345	1,212	994	187	853	1,408	581	172	130			61,903
Ne	Sw	Ne	9	Linsenmeyer	2	6/85-6/93			329	548	166	62	147	225	160						1,637
Se	Ne	Ne	9	Linsenmeyer	3	6/85-?			commingled with Linsenmeyer #1. Most production (about 40,000 BBLS) attributed to Linsenmeyer #1												
Ne	Ne	Se	9	Kelley	1	10/84-10/95		2,516	6,335	3,583	1,447	372	322	172	1,019	351	337	134			16,588
Sw	Sw	Nw	10	McFarland	2	10/84-9/92		21,208	24,873	4,539	5,177	3,071	2,902	2,678	2,815	1,170					68,433
Ne	Se	Sw	10	Clemons[1]	1	7/84-4/96		3,710	4,555	2,455	2,180	1,139	1,061	1,038	1,004	833	751	542	546	185	19,999
Ne	Nw	Sw	10	Hope	1	3/84-6/95		7,460	2,353	1,849	1,266	936	1,021	670	494	537	333	347	348		17,614
Ne	Sw	Sw	10	Eithel	1	7/84-11/95		3,661	3,494	2,258	2,021	1,090	697	105	177	348					13,851
W/2	Ne	Sw	10	Snyder	1	11/83-4/96	7,341	17,345	8,157	3,945	2,812	1,863	1,552	979	820	629	686	531	350	171	47,181
Cumulative Annual Production (BO)						→	7,341	86,517	66,500	28,522	16,281	9,527	7,889	6,720	7,897	4,449	2,279	1,684	1,244	356	
Number of producing oil wells						→	1	7	9	9	9	9	9	9	9	8	6	6	3	2	
								Cumulative primary oil production for field 11/83 through 4/96								→					247,206

[1] estimated from commingled Skinner production

TABLE 12. – Annual Red Fork Gas Production for Wells in Long Branch Field

Well information							Annual Gas Production (in MCF)														Cum Prod
S3	S2	S1	SEC	Lease name	Well	Prod date	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	(to 4-96)
T.18N., R.4E.																					
Se	Se	Ne	9	Linsenmeyer	1																
Ne	Sw	Ne	9	Linsenmeyer	2	6/85-7/86			4,090	5,612											9,702
Se	Ne	Ne	9	Linsenmeyer	3																
Ne	Ne	Se	9	Kelley	1	8/85-10/86			2,415	7,297											9,712
Sw	Sw	Nw	10	McFarland	2	5/85-7/86			26,174	6,310											32,484
Ne	Se	Sw	10	Clemons[1]	1	5/85-8/89			6,951	5,716	8,145	3,835	1,696								26,343
Ne	Nw	Sw	10	Hope	1	7/85-8/89			2,291	4,669	7,036	4,126	2,055								20,177
Ne	Sw	Sw	10	Eithel	1	7/85-2/87			2,464	1,625	269										4,358
W/2	Ne	Sw	10	Snyder	1	12/84-8/89		2,577	24,479	11,616	7,784	6,373	3,244								56,073
Cumulative Annual Production (MCF)						→		2,577	68,864	42,845	23,234	14,334	6,995								
Number of producing gas wells							→	1	7	7	4	3	3	0	0	0	0	0	0	0	
								Cumulative gas production for field 12/84 through 4/96								→					158,849

[1] estimated from commingled Skinner production

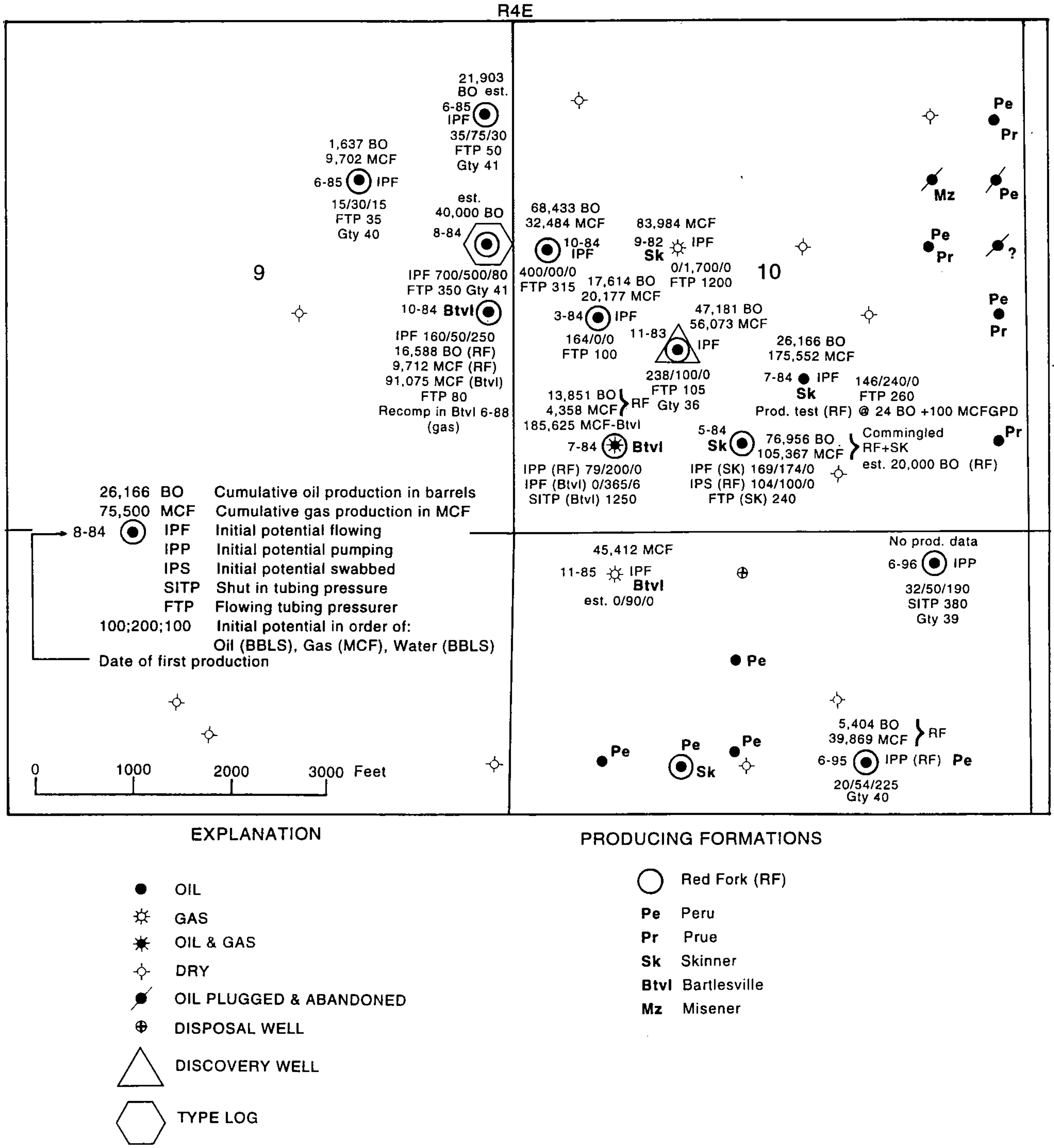


Figure 54. Map showing cumulative oil and gas production, date of first production, initial potential, tubing pressure, and initial gas/oil ratio (IGOR) for wells in Long Branch field. See Figure 44 for well names.

computer graphics was completed by Victoria French, University of Oklahoma graduate student, David Brown, GeoSystems technical project coordinator, and Carlyle Hinshaw, GeoSystems petroleum geologist. Core slabbing was made possible by Walter Esry and Larry Austin, OGS Core and Sample Library. Regional structure and isopach maps were prepared by Carlyle Hinshaw, GeoSystems petroleum geologist. Drafting and computer imaging was completed by Wayne T. Furr, OGS manager of cartography, Jim Anderson, cartographic drafting technician, Greg Taylor, contract drafting technician, Charlotte Lloyd, cartographic drafting technician, and Gary Leach, contract drafting technician. Publication review and editing was com-

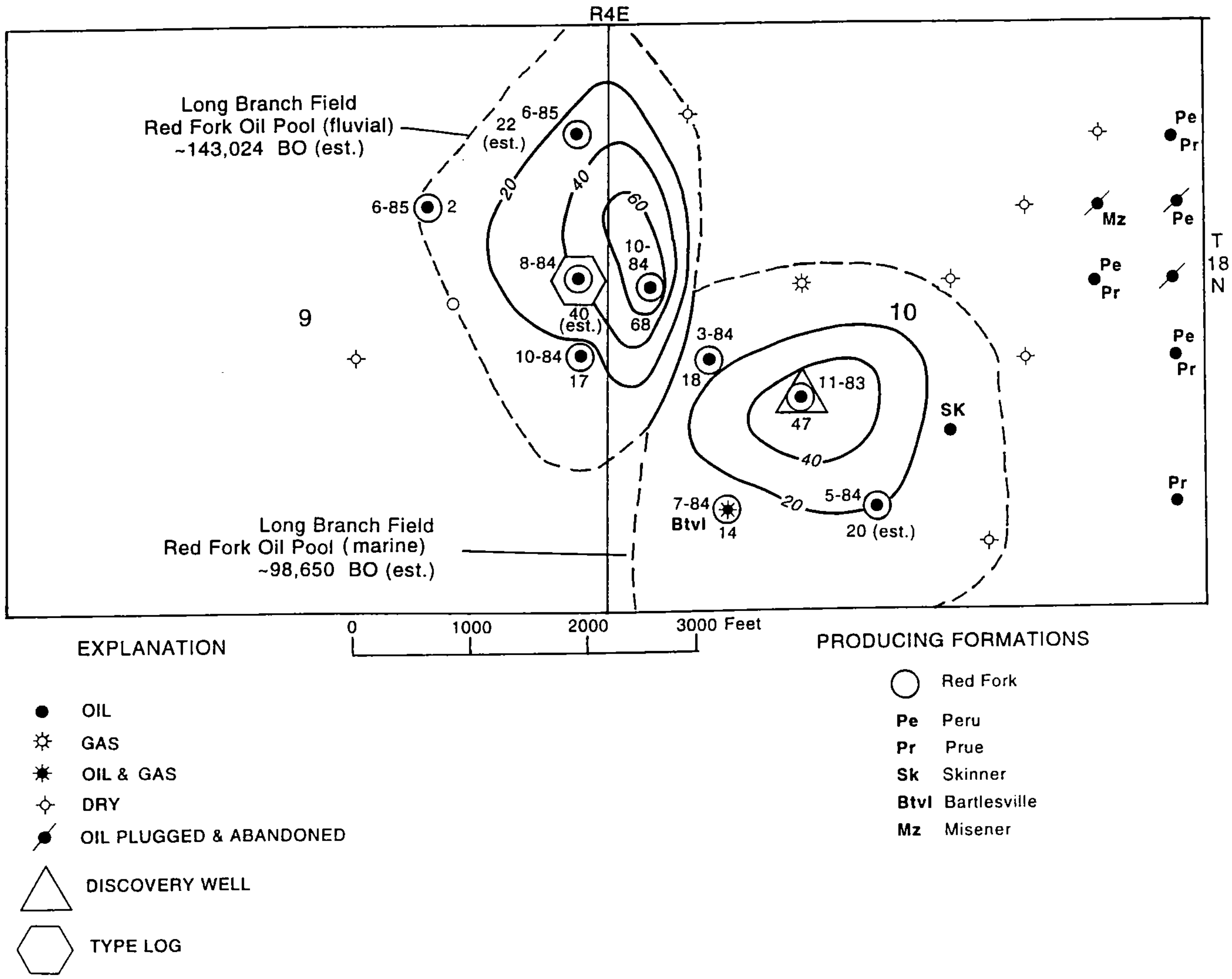


Figure 55. Red Fork cumulative oil production isopach map, Long Branch field. Contour interval is 20 MBO. (MBO = one thousand barrels of oil). Date of first production is also shown. See Figure 44 for well names and production codes.

pleted by Dorothy Swindler, consulting geologist/technical editor; Charles Mankin, OGS director; Kenneth Johnson, OGS associate director; Robert Northcutt, OGS consulting geologist; Carlyle Hinshaw, GeoSystems petroleum geologist; Christie Cooper, OGS editor; and Tracy Peeters, OGS associate editor. Printing of this special publication was done by Paul Smith and Richard Murray (OGS). Program organization and registration was performed by Michelle Summers, OGS technical project coordinator.

SELECTED REFERENCES

Ahmeduddin, Mir, 1968, Subsurface geology of the Wheatland area, Cleveland, McClain, Grady, Canadian, and Oklahoma Counties, Oklahoma: Shale Shaker, v. 19, no. 1, p. 2–19.

Akmal, M. G., 1953, Subsurface geology of northeast Lincoln and southeast Payne Counties, Oklahoma: Shale Shaker, v. 3, no. 9, p. 5–16.

Albano, M. A., 1975, Subsurface stratigraphic analysis, "Cherokee" Group (Pennsylvanian), northeast Cleveland County, Oklahoma: Shale Shaker, v. 25, no. 5, p. 94–103 [part 1]; v. 25, no. 6, p. 114–123 [part 2]; v. 25, no. 7, p. 134–143 [part 3].

Al-Shaieb, Zuhair; Shelton, J. W.; and Puckette, J. O., 1989, Sandstone reservoirs of the Mid-Continent; short course syllabus for American Association of Petroleum Geologists Mid-Continent Section 1989 annual meeting, Oklahoma City: Oklahoma City Geological Society, p. 73–82.

Anderson, Eric, 1993, Submarine-fan delta depositional environment of the Pennsylvania Redfork sandstone [abstract]: American Association of Petroleum Geologists Bulletin, v. 77, p. 1570.

Astarita, A. M., 1975, Depositional trends and environments of "Cherokee" sandstones, east-central Payne County, Oklahoma: Oklahoma State University unpublished M.S. thesis, 50 p.

Balke, S. C., 1984, The petrology, diagenesis, stratigraphy, depositional environment, and clay mineralogy of the Red Fork sandstone in north-central Oklahoma: Oklahoma State University unpublished M.S. thesis, 98 p.

Bass, N. W.; Leatherock, Constance; Dillard, W. R.; and Kennedy, L. E., 1937, Origin and distribution of the Bartlesville and Burbank shoestring oil sands in parts of Oklahoma and Kansas: American Association of Petroleum Geologists Bulletin, v. 21, p. 30–66.

Bass, N. W., and others, 1942, Subsurface geology and oil and gas resources of Osage County, Oklahoma: U.S. Geological Survey Bulletin 900, 393 p.

Bates, R. L.; and Jackson, J. A., 1987, Glossary of geology: American Geological Institute, Alexandria, Virginia, 788 p.

Bauer, C. M., 1921, Notes on geology of the Okmulgee district: American Association of Petroleum Geologists Bulletin, v. 5, p. 282–292.

Bennison, A. P., 1979, Mobil basin and shelf border area in northeast Oklahoma during Desmoinesian cyclic sedimentation, *in* Hyne, N. J. (ed.), Sandstones of the Mid-Continent: Tulsa Geological Society Special Publication 1, p. 283–294.

____ 1984, Shelf to trough correlations of Late Desmoinesian and Early Missourian carbonate banks and related strata, northeast Oklahoma, *in* Hyne, N. J. (ed.), Limestones of the Mid-Continent: Tulsa Geological Society Special Publication 2, p. 93–126.

Benoit, E. L., 1957, The Desmoinesian Series, Edmond area, central Oklahoma: Shale Shaker, v. 8, no. 3, p. 15–29.

Ben-Saleh, F. F., 1970, Stratigraphic analysis of Pennsylvanian rocks in southeastern Anadarko basin, Oklahoma: University of Tulsa unpublished M.S. thesis, 76 p.

Berg, O. R., 1969, Cherokee Group, west flank of the Nemaha Ridge, north-central Oklahoma: Shale Shaker, v. 19, no. 6, p. 94–110.

Berry, C. G., 1965, Stratigraphy of the Cherokee Group, eastern Osage County, Oklahoma: Shale Shaker, v. 16, no. 4, p. 78–92.

Berryhill, R. A., 1961, Subsurface geology of south-central Pawnee County, Oklahoma: Shale Shaker, v. 12, no. 4, p. 2, 6, 15–17.

Beveridge, R. C., 1954, The subsurface geology of Major County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 74 p.

Blatt, Harvey; Middleton, Gerard; and Murray, Raymond, 1980, Origin of sedimentary rocks: Prentice-Hall, Inc., Englewood Cliffs, New Jersey, 782 p.

Blumenthal, M. B., 1956, Subsurface geology of the Prague-Paden area, Lincoln and Okfuskee Counties, Oklahoma: Shale Shaker, v. 7, no. 1, p. 9–31.

Bradshaw, R. D., 1959, The Autwine field, Kay County, Oklahoma: University of Oklahoma unpublished M.G.E. thesis, 81 p.

Branson, C. C., 1954, Desmoinesian rocks of northeastern Oklahoma: Oklahoma Geological Survey Guidebook 2, 41 p.

Brenner, R. L., 1989, Stratigraphy, petrology, and paleogeography of the upper portion of the Cherokee Group (Middle Pennsylvanian), eastern Kansas and northeastern Oklahoma: Kansas Geological Survey Geology Series 3, 70 p.

Brown, L. R., Jr., 1979, Deltaic sandstone facies of the Mid-Continent, *in* Hyne, N. J. (ed.), Pennsylvanian sandstones of the Mid-Continent: Tulsa Geological Society Special Publication 1, p. 35–63.

____ 1989, A sequence-stratigraphic and systems-tract model for the Virgilian and Wolfcampian Series, Eastern shelf and Midland basin, Texas, *in* Boardman, D. R., II; Barrick, J. E.; Cocke, Jim; and Nestell, M. K. (eds.), Middle and Late Pennsylvanian chronostratigraphic boundaries in north-central Texas: glacial-eustatic events, biostratigraphy, and paleoecology: Texas Tech University Studies in Geology 2, p. 35–62.

Burchfield, M. R.,1985, Map of Oklahoma oil and gas fields: Oklahoma Geological Survey Map GM-28, scale 1:500,000.

Busch, D. A., 1953, The significance of deltas in subsurface exploration: Tulsa Geological Society Digest, v. 21, p. 71–80.

____ 1971, Genetic units in delta prospecting: American Association of Petroleum Geologists Bulletin, v. 55, p. 1137–1154.

Bush, J. L.; and Helander, D. P., 1968, Empirical prediction of recovery rate in waterflooding depleted sands: Journal of Petroleum Technology, September, p. 933–943.

Campbell, N. E., 1984, Subsurface stratigraphic analysis of the Skiatook and "Cherokee" Groups in the southwestern part of Noble County, northern part of Logan County, and the southeastern part of Garfield County, Oklahoma: Oklahoma State University unpublished M.S. thesis, 40 p.

Carpenter, Everett, 1927, Geology of Washington County, *in* Oil and gas in Oklahoma: Oklahoma Geological Survey Bulletin 40-V, 20 p.

Candler, C. E., 1977, Subsurface stratigraphic analysis of selected sandstones of the "Cherokee" Group, southern Noble County, Oklahoma: Shale Shaker, v. 28, no. 3, p. 56–59 [part 1]; v. 28, no. 4, p. 72–83 [part 2].

Clayton, J. M., 1965, Paleodepositional environments of the "Cherokee" sands of central Payne County, Oklahoma: Shale Shaker, v. 16, no. 3, p. 50–66.

Clement, W. A., 1992, East Clinton field–U.S.A., Anadarko basin, Oklahoma, *in* Foster, N. H.; and Beaumont, E. A. (eds.), Stratigraphic traps III, Treatise of petroleum geology atlas of oil and gas fields: American Association of Petroleum Geologists, Tulsa, p. 207–267.

Clements, K. P., 1961, Subsurface study of the Skinner and Red Fork sand zones (Pennsylvanian) in portions of Noble and Kay Counties, Oklahoma: University of Oklahoma unpublished M.S. thesis, 62 p.

Clinton, R. P., 1957, The geology of Osage County: Shale

Shaker, v. 8, no. 2, p. 8–21.

Cockrell, D. R., 1985, Stratigraphy, distribution and structural geology of Lower and Middle Pennsylvanian sandstones in adjacent portions of Okfuskee and Seminole Counties, Oklahoma: Oklahoma State University unpublished M.S. thesis, 55 p.

Cole, J. A., 1956, Subsurface geology of east central Lincoln County, Oklahoma: Shale Shaker, v. 6, no. 7, p. 7–33.

Cole, J. G., 1968, Stratigraphic study of the Cherokee and Marmaton sequences, Pennsylvanian (Desmoinesian), east flank of the Nemaha Ridge, north-central Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 90 p. (Published in Shale Shaker, 1969, v. 19, no. 8, p. 134–142 [part 1]; v. 19, no. 9, p. 150–159 [part 2]).

Coleman, J. M.; and Prior, D. B., 1980, Deltaic sand bodies: American Association of Petroleum Geologists Continuing Education Course Notes Series, no. 15, 171 p.

____ 1982, Deltaic environments of deposition, *in* Scholle, P. A.; and Spearing, D. (eds.), Sandstone depositional environments: American Association of Petroleum Geologists Memoir 31, p. 139–178.

Conybeare, C. E. B., 1976, Geomorphology of oil and gas fields in sandstone bodies: Journal of Sedimentary Geology, v. 19, no. 1, p. 79–80.

____ 1979, Lithostratigraphic analysis of sedimentary basins: Academic Press, New York, 555 p.

Cruz, J. A., 1966, Geometry and origin of the Burbank sandstone and Mississippian "Chat" in T. 25 and 26 N., R. 6 E., Osage County, Oklahoma: University of Tulsa unpublished M.S. thesis, 43 p. (Published in Shale Shaker, 1966, v. 16, no. 5, p. 102–116.)

Culp, E. F., 1963, Northeast Cherokee, *in* Cramer, R. D.; Gatlin, Leroy; and Hessman, H. G. (eds.), Oil and gas fields of Oklahoma reference report: Oklahoma City Geological Society, v. 1, p. 18A–21A.

Cutolo-Lozano, Francisco, 1969, Subsurface geology of the Seminole area, Seminole, Pottawatomie, and Okfuskee Counties, Oklahoma: Shale Shaker, v. 19, no. 7, p. 118–130.

Dale, T. B., 1985, Red Fork and lower Skinner sandstones in Northwest Tecumseh field, Pottawatomie County, Oklahoma: University of Tulsa unpublished M.S. thesis, 292 p.

____ 1987, Red Fork and lower Skinner sandstones in Northwest Tecumseh field, Pottawatomie County, Oklahoma [abstract]: American Association of Petroleum Geologists Bulletin, v. 71, p. 991.

Dalton, D. V., 1960, The subsurface geology of northeast Payne County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 69 p.

Darnall, C. A., 1963, Northwest Okeene and North Homestead, T's 9–20 N., R's 11–12 W., Blaine and Major Counties, *in* Cramer, R. D.; Gatlin, Leroy; and Hessman, H. G. (eds.), Oil and gas fields of Oklahoma reference report: Oklahoma City Geological Society, v. 1, p. 90A–93A.

Diba, M. H., 1974, Geology and logging study of the Bartlesville (Red Fork) sand of the southwest Clearbrook field in a portion of Cleveland County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 130 p.

Dogan, Nevzat, 1970, Subsurface study of Pennsylvanian rocks in east central Oklahoma (from the Brown Limestone to the Checkerboard Limestone): Shale Shaker, v. 20, no. 10, p. 192–213.

Duck, J. H., Jr., 1959, The Northwest Butner pool area, Seminole County, Oklahoma: Shale Shaker, v. 9, no. 5, p. 5–21.

Esfandiari, Bijan, 1965, Geological engineering study of the Redfork sand (Pennsylvanian) in a portion of Oklahoma County, Oklahoma: University of Oklahoma unpublished M.G.E. thesis, 112 p.

Ferguson, D. B., 1964, Subsurface geology of northern Lincoln County, Oklahoma: Shale Shaker, v. 14, no. 10, p. 4–14.

Furlow, Bruce, 1964, Subsurface geology of the Kellyville district, Creek County, Oklahoma: Shale Shaker, v. 15, no. 3, p. 32–51.

Galloway, W. E.; and Hobday, D. K., 1983, Terrigenous clastic depositional systems: Springer-Verlag, New York, 423 p.

Gamero, G. A., 1965, Subsurface stratigraphic analysis of northern Pottawatomie County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 52 p.

Gearhart, H. L., 1958, Subsurface geology of northwestern Pawnee County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 69 p.

Glass, J. L., 1981, Depositional environments, reservoir trends, and diagenesis of the Red Fork sandstone in Grant and eastern Kay Counties, Oklahoma: Oklahoma State University unpublished B.S. thesis, 100 p.

Gonzalez, G. C., 1969, Reservoir study, Red Fork sandstone in the Oakdale field, Woods County, Oklahoma: Shale Shaker, v. 19, no. 10, p. 170–179.

Greig, P. B., Jr., 1959, Geology of Pawnee County, Oklahoma: Oklahoma Geological Survey Bulletin 83, 188 p.

Hadler, H. G., 1947, A subsurface study of northwestern Cleveland County, Oklahoma, with emphasis on the South and West Moore oil fields: University of Oklahoma unpublished M.S. thesis, 33 p.

Hanke, H. W., 1967, Subsurface stratigraphic analysis of the Cherokee Group in north-central Creek County, Oklahoma: Shale Shaker, v. 17, no. 8, p. 150–167.

Hawisa, Ibrahim, Sr., 1965, Depositional environment of the Bartlesville, the Red Fork, and the Skinner sandstones in portions of Lincoln, Logan, and Payne Counties, Oklahoma: University of Tulsa unpublished M.S. thesis, 35 p.

Hawthorne, H. W., 1982, The Red Fork sandstone, Cherokee Group (Pennsylvanian) of the Southeast Thomas field, Custer County, Oklahoma: Baylor University unpublished B.S. thesis, 31 p. (Published in Shale Shaker, 1984, v. 35, no. 3, p. 50–58).

Hemish, L. A., 1990, Lithostratigraphy and core drilling, Upper Atoka Formation through Lower Senora Formation (Pennsylvanian), Northeastern Oklahoma shelf area, Oklahoma Geological Survey Special Publication 90-2, 54 p.

Hudson, A. S., 1970, Depositional environment of the Red Fork and equivalent sandstones east of the Nemaha Ridge, Kansas and Oklahoma: Shale Shaker, v. 21, no. 4, p. 80–95.

Hutchison, L. L., 1911, Preliminary report on the rock asphalt, asphaltite, petroleum and natural gas in Oklahoma: Oklahoma Geological Survey Bulletin 2, 256 p.

Ingham, W. I., 1941, Dora oil pool, Seminole County, Oklahoma, *in* Levorsen, A. I. (ed.), Stratigraphic type oil fields: American Association of Petroleum Geologists, Tulsa, p. 408–435.

Isokrari, O. F., 1974, Relationship between geological and engineering parameters in low permeability Red Fork shoestring oil reservoirs in Oklahoma: University of Oklahoma unpublished M.S. thesis, 77 p.

Johnson, C. L., 1984, Depositional environments, reservoir trends and diagenesis of Red Fork sandstones in portions of Blaine, Caddo, and Custer Counties, Oklahoma: Shale Shaker, v. 35, no. 2, p. 30–46.

____ 1992, Burbank field–U.S.A., Anadarko basin, Oklahoma, *in* Foster, N. H.; and Beaumont, E. A. (eds.), Stratigraphic traps III, Treatise of petroleum geology atlas of oil and gas fields: American Association of Petroleum Geologists, Tulsa, p. 333–345.

Johnson, K. S., and others, 1989, Geology of the southern Midcontinent: Oklahoma Geological Survey Special Publication 89-2, 53 p.

Jones, J. G., 1957, Geology of the Ashland-Kiowa area, Pittsburg County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 126 p.

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

____ 1959, Oil and gas in Creek County, Oklahoma, *in* Oakes, M. C., Geology and mineral resources of Creek County, Oklahoma: Oklahoma Geological Survey Bulletin 81, p. 61–100.

____ 1960, Oil and gas in Kingfisher County, Oklahoma: Oklahoma Geology Notes, v. 20, p. 303–314.

Joseph, L. E., 1986, Subsurface analysis, "Cherokee" Group (Desmoinesian), portions of Lincoln, Pottawatomie, Seminole, and Okfuskee Counties, Oklahoma: Shale Shaker, v. 37, no. 3, p. 44–69.

Kirk, M. S., 1957, A subsurface section from Osage County to Okfuskee County, Oklahoma: Shale Shaker, v. 7, no. 6, p. 2–21.

Krumme, G. W., 1975, Mid-Pennsylvanian source reversal on the Oklahoma platform: University of Tulsa unpublished Ph.D. dissertation, 151 p.

____ 1981, Stratigraphic significance of limestones of the Marmaton Group (Pennsylvanian, Desmoinesian) in eastern Oklahoma: Oklahoma Geological Survey Bulletin 131, 67 p.

Kurash, G. E., Jr., 1964, Subsurface geology of west-central Lincoln County, Oklahoma: Shale Shaker, v. 14, no. 6, p. 2–26.

Leatherock, Constance, 1937, Physical characteristics of Bartlesville and Burbank sands in northeastern Oklahoma and southeastern Kansas: American Association of Petroleum Geologists, v. 21, p. 246–258.

Levine, S. D., 1984, Provenance and diagenesis of the Cherokee sandstones, deep Anadarko basin, western Oklahoma: Shale Shaker, v. 34, no. 10, p. 120–144.

Lewis, F. S., 1993, Depositional variations and reservoir characterization in the Red Fork sandstone, Northwest Tecumseh field, Pottawatomie 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. 40–51.

Lillibridge, Margaret, 1963, Ringwood district: T's 21–22 N., R's 9, 10, 11, and 12 W., *in* Cramer, R. D.; Gatlin, Leroy; and Hessman, H. G. (eds.), Oil and gas fields of Oklahoma reference report: Oklahoma City Geological Society, v. 1, p. 100A–104A.

Logan, D. M., 1956, Outline of talk given on geology of the Okmulgee area [abstract]: Tulsa Geological Society Digest, v. 24, p. 74–77.

____ 1957, Geology of the Okmulgee district: Okmulgee Geological and Engineering Society, 8 p., 10 maps, 8 pls.

Lojek, C. A., 1984, Petrology, diagenesis and depositional environment of the Skinner sandstone, Desmoinesian, northeastern Oklahoma platform: Shale Shaker, v. 34, no. 7, p. 82–92 [part 1]; v. 34, no. 8, p. 95–103 [part 2].

London, W. W., 1975, A geological and engineering study of the Mustang pool, Canadian County, Oklahoma: Shale Shaker, v. 26, no. 1, p. 4–12 [part 1]; v. 26, no. 2, p. 26–35 [part 2]; v. 26, no. 3, p. 50–55 [part 3].

Lyon, G. M., 1971, Subsurface stratigraphic analysis, lower "Cherokee" Group, portions of Alfalfa, Major, and Woods Counties, Oklahoma: University of Oklahoma unpublished M.S. thesis, 33 p. (Published in Shale Shaker, 1971, v. 22, no. 1, p. 4–26).

Lyons, P. L.; and Dobrin, M. B., 1972, Seismic exploration for stratigraphic traps, *in* King, Robert (ed.), Stratigraphic oil and gas fields; classification, exploration methods, and case histories: American Association of Petroleum Geologists Memoir 16, p. 225–243.

Markham, E. O.; and Lamar, L. C., 1937, South Burbank pool, Osage County, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 21, p. 560–579.

Mason, E. P., 1982, The petrology, diagenesis and depositional environment of the Bartlesville sandstone in the Cushing oil field, Creek County, Oklahoma: Oklahoma State University unpublished M.S. thesis, 150 p.

McElroy, M. N., 1961, Isopach and lithofacies study of the Desmoinesian Series of north-central Oklahoma: Shale Shaker, v. 12, no. 1, p. 2–22.

Miller, E. G., 1970, Subsurface stratigraphic and statistical analysis, Cherokee, Marmaton, and Kansas City–Lansing Groups, Major and Woods Counties, Oklahoma: University of Oklahoma unpublished M.S. thesis, 58 p.

Mogharabi, Ataolah, 1963, Petroleum geology of T. 19 N., R. 6 W., Hennessey area, Kingfisher County, Oklahoma: Shale Shaker, v. 14, no. 4, p. 2–17.

Oakes, M. C., 1953, Krebs and Cabaniss Groups of Pennsylvanian age in Oklahoma: American Association of Petroleum Geologists Bulletin, v. 37, p. 1523–1526.

O'Reilly, K. L., 1986, Diagenesis and depositional environments of the Red Fork sandstone (Des Moinesian) in the Wakita trend, Grant County, Oklahoma: University of Tulsa unpublished M.S. thesis, 154 p.

Page, K. G., 1955, The subsurface geology of southern Noble County, Oklahoma: Shale Shaker, v. 5, no. 10, p. 5–25.

Petzet, G. A., 1988, Upper Red Fork trend pays off in Oklahoma: Oil and Gas Journal, v. 86, no. 11, p. 78–79.

Puckette, J. O., 1990, Depositional setting, facies, and petrology of Cabaniss (upper "Cherokee") Group in Beckham, Dewey, Custer, Ellis, Roger Mills, and Washita Counties, Oklahoma: Oklahoma State University unpublished M.S. thesis, 144 p.

Puckette, J. O.; and Al-Shaieb, Zuhair, 1990, Depositional facies of hydrocarbon-bearing reservoirs of Cabaniss ("Upper Cherokee") Group, Anadarko basin, *in* Bridges, S. D.; and Troutman, G. W. (eds.), Transactions of the 1989 American Association of Petroleum Geologists Mid-Continent Section Meeting: Oklahoma City Geological Society, 39 p.

Pulling, D. M., 1976, Subsurface stratigraphic and structural analysis, Cherokee Group, Pottawatomie County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 73 p. (Published in Shale Shaker, 1979, v. 29, no. 6, p. 124–137 [part 1]; v. 29, no. 7, p. 148–158 [part 2]).

Querry, J. L., 1958, Subsurface geology of south-central Kay County, Oklahoma: Shale Shaker, 1979, v. 8, no. 7, p. 10–29.

Rascoe, Bailey, Jr.; and Adler, F. J., 1983, Permo-Carboniferous hydrocarbon accumulations, Mid-Continent, U.S.A.: American Association of Petroleum Geologists Bulletin, v. 67, p. 979–1001.

Rau, H. L.; and Ackley, K. A., 1939, Geology and development of Keokuk pool, Seminole and Pottawatomie Counties, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 23, p. 220–245.

Ries, E. R., 1954, Geology and mineral resources of Okfuskee County, Oklahoma: Oklahoma Geological Survey Bulletin 71, 120 p.

Riggs, C. H.; and Smith, W. C., 1951, Water flooding of oil sands in Washington County, Oklahoma: U.S. Department of Interior, Bureau of Mines Report of Investigations 4795, 16 p.

Roark, S. D., 1992, Selected methods of investigation of "old" electric logs of the lower Skinner sandstone, and computer-assisted mapping of the "Cherokee" Group, township 15 north, range 3 east, Lincoln County, Oklahoma: Oklahoma State University unpublished M.S. thesis, 84 p.

Robertson, K. S., 1983, Stratigraphy, depositional environments, petrology, diagenesis, and hydrocarbon maturation related to the Red Fork sandstone in north-central Oklahoma: Oklahoma State University unpublished M.S. thesis, 137 p.

Rosewitz, L. E., 1981, Surface analysis, "Cherokee" Group (Desmoinesian), portions of Lincoln, Pottawatomie, Seminole, and Okfuskee Counties, Oklahoma: University of Oklahoma unpublished M.S. thesis, 57 p.

Sands, J. M., 1929, Burbank field, Osage County, Oklahoma, *in* Hull, J. P. D. (ed.), Structure of typical American oil fields, a symposium on the relation of oil accumulation to structure, v. I: American Association of Petroleum Geologists, Tulsa, p. 220–229.

Sartin, J. P., 1958, A cross sectional study of the oil producing rocks of Desmoinesian age in northeastern Oklahoma: University of Oklahoma unpublished M.S. thesis, 91 p.

Schneider, R. E.: and Clement, W. A., 1986, The East Clinton gas field, Custer County, Oklahoma, seismic-stratigraphic case history: Shale Shaker, v. 37, no. 1, p. 10–14.

Scott, J. D., 1970, Subsurface stratigraphic analysis, "Cherokee" Group, northern Noble County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 56 p.

Shell Oil Company, 1963, Cheyenne Valley, T's 21–22 N., R's 14–15 W., Major County, *in* Cramer, R. D.; Gatlin, Leroy; and Hessman, H. G. (eds.), Oil and gas fields of Oklahoma reference report: Oklahoma City Geological Society, v. 1, p. 24A–25A.

Shelton, J. W.; Bingham, R. H.; and Jenkins, W. A., 1980, Geology and mineral resources of Noble County, Oklahoma: Oklahoma Geological Survey Bulletin 128, 66 p.

Shelton, J. W.; Ross, J. S.; Garden, A. J.; and Franks, J. L., 1985, Geology and mineral resources of Payne County, Oklahoma: Oklahoma Geological Survey Bulletin 137, 92 p.

Shelton, J. W.; Stewart, Garry; and Al-Shaieb, Zuhair, 1987, Depositional environments, diagenesis and porosity development, and petrophysical features of selected Pennsylvanian sandstones in Oklahoma: an examination of outcrop and subsurface data: American Association of Petroleum Geologists 1987 Mid-Continent Section Meeting, Field Trip Guidebook, 30 p.

Sheriff, R. E., 1984, Encyclopedic dictionary of exploration geophysics [2nd edition]: Society of Exploration Geophysicists, Tulsa, 323 p.

Shipley, R. D., 1977, Local depositional trends of "Cherokee" sandstones, Payne County, Oklahoma: Shale Shaker, v. 28, no. 2, p. 24–35 [part 1]; v. 28, no. 3, p. 48–55 [part 2].

Shirley, S. H., 1986, Stratigraphic and structural subsurface analysis of pre-Missourian rocks in the northwest Norman area, Cleveland and McClain Counties, Oklahoma: University of Oklahoma unpublished M.S. thesis, 98 p.

Shulman, Chaim, 1966, Stratigraphic analysis of the "Cherokee" Group in adjacent portions of Lincoln, Logan, and Oklahoma Counties, Oklahoma: Shale Shaker, v. 16, no. 6, p. 126–140.

Stanbro, G. E., Jr., 1960, A subsurface study of the "Cherokee" Group, Grant County, and a portion of Alfalfa County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 34 p.

Stringer, C. P., Jr., 1957, Subsurface geology of western Payne County, Oklahoma: Shale Shaker, v. 7, no. 8, p. 3–20.

Swanson, D. C., 1976, Meandering stream deposits: Swanson Petroleum Enterprises, Cygnet Group, Inc., Houston, 30 p.

____ 1993, The importance of fluvial processes and related reservoir deposits: Journal of Petroleum Technology, v. 45, no. 4, p. 368–377.

Swesnik, R. M., 1948, Geology of West Edmond oil field, Oklahoma, Logan, Canadian, and Kingfisher Counties, Oklahoma, *in* Howell, J. V. (ed), Structure of typical American oil fields, a symposium on the relation of oil-accumulation to structure, v. III: American Association of Petroleum Geologists, Tulsa, p. 359–398.

Talley, J. B., 1955, The subsurface geology of northeastern Noble County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 58 p.

Tate, W. L., 1985, The depositional environment, petrology, diagenesis, and petroleum geology of the Red Fork sandstone in central Oklahoma: Oklahoma State University unpublished M.S. thesis, 189 p.

Thalman, A. L., 1967, Geology of the Oakdale Red Fork sand field, Woods County, Oklahoma: Shale Shaker, v. 18, no. 1, p. 3–11.

____ 1973, Northwest Oakdale field (Red Fork sand), T's 23–25 N., R. 13 W., Woods County, Oklahoma, *in* Berg, O. R. (ed.), Oil and gas fields of Oklahoma reference report: Oklahoma City Geological Society, v. 1, Supplement A, p. 18.

Tolson, P. M., 1993, Depositional environments of the Redfork sandstone in Custer and Roger Mills Counties, Southwestern Oklahoma [abstract]: American Association of Petroleum Geologists Bulletin, v. 77, p. 1577–1578.

Trantham, J. C.; Threlkeld, C. B.; and Patterson, H. L., Jr., 1980, Reservoir description for a surfactant/polymer pilot in a fractured, oil-wet reservoir, North Burbank Unit Tract 97: Journal of Petroleum Technology, v. 32, p. 1647–1656.

Udayashankar, K. V., 1985, Depositional environment, petrology, and diagenesis of the Red Fork sandstone in central Dewey County, Oklahoma: Oklahoma State University unpublished M.S. thesis, 188 p.

Valderrama, Rafael, 1976, The Skinner sandstone zone of central Oklahoma: Shale Shaker, v. 26, no. 5, p. 86–98 [part 1]; v. 26, no. 6, p. 106–114 [part 2].

Van Wagoner, J. C.; Mitchum, R. M.; Campion, K. M.; and Rahmanian, V. D., 1990, Siliciclastic sequence stratigraphy in well logs, cores, and outcrops: concepts for high-resolution correlation of time and facies: American Association of Petroleum Geologists Methods in Exploration Series, no. 7, 55 p.

Verish, N. P., 1979, Reservoir trends, depositional environments, and petroleum geology of "Cherokee" sandstones in T11–13N, R4–5E, central Oklahoma: Shale Shaker, v. 29, no. 9, p. 209 [part 1]; v. 29, no. 10, p. 224–237 [part 2].

Visher, G. S.; Saitto, B. S.; and Phares, R. S., 1971, Pennsylvanian delta patterns and petroleum occurrences in eastern Oklahoma: American Association of Petroleum Geologists Bulletin, v. 55, p. 1206–1230.

Walker, R. G., 1984, Sandy fluvial systems, *in* Walker, R. G. (ed.), Facies models [2nd edition]: Geoscience Canada Reprint Series 1, p. 71–89.

Walker, R. K., 1982, Structural geology and distribution of Lower and Middle Pennsylvanian sandstones in adjacent portions of Lincoln, Okfuskee, Seminole, and Pottawatomie Counties, Oklahoma: Oklahoma State University unpublished M.S. thesis, 53 p.

Wanless, H. R., and others, 1970, Late Paleozoic deltas in the central and eastern United States, *in* Morgan, J. P. (ed.), Deltaic sedimentation, modern and ancient: Society of Economic Paleontologists and Mineralogists Special Publication 15, p. 215–245.

Ware, H. E., Jr., 1955, Surface and shallow subsurface investigation of the Senora Formation of northeastern Oklahoma: Shale Shaker, v. 5, no. 7, p. 5–22.

Warner, G. E., 1968, Waterflooding a highly stratified reservoir: Journal of Petroleum Technology, v. 20, no. 2, p. 1179–1186.

Weaver, O. D., Jr., 1952, The geology of Hughes County, Oklahoma: University of Oklahoma unpublished Ph.D. dissertation, 201 p.

Weirich, T. E., 1929, Cushing oil and gas field, Creek County, Oklahoma, *in* Structure of typical American oil fields, a symposium on the relation of oil accumulation to structure, v. II: American Association of Petroleum Geologists, Tulsa, p. 396–406.

____ 1953, Shelf principle of oil origin, migration, and accumulation: American Association of Petroleum Geologists Bulletin, v. 37, p. 2027–2045.

Wheeler, D. M.; Scott, A. J.; Coringrato, V. J.; and Devine, P. E., 1990, Stratigraphy and depositional history of the Morrow Formation, southeast Colorado and southwest Kansas, *in* Sonnenberg, S. A., and others (eds.), Morrow sandstones of southeast Colorado and adjacent areas: Rocky Mountain Association of Geologists, Denver, p. 9–35.

White, P. B., 1989, Boggy-Thurman (Middle Pennsylvanian) relationships—sedimentological evidence in the Arkoma basin, Oklahoma, for the time of recurrent uplift in the Ouachita fold belt: University of Oklahoma unpublished M.S. thesis, 143 p.

White, S. B., 1941, Davenport field, Lincoln County, Oklahoma, *in* Levorson, A. I. (ed.), Stratigraphic type oil fields, a symposium: American Association of Petroleum Geologists, Tulsa, p. 386–407.

Whiting, P. H., 1984, Depositional environment of Red Fork sandstones, deep Anadarko basin, western Oklahoma: Shale Shaker, v. 34, no. 9, p. 104–119.

Withrow, P. C., 1967, The Red Fork sandstone in the Wakita trend, Grant and Alfalfa Counties, Oklahoma: Shale Shaker, v. 17, no. 10, p. 198–205.

____ 1968, Depositional environments of Pennsylvanian Red Fork sandstone in northeastern Anadarko basin, Oklahoma: American Association of Petroleum Geologists Bulletin, v. 52, p. 1638–1654.

Wright, Randall, 1941, Red Fork shoestring sand pool, Pawnee, Creek, and Tulsa Counties, northeastern Oklahoma, *in* Levorsen, A. I. (ed.), Stratigraphic type oil fields: American Association of Petroleum Geologists, Tulsa, p. 473–491.

Zeliff, C. W., 1976, Subsurface analysis, "Cherokee" Group (Pennsylvanian), northern Kingfisher County, Oklahoma: Shale Shaker, v. 27, no. 1, p. 4–6 [part 1]; v. 27, no. 2, p. 24–32 [part 2]; v. 27, no. 3, p. 44–56 [part 3].

APPENDIXES ▷ ▷ ▷

APPENDIX 1

Various Size Grade Scales in Common Use

(from Blatt and others, 1980)

Udden–Wentworth	*ϕ values*	*German scale†* *(after Atterberg)*	*USDA and Soil Sci. Soc. Amer.*	*U.S. Corps Eng., Dept. Army and Bur. Reclamation‡*
		(Blockwerk)		
Cobbles		——200 mm——	Cobbles	Boulders
			——80 mm——	——10 in.——
——64 mm——	−6			Cobbles
		Gravel		——3 in.——
Pebbles		(Kies)		
				Gravel
——4 mm——	−2		Gravel	
				——4 mesh——
Granules				
				Coarse sand
——2 mm——	−1	——2 mm——	——2 mm——	——10 mesh——
Very coarse sand			Very coarse sand	
——1 mm——	0		——1 mm——	
Coarse sand		Sand	Coarse sand	Medium sand
——0.5 mm——	1		——0.5 mm——	
				——40 mesh——
Medium sand			Medium sand	
——0.25 mm——	2		——0.25 mm——	
Fine sand			Fine sand	Fine sand
——0.125 mm——	3		——0.10 mm——	
Very fine sand				
			Very fine sand	——200 mesh——
——0.0625 mm——	4	—0.0625 mm—		
			——0.05 mm——	
Silt		Silt		
			Silt	Fines
——0.0039 mm——	8			
		—0.002 mm—	——0.002 mm——	
Clay		Clay	Clay	
		(Ton)		

†Subdivisions of sand sizes omitted.

‡Mesh numbers are for U.S. Standard sieves: 4 mesh = 4.76 mm, 10 mesh = 2.00 mm, 40 mesh = 0.42 mm, 200 mesh = 0.074 mm.

APPENDIX 2

Abbreviations Used in Text and on Figures, Tables, and Plates

API	American Petroleum Institute
BCF	billion cubic feet (of gas)
BCFG	billion cubic feet of gas
BO	barrels of oil
BOPD	barrels of oil per day
BHP	bottom-hole pressure
BWPD	barrels of water per day
cp	centipoise (a standard unit of viscosity)
DST	drill stem test
GOR	gas to oil ratio
gty	gravity
IPF	initial production flowing
IPP	initial production pumping
MBO	thousand barrels of oil
MCF	thousand cubic feet (of gas)
md	millidarcies, or 0.001 darcy
MMBO	million barrels of oil
MMCF	million cubic feet (of gas)
MMCFG	million cubic feet of gas
MMCFGPD	million cubic feet of gas per day
MMSCF	million standard cubic feet (of gas)
MMSTB	million stock tank barrels
MSCF/STB	thousand standard cubic feet per stock tank barrel
MSTB	thousand stock tank barrels
OOIP	original oil in place
OWC	oil-water contact
OWWO	oil well worked over
PSI	pounds per square inch
PSIA	pounds force per square inch, absolute
PVT	pressure volume temperature
RB	reservoir barrels (unit of measurement of oil in the subsurface where the oil contains dissolved gas); see STB or STBO
RB/STB	reservoir barrels per stock tank barrels
SCF/STB	standard cubic feet per stock tank barrel
STB or STBO	stock tank barrels of oil (unit of measurement for oil at the surface in a gas-free state rather than in the subsurface reservoir where the oil contains dissolved gas); see RB
STB/DAY	stock tank barrels (of oil) per day
TSTM	too small to measure

APPENDIX 3
Glossary of Terms
(as used in this volume)

Definitions modified from Bates and Jackson (1987), Sheriff (1984), and Van Wagoner and others (1990).

allogenic—Formed or generated elsewhere.

anastomosing stream—A fluvial depositional system characterized by a branching network of shallow channels. Similar in form to braided river systems except that anastomosing rivers have alluvial islands covered by dense and permanent vegetation that stabilizes river banks.

authigenic—Formed or generated in place.

avulsion—A sudden cutting off or separation of land by a flood or by an abrupt change in the course of a stream, as by a stream breaking through a meander or by a sudden change in current whereby the stream deserts its old channel for a new one.

bar finger—An elongated, lenticular body of sand underlying, but several times wider than, a distributary channel in a bird-foot delta.

bed load—The part of the total stream load that is moved on or immediately above the stream bed, such as the larger or heavier particles (boulders, pebbles, gravel) transported by traction or saltation along the bottom; the part of the load that is not continuously in suspension or solution.

braided stream—A stream that divides into or follows an interlacing or tangled network of several small branching and reuniting shallow channels separated from each other by branch islands or channel bars.

capillary pressure—The difference in pressure across the interface between two immiscible fluid phases jointly occupying the interstices of a rock. It is due to the tension of the interfacial surface, and its value depends on the curvature of that surface.

centipoise—A unit of viscosity equal to 10^{-3}kg/s.m. The viscosity of water at 20°C is 1.005 centipoise.

channel deposit—An accumulation of clastic material, commonly consisting of sand, gravel, silt, and clay, in a trough or stream channel where the transporting capacity of the stream is insufficient to remove material supplied to it.

clay drapes—Layers of clay and silt deposited on lateral accretionary surfaces of point bars during periods of decreased river discharge.

crevasse-splay deposit—See *splay*.

delta—The low, nearly flat, alluvial tract of land at or near the mouth of a river, commonly forming a triangular or fan-shaped plain of considerable area, crossed by many distributaries of the main river, perhaps extending beyond the general trend of the coast, and resulting from the accumulation of sediment supplied by the river in such quantities that it is not removed by tides, waves, and currents. See also: *delta plain, delta front, prodelta, lower delta plain,* and *upper delta plain.*

delta front—A narrow zone where deposition in deltas is most active, consisting of a continuous sheet of sand, and occurring within the effective depth of wave erosion (10 m or less). It is the zone separating the *prodelta* from the *delta plain,* and it may or may not be steep.

delta plain—The level or nearly level surface composing the landward part of a large delta; strictly, an alluvial plain characterized by repeated channel bifurcation and divergence, multiple distributary channels, and interdistributary flood basins.

diagenesis—All changes that affect sediments after initial deposition, including compaction, cementation, and chemical alteration and dissolution of constituents. It does not include weathering and metamorphism of preexisting sediments.

diapir—A dome or anticlinal fold in which the overlying rocks have been ruptured by the squeezing-out of plastic core material. Diapirs in sedimentary strata usually contain cores of salt or shale.

distributary channel—(a) A divergent stream flowing away from the main stream and not returning to it, as in a delta or on an alluvial plain. (b) One of the channels of a braided stream; a channel carrying the water of a stream distributary.

distributary mouth bar—The main sediment load of a distributary channel in the subaqueous portion of a *delta* (also called the *delta front*). It consists predominantly of sand and silt; grain size decreases seaward.

eustatic—Pertaining to worldwide changes of sea level that affect all the oceans.

facies—(a) A mappable, areally restricted part of a lithostratigraphic body, differing in lithology or fossil content from other beds deposited at the same time and in lithologic continuity. (b) A distinctive rock type, broadly corresponding to a certain environment or mode of origin.

fluvial—(a) Of or pertaining to a river or rivers. (b) Produced by the action of a stream or river.

formation-volume factor—The factor applied to convert a barrel of gas-free oil in a stock tank at the surface into an equivalent amount of oil in the reservoir. It generally ranges between 1.14 and 1.60. See also: *shrinkage factor.*

highstand—The interval of time during one or more cycles of relative change of sea level when sea level is above the shelf edge in a given local area.

highstand system tract (HST)—The stratigraphically higher (or younger) depositional system(s) in a succession of genetically related strata bounded by unconformities or their correlative counterparts.

incised valleys—Entrenched fluvial systems that extend their channels basinward and erode into underlying strata.

infilling—A process of deposition by which sediment falls or is washed into depressions, cracks, or holes.

isopach—A line drawn on a map through points of equal true thickness of a designated stratigraphic unit or group of stratigraphic units.

lacustrine—Pertaining to, produced by, or formed in a lake or lakes.

lower delta plain—Depositional environment within a *delta* which extends from the subaqueous *delta front* to the landward limit of marine (tidal) influence.

lowstand—The interval of time during one or more cycles of relative change of sea level when sea level is below the shelf edge.

lowstand system tract (LST)—The stratigraphically lower (or older) depositional system(s) in a succession of genetically related strata bounded by unconformities or their correlative counterparts.

meander—One of a series of regular freely developing sinuous curves, bends, loops, turns, or windings in the course of a stream. See also: *meander belt.*

meander belt—The zone along a valley floor across which a meandering stream shifts its channel from time to time; specifically the area of the flood plain included between two lines drawn tangentially to the extreme limits of all fully developed meanders. It may be from 15 to 18 times the width of the stream.

meteoric water—Pertaining to water of recent atmospheric origin.

millidarcy (md)—The customary unit of measurement of fluid permeability, equivalent to 0.001 darcy.

mud cake—A clay lining or layer of concentrated solids adhering to the walls of a well or borehole, formed where the drilling mud lost water by filtration into a porous formation during rotary drilling.

natural water drive—Energy within an oil or gas pool, resulting from hydrostatic or hydrodynamic pressure transmitted from the surrounding aquifer.

offlap—A term commonly used by seismic interpreters for reflection patterns generated from strata prograding into deep water.

onlap—The progressive submergence of land by an advancing sea.

point bar—One of a series of low, arcuate ridges of sand and gravel developed on the inside of a growing meander by the slow addition of individual accretions accompanying migration of the channel toward the outer bank.

prodelta—The part of a delta that is below the effective depth of wave erosion, lying beyond the *delta front,* and sloping gently down to the floor of the basin into which the delta is advancing and where clastic river sediment ceases to be a significant part of the basin-floor deposits.

progradation—The building forward or outward toward the sea of a shoreline or coastline (as of a beach, delta, or fan) by nearshore deposition of river-borne sediments or by continuous accumulation of beach material thrown up by waves or moved by longshore drifting.

proppant—As used in the well completion industry, any type of material that is used to maintain openings of induced fractures. Proppants usually consist of various sizes of sand, silica beads, or other rigid materials, and they are injected into the formation while suspended in a medium such as water, acid, gel, or foam.

regression—The retreat or contraction of the sea from land areas, and the consequent evidence of such withdrawal (such as enlargement of the area of deltaic deposition).

residual oil—Oil that is left in the reservoir rock after the pool has been depleted.

ribbon sand—See: *shoestring sand.*

rip-up—Said of a sedimentary structure formed by shale clasts (usually of flat shape) that have been "ripped up" by currents from a semiconsolidated mud deposit and transported to a new depositional site.

river bar—A ridge-like accumulation of alluvium in the channel, along the banks, or at the mouth, of a river.

shoestring sand—A shoestring composed of sand or sandstone, usually buried in the midst of mud or shale; e.g., a buried distributary mouth bar, coastal beach, or channel fill.

shrinkage factor—The factor that is applied to convert a barrel of oil in the reservoir into an equivalent amount of gas-free oil in a stock tank at the surface. It generally ranges between 0.68 and 0.88. See also: *formation-volume factor.*

splay—A small alluvial fan or other outspread deposit formed where an overloaded stream breaks through a levee (artificial or natural) and deposits its material on the flood plain or delta plain.

stillstand—Stability of an area of land, as a continent or island, with reference to the Earth's interior or mean sea level, as might be reflected, for example, by a relatively unvarying base level of erosion between periods of crustal movement.

subaerial—Said of conditions and processes, such as erosion, that exist or operate in the open air on or immediately adjacent to the land surface; or of features and materials, such as eolian deposits, that are formed or situated on the land surface. The term is sometimes considered to include fluvial.

tabular cross-bedding—Cross-bedding in which the cross-bedded units, or sets, are bounded by planar, essentially parallel surfaces, forming a tabular body.

thalweg—The line conecting the lowest or deepest points along a stream bed or valley, whether under water or not.

transgression—The spread or extension of the sea over land areas, and the consequent evidence of such advance.

transgressive system tract (TST)— A depositional episode that is bounded below by the transgressive surface and above by sediments representing a period of maximum flooding. The depositional environment of a TST becomes progressively deeper upward in the section.

transverse river bar—A channel bar deposit which is generally at an angle across the channel but prograding on the downstream side. This type of river deposit may be lobate, straight, or sinuous in map view.

trough cross-bedding—Cross-bedding in which the lower bounding surfaces are curved surfaces of erosion; it results from local scour and subsequent deposition.

upper delta plain—Depositional environment in a *delta* that extends from the down-flow edge of the flood plain to the effective limit of tidal inundation of the *lower delta plain*. The upper delta plain essentially is that portion of a delta unaffected by marine processes.

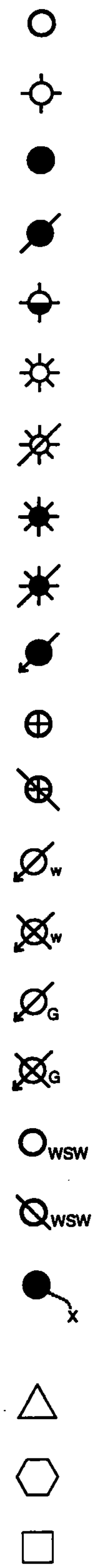
unitized—Consolidating the management of an entire oil or gas pool, regardless of property lines and lease boundaries, in the interest of efficient operation and maximum recovery.

valley fill—Sediment deposited in a valley or trough by any process; commonly, fluvial channel deposition is implied.

water leg—A water-saturated zone that extends below an oil- or gas-saturated zone.

APPENDIX 4

Well Symbols Used in Figures and Plates



- Location
- Dry hole
- Oil well
- Abandoned oil well
- Dry hole, show of oil
- Gas well
- Abandoned gas well
- Oil and gas well-dual completion
- Abandoned oil and gas well
- Oil well converted to injection well
- Salt-water disposal well
- Abandoned salt-water disposal well
- Water injection (input) well
- Abandoned water injection well
- Gas injection (input) well
- Abandoned gas injection well
- Water supply well
- Abandoned water supply well
- Directionally drilled well
  (Surface location shows well completion status. X indicates bottom hole location.)
- Discovery well
- Type or representative log well
- Cored well

NDE- Not deep enough

DNP- Did not penetrate

ND- No well data

NL- No well log

APPENDIX 5

Core Descriptions, Well Logs, and Digital Images of Select Rock Intervals for the Following Wells:

1. **Clifford Resources, Inc. Neighbors No. 1-27**
   NE¼SE¼NW¼ sec. 27, T. 13 N., R. 5 E.
   Red Fork, incised channel
   Cored interval: 3,975–4,032 ft

2. **Helmerich and Payne No. 2-32 Sanborn**
   NE¼SW¼NE¼ sec. 32, T. 10 N., R. 12 W.
   Red Fork, marine shelf bar
   Cored interval: 12,788–12,815 ft

3. **Anadarko Petroleum Sackett "B" No. 1**
   CNW¼SW¼ sec. 14, T. 23 N., R. 13 W.
   Red Fork (mystery rock?), possibly reworked valley-fill channel sand?, from Oakdale Field
   Cored interval: 6,447–6,500 ft

Clifford Resources, Inc. Neighbors No. 1-27

NE¼SE¼NW¼ sec. 27, T. 13 N., R. 5 E.

Red Fork Sandstone Core Description

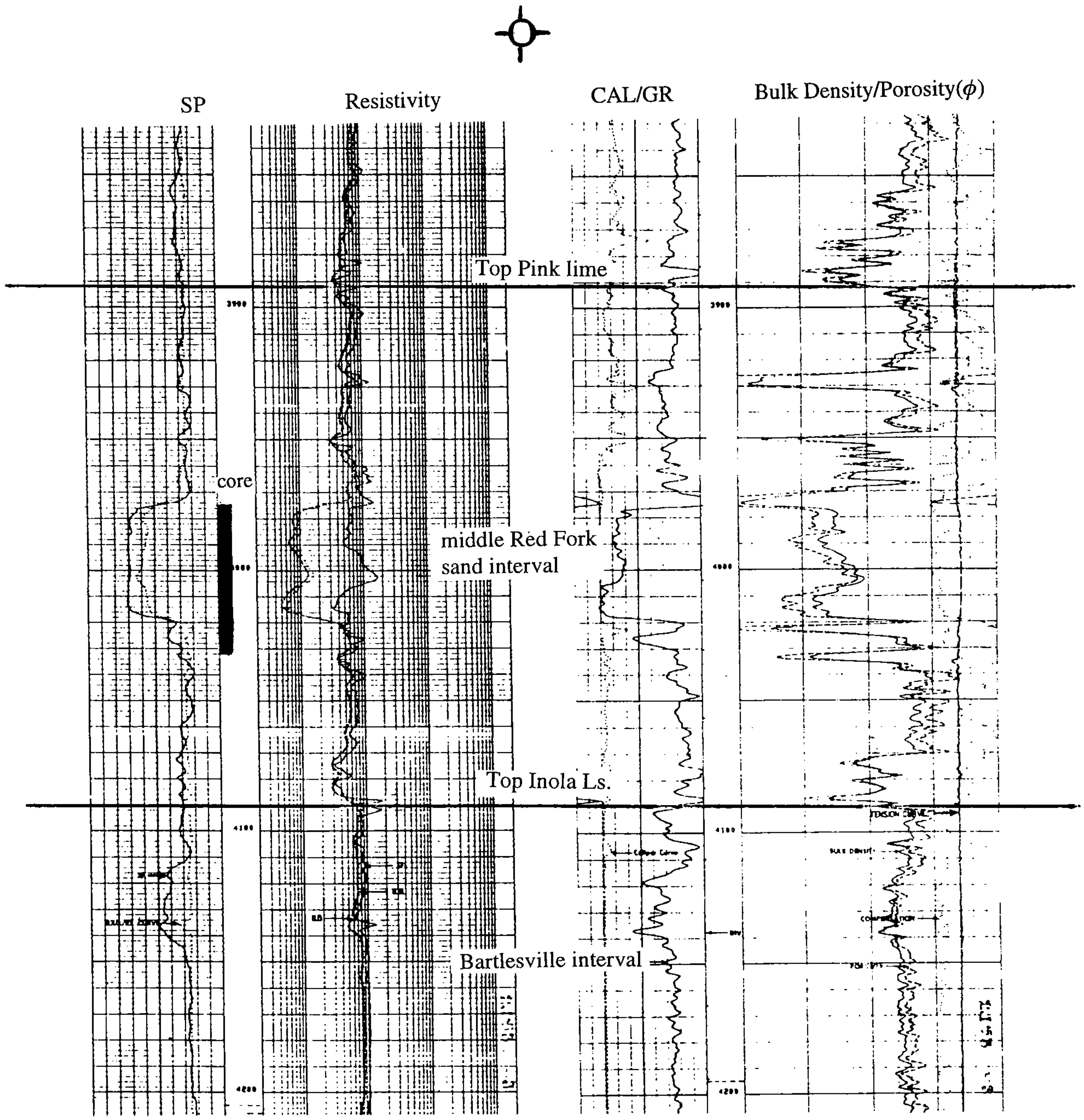
Core depth ≈ Log depth — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
3,975–3,977	Shale, black, fissile, splintery.
3,977–3,979.6	***Top of incised channel.*** Sandstone, very fine to fine grained, medium- to high-angle cross bedding, faint shale laminae, occasional ripple bedding.
3,979.7–3,980.2	Sandstone, very fine to fine grained with interbedded zones of rounded, elongate, orangish mud clasts and black shale fragments. Shale fragment horizon is burrowed as are? some of the shale fragments. "Wispy," carbonaceous shale rip-up clasts occur above the lower mud clast horizon.
3,980.2–3,982	Sandstone, very fine to fine grained, low- to medium-angle inclined bedding, some ripple bedding.
3,982–3,984	Sandstone, very fine to fine grained, deformed bedding (flowage).
3,984–3,986	Sandstone, very fine to fine grained, horizontal to medium-angle inclined bedding. Relatively clean, uniform, almost massive bedding in places.
3,987–3,987.25	Shale, highly micaceous with interbedded carbonaceous debris.
3,987.25–3,994	Sandstone, very fine grained, clean, horizontal to slightly inclined to almost massive bedding, occasional thin, highly micaceous shale with moderate carbonaceous debris.
3,994–4,005	Sandstone, very fine to fine grained, gently inclined to massive bedding. Numerous small (1/16″ to ¼″) brownish orange mud clasts, and small, thin carbonaceous fragments are randomly oriented throughout sandstone. Relatively clean except for mud clasts.
4,005–4,011	Sandstone, very fine to fine grained, clean, with very few mud clasts and very little organic debris, massive to gently inclined bedding. Few zones of interbedded micaceous shale and carbonaceous debris.
4,011–4,013	Sandstone, very fine to fine grained, low- to high-angle inclined bedding with thin micaceous, carbonaceous laminae.
4,014–4,014.25	***Middle to lower channel facies.*** Mud clasts (¼″ to 1″ diameter) with orange-brown staining (recent oxidation?).
4,014.25–4,017	Sandstone, fine to medium grained, horizontal to low-angle inclined bedding, excellent porosity, little or no carbonaceous laminations.
4,017–4,017.5	Sandstone and interbedded shale having highly micaceous and carbonaceous zones, rooted?
4,017.5–4,019	Sandstone, medium grained, excellent porosity, medium to highly inclined bedding. Some interbedded shale laminae and thin shale beds are highly micaceous and carbonaceous. ***Base of channel.***
4,019–4,023	Shale, black, splintery, fissile, and in places, fossiliferous. Poor sample recovery.
4,023–4,025	Siltstone and shale, light to dark gray, rubblized.
4,026–4,032	Siltstone and shale, greenish gray, highly bioturbated and burrowed.

Clifford Resources, Inc. Neighbors No. 1-27 (NE¼SE¼NW¼ sec. 27, T. 13 N., R. 5 E.)

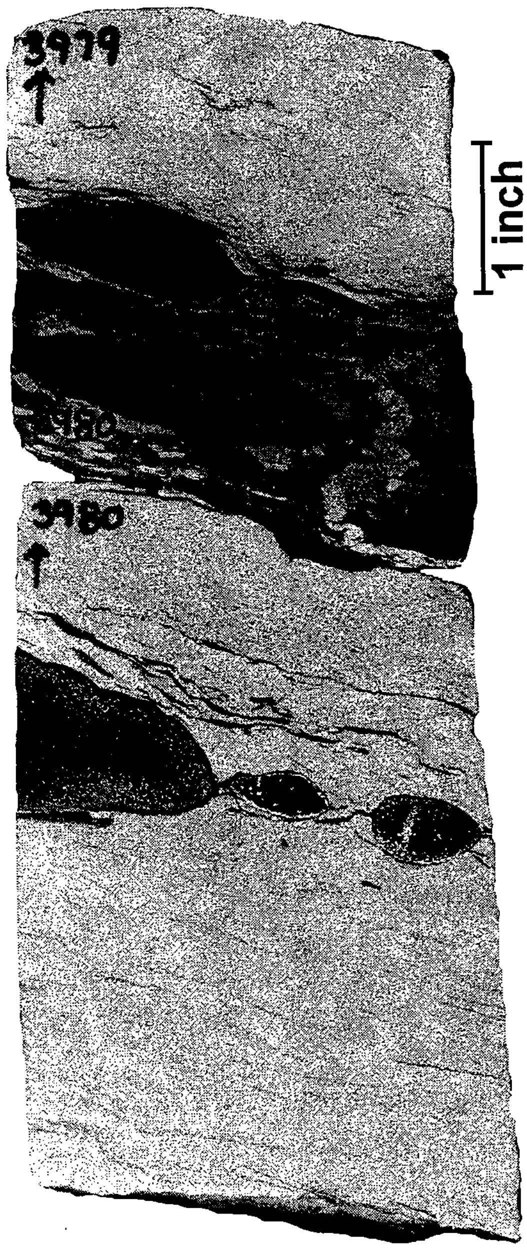
Reservoir: Red Fork sandstone
Depositional environment: Incised channel

Log depth: 3,975–4,032 ft
Core depth: 3,975–4,032 ft



T.D.: 4,232 ft
P & A 1/10/81

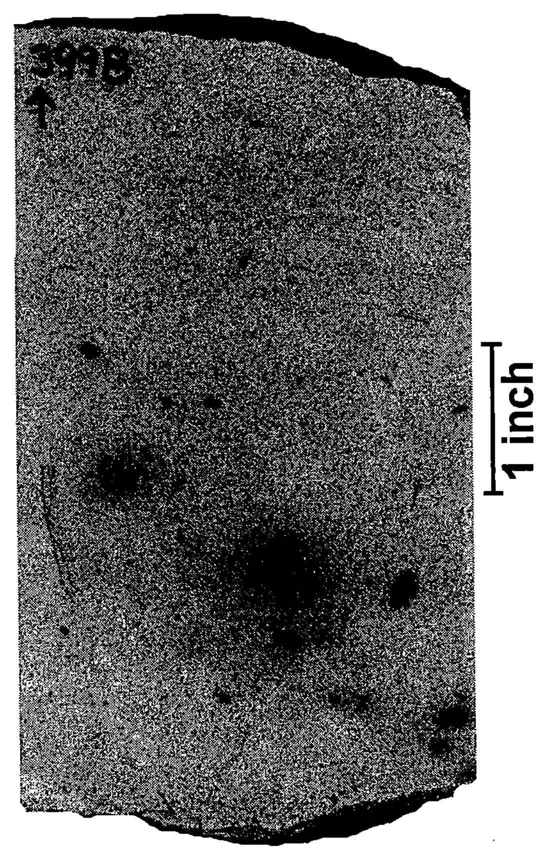
Clifford Resources, Inc. Neighbors No. 1-27 (NE¼SE¼NW¼ sec. 27, T. 13 N., R. 5 E.)



Core depth: 3,979.8–3,980.2 ft
Log depth: ~ 3,980 ft

Sandstone, very fine grained, interbedded with thin zones (1″ to 2″ thick) of rounded, orangish mud clasts and black shale fragments. The black shale zone beneath the orange mud clasts is burrowed as are? the shale fragments. The elongate orangish mud clasts could be rip-up clasts and are of a different source and composition than the black shale fragments. "Wispy" shale laminations above the lower mud clast horizon are highly carbonaceous and indicate terrestrial proximity. They were formed when organic debris was disseminated during sand deposition.

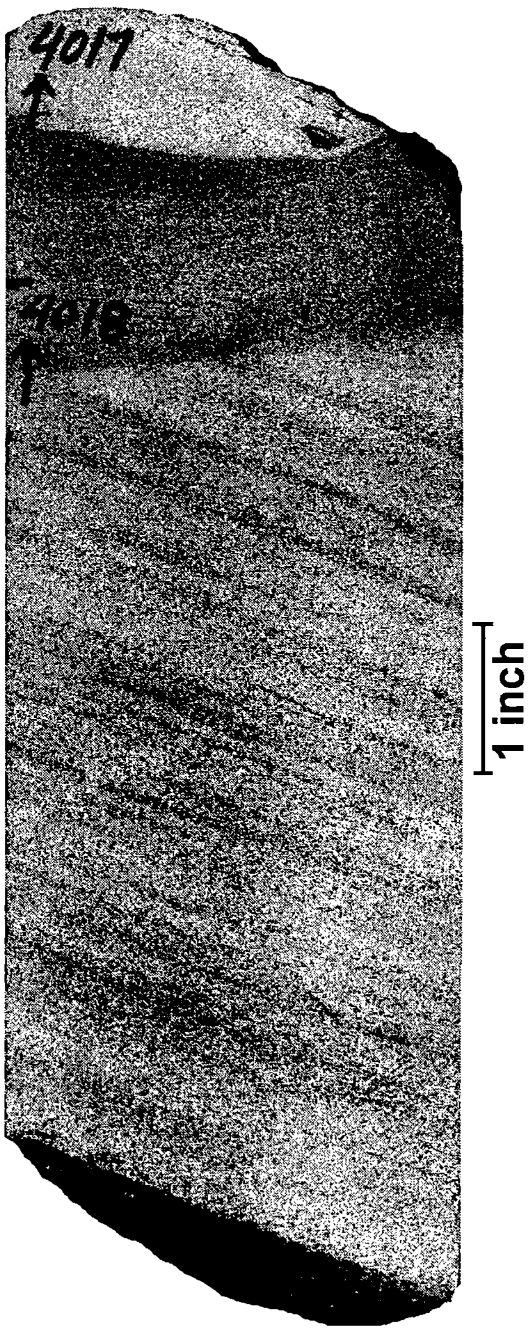
In a stratigraphic sense, the presence of marine indicators (burrowing in the shaly zone) at the top of the sand sequence and continuation of marine shale above the Red Fork sandstone indicates that a marine transgression took place near the end of channel deposition. This core sample is probably close to the transgressive boundary, although still within the channel facies.



Core depth: 3,998–3,998.4 ft
Log depth: ~3,998 ft

Sandstone, very fine to fine grained, gently inclined to massive bedding. Numerous small (1/16″ to ¼″) brownish orange mud clasts, and small thin carbonaceous fragments are randomly oriented throughout the sandstone. The lack of distinct bedding and random orientation of mud clasts indicates rapid deposition with little or no reworking of sediment. Coloration of mud clasts may be due to recent oxidation following coring.

Clifford Resources, Inc. Neighbors No. 1-27 (NE¼SE¼NW¼ sec. 27, T. 13 N., R. 5 E.)

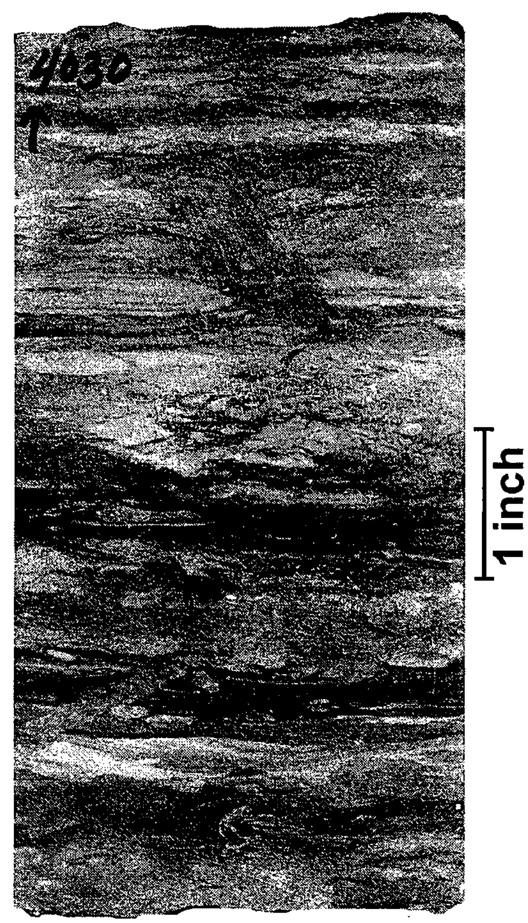


Core depth: 4,018–4,018.5 ft
Log depth: ~4,018 ft

Middle to lower channel facies. Sandstone, medium grained, medium- to high-angle cross bedding, excellent porosity. The increase of grain size in the lower part of the channel (from fine to medium grained) and the highly inclined bedding indicates that this zone may be in the lower channel facies.

Core depth: 4,030–4,030.5 ft
Log depth: ~4,030 ft

Siltstone and shale, greenish gray. Horizontal to indistinct bedding, the latter of which was caused by bioturbation and burrowing in a shallow marine? environment. This zone underlies the channel sandstone pictured at the left.



Helmerich and Payne, Inc. Sanborn No. 2-32

NE¼SW¼NE¼ sec. 32, T. 10 N., R. 12 W.

Red Fork Sandstone Core Description

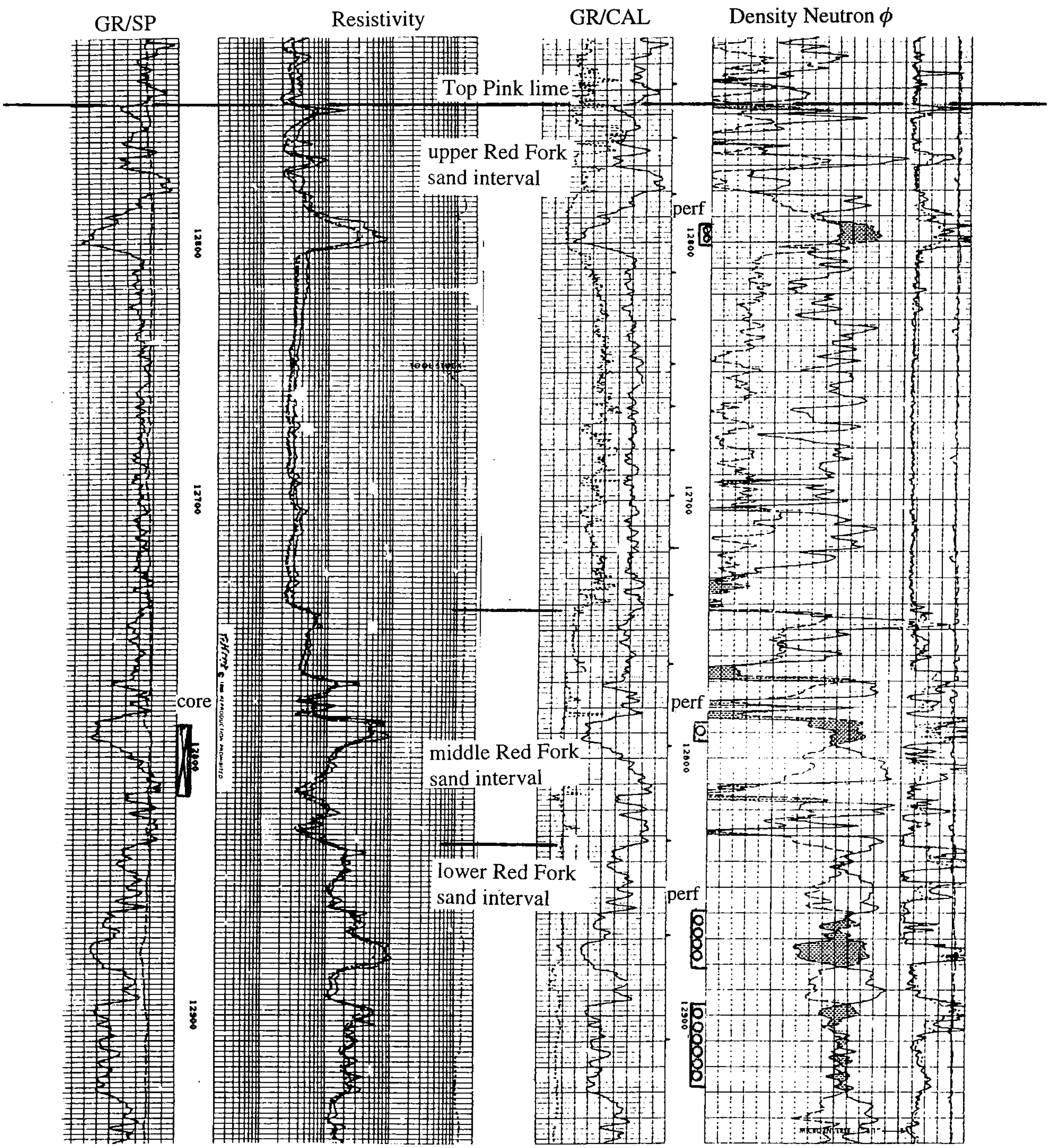
Log depth ≈ Core depth — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
12,788–12,790	***Middle to upper marine bar facies.*** Sandstone, very fine grained, horizontal to slightly ripple bedded.
12,790–12,791.3	Sandstone, very fine grained, medium- to high-angle cross bedding, faint shale laminae, very little mica. Small amount of carbonaceous material is present in laminations and as discrete particles.
12,791.4–12,796.9	***Marine bar transition facies.*** Sandstone, very fine grained with interbedded shale laminae or thin shale beds. Horizontal and ripple bedding predominates. There is very little mica and no carbonaceous material on bedding surfaces.
12,796.9–12,799	Sandstone, very fine grained without distinct bedding (upper part) overlying thin contorted zone (~3″) of interlaminated very fined grained sandstone and shale (flowage). Beneath flowage is a very fine grain sandstone and interbedded shale sequence with horizontal or wavy bedding. Bioturbation? at 12,798.
12,799–12,801	Sandstone, very fine grained with thin shale and siltstone interbeds. Horizontal to small-scale cross bedding.
12,802–12,805	Sandstone, very fine grained with thin shale interbeds, burrowed and bioturbated. ***Base of marine bar facies.***
12,805.5–12,813	Shale, black, no fossils.
12,813–12,813.5	Shale, black, waxy.
12,813–12,814	Limestone, black, fossiliferous with numerous shell fragments.
12,814–12,815	Shale, black, and very fine grained, dark gray sandstone, bioturbated.

Helmerich & Payne, Inc. Sanborn No. 2-32 (NE¼SW¼NE¼ sec. 32, T. 10 N., R. 12 W.)

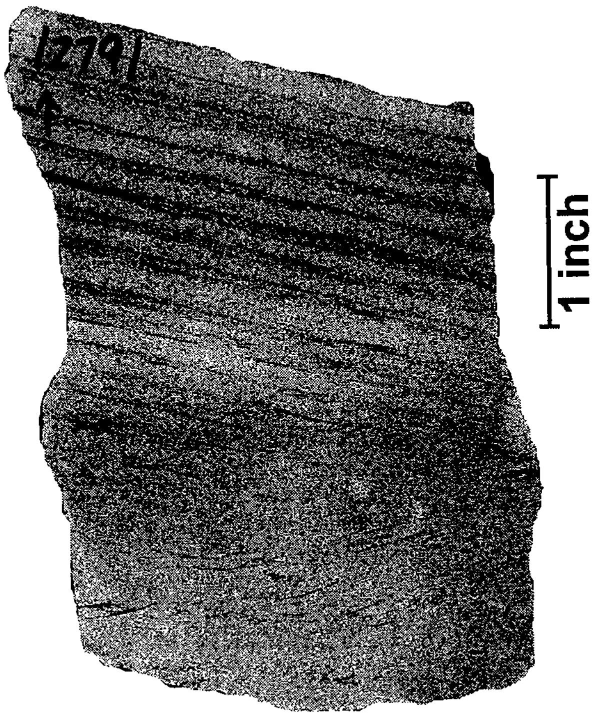
Reservoir: Middle Red Fork sandstone
Depositional environment: Detached offshore bar (marine shelf) or possibly a delta front (distributary mouth) bar

Log depth: 12,788–12,815 ft
Core depth: 12,788–12,815 ft



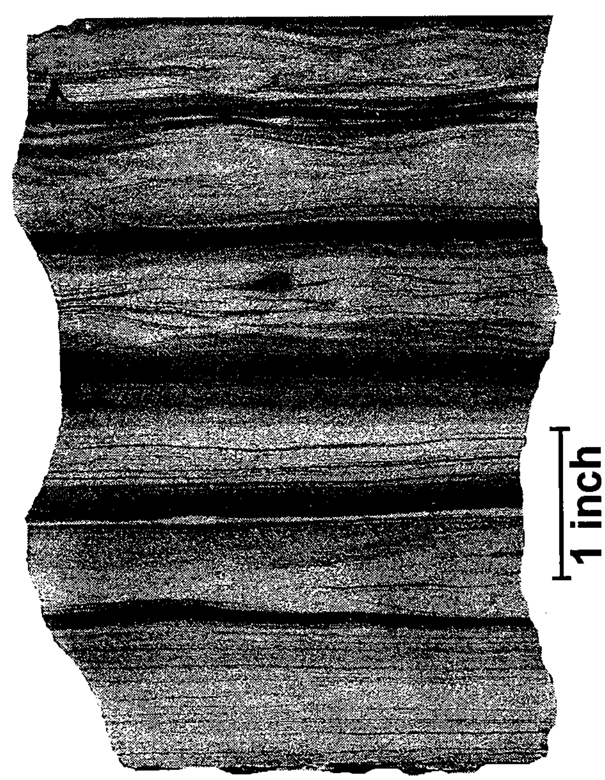
T.D.: 13,058 ft
Completion date: 9/26/86
Perforated: 12,593–12,601, 12,786–12,793, 12,859–12,881, 12,895–12,897, 12,900–12,928, 12,952–12,964 ft
IPF (Red Fork) 721 MCFGPD and 1 BWPD
FTP 714 PSI, SITP 7300 PSI

Helmerich & Payne, Inc. Sanborn No. 2-32 (NE¼SW¼NE¼ sec. 32, T. 10 N., R. 12 W.)



Core depth: 12,791–12,791.3 ft
Log depth: ~12,791 ft

Middle to upper marine bar facies. Sandstone, very fine grained, faint shale laminae, very little mica. The moderate-angle cross-bedding indicates deposition by relatively high-energy currents, which are characteristic near the upper part of a marine bar (or shoreface). The small but conspicuous presence of carbonaceous material (laminated and as discrete particles) indicates that the sediment was deposited fairly close to a source of a terrestrial organic matter, such as in a distributary mouth bar rather than at a shoreface. However, the distance from known fluvial deposits and the degree of bioturbation lower in the section indicates that this sandstone may be a detached offshore bar.



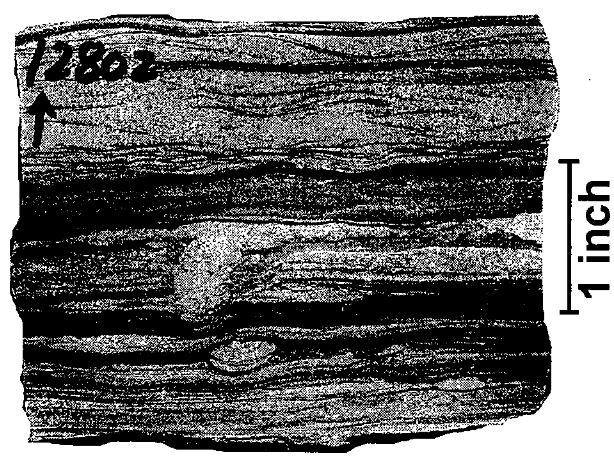
Core depth: 12,796–12,796.3 ft
Log depth: ~12,796 ft

Marine bar transition facies. Sandstone, very fine grained with interlaminated and interbedded shale. Horizontal and ripple bedding predominates. There is very little mica and no carbonaceous material on bedding surfaces. The transition zone is defined mainly by the presence of interbedded shale.

Helmerich & Payne, Inc. Sanborn No. 2-32 (NE¼SW¼NE¼ sec. 32, T. 10 N., R. 12 W.)

Core depth: 12,796.8–12,797.4 ft
Log depth: ~12,797 ft

Contorted bed of interlaminated very fine grained sandstone and shale is overlain by very fine grained sandstone with no apparent structure and, finally, by an undeformed bed of horizontal sandstone and shale laminae. Soft-sediment deformation in the lower or transition facies of marine bars is caused by rapid sedimentation of the overlying sand.



Core depth: 12,802 ft
Log depth: ~12,802 ft

Sandstone, very fine grained with interlaminated shale. Burrowing and bioturbation that is evident in the center part of core image destroys original bedding surfaces. Trace fossils such as these commonly occur in the transition facies of a marine bar where current energy is relatively low.

Anadarko Petroleum Sackett "B" No. 1

CNW¼SW¼ sec. 14, T. 23 N., R. 13 W.

Red Fork Sandstone Core Description

Oakdale Field

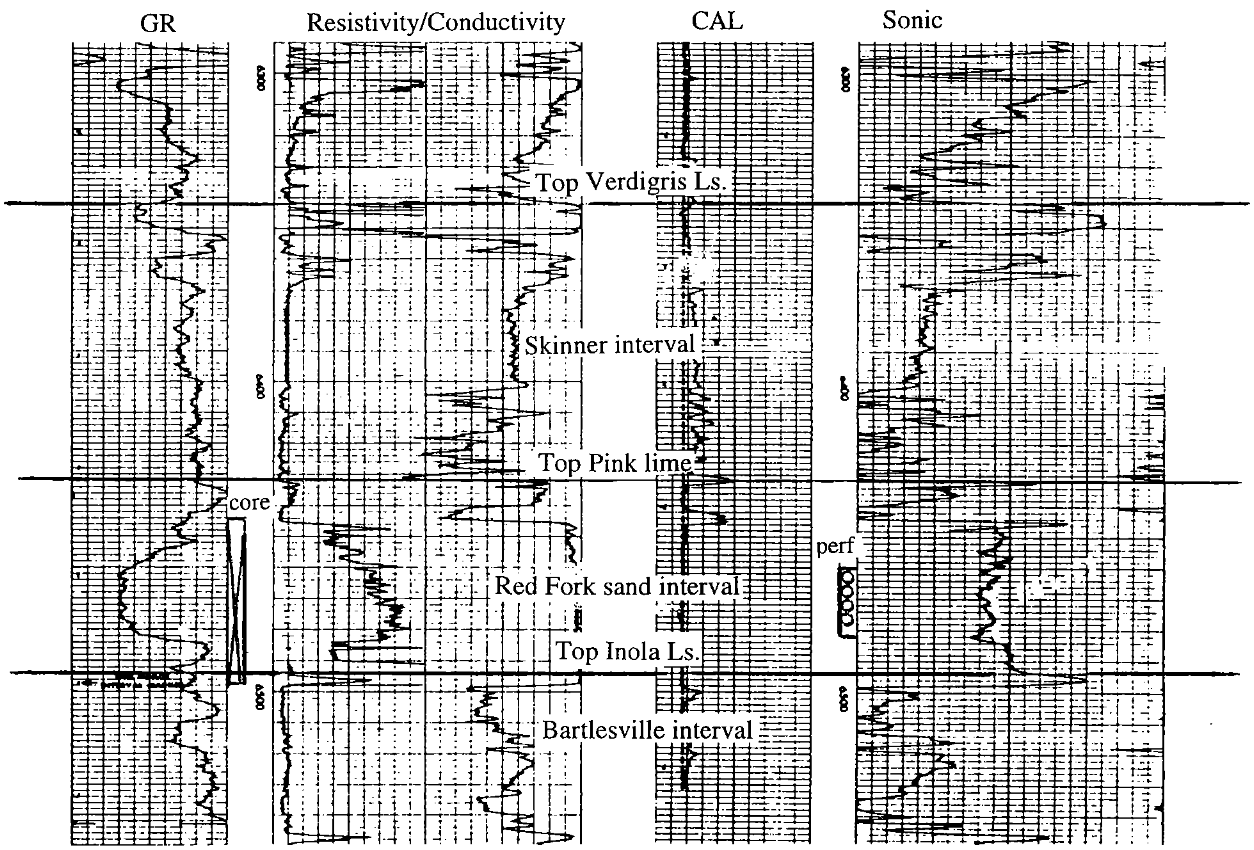
Log depth = Core depth minus 2–3 ft — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
6,447–6448	Siltstone and shale, dark gray with numerous sideritic? mud clasts.
6,448–6,452	Sandstone, very fine grained, light gray to buff, with numerous orange specks that possibly are due to recent oxidation of iron sulfide minerals. Gently inclined cross bedding. Shaly zone at 6,451 appears bioturbated.
6,453–6,454	Shale, silty, dark gray, no fossils or carbonaceous debris.
6,455–6,459	***Upper sand body facies.*** Sandstone, very fine grained, tight, ripple bedding common, occasional small-scale cross bedding, faint shale laminae or thin shaly zones in bottom 6 in.
6,460–6,465	Sandstone, very fine grained, very few shale laminae, horizontal to slightly inclined bedding, occasional orange staining of sand grains near particles of weathered siderite? No mica or carbonaceous debris.
6,466–6,476	***Lower to middle sand body facies.*** Sandstone, very fine grained, medium angle inclined bedding, no shale laminae, relatively clean sand, fair porosity. No fossils or bioturbation.
6,477–6,484	Sandstone, very fine to fine grained, medium to low angle inclined bedding, no shale laminations, no fossils, mica, or bioturbation. Fair porosity. Sharp basal contact with underlying shale. ***Base of sand body (channel)?***
6,485–6,492	Shale and interbedded very fine grained sandstone, ripple bedding common, slightly carbonaceous, no mica. Similar to sand/shale sequence described below at 6,496–6497 ft. Tidal flat?
6,493–6,495	Sandstone, very fine grained, mostly massive, occasional highly carbonaceous bedding surfaces, no mica.
6,496–6,497	**Estuarine—tidal flat?** Sandstone with interbedded shale. Sandstone is very fine grained and occurs in small discrete lenses. Bedding is mostly horizontal or wavy but small scale cross bedding is also common. The shale occurs as laminations or in thin, moderately carbonaceous beds with conspicuous amounts of organic debris. Interbedded mica is not readily discernible.
6,497–6,500	***Inola Limestone.*** Light brown to grayish brown, fossiliferous.

Anadarko Petroleum Sackett "B" No. 1 (CNW¼SW¼ sec. 14, T. 23 N., R. 13 W.)

Reservoir: Red Fork sandstone
Depositional environment: Incised channel? Possibly tidally influenced valley-fill channel bar

Log depth: 6,444–6,497 ft
Core depth: 6,447–6,500 ft

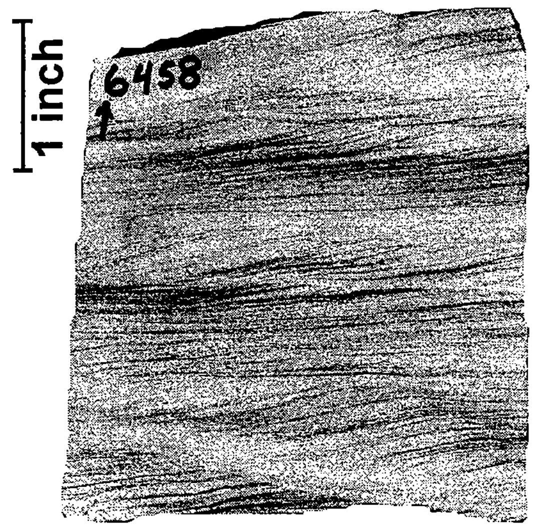


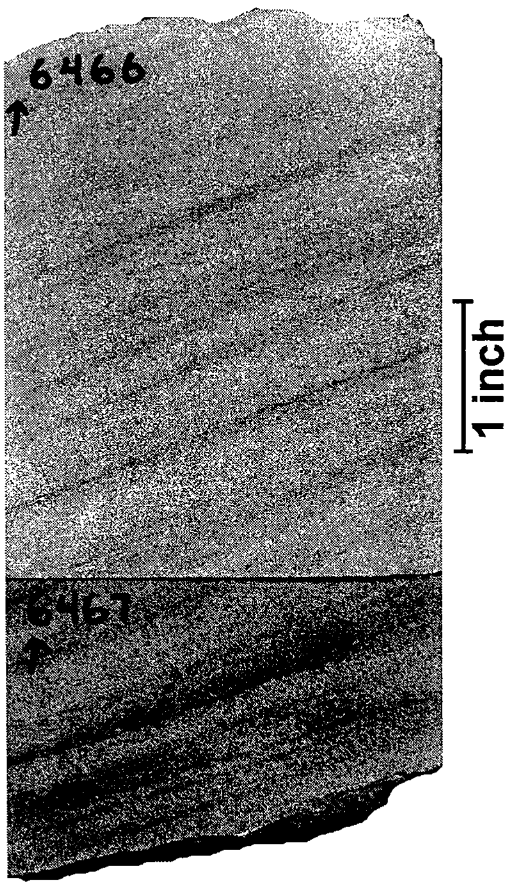
T.D.: 6,560 ft
Completion date: 10/18/66
Perforated: 6,460–6,482 ft
IPF (Red Fork) 193 BOPD, 141 MCFGPD, no water
FTP 790 PSI, Csg. pressure 1075 PSI

Anadarko Petroleum Sackett "B" No. 1 (CNW¼SW¼ sec. 14, T. 23 N., R. 13 W.)

Core depth: 6,458–6,458.25 ft
Log depth: ~6,455

Upper sand body facies. Sandstone, very fine grained, tight, small scale cross bedding at the top and center of sample with climbing ripples at the base. Faint shale laminae in the center part of sample are nearly horizontal. Bedding such as this is very common in the upper facies of fluvial channel deposits.



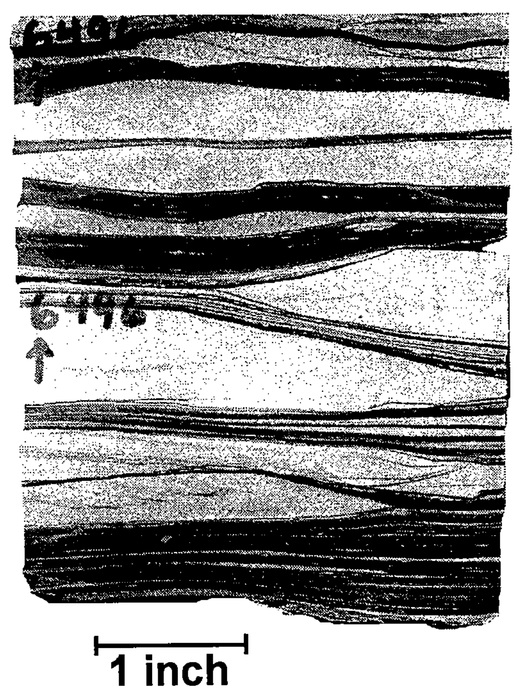


Core depth: 6,466.7–6,467 ft
Log depth: ~6,464 ft

Middle sand body facies. Sandstone, very fine grained, medium-angle cross bedding. The sandstone is relatively clean, has fair porosity, and is free of shale laminations. No fossils or bioturbation were noticed in any of the samples of this sand unit. Although the attitude of bedding as seen in this sample is common in the middle or lower part of channel deposits, the absence of carbonaceous material and mica is not characteristic of fluvial deposits.

Core depth: 6,496–6,496.3 ft
Log depth: ~6,493 ft

Estuarine–tidal flat? Discrete bundles of interbedded very fine grained sandstone and shale may indicate oscillatory depositional episodes. Tidal transport of sand from a marine? source can become ripple bedded with shale being deposited within ripple troughs or depressions. The shale may have a terrestrial source since it is carbonaceous and contains conspicuous organic debris. This portion of the core lies below the main sand body described in the core description.



Oklahoma Geological Survey
Supplement to Special Publication 97-1

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Red Fork Play

PART III

Reservoir Simulation of a Red Fork Reservoir in the North Carmen Field, Alfalfa County, Oklahoma

CONTENTS

Reservoir Simulation of a Red Fork Reservoir in the North Carmen Field, Alfalfa County, Oklahoma **92**
Introduction 92
Overview of Field Development 92
Data Availability 92
Rock Data and Fluid Properties 92
History Matching 94
Estimation of Reserves and Oil Recovery Factor 95
Evaluation of Future Reservoir Management Strategies 95
Base Case 95
Case 2 100
Case 3 100
Summary 100
References Cited 101

LIST OF ILLUSTRATIONS

Figures

56. Average daily oil and gas production from the Red Fork sand, North Carmen field 93
57. Observed and simulated cumulative gas production curves for the Dewitt No. 1 well 94
58. Observed and simulated cumulative gas production curves for the Partners Kassick No. 1 well 96
59. Observed and simulated cumulative gas production curves for the Anadarko Kassick No. 2A well 96
60. Observed and simulated cumulative gas production curves for the Wil-Mc Kassick No. 1 well 97
61. Observed and simulated cumulative gas production curves for the Pruett No. 2 well 97
62. Observed and simulated Red Fork gas production history, North Carmen field 98
63. Reported and simulated water injection history for North Carmen field 98
64. Base Case oil and water production rates 99
65. Case 2 oil and water production rates 99
66. Case 3 oil and water production rates 100

Tables

13. Well information for Red Fork sand reservoir in North Carmen field 93
14. Average reservoir properties for the Red Fork sandstone in North Carmen field 94
15. Five-year production forecasts based on reservoir simulations 95

RESERVOIR SIMULATION OF A RED FORK RESERVOIR IN THE NORTH CARMEN FIELD, ALFALFA COUNTY, OKLAHOMA

R. M. Knapp and X. H. Yang
School of Petroleum and Geological Engineering
University of Oklahoma

INTRODUCTION

The Red Fork oil reservoir in the North Carmen field is located in secs. 34 and 35, T. 25 N., R. 12 W., and secs. 2 and 3, T. 24 N., R. 12 W., Alfalfa County, Oklahoma (Fig. 18, Part II). The top of the Red Fork sand zone in this field is at a depth of about 6,050 ft (–4,670 ft). The average net sand thickness is 12 ft with an areal extent of 635 acres. The Red Fork reservoir is a channel sandstone surrounded and sealed by the shale. A complete discussion of the North Carmen field, including lithology, depositional environment, and log characteristics, can be found in Part II of this volume.

The major objectives of this study were to develop a reservoir simulation model of the Red Fork pool in North Carmen field and to use the model to analyze past field performance and potential strategies to improve oil recovery. The reservoir model was developed for use in BOAST3 (Mathematical and Computer Services, Inc., 1995), which is a three-dimensional, three-phase black oil applied simulation tool (reservoir simulator). BOAST3 is public domain software available from the U.S. Department of Energy.

OVERVIEW OF FIELD DEVELOPMENT

The Red Fork reservoir in North Carmen field was discovered in December 1984 by the Duncan Oil Zoa No. 1 (SW¼NW¼SW¼ sec. 34, T. 25 N., R. 12 W.). (Well names and locations are shown in Figure 19, Part II.) The initial flowing potential of the Zoa No. 1 was reported to be 108 BOPD and 344 MCFGPD. From May 1985 through June 1986, 13 more wells were completed in the Red Fork sand (Table 13). The 12-year production history of the field is shown by the average monthly production and cumulative production curves in Figure 28, Part II. Annual oil and gas production are listed by well in Tables 4 and 5, Part II. The field oil production rate declined from the peak of 1,000 BOPD from 10 wells in January of 1986 to 6 BOPD from six wells in April of 1995 (Fig. 56). In January 1986, 10 wells were producing from the Red Fork. Four more Red Fork wells were completed between February and June of 1986 (Table 13), but production continued to decline (see Fig. 56). The average daily gas production rate for the field declined from the peak rate of 4,000 MCFGPD in April of 1986 to about 15 MCFGPD in July of 1995 (Fig. 56). By the time the field was unitized by Ensign Oil and Gas, Inc. (EOG) in 1995, four wells had already been abandoned: the Davis No. 1, Zoa No. 1, Hughes No. 1-F, and Horn No. 1-B (see Table 13 for abandonment dates and Fig. 19, Part II, for well locations). After unitization, five wells—Dewitt No. 1, Geraldine No. 2, Hughes No. 1-A, Kassick No. 1-A, and Zoa No. 2—were converted to water injection wells leaving five wells for production. Water injection began in September 1995, and in November 1995 a small increase in production was noted by EOG.

The average initial pressure of the reservoir was about 2,400 PSIA, and the oil is believed to have been initially undersaturated. Based on production data, the main recovery mechanism in this field was solution gas drive and is now waterflood drive. After 15 months of water injection, in November 1996, the average bottom-hole pressure was about 4,440 PSIA in the injection wells and 450 PSIA in the production wells. Cumulative Red Fork production at the end of December 1996 was 423,402 STB of oil and about 2,300 MMCF of gas (Natural Resources Information System [NRIS], 1996; EOG, personal communication, 1996).

DATA AVAILABILITY

Data used for the reservoir model and the simulation include depth to the top of the Red Fork sandstone, gross and net sandstone thickness, porosity, permeability, initial gas-to-oil ratio (IGOR), and initial water saturation. Oil and gas production histories were obtained from NRIS and EOG; water injection records were obtained from EOG. The following maps from Andrews (Part II, this volume) were digitized and form part of the data file that describes the reservoir: depth to the top of Red Fork sandstone (Fig. 23), gross sand thickness (Fig. 24), and net sand thickness ($\phi \geq 10\%$) (Fig. 25). Porosity, permeability, and initial water saturation data are discussed by Andrews (Part II, this volume). Other data that are useful for reservoir studies but were not available include reservoir pressures at several times during the production history and capillary pressure and relative permeability data.

ROCK DATA AND FLUID PROPERTIES

The rock and fluid properties used in the reservoir model are shown in Table 14. Estimates of average porosity (16%) and initial water saturation (28%) were based on log calculations by Andrews (Part II, this volume). Based on pressure transient test analysis, EOG

TABLE 13. – Well Information for Red Fork Sand Reservoir in North Carmen Field, Alfalfa County, Oklahoma

No.	WELLS	Grid X	Grid Y	Grid Z	Perf. Intval subsea, (ft)	Net-Thk (ft)	Start.–Shut (Mon/Year)	Conv. Time (Mon/Year)	Cum. Oil Prod Primary (stb) to 10/95	Cum. Oil Prod Secondary (stb) to 12/96	Cum. Gas Prod Primary (mscf) to 10/95	Cum. Gas Prod Secondary (mscf) to 4/96	Locations
1	Davis1	7	5	1	4631-4649	7	6/86-10/91	Abnd	4,877	0	48,176	0	Sec. 33, SE NE SE
2	Dewitt1	28	13	1	4670-4695	16	5/85-9/94	9/95,	64,326	0	241,943	0	Sec. 3, NW NE
3	Geraldin1	34	13	1	4698-4707	15	8/85-2/95	9/95,	36,297	0	139,294	0	Sec. 3, E/2 NE NE
4	Horn1-A	43	6	1	4663-4671	7	6/85-12/96		14,461	2,940	12,000	n.a.[a]	Sec. 35, E/2 W/2 SE
5	Horn1-B	46	8	1	4663-4669	4	2/86-2/87	Abnd	1,613	0	0	0	Sec. 35, C SE SE
6	Hughes1-A	20	9	1	4661-4682	19	2/86-4/95	9/95,	22,006	0	234,069	0	Sec. 34, S/2 SW SE
7	Hughes1-F	24	9	1	4670-4695	9	8/85-3/88	Abnd	7,601	0	22,898	0	Sec. 34, SW SE SE
8	Kassick1	14	9	1	4648-4680	15	8/85-12/96		42,708	2,092	173,000	n.a.	Sec. 34, SW SE SW
9	Kassick1-A	37	9	1	4672-4692	20	8/85-9/93	9/95,	42,796	0	397,861	0	Sec. 35, SE SE SW
10	Kassick2-A	31	9	1	4680-4694	12	11/85-12/96		24,308	2,792	250,063	n.a.	Sec. 35, S/2 SW SW
11	Kassick1-W[b]	38	13	1	4676-4694	18	6/85-12/96		61,451	2,149	282,837	n.a.	Sec. 2, NW NW
12	Pruett2	24	12	1	4675-4695	18	9/85-12/96		39,979	620	219,195	n.a.	Sec. 3, NE NE NW
13	Zoa1	9	4	1	4638-4654	9	12/84-8/87	Abnd	13,612	0	49,566	0	Sec. 34, SW NW SW
13	Zoa2	12	7	1	4659-4678	8	4/86-3/95	9/95,	36,774	0	240,990	0	Sec. 34, NE SW SW
14	Infill 1	6	4	1	4625-4630	7	Infill production well						Sec. 33, SE NE SE
15	Infill 2	38	16	1	4670-4675	10	Infill production well						Sec. 2, N/2 SW NW
Total										**423,402**	**2,311,892**		

[a]n.a. = not available.

[b]Kassick1-W is the Wil-Mc Kassick No. 1, sec. 2, T. 24 N., R. 12 W.

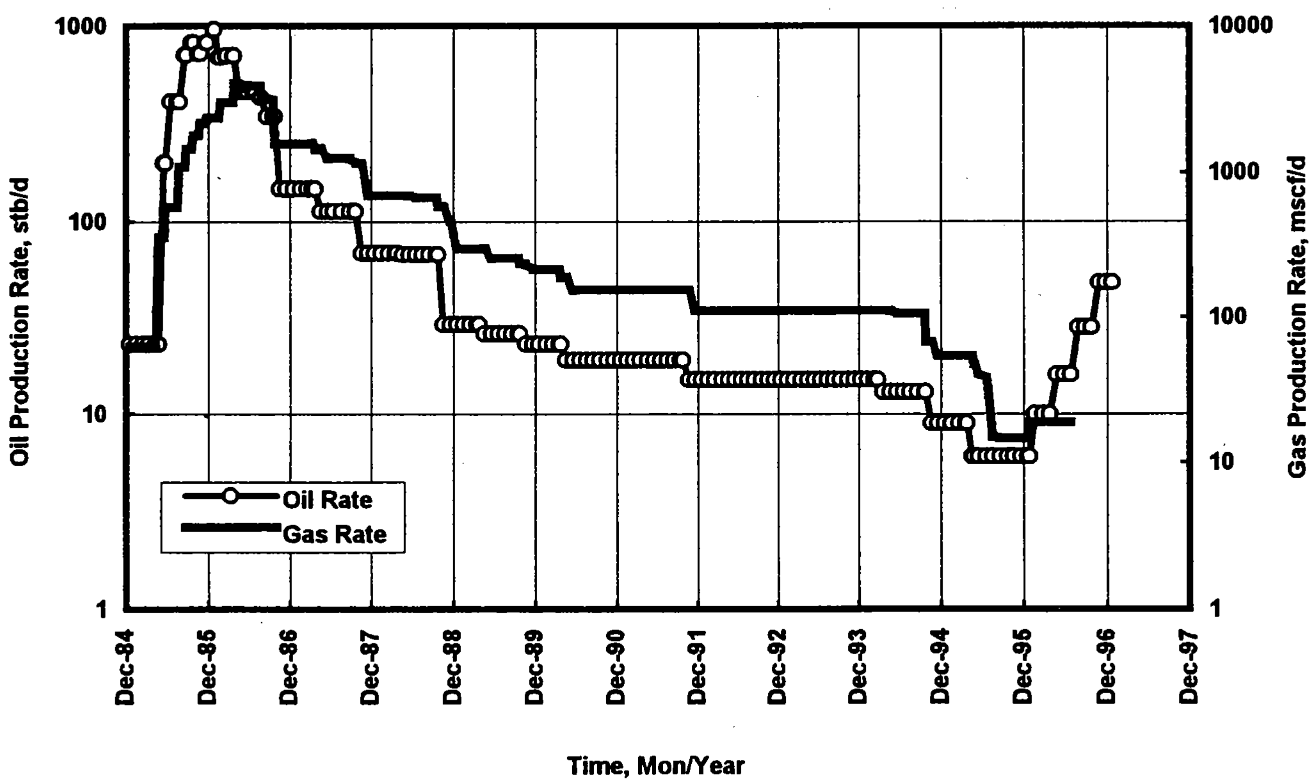


Figure 56. Average daily oil and gas production from the Red Fork sand, North Carmen field.

TABLE 14. – Average Reservoir Properties of the Red Fork Sandstone in North Carmen Field, Alfalfa County, Oklahoma

Porosity	16%
Permeability	16 md
Average net pay thickness	12 ft
Initial water saturation	28%
Initial bottom-hole pressure	2,400 PSIA
Solution gas-to-oil ratio	835 SCF/STB
Formation volume factor	1.46 RB/STB
Reservoir temperature	135°F
Oil gravity	41°API
Gas specific gravity (air = 1)	0.77
Original oil in place	3.62 MMSTB

estimated the average permeability for the field to be about 16 md. The well-test data was not sufficient to spatially vary permeability in the model. Because the wells in the field were stimulated with fracture treatments, permeability was assumed to be 100 md in the simulation-grid blocks containing wells. Capillary pressures were estimated using the method of Smith (1991). Relative permeabilities were estimated using Honarpour's method (Honarpour and others, 1986).

The average reservoir temperature from well logs was 135°F. The oil gravity is 41°API (EOG, personal communication, 1996). The specific gravity (1.15) and salinity (240,000 ppm) of the water were estimated from Bradley (1987). The oil formation volume factor, 1.45 RB/STB, and gas-to-oil ratios were estimated from the Standing correlations (Craft and others, 1991) using oil gravity, reservoir temperature, and initial pressure. The gas specific gravity in 1985 was reported by EOG to be 0.77. The IGORs calculated from the initial production reported on scout tickets of all 14 wells are shown in Figure 30, Part II. The IGORs of wells drilled during the first year after the field was discovered ranged from 618 to 3,185 SCF/STB. The initial solution GOR used in the reservoir model, 835 SCF/STB, was calculated using the gas specific gravity in conjunction with producing IGORs and the depth of the Red Fork. The saturation pressure (bubble-point) of hydrocarbon estimated by Core Laboratories, Inc. (1985) from reservoir fluid analysis was 2,383 PSIA. The average initial pressure of the reservoir was about 2,400 PSIA. The estimated average initial oil formation-volume factor was 1.45 RB/STB; oil viscosity at reservoir conditions was 0.40 cp.

HISTORY MATCHING

To be confident that the reservoir model represented the behavior of the reservoir, the model was tested by comparing the production performance pre-

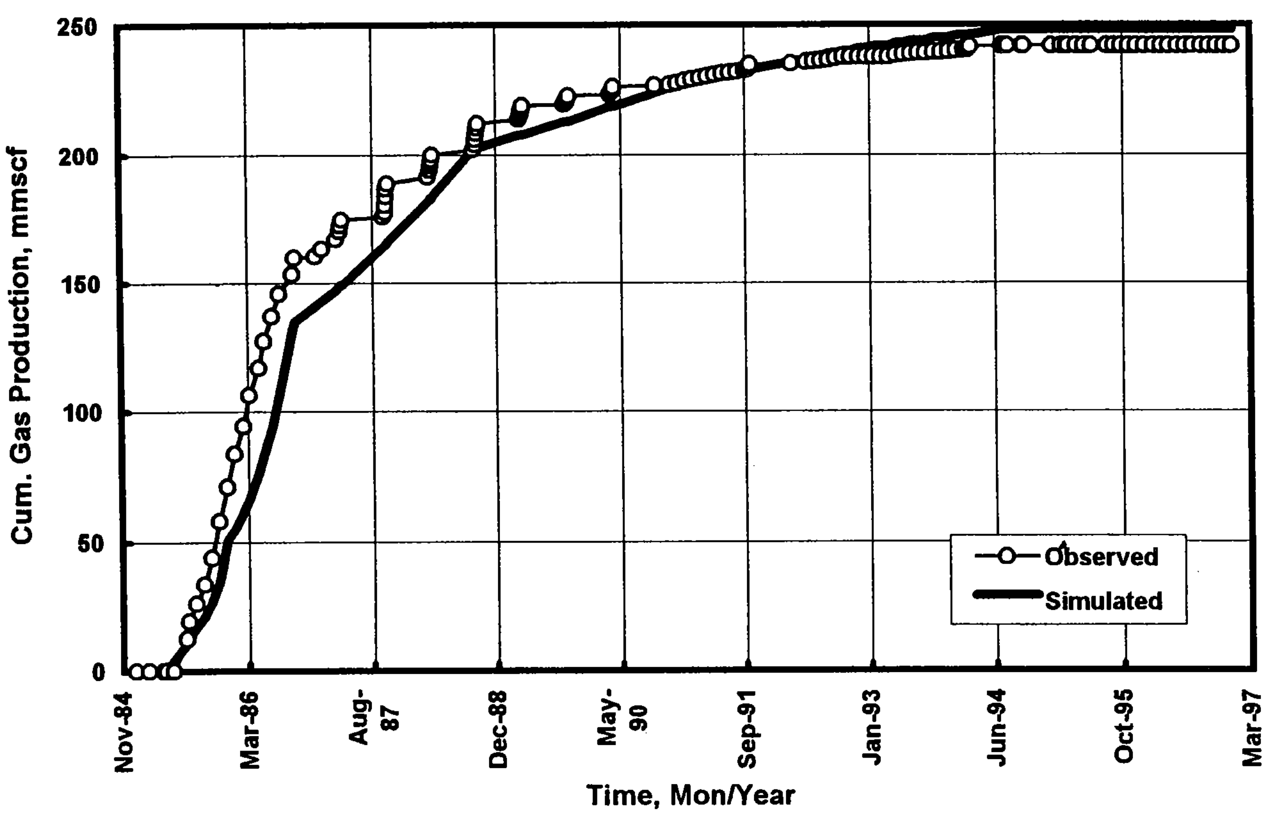


Figure 57. Observed and simulated cumulative gas production curves for the Dewitt No. 1 (NW¼NE¼ sec. 3, T. 24 N., R. 12 W.).

TABLE 15. – Five-Year Production Forecasts Based on Reservoir Simulations

	Base Case	Case 2	Case 3
Total oil production 1997–2001 (STB)	506	637	737
Maximum oil production rate (STB/D)	380	590	620
Time at maximum production rate	May 1998	Jan. 1998	Apr. 1998
Cumulative water production, Dec. 2001 (MSTB)	950	1,590	1,380
Cumulative water injection, Dec. 2001 (MSTB)	2,930	3,690	3,600
Cumulative gas production, Dec. 2001 (MMSCF)	2,680	2,710	2,700
Oil production rate, Dec. 2001 (STB/D)	150	170	190
Cumulative oil recovery, Dec. 2001 (MSTB)	930	1,060	1,160
Cumulative recovery as percent of OOIP	25.7%	29.3%	32.0%
Incremental recovery (MSTB more than Base Case recovery)		130	230

dicted by the simulation to the actual production history of each well in the field. The history-matching process entails adjustment of uncertain parameters in the reservoir model in order to bring simulated production curves into close agreement with the observed production curves. The actual oil production rates were specified for the history-match simulations because they were considered to be the most reliable data available. The targets for the history match simulations were cumulative gas production and cumulative water injection.

As a result of the history-matching process, the reservoir model was partitioned into three regions characterized by different gas relative permeability functions. The critical gas saturation is the minimum saturation required for "free" gas flow. In order to match the simulated gas production to the historical production, critical gas saturation values of 0%, 4%, and 6% were used. In addition, a north–south trending "barrier" of low permeability (0.16 md compared to the average reservoir permeability of 16 md) was set in the middle of the reservoir. The permeability barrier was placed in the area shown by the "channel + non-channel" facies in the the center of the north half of section 3 and the southeast corner of section 34 (see Fig. 26).

The simulated and observed gas production curves are shown for five wells in the field—Dewitt No. 1 (Fig. 57), Partners Kassick No. 1 (Fig. 58), Anadarko Kassick No. 2-A (Fig. 59), Wil-Mc Kassick No. 1 (Fig. 60) and the Pruett No. 2 (Fig. 61). (See Figure 19, Part II, for well locations.) Good matches of both cumulative gas production and cumulative water injection were obtained for the North Carmen field. Figure 62 shows the simulated and observed cumulative gas production curves for the field; Figure 63 shows simulated and observed cumulative water injection curves for the field.

ESTIMATION OF RESERVES AND OIL RECOVERY FACTOR

The estimated total original oil in place (OOIP) for the Red Fork reservoir was 3.62 MMSTB. Using a conservative value of 35% for the residual oil saturation, the amount of unrecoverable immobile oil is estimated to be 1.9 MMSTB (53% of OOIP). Therefore, the theoretical maximum recovery could be as much as 1.7 MMSTB (47% of OOIP). At the end of 1996, 423,402 STB (12% of OOIP) had been produced leaving an estimated 1.26 MMSTB (35% of OOIP) of unproduced mobile oil.

EVALUATION OF FUTURE RESERVOIR MANAGEMENT STRATEGIES

Three reservoir management strategies described below were evaluated using the reservoir simulation model of North Carmen field and BOAST3. For each management strategy, five years of production beginning in January 1997 were simulated. The effectiveness of the three strategies can be compared on the basis of the model-predicted oil and water production rates and volumes (Table 15).

Base Case

The Base Case is the simulated continuation of the operating conditions (i.e., well configuration and bottom hole pressures) that were in effect in December of 1996. The well configuration, which includes five production wells and five injection wells, is shown in Figure 25 (Part II). The oil and water production rates predicted by the Base Case simulation for 1997–2001 are shown in Figure 64. At the end of the simulation period, the average daily field production rate was 150 BOPD with 85% water cut (~870 BWPD) (Fig. 64; Table

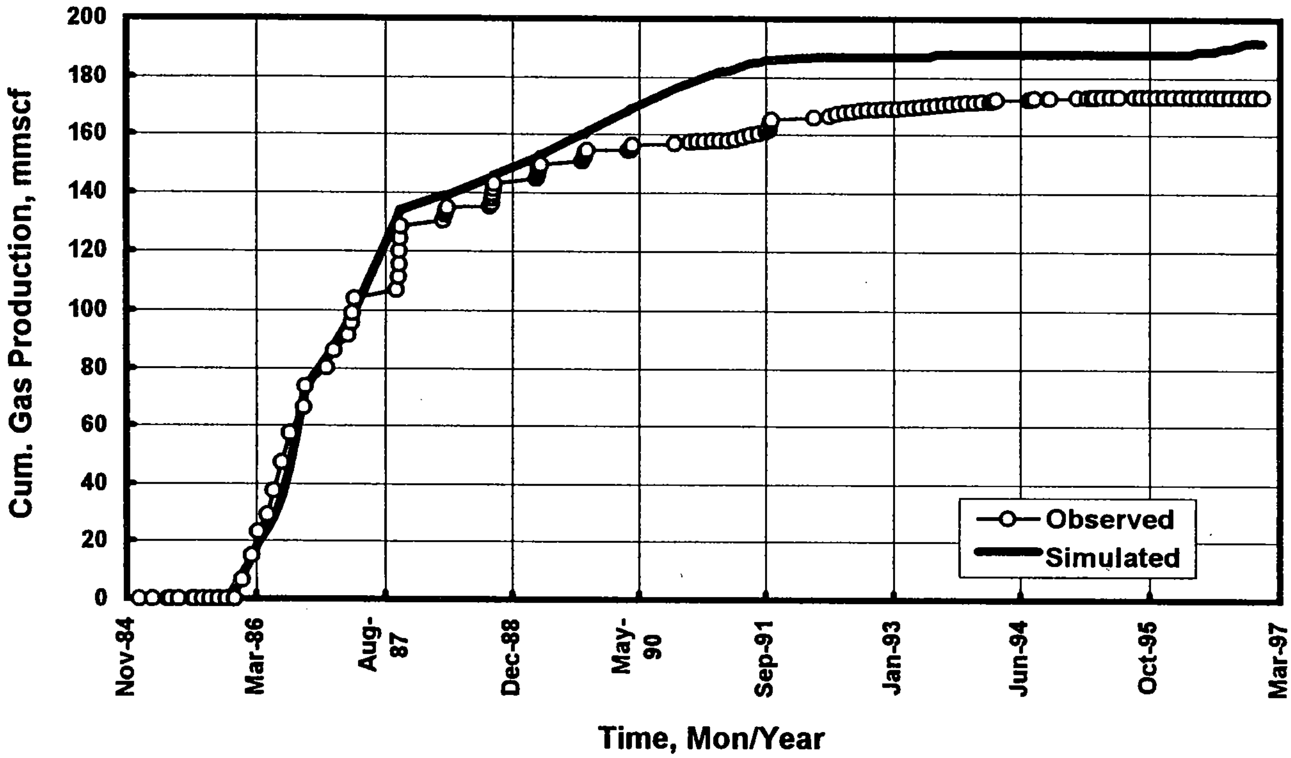


Figure 58. Observed and simulated cumulative gas production curves for the Partners Kassick No. 1 (SW¼SE¼SW¼ sec. 34, T. 25 N., R.12 W.).

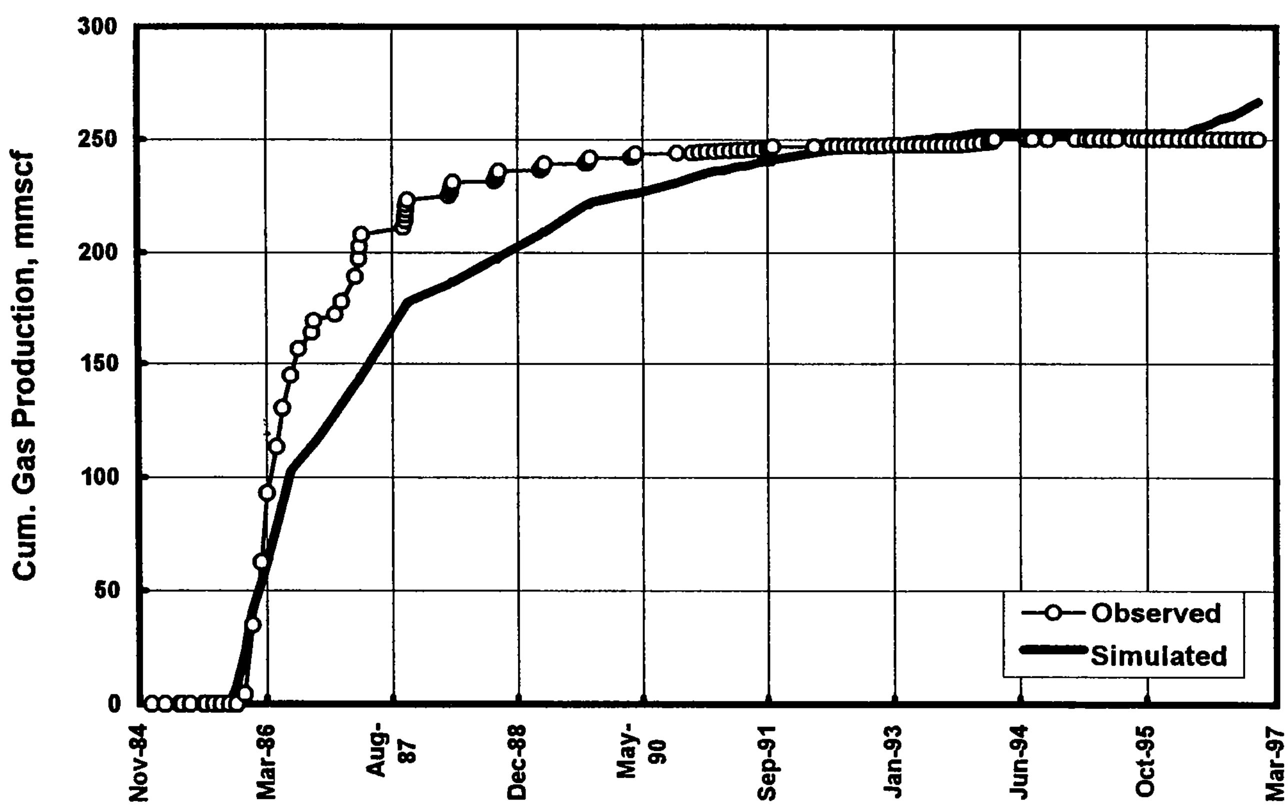


Figure 59. Observed and simulated cumulative gas production curves for the Anadarko Kassick No. 2A (S½SW¼SW¼ sec. 35, T. 25 N., R. 12 W.).

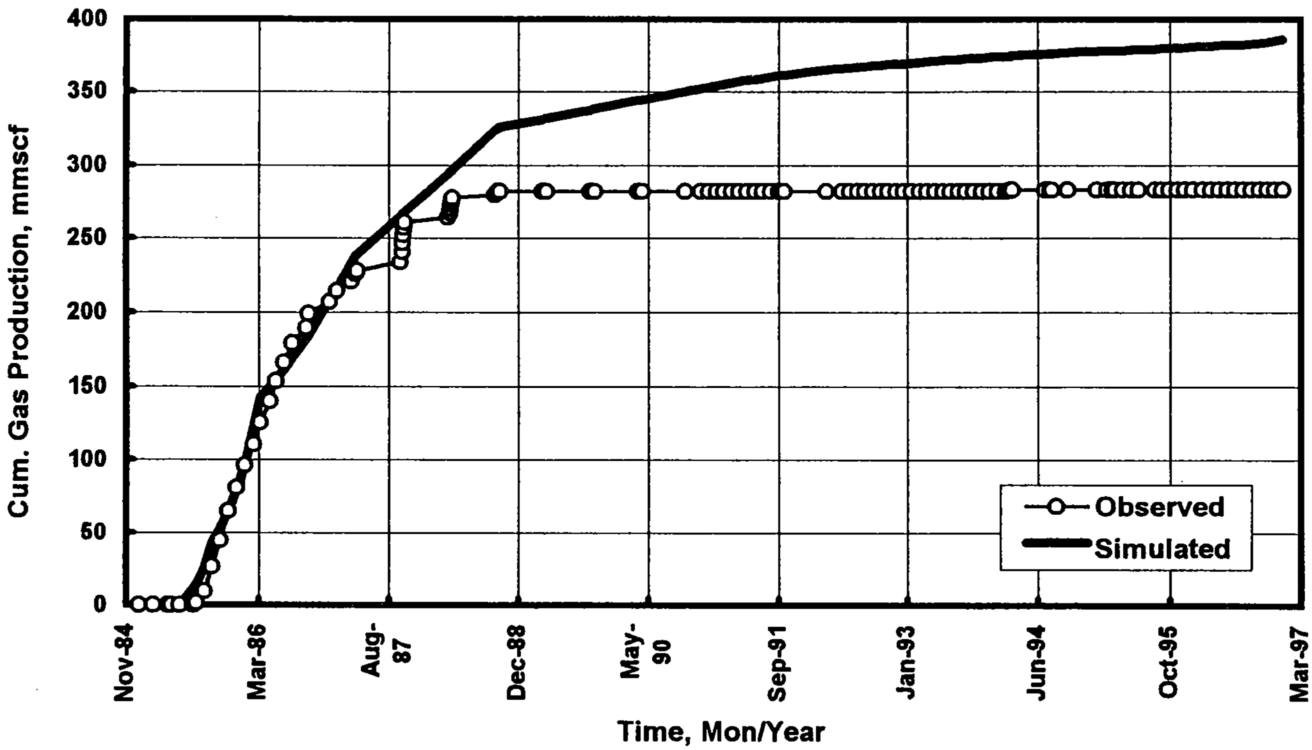


Figure 60. Observed and simulated cumulative gas production curves for the Wil-Mc Kassick No. 1 (NW¼NW¼ sec. 2, T. 24 N., R. 12 W.).

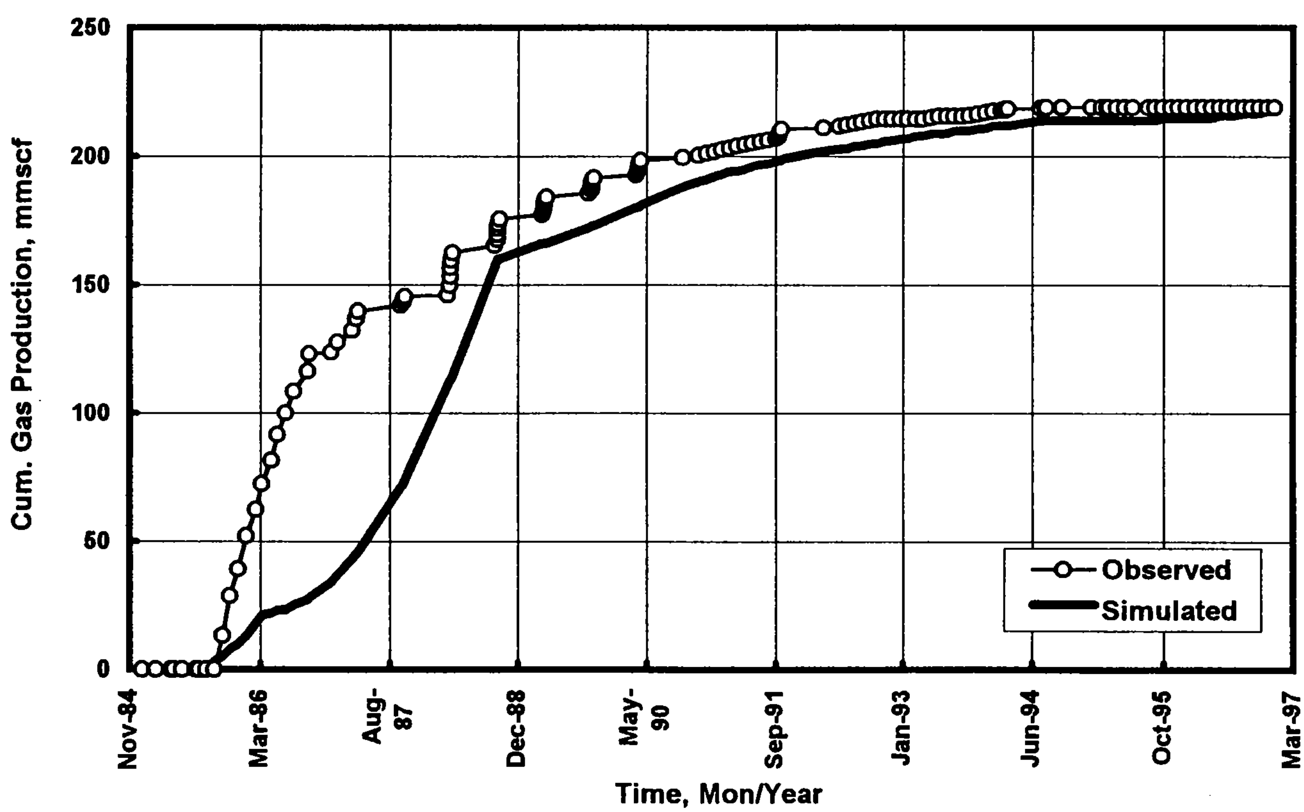


Figure 61. Observed and simulated cumulative gas production curves for the Pruett No. 2 (NE¼NE¼NW¼ sec. 3, T. 24 N., R. 12 W.).

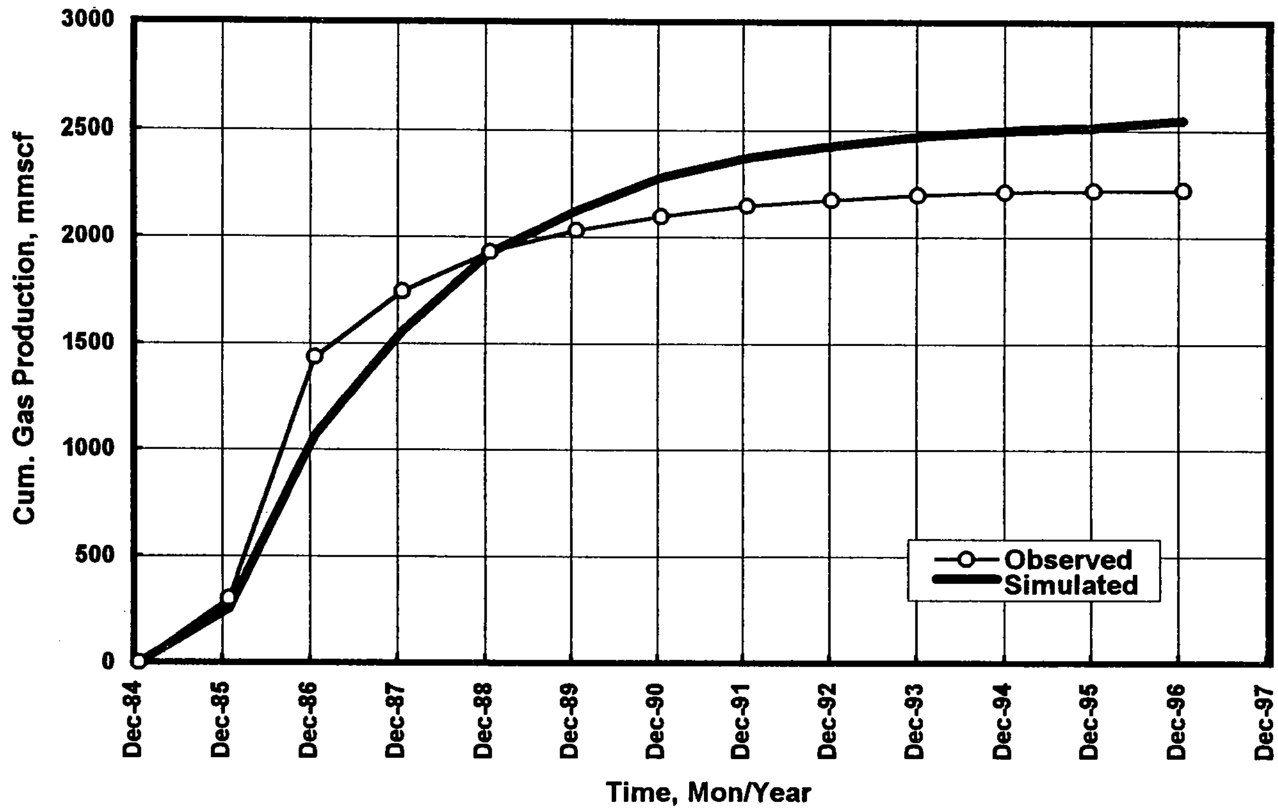


Figure 62. Observed and simulated Red Fork gas production history, North Carmen field.

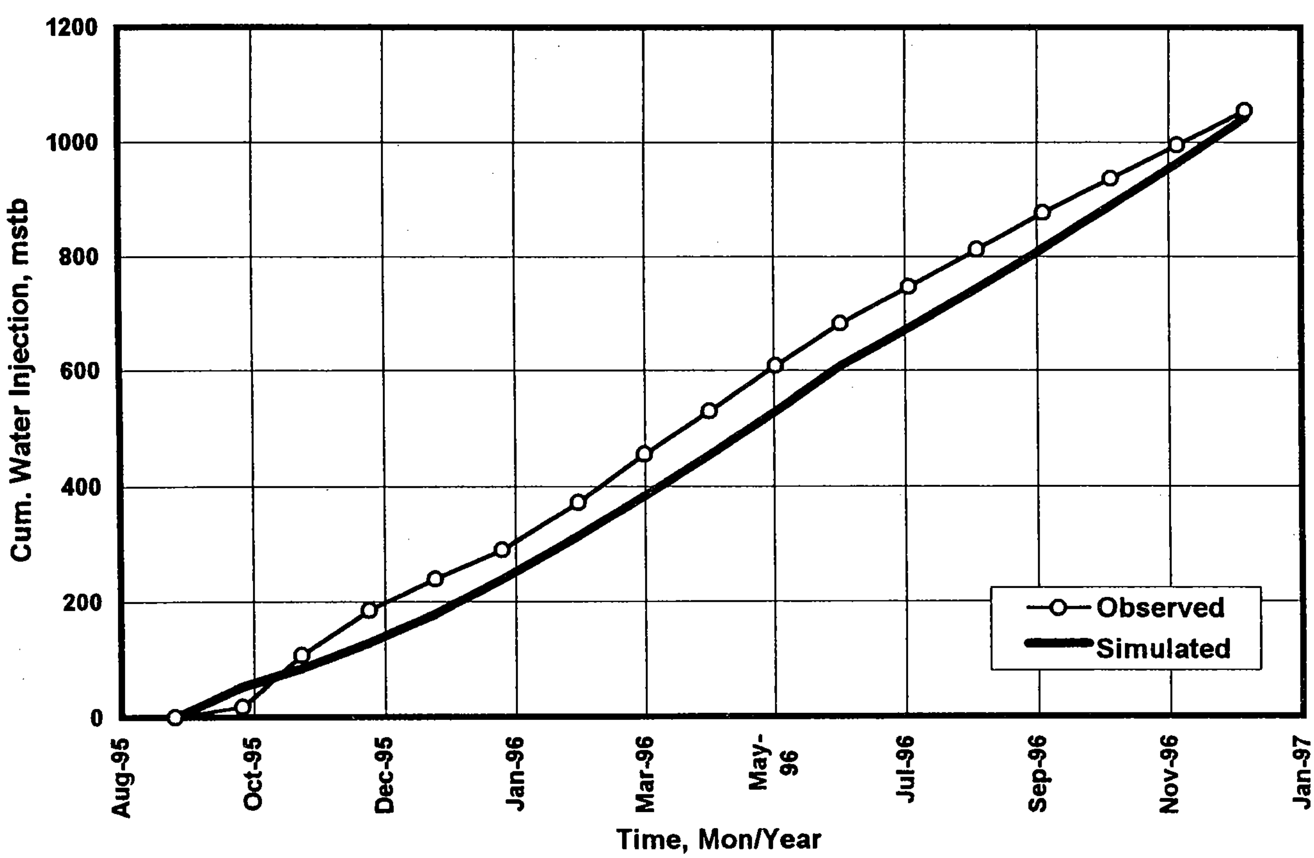


Figure 63. Reported and simulated water injection history for North Carmen field.

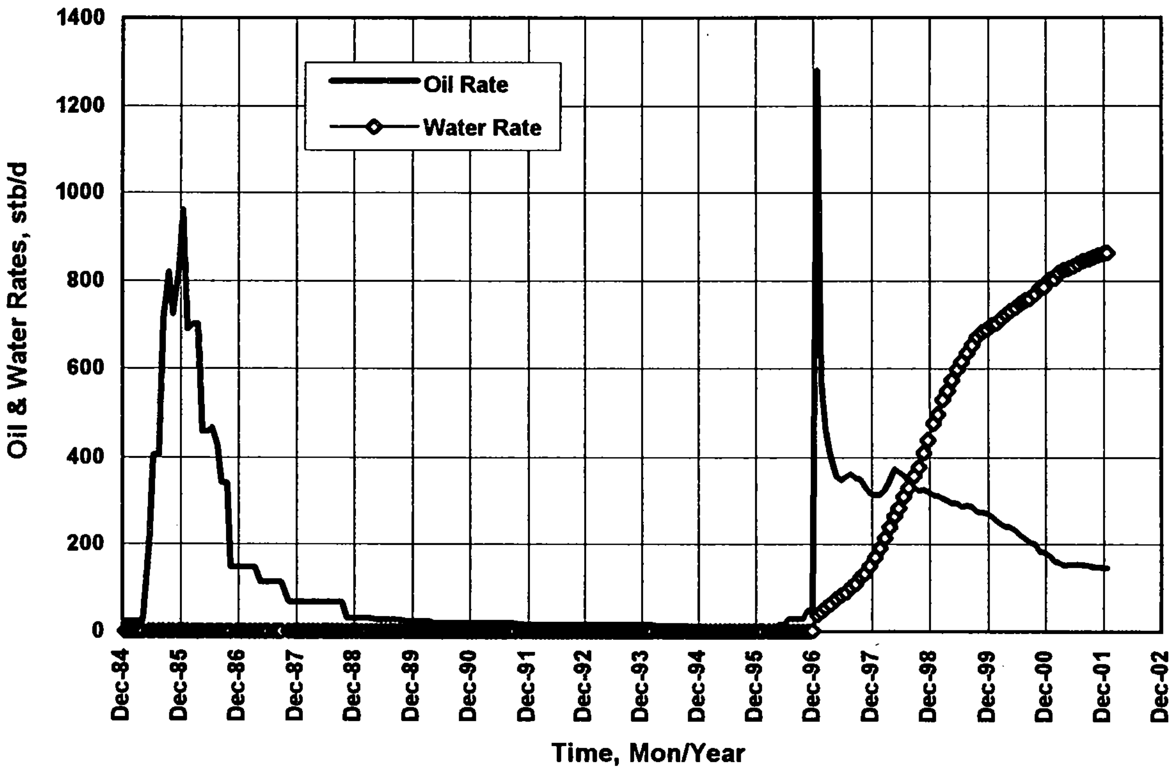


Figure 64. Base Case oil and water production rates. The Base Case simulation used the well configuration and operating conditions that were in effect in 1996. The curve prior to 1996 was constrained by historical production rates. The December 1996 spike is an artifact at the junction between the historically-constrained and simulated parts of the curve.

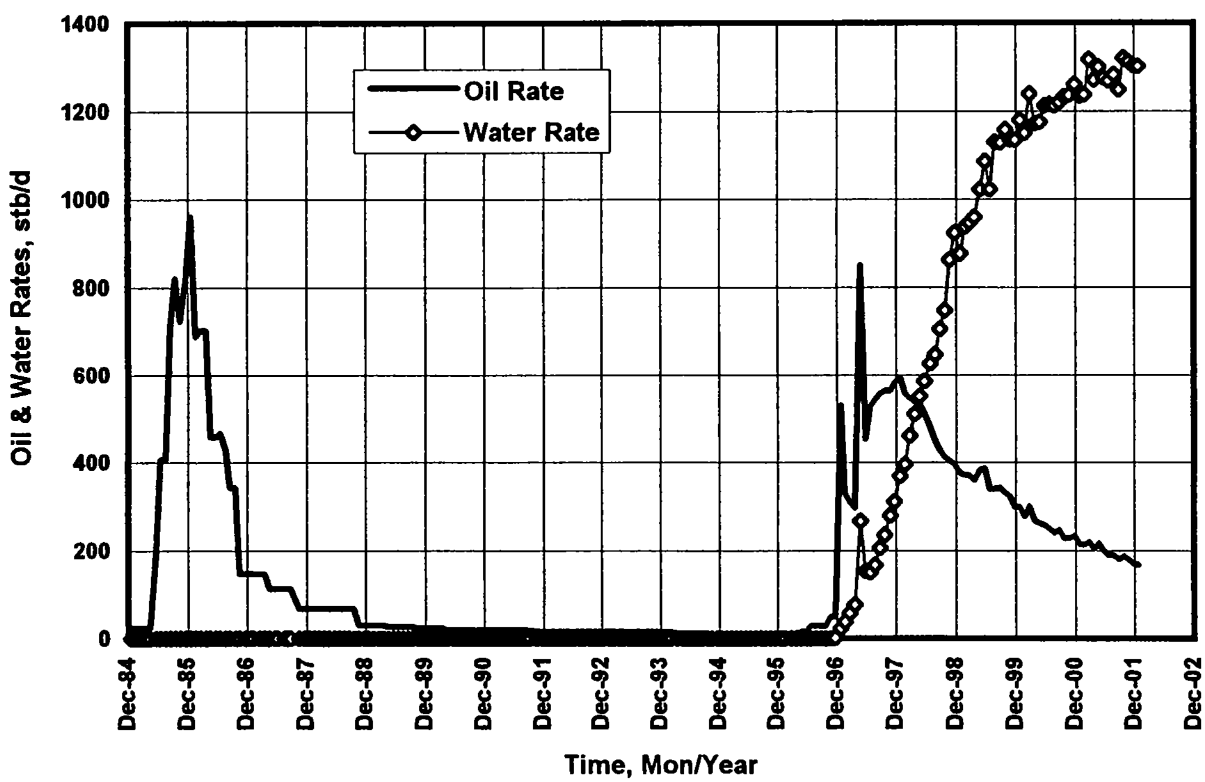


Figure 65. Case 2 oil and water production rates. Case 2 simulated the 1996 well configuration with higher bottom-hole pressures—5,500 PSIA in the injection wells and 800 PSIA in the production wells. The curve prior to 1996 reflects historical conditions and was constrained by historical production rates. The spikes in early 1997 are artifacts.

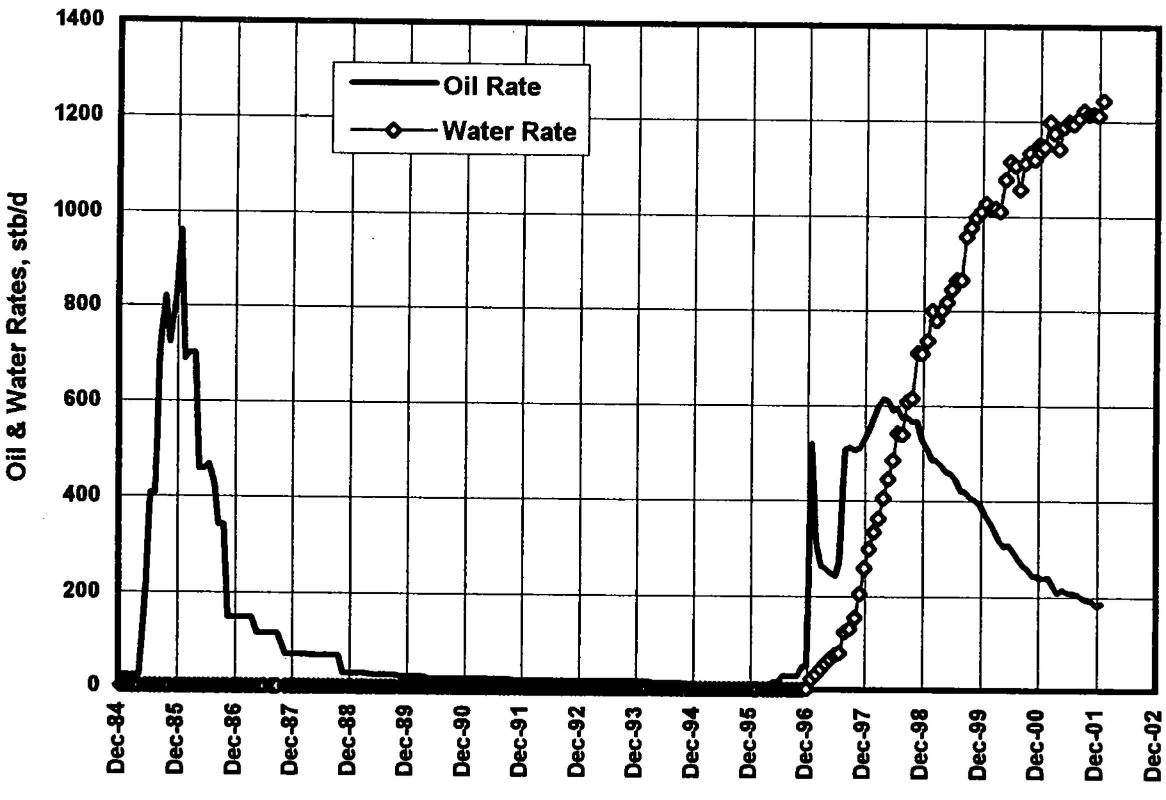


Figure 66. Case 3 oil and water production rates. Case 3 simulated the 1996 well configuration plus 2 producers and 1 injector with a constant injection pressure of 4,440 PSIA and constant BHP in production wells of 800 PSIA. The curve prior to 1996 reflects historical conditions and was constrained by historical production rates. The December 1996 spike is an artifact at the junction between the historically-constrained and simulated parts of the curve.

15). The maximum oil production rate of 380 BOPD was in May 1998 (Fig. 64). The total 5-year oil production predicted by the Base Case simulation is 506 MSTB (14% of OOIP).

Case 2

In Case 2, the management strategy simulated used the 1996 well configuration with a modification of bottom-hole pressures. The injection pressure for all injection wells was raised from the 1996 Base Case value of about 4,440 PSIA to 5,500 PSIA where it was held constant. The bottom-hole flowing pressure in the oil wells was raised from the 1996 Base Case level of 450 PSIA to 800 PSIA and held constant. At the end of the simulation period, the average daily field production rate was 170 BOPD with 88% water-cut (~1,300 BWPD) (Fig. 65; Table 15). The maximum oil production rate of 590 BOPD was in January of 1998 (Fig. 65). The total 5-year oil production predicted by the Case 2 simulation was 637 (17.0% of OOIP).

Case 3

The management strategy simulated by Case 3 involved the addition of two production wells and an injection well to the 1996 well configuration. One production well was placed at the northwest end of the field, SE¼NE¼SE¼ sec. 33. The other production well was placed at the south edge of the east half of the field, N½SW¼NW¼ sec. 2. An abandoned well at the northeast end of the field, the Horn No. 1-B (SE¼SE¼ sec. 35), was converted to an injection well for the simulation. The bottom-hole pressure specified for the injection wells was 4,440 PSIA (same injection pressure as in the Base Case). The bottom-hole flowing pressure specified for the production wells was 800 PSIA (same pressure as in Case 2). At the end of the simulation period, the average daily field production rate was 190 BOPD with 87% water-cut (~1,250 BWPD) (Fig. 66; Table 15). The maximum oil production rate of 620 BOPD was in April of 1998. The total 5-year oil production predicted by the Case 3 simulation is 737 MSTB (20% of OOIP).

SUMMARY

The original oil in place in the Red Fork pool of the North Carmen field is estimated to be about 3.62 million barrels of oil. As of January 1997, after about 11 years of primary production and 1 year of waterflood production, 423,402 BO (12% of OOIP) and about 2.3 MMCF gas had been produced. The estimated

1,260,000 STB (35% OOIP) of unproduced mobile oil is a strong incentive to consider future oil recovery opportunities.

The results of the three strategies evaluated are shown in Table 15. Of the three management strategies simulated, Case 3 (1996 well configuration plus two new producers and 1 injection well) resulted in the greatest amount of oil recovery in five years: 737,000 BO or 20.0% of OOIP. This is about 1.7 times the amount recovered in the first 12 years of production. The cumulative recovery predicted by the Case 3 simulation is 1,160,000 BO (32% of OOIP) compared to 1,060,000 BO (29% of OOIP) predicted by Case 2 and 930,000 BO (26% of OOIP) predicted by the Base Case simulation (Table 15).

REFERENCES CITED

Bradley, H. B., 1987, Petroleum engineering handbook: Society of Petroleum Engineers, Richardson, Texas, p. 24–10.

Core Laboratories, Inc., 1985, Reservoir fluid analysis: File No. RFL 850448.

Craft, B. C.; Hawkins, M.; and Terry, R. E. (eds.), 1991, Applied petroleum reservoir engineering [2nd edition]: Prentice Hall, Englewood Cliffs, New Jersey, p. 31–44.

Honarpour, M.; Koederitz, L.; and Harvey, A. H., 1986, Relative permeability of petroleum reservoirs: CRC Press, Inc., Boca Raton, Florida, p. 40.

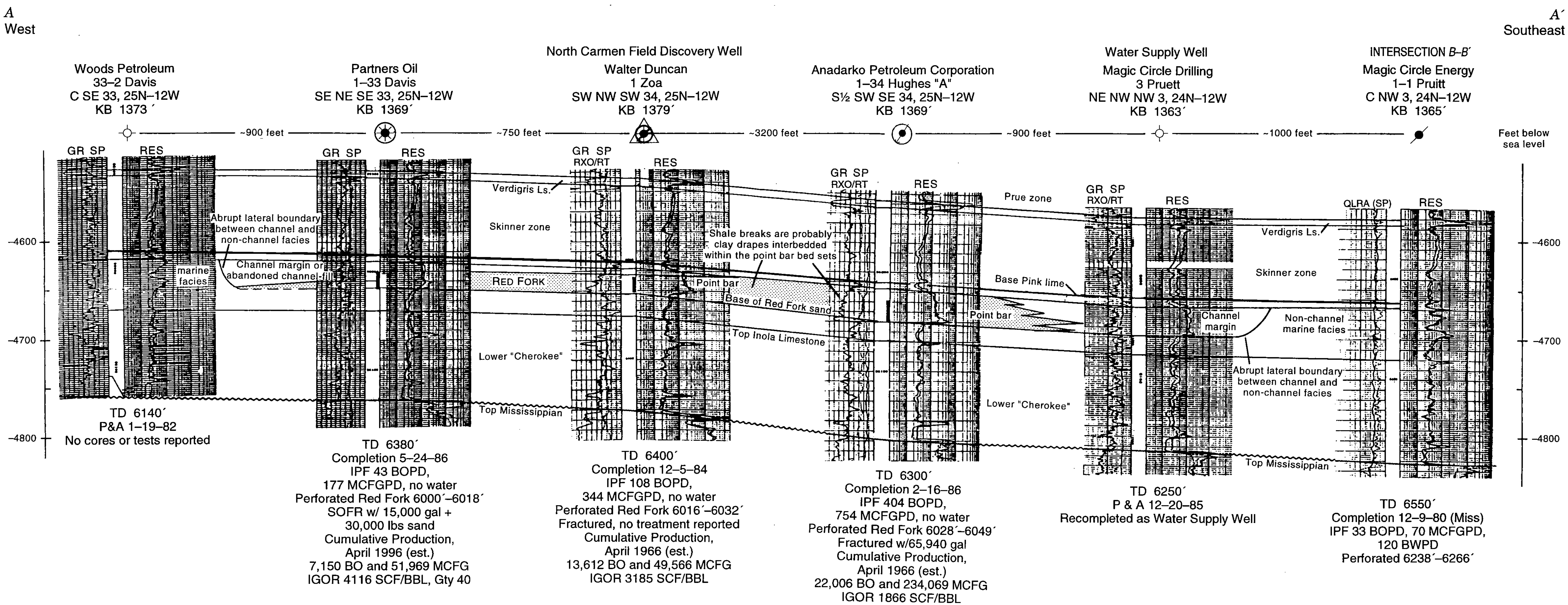
Mathematical and Computer Services, Inc., 1995, BOAST3, A modified version of Boast II with post processors B3 PLOT and COLORGRID, 63 p.

Natural Resources Information System (NRIS), 1996, Production data for the North Carmen field, August 6: NRIS oil and gas production data base, available from Geo Information Systems, University of Oklahoma, Norman.

Andrews, R. D., 1997, The Red Fork play, *part II of* Fluvial-dominated deltaic (FDD) oil reservoirs in Oklahoma: the Red Fork play: Oklahoma Geological Survey Special Publication 97-1 [this volume], p. 13–71.

Smith, Dan, 1991, Predicting a downdip water level using capillary-pressure relationships: The Log Analyst, September/October, p. 571–574.

OKLAHOMA GEOLOGICAL SURVEY
1908



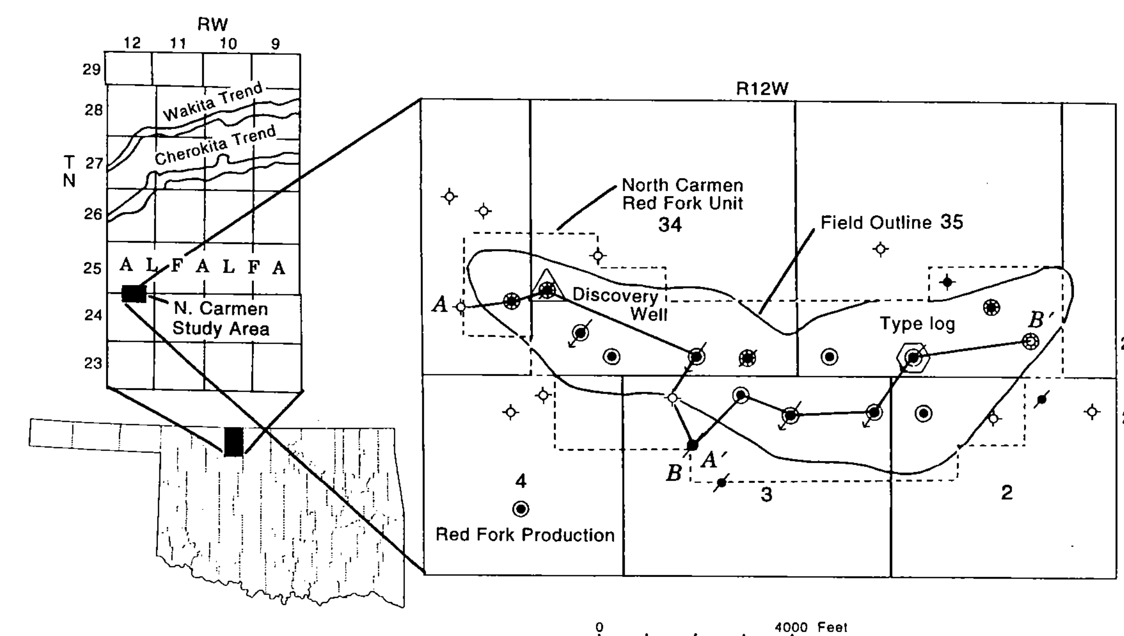
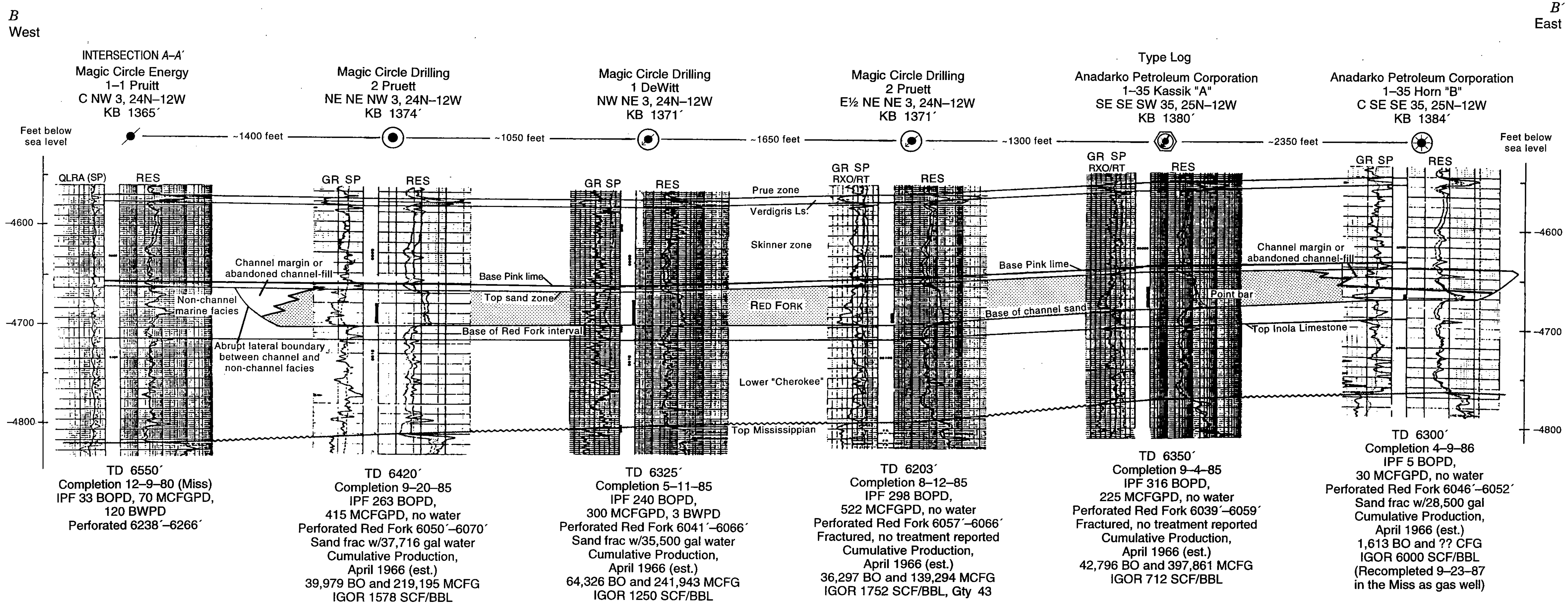


Figure 21. Structural and stratigraphic cross-section A–A' and index map, N. Carmen field, Alfalfa County, Oklahoma. (Datum: sea level, no horizontal scale.)



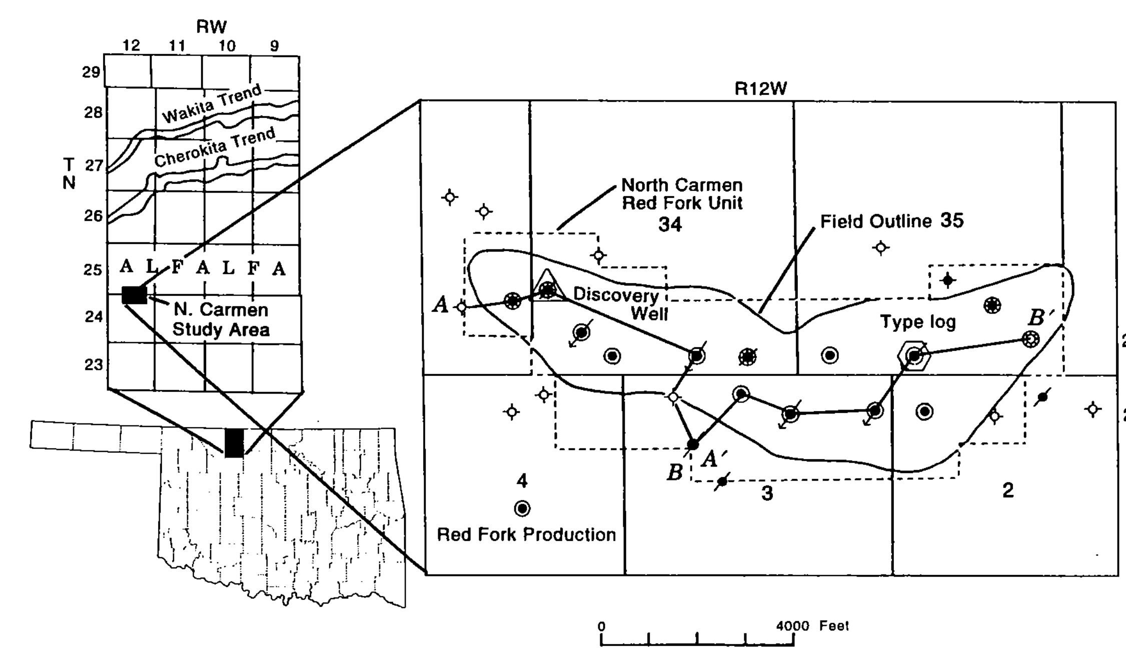


Figure 22. Structural and stratigraphic cross-section B–B' and index map, N. Carmen field, Alfalfa County, Oklahoma. (Datum: sea level, no horizontal scale.)

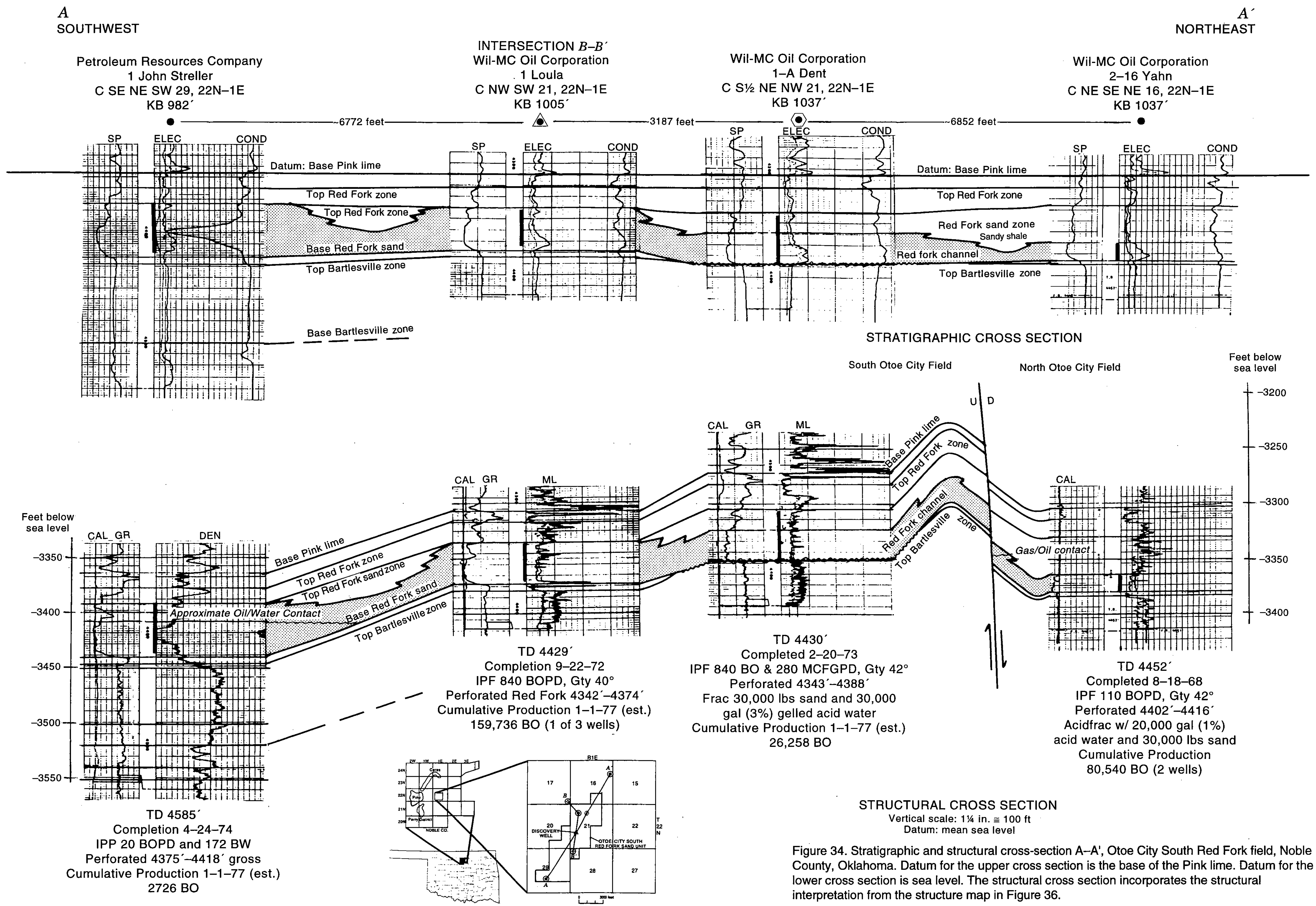
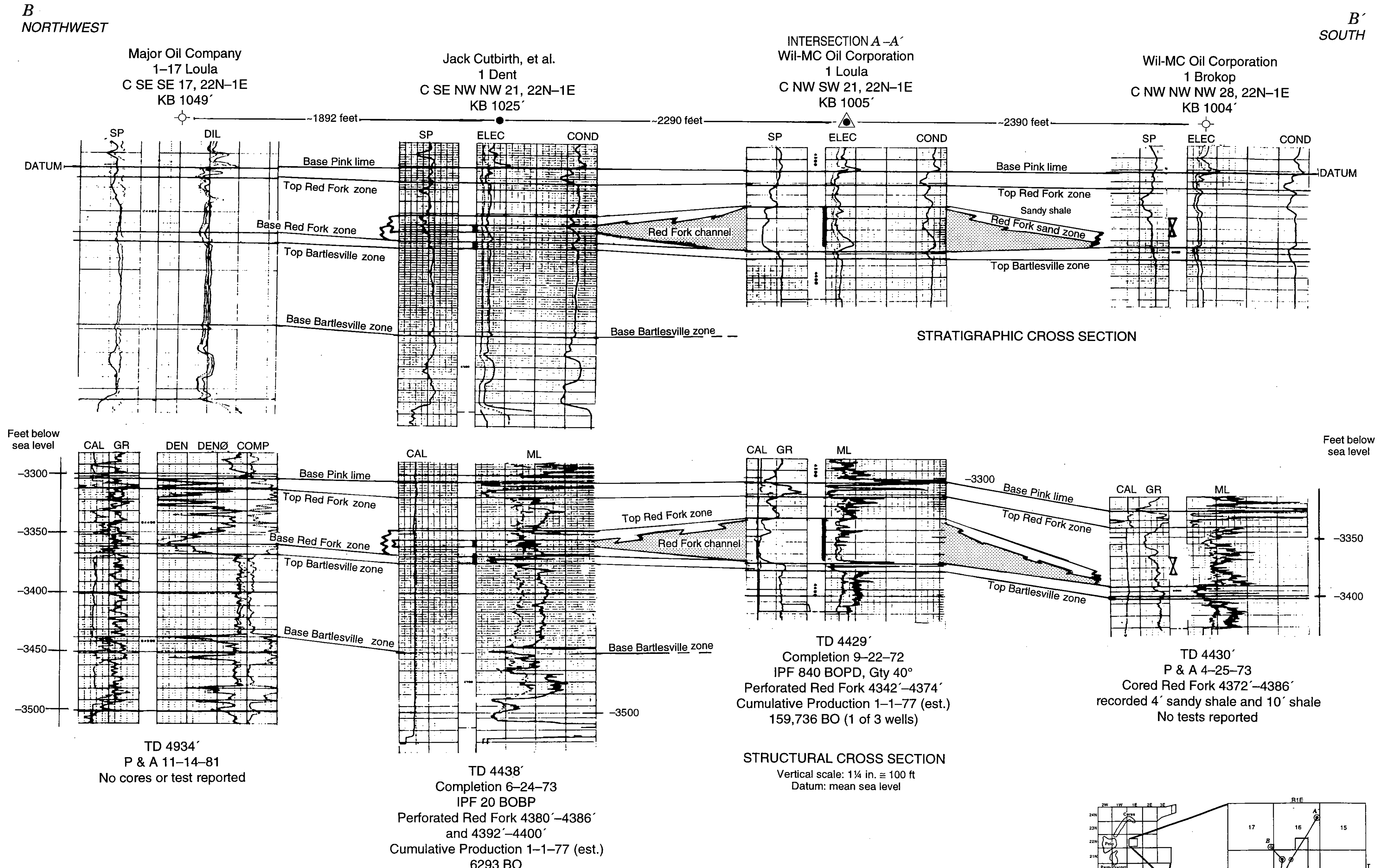


Figure 34. Stratigraphic and structural cross-section A–A', Otoe City South Red Fork field, Noble County, Oklahoma. Datum for the upper cross section is the base of the Pink lime. Datum for the lower cross section is sea level. The structural cross section incorporates the structural interpretation from the structure map in Figure 36.



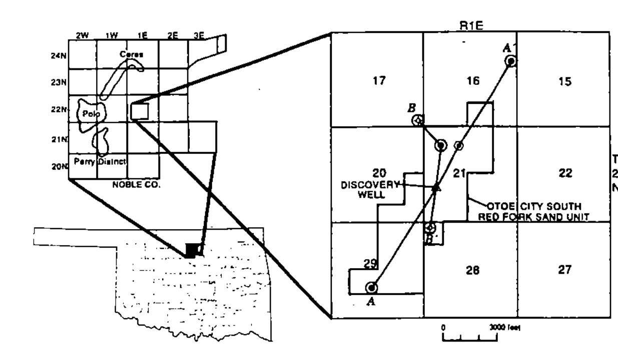
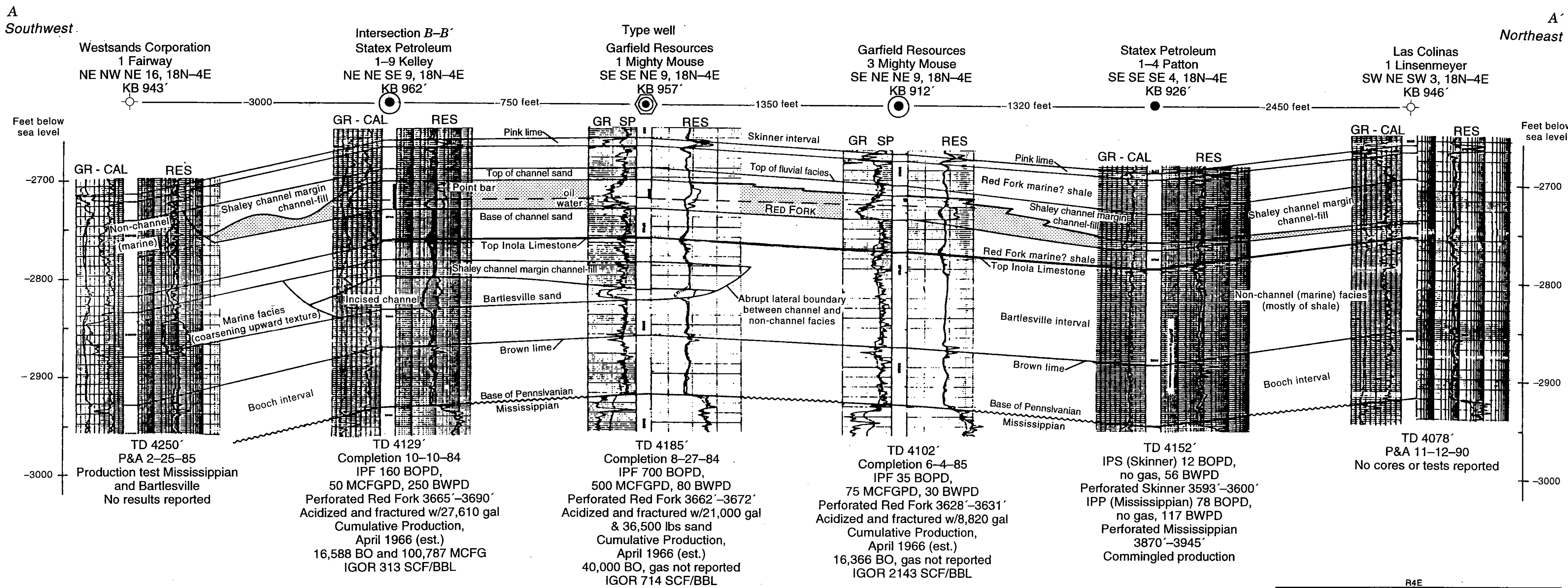


Figure 35. Structural and stratigraphic cross-section B–B', Otoe City South Red Fork study area, Noble County, Oklahoma. Datum for the upper cross section is the base of the Pink lime. Datum for the lower cross section is sea level. The structural cross section incorporates the structural interpretation from the structure map in Figure 36.



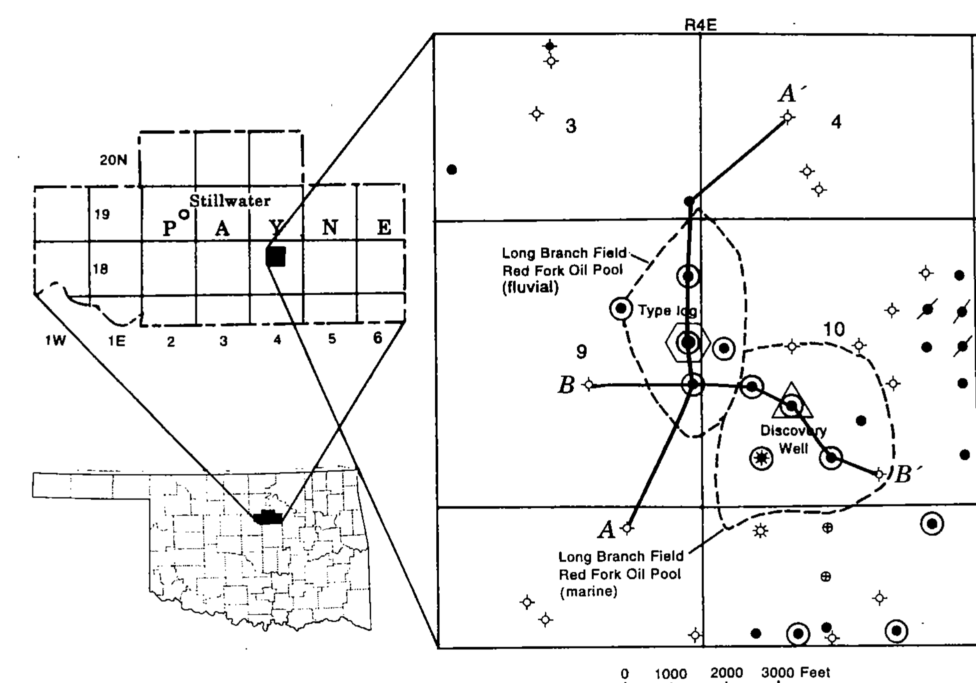
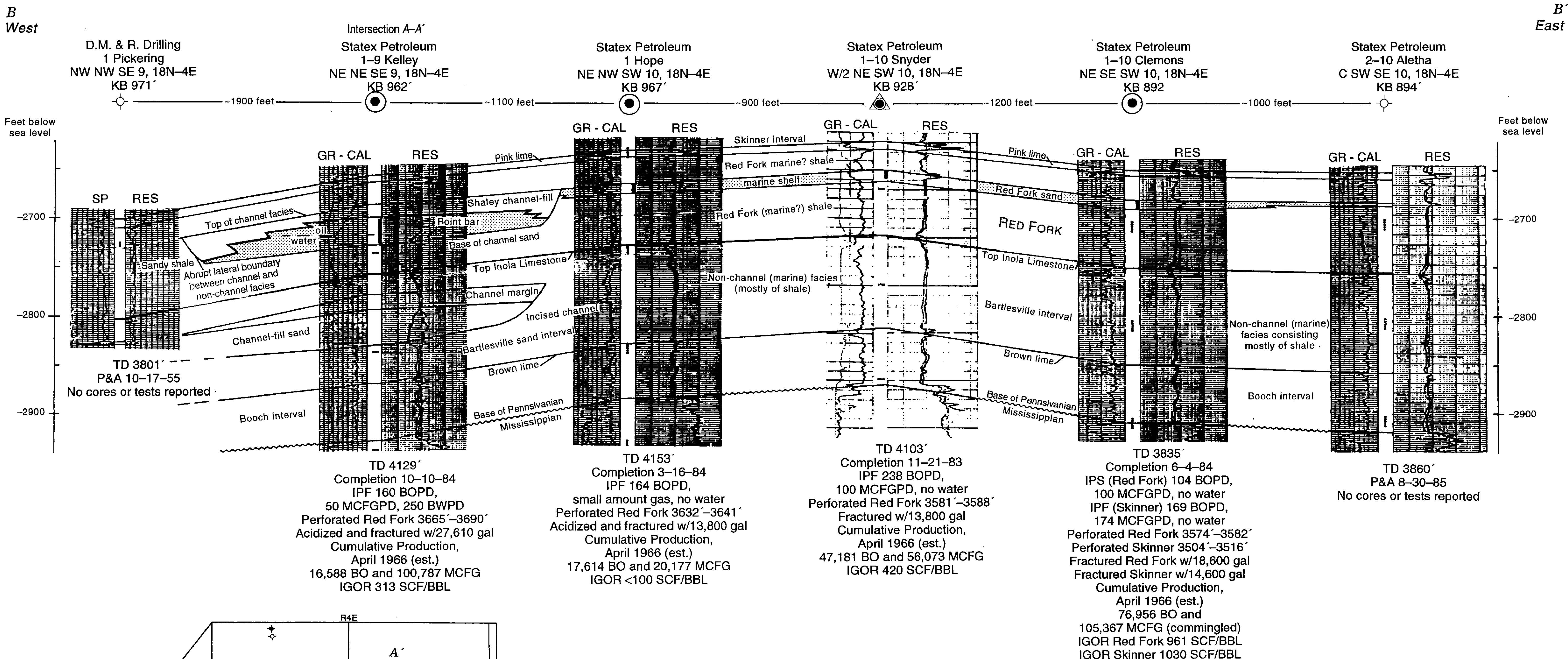


Figure 46. Structural and stratigraphic cross-section A–A', Long Branch field, Payne County, Oklahoma. (Datum: sea level, no horizontal scale)



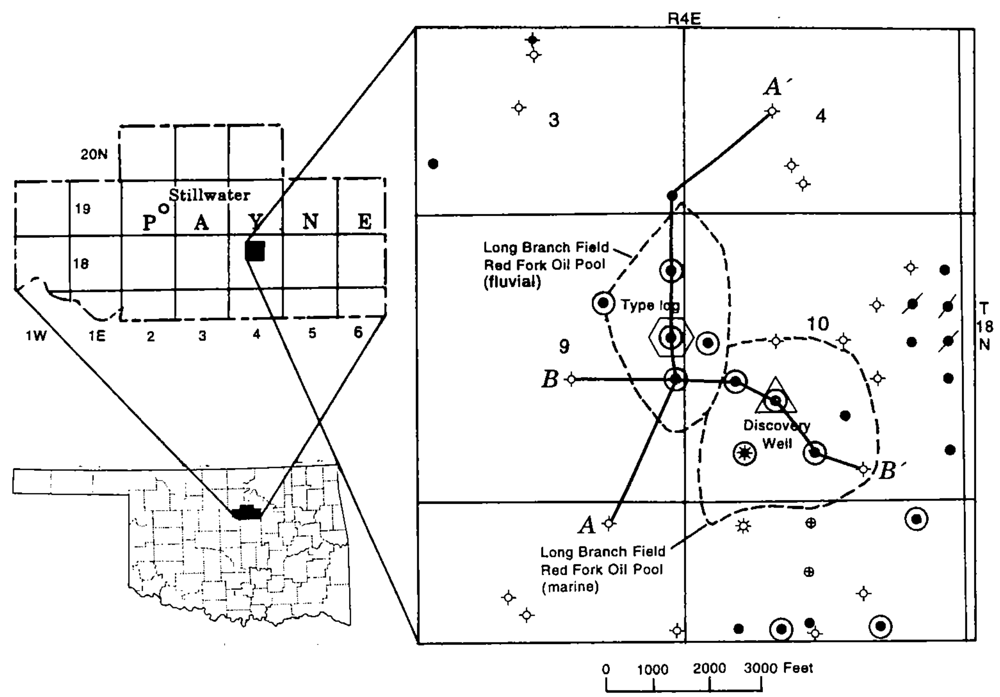


Figure 47. Structural and stratigraphic cross-section B–B',
Long Branch field, Payne County, Oklahoma. (Datum: sea level, no horizontal scale)