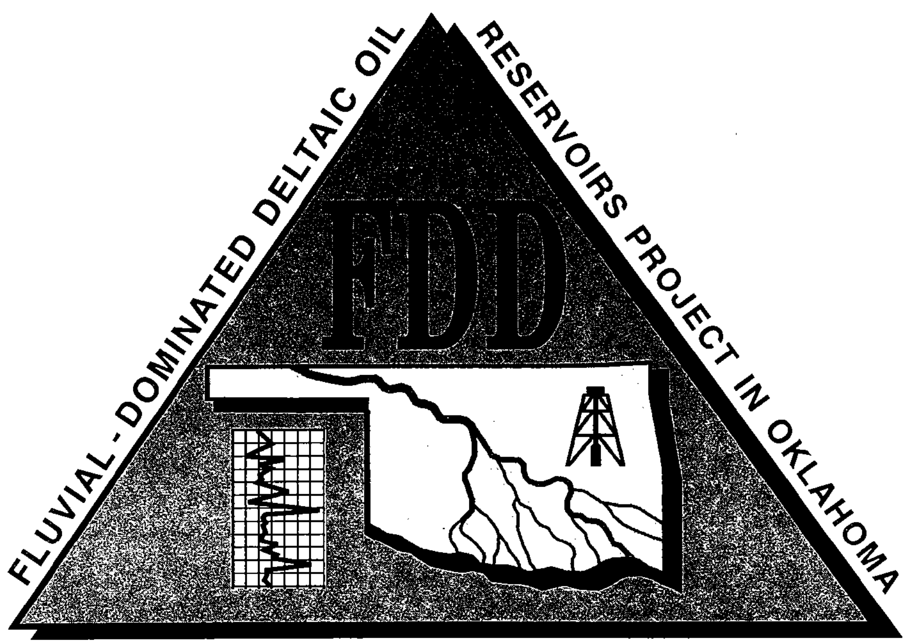
Oklahoma
Geological
Survey
1996

Special Publication 96-2

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Skinner and Prue Plays



Oklahoma Geological Survey
Charles J. Mankin, *Director*

Special Publication 96-2
ISSN 0275-0929

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Skinner and Prue Plays

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 Skinner and Prue Plays**
by
Richard D. Andrews
with contributions from Kurt Rottmann

PART III.—**Reservoir Simulations**
Reservoir Simulation of a Skinner Reservoir, Salt Fork North Field, Grant County, Oklahoma
by Z. N. Bhatti and R. M. Knapp

Reservoir Simulation of a Prue Reservoir, Long Branch Field, Payne County, Oklahoma
by X. H. Yang, R. M. Knapp, and R. P. Simpson

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

1996

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.

ERRATA

Oklahoma Geological Survey Special Publication 96-2

The Skinner and Prue Plays

On pages 43 and 44, captions for Figures 41 and 42 are reversed.

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. 2,000 copies have been prepared at a cost of $10,227 to the taxpayers of the State of Oklahoma. Copies have been deposited with the Publications Clearinghouse of the Oklahoma Department of Libraries.

◁ CONTENTS ▷

LIST OF ILLUSTRATIONS

Figures

Plates

TABLES

PART I

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

Richard D. Andrews
Geo Information Systems

with contributions from

Jock A. Campbell *and* *Robert A. Northcutt*
Oklahoma Geological Survey · 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 sources of publicly accessible information on FDD reservoirs, including the OGS Resources Facility, a computer laboratory.

The computer laboratory contains all the data files for the plays, as well as other oil and gas data files for the State, and the necessary software to analyze the information. Technical support staff are available to assist interested operators in the evaluation of their producing properties, and professional geological and engineering outreach staff are available to assist operators in determining appropriate improved-recovery technologies for those properties. The lab is equipped with PCs, plotters, laser printers, CD-ROM readers, and scanning and digitizing equipment. Geology-related mapping software, such as GeoGraphix, ARC/INFO, ArcView, Surfer, Atlas MapMaker for Windows and Radian CPS/PC, is available for public use. Access to data is through menu-driven screen applications that can be used by computer novices as well as experienced users.

The OGS Resources Facility opened June 1, 1995. In the future, it will be possible to access the facility from other locations through remote modems and, eventually, 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 Prue & Skinner play, 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

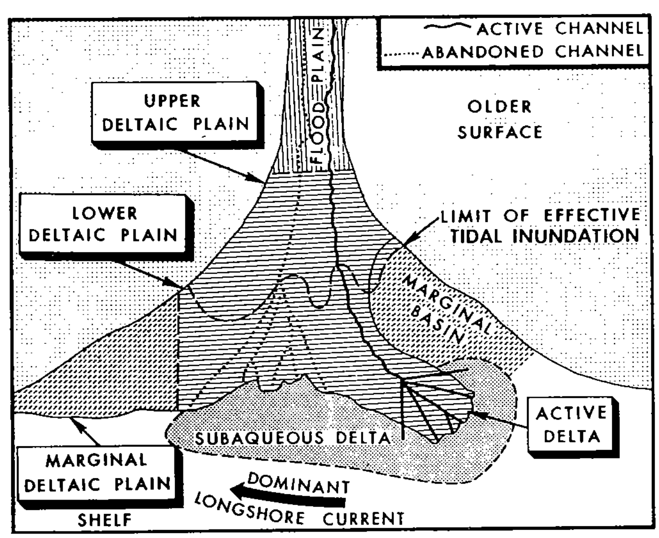
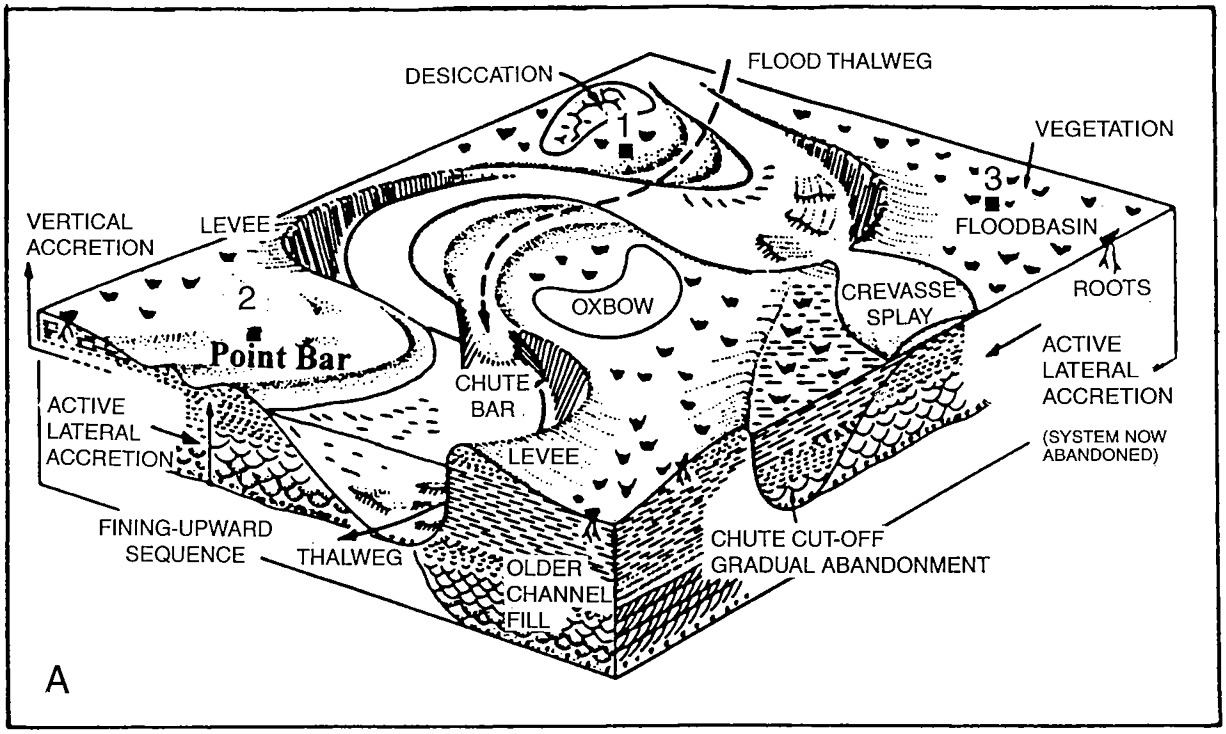


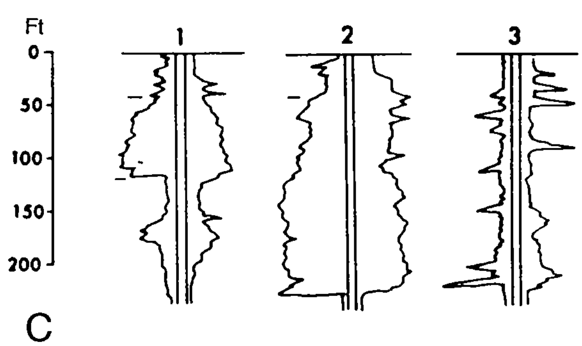
Figure 1. Components of a delta system. From Coleman and Prior (1982).

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, semimarine 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





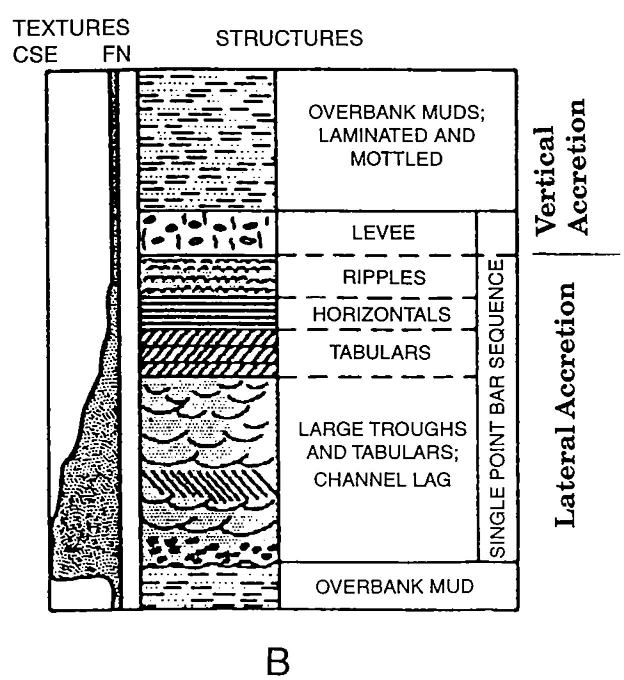


Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified 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

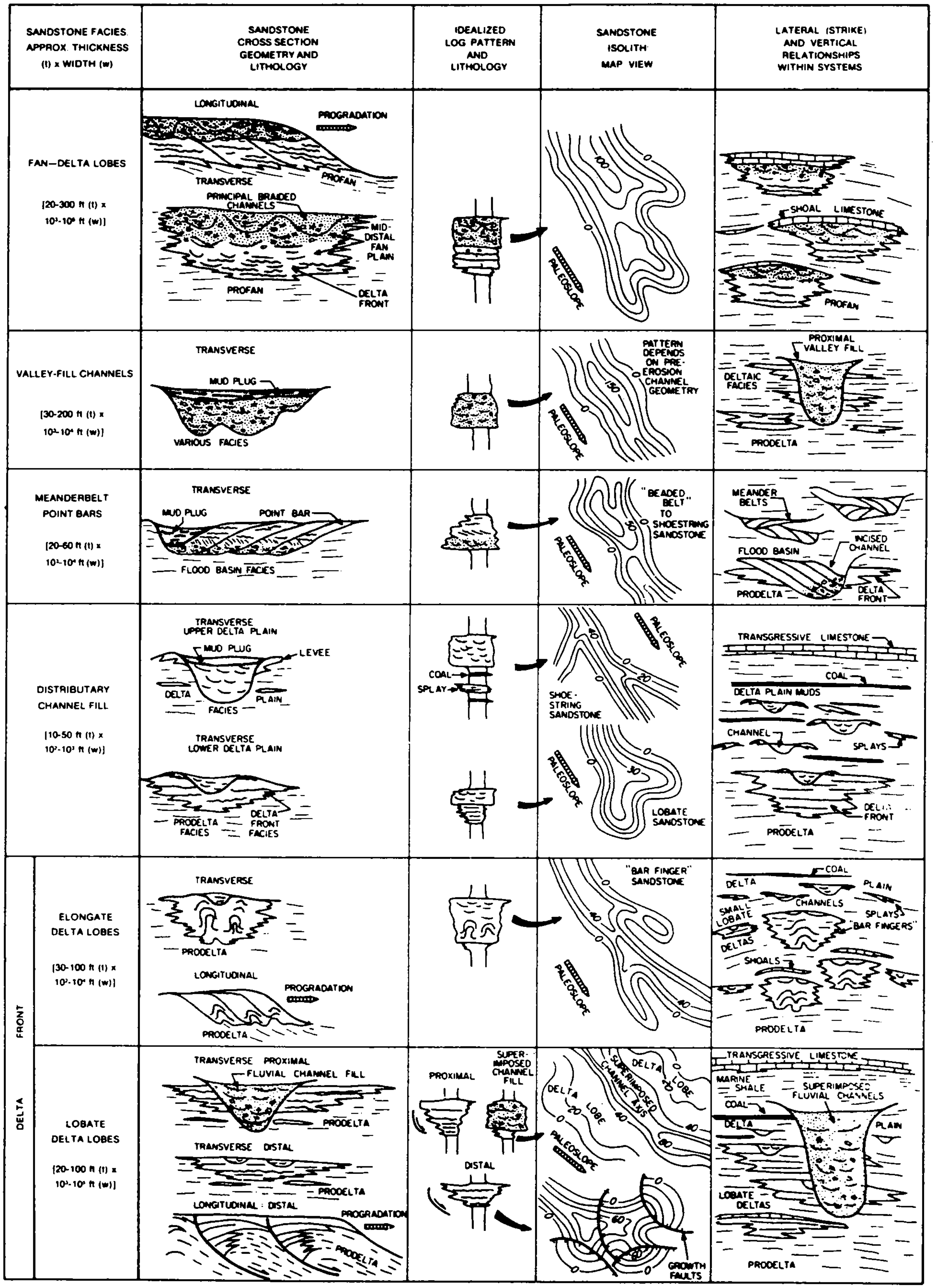


Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

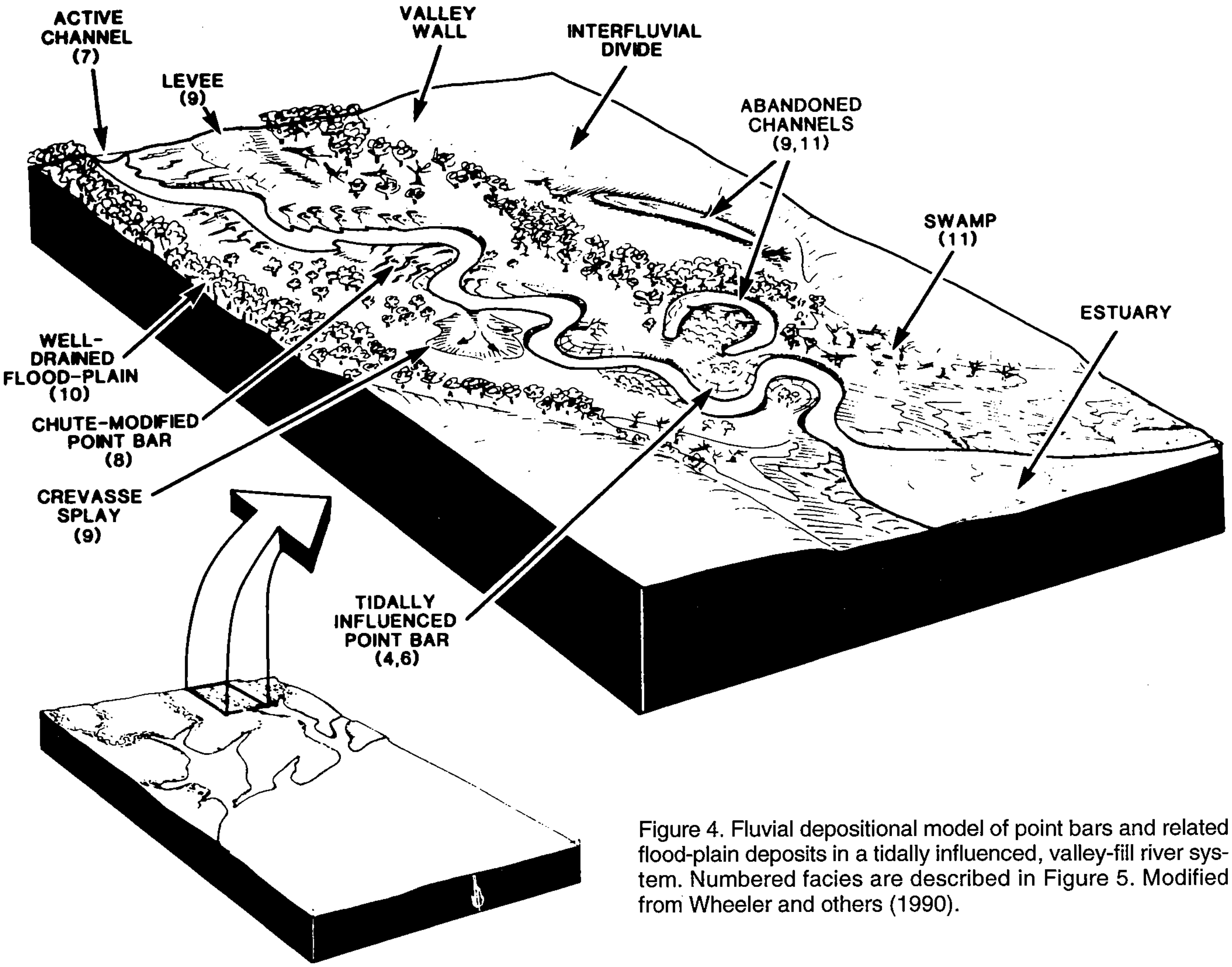


Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

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

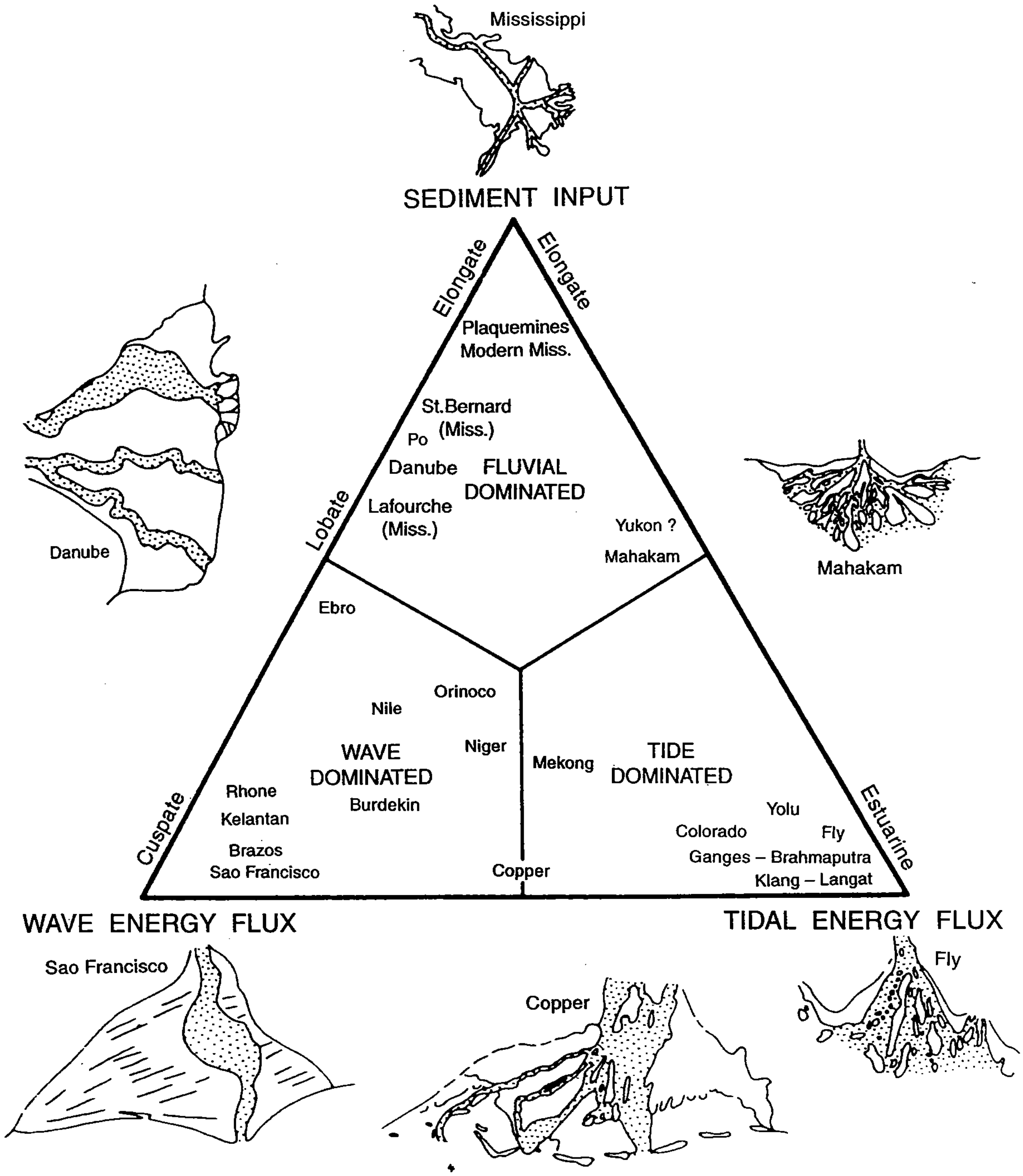


Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

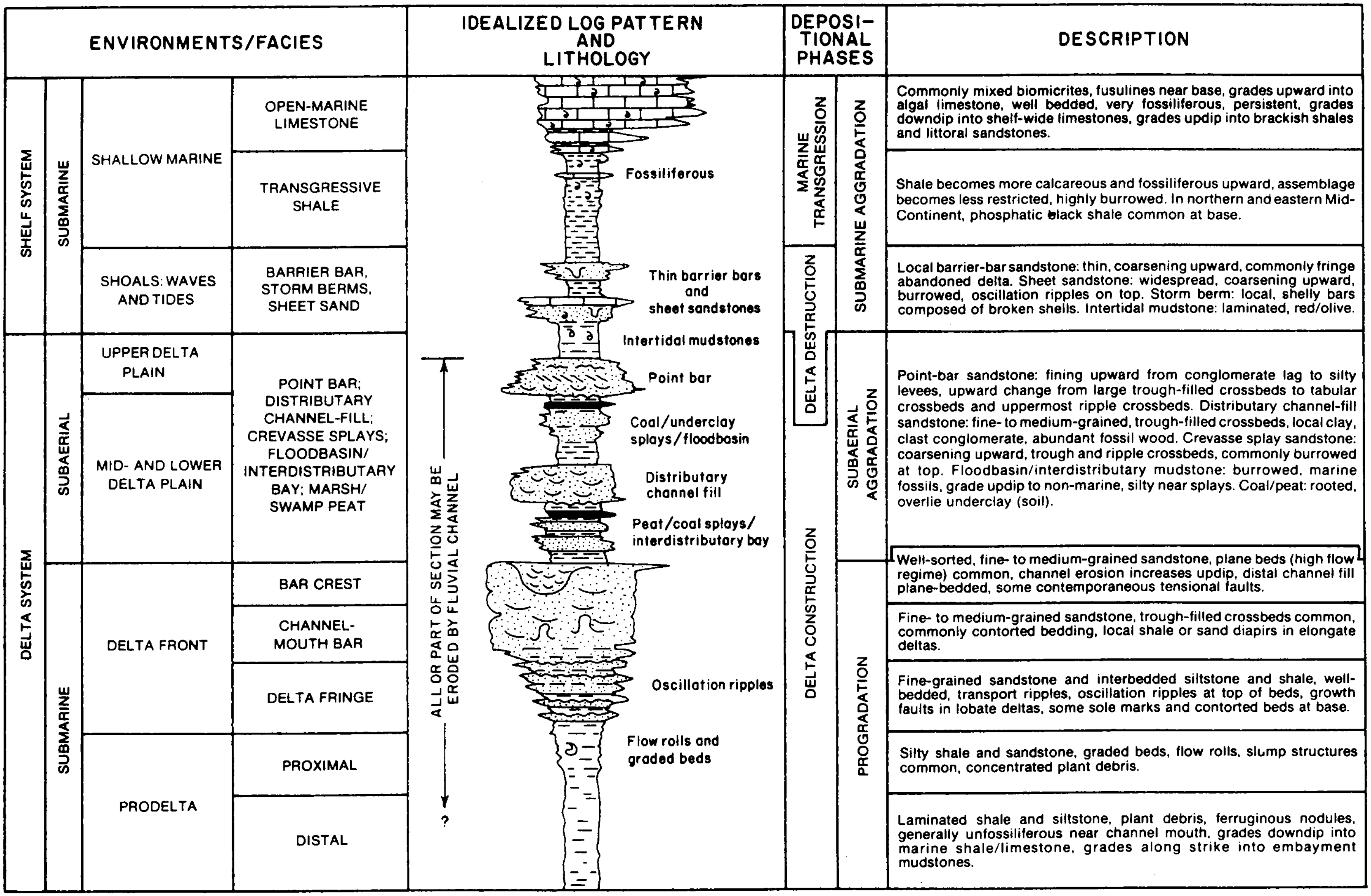


Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

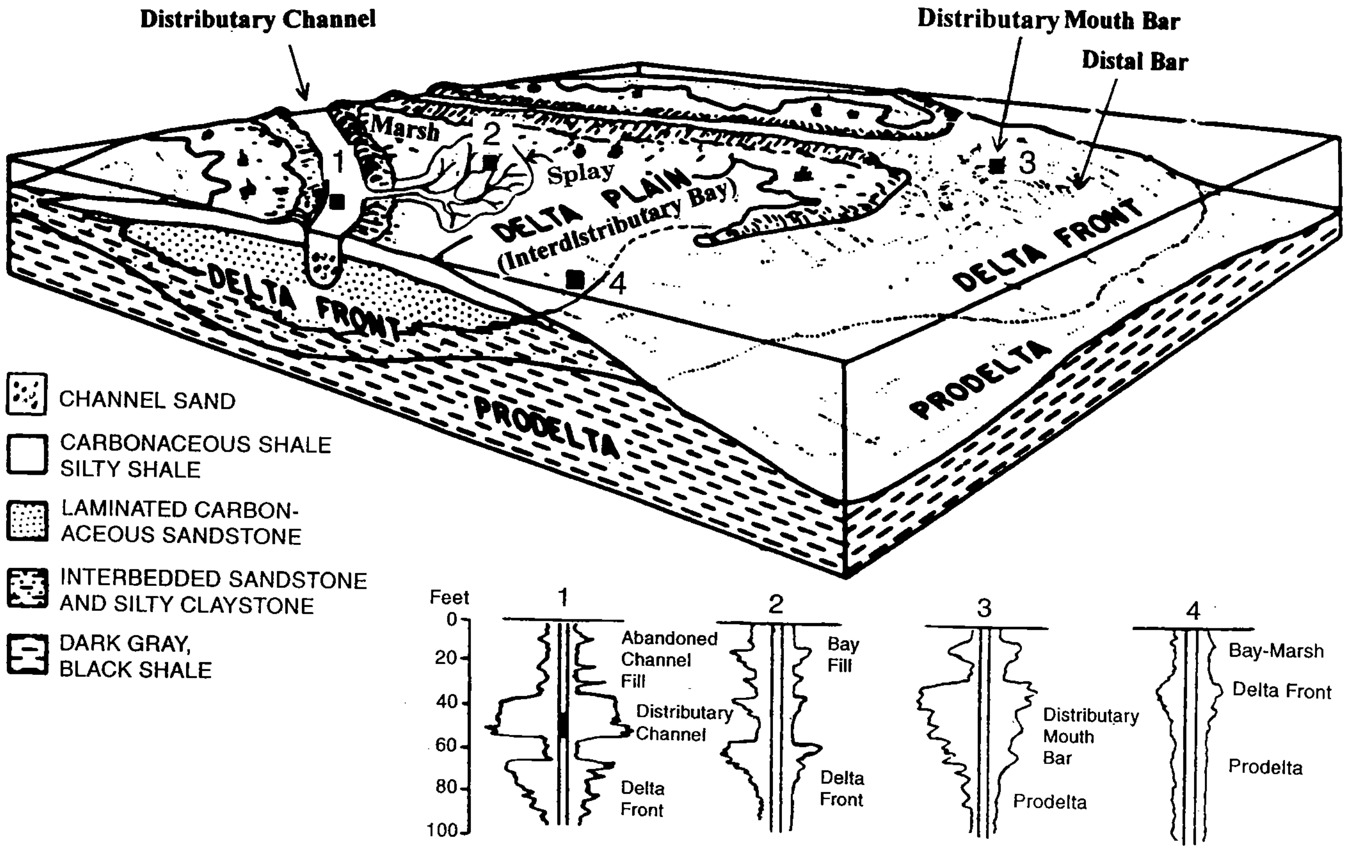


Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

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-

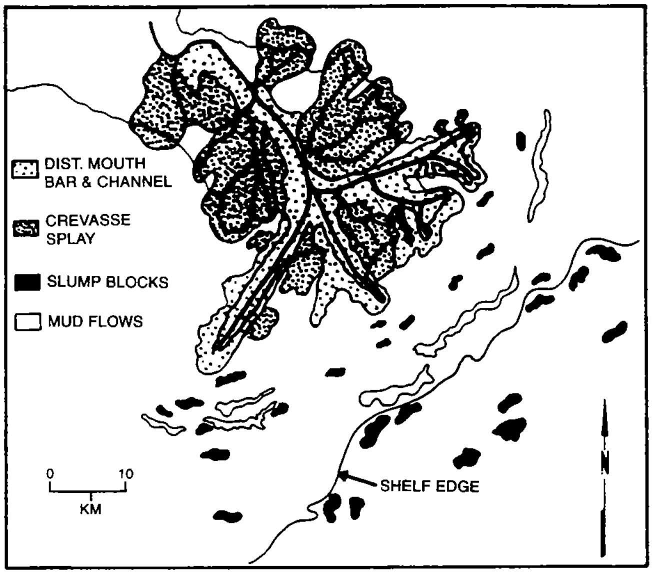


Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

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

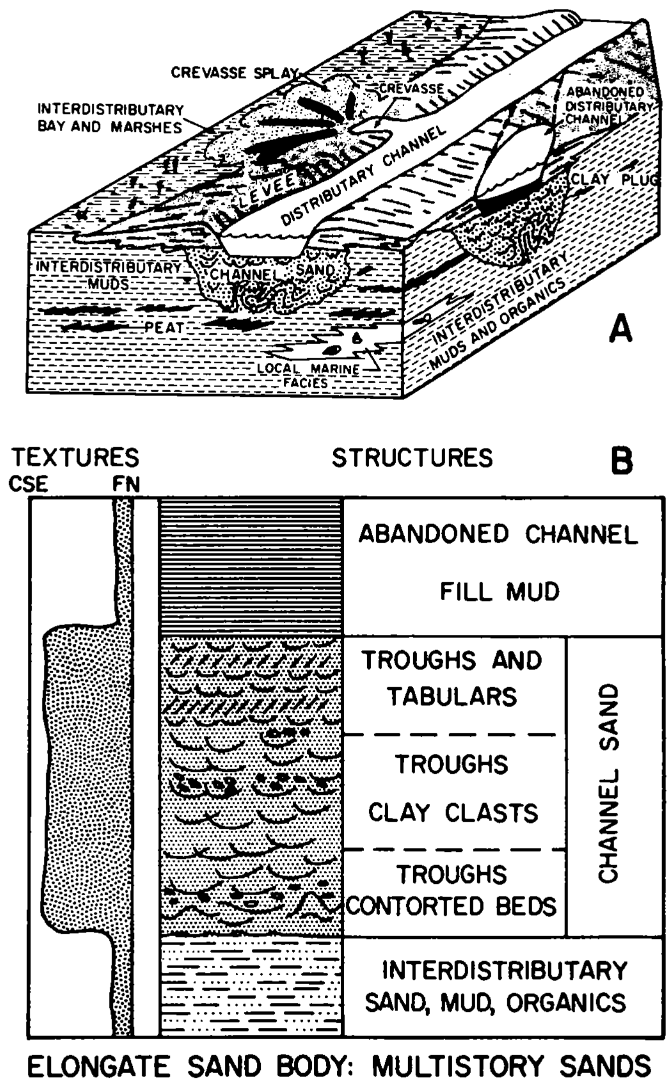


Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

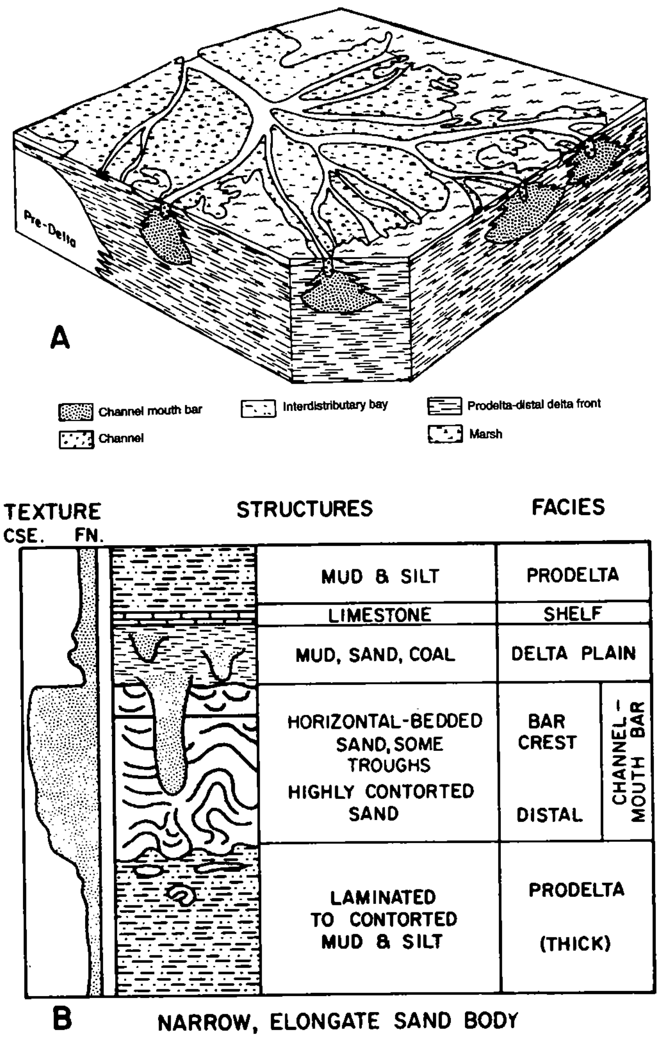


Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

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 Skinner and Prue Plays

Richard D. Andrews
Geo Information Systems

THE SKINNER-SENORA PLAY

INTRODUCTION

Skinner

The upper "Cherokee" Skinner sandstone was first named by Wood in 1913 from productive sands underlying the Skinner lease in the Lauderdale oil pool, T. 20 N., R. 8 E., Pawnee County, Oklahoma (Jordan, 1957). The Skinner sand zone was later defined as the interval between the Verdigris Limestone and the Pink lime and consists of up to three distinct intervals.

Deposition of Skinner sandstone occurred throughout much of Oklahoma and is not confined to just the Cherokee platform. Although certain episodes of Skinner deposition were suppressed in central Oklahoma by positive elements along the Nemaha fault zone, a few major fluvial systems did advance into the western part of the Anadarko basin. These depositional phases occurred primarily during upper Skinner time and are mapped in western Oklahoma as far as Roger Mills County (Pl. 1, in envelope). Only northwest Oklahoma and the Wichita uplift area in southern Oklahoma were unaffected by Skinner deposition. Much of the Skinner sandstone, however, occurs east of the Nemaha fault zone and lies stratigraphically in the lower or middle part of the Skinner section (Pl. 2, in envelope). In the southeastern part of Oklahoma, the Skinner merges with a much thicker depositional system in the Arkoma basin in a manner similar to the younger Prue-Calvin play. In this area, the stratigraphic equivalent of the lower Skinner sand interval is referred to as the lower Senora Formation, Chelsea Sandstone, or Allen sand (Fig. 12). In general, the Skinner FDD system advanced to the southwest from a northeasterly source area, whereas the Senora FDD system was sourced by the Ouachita uplift and advanced to the northwest (Fig. 13).

Skinner reservoirs generally produce oil and associated gas throughout most of its areal extent (Pl. 3, in envelope). The oil is moderately to highly gas saturated and often has a high shrinkage factor upon production. Therefore, the principal drive mechanism in many Skinner reservoirs is solution gas expansion, and wells commonly produce relatively large amounts of associated gas along with the oil. In the deeper portions of the Anadarko basin, Skinner wells produce chiefly gas.

Skinner oil production is commonly commingled with production from other reservoirs, which makes it difficult to interpret production statistics. This is illustrated in Table 1, which shows the amount of Skinner oil produced from Skinner-only leases and commingled Skinner production. Annual Skinner and Prue production are plotted in Figure 14. Since 1979, annual Skinner (single-zone) production ranged from about 1 million bbl to just under 3 million bbl and has declined moderately since 1987. Since 1980, annual Skinner oil production has consistently been about 0.75 to 1 million bbl greater than that from the Prue.

Production from the Skinner is from both fluvial and nonfluvial facies, although the latter is more widespread. Nonfluvial reservoirs typically have a coarsening upward textural profile, and deposition may have been in shallow marine, deltaic, or flood plain environments. Many lower Skinner sands in the north-central Cherokee platform area have this textural characteristic and contain abundant terrestrial carbonaceous material. These lower Skinner sandstones generally lack marine fossils and occur adjacent to major fluvial channel deposits. Characteristics such as these indicate that deposition occurred in a coastal environment or in a coastal or delta front environment (distributary mouth bars). A more complete discussion of depositional environments is included within a later section of this report.

Senora

Sandstones in the Senora Formation were first described by Taff in 1901 for exposures near the old post office of Senora, southern Okmulgee County (Weaver, 1952). Although the Senora Formation is now formally used to include all sandstones between the Oswego and Pink limestones, the name is generally used in the oil and gas industry as referring to sandstones and shale occurring in the Arkoma basin that are stratigraphically equivalent to the Skinner interval. Other formal and informal names that are or have been applied to Senora Formation sandstones in the Arkoma basin include the Allen and Olympic sands, the Chelsea Sandstone, and the Hart sands (Fig. 12). Use of the name "Senora" in the subsurface persists into the northern part of Seminole and Pottawatomie Counties (to about T. 11–12 N., R. 5–10 E.) where the stratigraphic

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 12. Stratigraphic nomenclature chart of the "Cherokee" Group, Cherokee platform and Anadarko shelf-basin areas, Oklahoma.

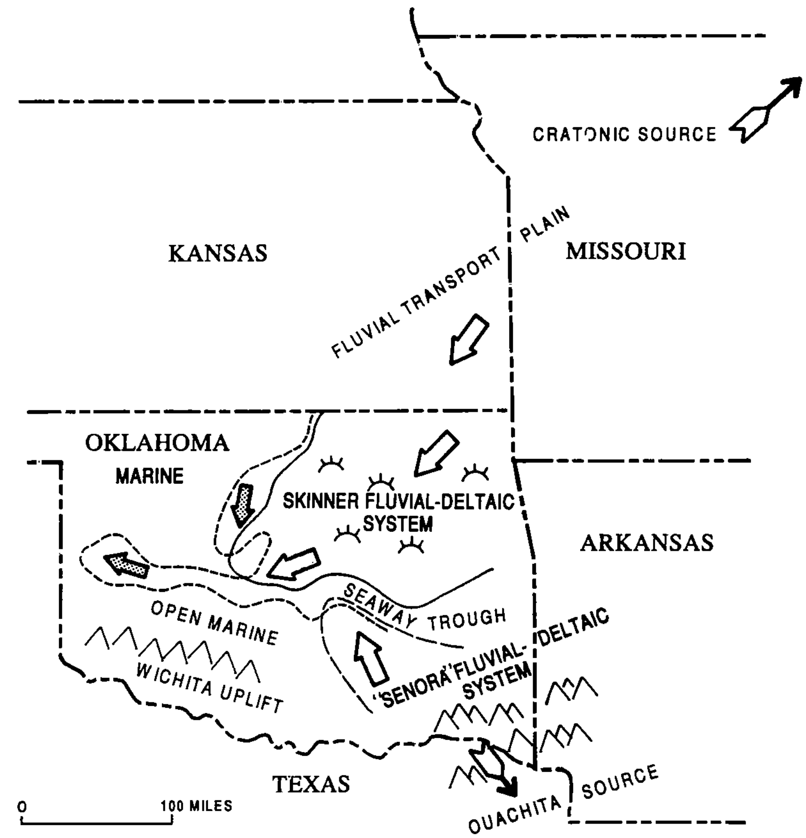


Figure 13. Paleogeography of the central Midcontinent region during deposition of Skinner and Senora (often called Allen or Chelsea) sandstones. Solid outline indicates areas of lower and middle Skinner sandstone and equivalents, whereas the dashed outline indicates the regional extent of the upper Skinner sandstone.

relationships of the Skinner and "Senora" become complex. This area also coincides approximately with the Wilzetta fault zone and is characterized by thinning of the Senora Formation and by lithologies consisting of marine shale (prodelta?) and detached offshore bars.

Senora sandstones in southeastern Oklahoma occur as a relatively small but discrete play within the western margin of the Arkoma basin (Pl. 2). Production is concentrated in Seminole and northern Pontotoc Counties and consists primarily of oil and relatively small amounts of associated gas. A small percentage of Senora sandstone wells, located mostly in northern Hughes and southern Okfuskee Counties, are completed as gas wells (Pl. 3). Sandstones in these areas are predominantly of marine origin and are more tightly cemented and finer grained. In a manner similar to sandstones in the overlying Calvin Formation, many sandstones in the Senora Formation that are of fluvial origin are wet and nonproductive due to a lack of stratigraphic trapping.

STRATIGRAPHY

Skinner

Skinner sands are Middle Pennsylvanian in age and belong to the upper "Cherokee" (Cabaniss) Group (Fig. 12). Stratigraphically, they occur just beneath the Verdigris Limestone and overlie the regionally extensive Pink lime. The Skinner interval is commonly 100–250 ft thick and is informally divided into an upper and lower zone, although in many areas a middle sandstone is also distinguishable. Due to complexities in subsurface correlation, various informal names have been used by the oil and gas industry in referencing these sands from one area to another (Fig. 12). In this report, the lower and middle Skinner sand zones are grouped together for regional sand mapping purposes.

Skinner sands are generally very fine to fine grained, although medium- to coarse-grained sand is sometimes observed. The sand consists mostly of quartz, averaging 66–80% depending on location (Lojek, 1984; Valderrama, 1976). Core samples have a relatively large proportion of rock fragments (est. 5–10%), are slightly micaceous along bedding planes, and have abundant carbonaceous shale and carbonized plant remains. Authigenic constituents consist of carbonate cements, pyrite, hematite, and clays (kaolinite, chlorite, and illite) (Lojek, 1984). Porosity is primarily secondary and fracturing was not documented in most references used in this study or observed in cores examined by the author. Included in Appendix 5 of this report are descriptions of three Skinner cores. These descriptions are integrated with digitally scanned images of select core intervals and highlight the typical characteristics of both channel and nonchannel facies.

Regional stratigraphy of the Skinner interval is best illustrated by stratigraphic cross sections constructed across the Cherokee platform and surrounding shelf areas. Regional cross section A–A′ (Pl. 4, in envelope) is oriented in an east-west direction across major producing areas of both the Prue and Skinner. This line of section clearly shows the stratigraphic and lateral characteristics of the Skinner interval across the Nemaha fault zone and distal facies both to the west and east. Notice that the Skinner interval is thin in wells on the central Oklahoma uplift area (just west of the Nemaha fault zone) and that the lower Skinner interval is very thin and rests unconformably on Mississippian or older strata (see Rivondale No. 1-5 Nelson, SE¼SE¼ SE¼ sec. 5, T. 15 N., R. 2 W., A–A′, Pl. 4). Located in this general area, the S.W. Guthrie Skinner Sand Unit is the subject of a detailed geologic study included in this volume.

Regional cross section B–B′ (Pl. 4) is a north-south line situated mostly west of the Nemaha fault zone. It is positioned to intersect areas with both Prue and Skinner production and shows the character of sandstones along the distal (western) edge of the Skinner FDD system. The northern part of this section shows log patterns of the Skinner "Kremlin" channel complex which is commonly >50 ft thick. This major channel deposit rests on lower Skinner shale and has no apparent deltaic deposits such as delta front sands beneath it. In the southern part of the cross section, the Skinner interval is generally characterized by coarsening-upward (or sandier-upward) log signatures. In the last two wells along the southern end of B–B′, sandstone log signatures resemble thin deltaic sequences in that channel sands are interpreted to overlie delta-front deposits. Significant lower Skinner channels in this cross section lie just above the Pink lime and apparently are not underlain by deltaic deposits.

Regional cross section C–C′ (Pl. 4), which is a north-south tie between A–A′ and B–B′, illustrates the stratigraphic changes in the Skinner-Senora interval between the Cherokee platform and Arkoma basin. Log profiles that are typical of fluvial-deltaic sequences in the Senora-Chelsea stratigraphic section are particularly well developed in the Arkoma basin (see southern end of C–C′, Pl. 4). The thicker section of sediments that characterizes the lower part of the Senora Formation in the Arkoma basin is primarily due to a steeper basinward slope along the depositional edge of the prograding Senora fluvial (deltaic?) system.

TABLE 1. – Annual Oil Production from the Skinner and Prue Reservoirs in Oklahoma, 1979–95

	SKINNER				PRUE			
	Skinner only		Skinner commingled with other reservoirs		Prue zones only		Prue commingled with other reservoirs	
Year	Production (MBO)	# of leases	Production (MBO)	# of leases	Production (MBO)	# of leases	Production (MBO)	# of leases
79	1,174	581	3,958	1,078	1,347	332	3,077	562
80	1,279	680	4,091	1,283	1,283	361	3,062	656
81	2,110	791	5,214	1,523	1,267	385	3,152	729
82	2,298	891	5,619	1,756	1,634	472	3,956	889
83	2,265	937	5,648	1,861	1,800	534	4,256	990
84	2,669	1,032	6,125	2,019	1,959	597	4,197	1,089
85	2,706	1,087	5,947	2,106	2,179	647	4,360	1,168
86	2,791	1,094	6,016	2,098	1,995	650	4,079	1,179
87	2,973	1,069	5,581	2,061	1,549	610	3,150	1,135
88	2,776	1,018	5,232	1,989	1,260	606	2,671	1,107
89	2,329	1,043	4,511	2,045	1,127	640	2,534	1,157
90	2,080	1,057	4,117	2,040	1,246	627	2,611	1,132
91	2,128	968	4,045	1,902	1,177	614	2,457	1,084
92	1,877	906	3,718	1,823	1,078	602	2,335	1,063
93	1,497	883	3,238	1,781	884	513	2,037	974
94	1,439	792	3,093	1,602	820	490	1,963	897
95	1,592	808	3,112	1,579	742	477	1,831	910
Cumulative (MBO)	35,982		79,264		23,346		51,726	

NOTE: Production data from NRIS. MBO = thousand barrels of oil.

Upper Skinner Sandstone (Plate 1)

In an ideal stratigraphic sequence, the upper Skinner sandstone occurs between the Verdigris Limestone and a thin persistent marker bed about 60–100 ft below the Verdigris Limestone that appears in well logs and is most prevalent on the Cherokee platform. The marker bed typically lies just beneath a thin "hot" shale interval and is often referred to as the Mineral (Morris) coal. Sample descriptions by Hanke (1967) and bulk density readings from modern well logs reveal that the marker bed occurs in a thin zone consisting of thinly interbedded limestone, carbonaceous shale, and coal. The narrow stacking arrangement of these diverse lithofacies and continuity over very large areas clearly indicate that widespread changes in depositional environments occurred with only subtle variations in sea level.

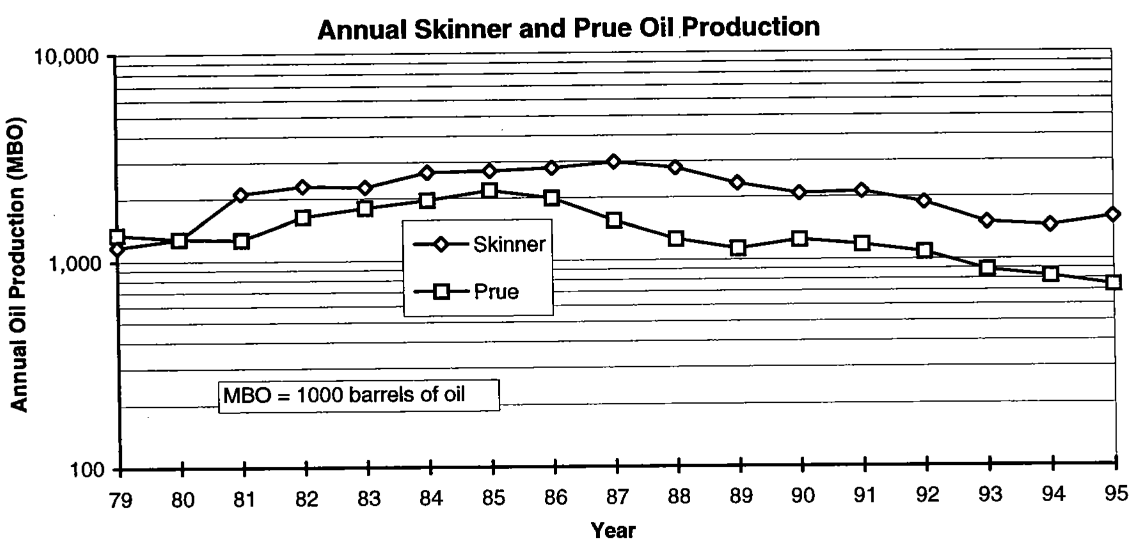


Figure 14. Production curves of annual oil production from wells producing only from the Skinner and Prue reservoirs.

This would only be expected in an area with a very low gradient, such as in a coastal- or delta-plain environment.

In many parts of the Cherokee platform area, the upper Skinner sandstone is only 10–25 ft thick and was apparently deposited in a shallow-marine environment. These shallow-marine Skinner sandstones have a distinctive coarsening-upward log signature, are commonly tight and limy, and bedding is relatively continuous and horizontal. In other areas, particularly in the southern and southeastern part of the upper Skinner FDD system, the thickness and areal distribution patterns are very irregular. Where present, the sandstones are generally 10–30 ft thick and are probably fluvial deposits. An amalgamated sandstone 50–100 ft thick occurs in a prominent east-west channel complex that is located in southern Lincoln and northern Pottawatomie and Okfuskee Counties (Pl. 1). This same channel complex extends westward into the southern townships of Oklahoma and Canadian Counties and is productive in T. 10–11 N., R. 3–7 W. in what is called the Airport Trend (Pl. 1). In the Airport trend, individual upper Skinner sandstones are about 25–50 ft thick and commonly rest directly on sandstone in the lower Skinner interval. Distinction of the upper and lower Skinner sand within the amalgamated sand sequence is, therefore, very difficult. The channel sandstones typically have a pebbly to conglomeratic basal section several inches thick and fine upward. Sedimentary features of this channel complex are shown in Appendix 5 in a core description with logs of a well in sec. 17, T. 10 N., R. 5 W. Farther west, this same channel complex becomes part of the Weatherford–Moorewood–Strong City trend that produces gas from both the Skinner and Red Fork FDD systems. In this area, the upper Skinner sand is >100 ft thick; this is the westernmost extent of sandstone in the upper Skinner interval.

Another dominant upper Skinner fluvial system occurs in the northwest part of the mapped area and is referred to as the "Kremlin" channel. This FDD system is important because it is the northernmost Skinner fluvial system west of the Nemaha fault zone. In the "Kremlin" channel trend area, the Salt Fork North field is the subject of a field study for reservoir modeling and water-flood simulation.

Lower and Middle Skinner Sandstone (Plate 2)

The lower Skinner sandstone is probably the most prevalent Skinner sandstone in the Cherokee platform area. It is mapped together with the middle Skinner sandstone because the lower and middle sands are not always easily distinguished from one another regionally and because the middle sandstone is not distinct over very large areas. For regional mapping, in this study, the lower Skinner interval is between the Morris or Mineral coal zone and the Pink lime. Where the Mineral coal marker horizon is absent or not recognized, the distinction between upper and lower Skinner sandstones is based simply on relative stratigraphic position within the Skinner interval.

In the northern part of the map area, the lower Skinner sandstone is often distinguished by a coarsening upward textural profile, is about 5–20 ft thick, and occurs in lobate areas or patches that resemble river mouth bars or delta front lobes. However, much thicker sand, or channels, are identified in this area that have a blocky or fining upward log textural profile. The largest of these deposits are 50–100 ft thick and ~1 mi wide. They occur in well-defined trends that extend in a northeast-southwest direction for several townships. In places, the Pink lime is absent, and lower Skinner channels cut into the underlying Red Fork sandstone. One such channel, informally called the Stillwater channel (about T. 21 N., R. 3 E.), is probably one of only a few major fluvial channels that were active during deposition of the lower Skinner.

North of T. 18 N., in a purely stratigraphic sense, the thinner nonchannel lower–middle Skinner sands appear to be the principal productive reservoirs. Many lower Skinner oil fields in this area have pay zones of only 5–10 ft, yet produce 20–30 MBO per well at depths of <4,000 ft. An example of this type of lower Skinner reservoir and accompanying well log is shown in the Jeron No. 2 Fisher well (Appendix 5). Although the thick channel sands of the lower Skinner interval have by far the best reservoir properties, they are commonly wet except on structure.

In the southern and southwest part of the lower Skinner FDD system, the lower Skinner sand occurs in two major fluvial systems. One of these persists through Logan and southern Kingfisher Counties and is an extension of the Stillwater fluvial system previously mentioned. The second fluvial system extends from eastern Okfuskee County (about T. 12 N., R. 11 E.) through most of southern Canadian County, a distance of ~115 mi. Within these trends, sandstones are mostly fluvial in origin including laterally related deposits such as river mouth or delta front bars. Both of these systems contain individual sands that are 20–40 ft thick, but stacked assemblages >100 ft thick are found in the center of major channel complexes.

Lower Skinner fluvial systems were highly influenced by positive elements along the Nemaha fault zone. This is particularly true in the northern portion of Oklahoma where at best, only a few fluvial systems extend west of this fault zone. The most notable of these is the "Kremlin" trend in Garfield and southern Grant Counties, which is perpendicular to the Nemaha fault zone. The fluvial system expanded as evidenced by the upper Skinner sandstone and forms one of the most significant channel complexes west of the Nemaha fault zone, as shown in Plate 1. As previously described, another major lower Skinner fluvial system extends across the southern portion of the Nemaha fault zone. Significantly, all of these major fluvial trends contain both upper and lower Skinner sandstone; some contain Red Fork sandstone. This indicates that the same fluvial patterns persisted during much of the middle and upper "Cherokee," suggesting that major physiographic characteristics of the region were relatively stable.

Senora, Chelsea, Allen (Pl. 2): In the Arkoma basin, the Chelsea Sandstone and Allen sand of the Senora Formation are stratigraphically equivalent to the lower Skinner interval of the Cherokee platform. This is illustrated in the stratigraphic nomenclature cross section of Figure 15 and in the stratigraphic column of Figure 12. In the Arkoma basin, the Senora Formation is bounded by the younger Calvin Formation and underlain by the Stuart Shale. At outcrop and in the subsurface, it varies in thickness from about 150 to 500 ft with an overall thinning trend to the north. North of about T. 11–12 N., R. 7 E., the Senora Formation is predominantly shale where it merges with the Skinner-Prue intervals of the Cherokee platform (see regional cross section C–C′, Pl. 4). Overall thickening of the Skinner-Senora interval and the entire Desmoinesian Series in a southward direction occurred because of foreland basin subsidence and mountain front faulting in the adjacent Ouachita uplift. Senora sandstones in the Arkoma

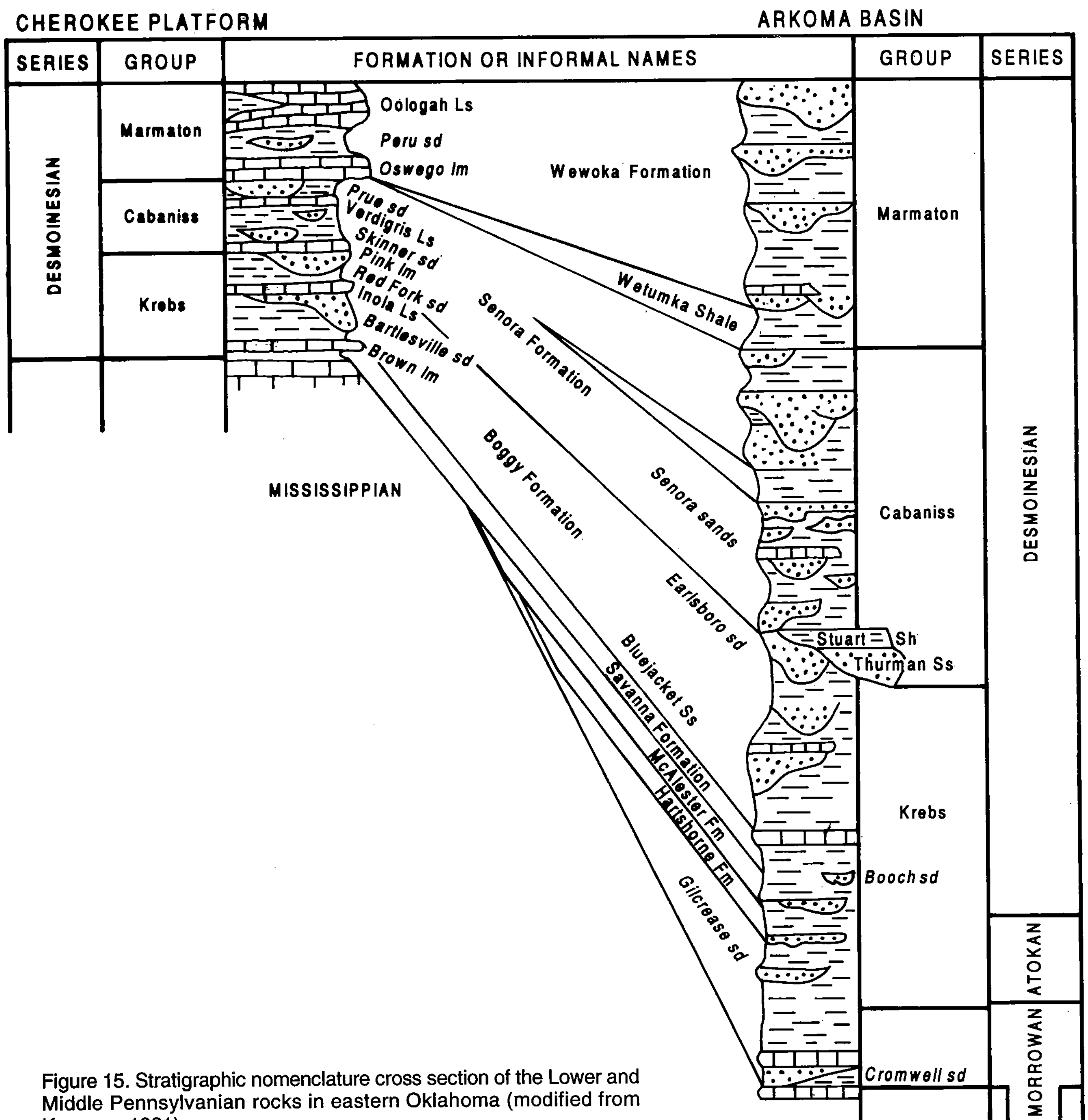


Figure 15. Stratigraphic nomenclature cross section of the Lower and Middle Pennsylvanian rocks in eastern Oklahoma (modified from Krumme, 1981).

basin, therefore, appear to be sourced from the Ouachita uplift to the southeast.

The Senora Formation is informally subdivided into an upper and lower zone. The upper zone is mostly shale and varies in thickness from about 50 to 150 ft. It appears to be equivalent stratigraphically to the upper Skinner zone of the Cherokee platform. The base of the upper Senora zone is approximately equal to the Henryetta coal zone as shown on cross section C–C′ (Pl. 4). The lower Senora zone is correlative to the lower and middle Skinner intervals of the Cherokee platform. It is composed of interbedded sandstone and shale and is usually much thicker than the upper zone. In the subsurface, individual sands of the lower Senora are typically about 10–30 ft thick, although amalgamated sandstone sequences in the shallow subsurface or at outcrop are often more than 150–320 ft thick (Weaver, 1952). Due to the proximity of sourcing, sandstones are fine to coarse grained and massive to thinly bedded. Sandstones commonly have contorted bedding, fluvial scour, and appear reddish-brown or gray at outcrop (Weaver, 1952). The northernmost area of "Senora" deposition is characterized by thick shale sequences and thin, shaly sand bodies having coarsening upward textural profiles (marine?) as interpreted from gamma ray logs. Farther to the south, Senora sands occur in stratigraphic sequences consisting of coarsening upward lithologies (delta front?) overlain by fining upward sand bodies (channels?). This vertical and lateral relationship of implied depositional environments is indicative of a prograding deltaic complex. At outcrop or in the very shallow subsurface, many sandstones in the Senora Formation appear to have sedimentary structures and log patterns primarily of channel deposits such as point bars. This may indicate a subaerial coastal plain (flood plain) or upper delta plain depositional environment.

Stratigraphy of the Senora Formation is best illustrated in the southern half of regional cross section C–C′ (Pl. 4). In this line of section, the Senora Formation is informally divided into an upper and lower unit because of depositional phases represented in each zone. The upper zone is predominantly marine shale, whereas the lower zone has stratigraphic sequences that are indicative of a progradational fluvial deltaic environment. The latter depositional phase is characterized by a vertical assemblage consisting of marine (or delta front) sands overlain by fluvial channel deposits. This relationship persists northward ~30 mi from outcrop where the lower Senora interval becomes mostly marine shale as shown in the Simasko No. 1 Krueger well in NE¼SE¼NW¼ sec. 21, T. 10 N., R. 7 E.

DEPOSITIONAL MODEL

Skinner

Sandstones in the Skinner interval originated from major fluvial systems that advanced across much of the Cherokee platform in a southwest direction (Fig. 13). Due to prevailing depositional patterns and the fine-grained nature of clastic material, the predominant clastic source area was probably cratonic areas far to the northeast. Sediment transport occurred in a mixed load depositional system and included large amounts of suspended clay, silt, and very fine grained sand. Bed load material was mostly fine grained sand consisting of quartz and very small rock fragments, although larger grained material is noted in the Skinner sands in southeastern Kansas. Large amounts of organic material such as leaf and wood fragments are also included within the sandstones of both fluvial and some marginal marine facies.

Areal distribution of Skinner sandstones appears to have been controlled mostly by the attitude of the Cherokee platform, the Nemaha fault zone (Nemaha uplift), and by the intensity and duration of Skinner fluvial systems. In northeast Oklahoma, major fluvial systems advanced across a very low gradient coastal or delta plain during episodes of sea level lowering, or regression. Sediment transport was generally to the southwest at an attitude roughly normal to the structural contours of the Verdigris Limestone, as shown in Figure 16. However, Skinner deposition was largely attenuated west of the Nemaha fault zone, since portions of this fault zone in northern Oklahoma remained structurally high during much of Skinner deposition. Because of this, fluvial systems in both the upper and lower Skinner zones were redirected farther to the south where structural uplift along the central Oklahoma fault zone was not appreciable during Skinner time. Even so, fluvial deposition along the southern FDD trend is largely contained in the upper Skinner interval, which was least affected by structural adjustments along the central Oklahoma fault zone. This resulted in the development of the west-trending Skinner-Prue channel complex in the Airport trend, which is located in southern Oklahoma and Canadian Counties. Other fluvial systems that persisted to the west in northern Oklahoma probably were initially established where structural breaks occurred along the Nemaha fault zone.

Skinner sandstones were probably deposited in a transitional environment ranging from subaerial coastal plain and deltaic to shallow marine. Depositional slope throughout most areas in the Cherokee platform was very small, which inhibited thick accumulations of sediment particularly in basinward areas where nearshore marine or nonchannel environments prevail. Therefore, some of the thickest Skinner sandstones occur in fluvial channels, although, in terms of areal distribution patterns, nonchannel sandstone facies are much more common.

Major Skinner channel deposits are almost always incised directly into marine(?) shale and seldom occur stratigraphically above sediments that can be interpreted as delta front. Laterally equivalent sandstones that have coarsening upward textural profiles are commonly clustered in the vicinity of channel deposits but are rarely of comparable thickness. They form excellent

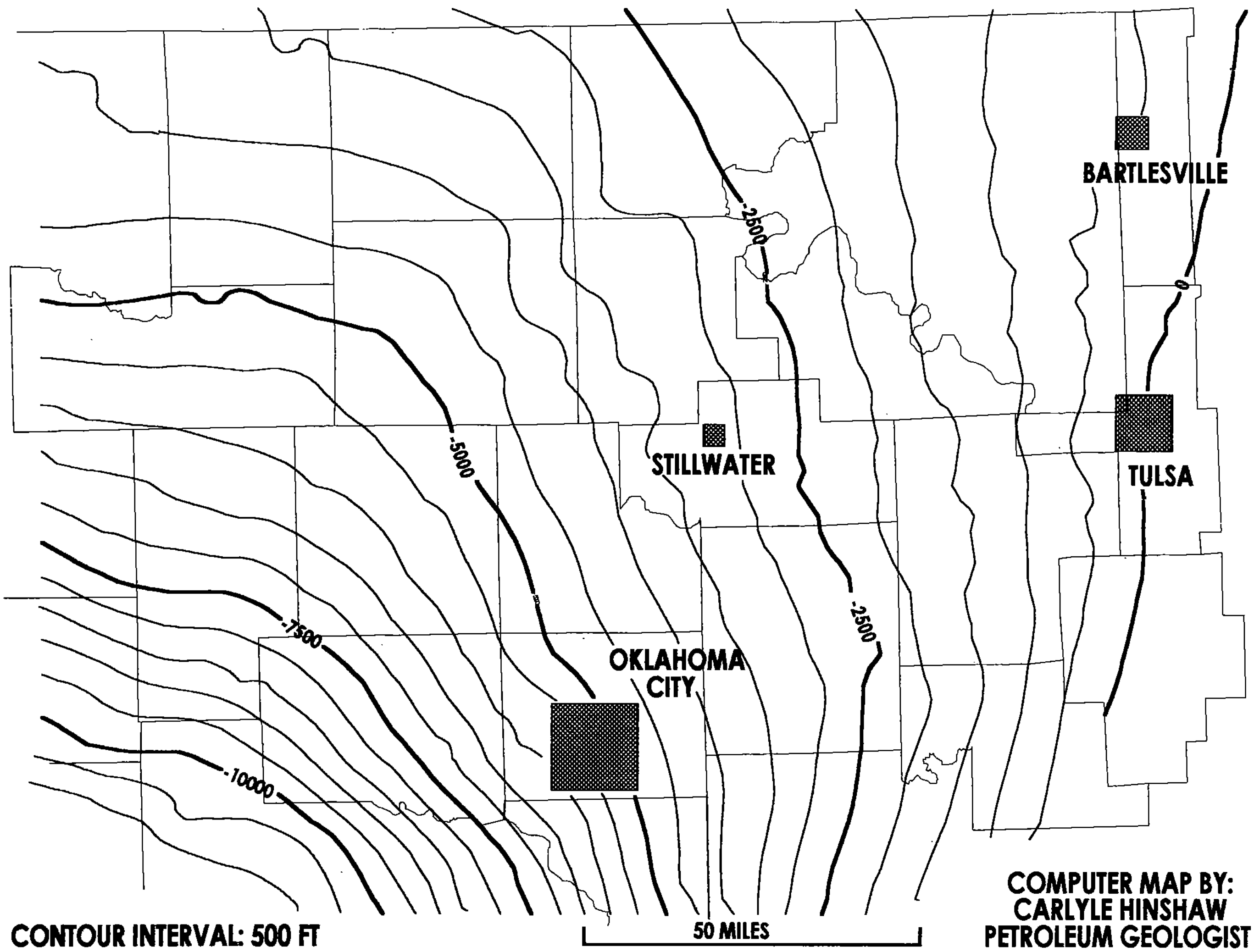


Figure 16. Generalized regional structure map of the top of the Verdigris Limestone, Oklahoma. Contour interval is 500 ft.

reservoirs and commonly have sedimentary structures more closely related to river mouth bars rather than splay deposits, the latter of which are more characteristic of deltaic sedimentation. The lateral and thickness relationships of Skinner sandstones are indicative of an interdistributary depositional environment and the distinction between deltaic origin versus coastal plain is controversial. However, delta front sediments originating from major channels are generally many times thicker than the actual sand thickness within the channel. Additionally, major channels with heavy sediment load do not carry very far in environments with very low basinward gradients before being abandoned. These characteristics are not entirely consistent with the Skinner sands in the Cherokee platform area since major Skinner fluvial systems persisted for possibly hundreds of miles without development of significant delta front sandstone deposits. Therefore, Skinner deposition appears to be largely the result of fluvial processes brought about by downward fluctuations of eustatic sea level in a manner similar to the deposition model shown in Figure 17. Sediment dispersal in a basinward direction and adjacent to major channels resulted in the formation of discontinuous offshore bars and small, marginal marine distributary mouth bars respectively. Interdistributary bay-fill material and sand bodies originating from crevasse splays are probably also a persistent facies within the Skinner FDD system.

In certain areas between major channels and along the leading edge of the Skinner FDD trends, thinner channel deposits are sometimes stacked above sediments considered to be small distributary mouth bars. This relationship may be interpreted to represent small-scale development of delta lobes. Farther to the south and west, the Skinner interval largely consists of shale and stacked sandstone assemblages having a coarsening upward textural profile. In these distal areas, the depositional environment is interpreted to be prodelta (shale) or near-shore marine (detached bars). One major upper Skinner trend continues into the deep Anadarko basin and is interpreted to be an extension of the southern "Airport" trend of southern Oklahoma and Canadian Counties as previously discussed.

Senora

The depositional origin of sandstones in the lower Senora Formation in the Arkoma basin is more closely related to fluvial-deltaic environments than that of the Skinner of the Cherokee platform. It is also similar to that of the overlying Calvin FDD system. Fluvial systems originating in the Ouachita uplift area (Fig. 13) carried sediments to the northwest in what is now the Arkoma basin. Basinward dip along the leading edge of this depositional system was probably much greater and resulted in a clastic assemblage at least twice as thick as the Skinner interval of the Cherokee platform. Depositional phases that characterize a prograding deltaic sequence consist of sandstones having coarsening upward textural profiles (delta front?) overlain by sandstones having sharp basal contacts and fining up-

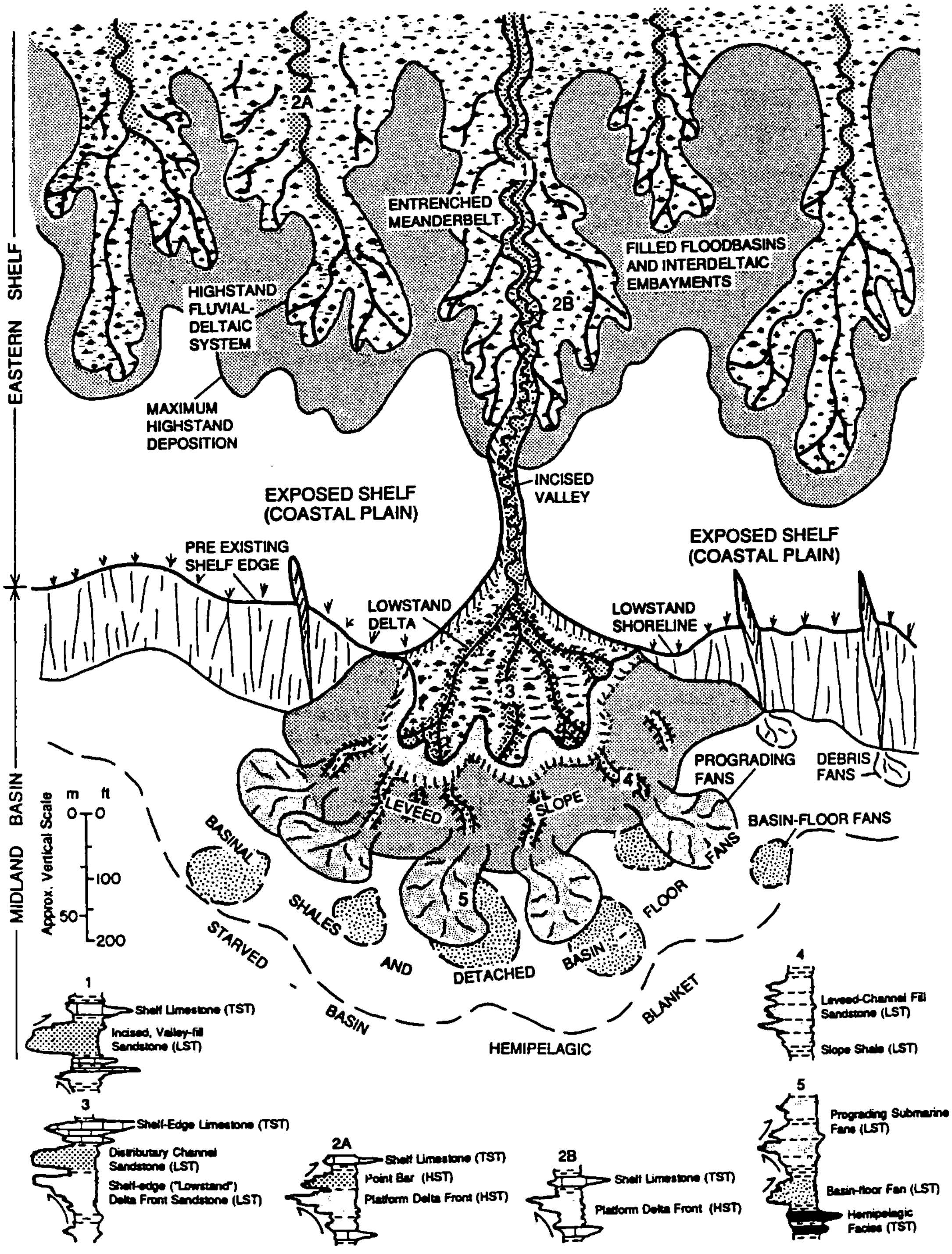


Figure 17. Depositional systems tracts—highstand system tract (HST), lowstand system tract (LST), transgressive system tract (TST)—at maximum progradation of terrigenous clastic systems. Representative logs illustrate facies within various systems comprising the tracts. From Brown (1989).

ward textural profiles (channel deposits). In a basinward direction (northwest), the lower Senora interval decreases in thickness chiefly by the thinning of individual sandstone beds and becomes mostly, if not entirely, of marine origin.

FDD IN THE SKINNER

The regional distribution of sandstone and interpretation of depositional facies is shown on Plates 1 and 2. Plate 1 primarily shows the distribution of the upper Skinner sand, although in some areas the middle or lower Skinner sand may also be incorporated when the sandstone sequence is amalgamated. Plate 2 primarily shows the distribution of the lower Skinner sandstone but may also contain segments of the upper Skinner sand when the distinction is not clear. Two prominent fluvial depositional systems are also mapped on Plate 2, including the Skinner trend in the northern half of the map and the lower Senora trend located in the southeastern part of the map (Arkoma basin). These two systems are generally separated by a marine seaway or trough where deposition is largely shale. Areas identified as sandstone within each trend contain primarily fluvial and marginal marine deposits including delta front sandstones. As used throughout this paper, marginal marine implies deposition in a marine-influenced environment such as in a delta plain or very near-shore marine environment such as a river mouth bar. Marginal marine does not necessarily mean delta fringe, which implies deltaic sedimentation. References to marine sand bodies or offshore bars in this paper refer to detached sand bars originating in a shallow marine shelf environment.

Oil and gas producing areas attributable to either the Skinner or Senora FDD sand trends are illustrated on the field map (Pl. 5, in envelope). Any field that has produced at least 5,000 bbl of Skinner-Senora oil, or at least 3 BCF of gas, in the past 15 years (since 1979) is included on this plate. Field names and boundaries are consistent with field designations by the Oklahoma Nomenclature Committee of the Mid-Continent Oil and Gas Association. In some cases, Skinner-Senora production is found only in one part of the field. In other places, Skinner-Senora produces outside of the formal field boundaries. This occurs, in part, because the effort to formally extend field boundaries lags behind the extension of producing areas.

All available sources of information were used in the identification of fluvial and FDD areas, including theses, articles in *Shale Shaker*, consultants, and personal investigations by the author. Selected references used for mapping this play are listed alphabetically on Plate 6 (in envelope) and designated with a numerical code that can be used to identify the area of geologic interpretation. A more complete list of references is included as part of this volume.

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 Appendix 2 and 3, respectively. All well symbols as used in geologic maps are consistent in every field study area and regional plate. These symbols are illustrated and defined in Appendix 4. Four cores are provided for examination by workshop attendees. Three are of Skinner sands and one is a Prue channel sand. A brief core description and facies interpretation is provided along with well logs and select digital images in Appendix 5.

Perry S.E. Skinner Sand Unit

(T. 21 N., R. 1 E. and 1 W., Noble County, Oklahoma)

by Kurt Rottmann

The Perry S.E. Skinner Sand Unit is located in southern Noble County in north-central Oklahoma in the southern part of the Perry Townsite field (Fig. 18). The Perry S.E. study area lies about three townships east of the Nemaha fault zone and in an area often referred to as the Cherokee platform province (Pl. 2). Production from wells in the unit is from the lower Skinner sandstone, although several other formations are productive in the study area. A map showing well locations, lease names, well numbers, operators, and producing formations is shown in Figure 19. Much of the information for this field was provided by Daryl Mayfield of Axem Resources, Denver. Sincere appreciation is extended for Axem's courtesy and support for this study.

The first well in the study area that produced oil from the Skinner was the MacKeller, Inc. No. 1 Warren well (S½NW¼NW¼NW¼ sec. 25, T. 21 N., R. 1 W.). The well was completed August 18, 1983, with an initial pumping potential of 45 BO, 175 MCFG, and 20 BLW per day. Within two years, 22 additional oil wells were completed in the lower Skinner. Completion techniques varied but generally consisted of setting and cementing casing through the Skinner, perforating, acidizing, and fracture treating.

Stratigraphy: The stratigraphic section in the Perry S.E. Skinner Sand Unit is illustrated by logs from the Harris Minerals Corp. No. 1-25 Aigner (Fig. 22). The Skinner zone is the interval from the base of the Verdigris Limestone to the top of the Pink lime. As shown on the regional cross sections (Pl. 4), the Skinner is separated into upper Skinner and a lower–middle undifferentiated zone. The base of the thin shale marker bed (4,622 ft in Fig. 22) is the "top of sand zone" that appears in cross sections and maps in this report.

The stratigraphy for the Skinner Sand Unit is shown in detailed cross sections A–A′ and B–B′ (Figs. 20 and 21, in envelope). The stratigraphic datum for both cross sections is the base of the hot shale immediately below the Pink lime. In wells where the Skinner sand rests directly on the Pink lime, the Pink lime is thinner and the

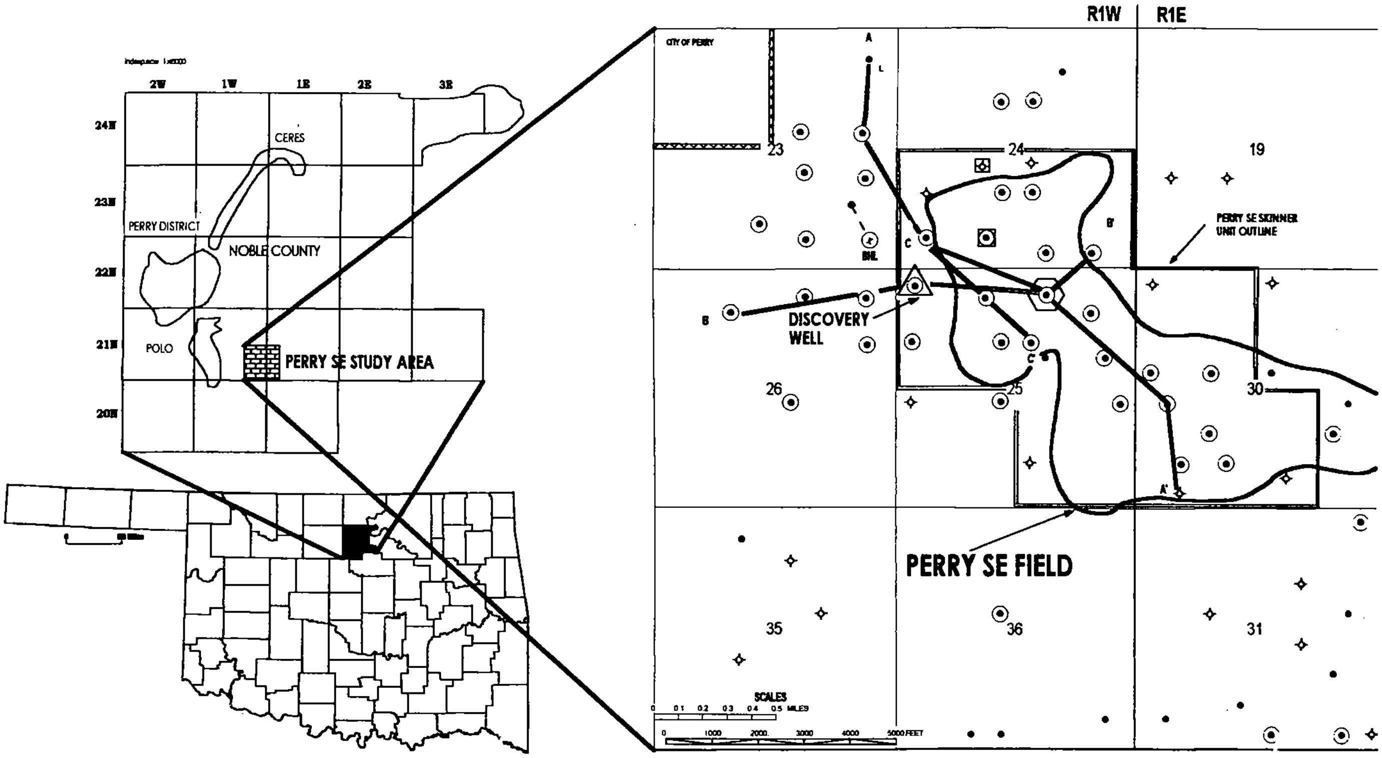


Figure 18. Generalized location map of Perry S.E. field study area, Noble County, Oklahoma. Solid black line is the outline of the Perry S.E. Skinner Sand Unit pool.

upper part of the limestone is missing. In wells in which the Skinner sandstone rests on the shale above the Pink, the Pink lime exhibits a uniform thickness and log signature that is observed regionally.

The log signatures of the thick Skinner sandstone generally display a sharp basal contact, blocky SP and gamma-ray profile through the body of the sandstone, and at the top, a fining- or shalier-upward gamma ray profile, which indicates that this is a channel sandstone in a fluvial depositional environment.

Cross section B–B′ shows thinning of the lower Skinner zone. This thinning is obvious between the No. 1-25 Aigner well (NW¼NE¼ sec. 25, T. 21 N., R. 1 W.) and the No. 3-B Warren (SW¼SE¼SE¼ sec. 24, T. 21 N., R. 1 W.). The difference in the Skinner zone thickness in these two wells is the result of differential compaction between sand-rich and sand-poor sections, with the sand-poor section being more compactable and therefore thinner.

The lower Skinner sandstone within the field area has a maximum thickness of ~30 ft in the central part of the channel.

Isopach Mapping: Figure 23 is an isopach map of the interval from the top of the Skinner sand zone to the top of the Pink lime. This marker horizon is present in all wells in the study area; in cross sections A–A′ and B–B′ (Figs. 20,21) it is identified as "top of sand zone."

Figure 24 shows the combined thickness of the Pink lime and the underlying hot shale. The two areas shaded gray are thin and have <8 ft of the Pink lime–hot shale interval. One of the thin areas trends northwest-southeast through the center of the Perry S.E. unit. The second thin area is at the western edge of the study area. Note the similarity in appearance of the Pink lime–hot shale map and the Skinner zone isopach map (Fig. 23). Thick sand zone trends coincide with thin Pink lime–hot shale trends, and areas where the sand zone is thin coincide with areas where the Pink lime–hot shale interval is thick. Cross sections (Figs. 20,21) show that where the Pink lime is thin, the upper part is missing and it is overlain by Skinner sandstone. The channel that eroded the Pink lime may have also deposited the Skinner sand, or the Pink lime was eroded and the channel sandstone deposited later. With either scenario, a thin Pink lime–hot shale interval could indicate the presence of a lower Skinner channel sandstone.

Figure 25 shows the thickness of the lower Skinner gross sand in the Perry S.E. Skinner Sand Unit. The sandstone trends northwest to southeast and the maximum gross sand thickness is ~30 ft. Almost all the wells in the Perry S.E. unit have blocky to fining upward gamma ray log profiles with sharp basal contacts that indicate fluvial depositional processes. The sand is bounded on the east and the west by shale.

Together, the Skinner sand zone map (Fig. 23) and the gross sand map (Fig. 25) show that where the Skinner sand is thick, the sand zone is thick, and where the

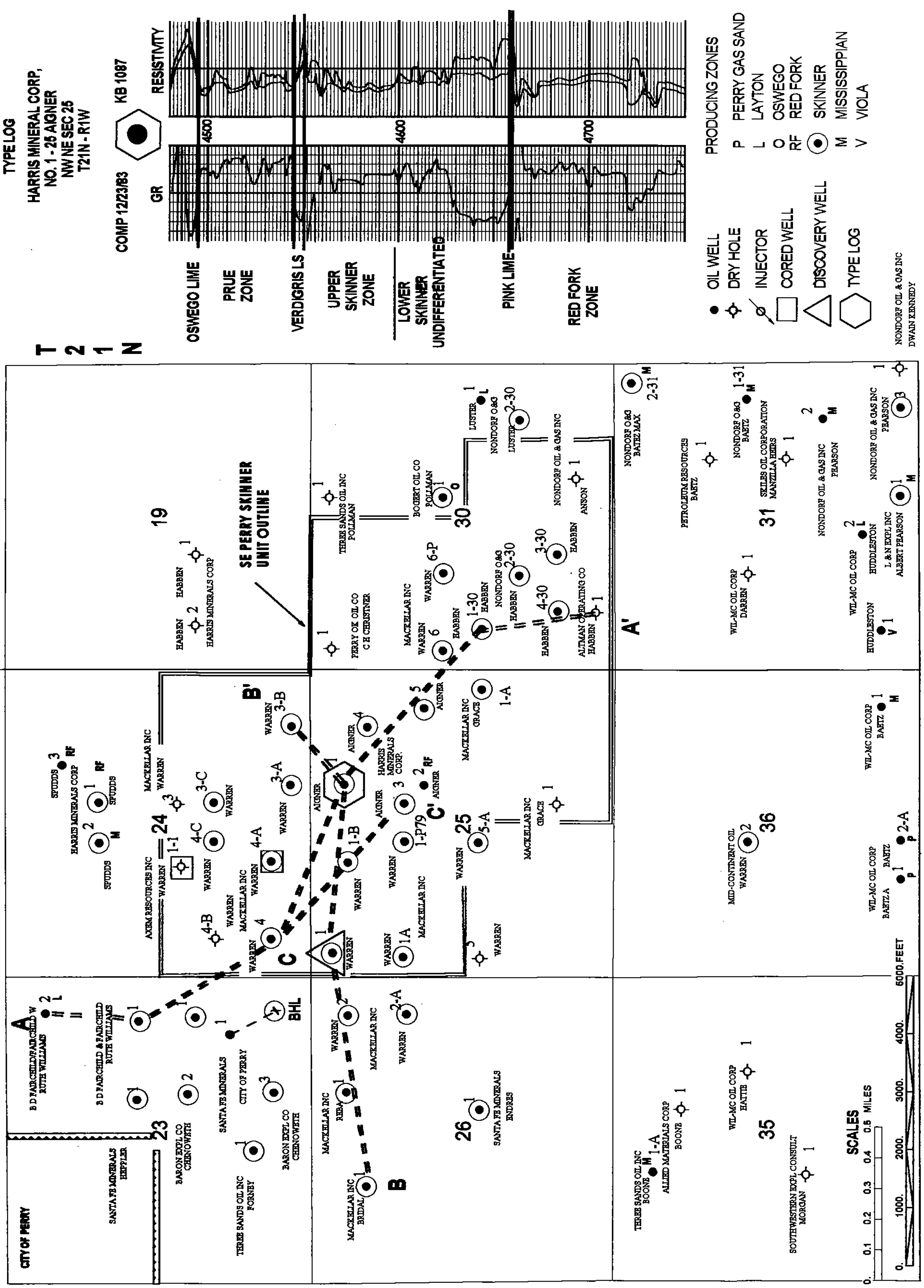


Figure 19. Well information map showing operator, lease, well number, and producing reservoirs for wells in Perry S.E. field, southern Noble County, Oklahoma.

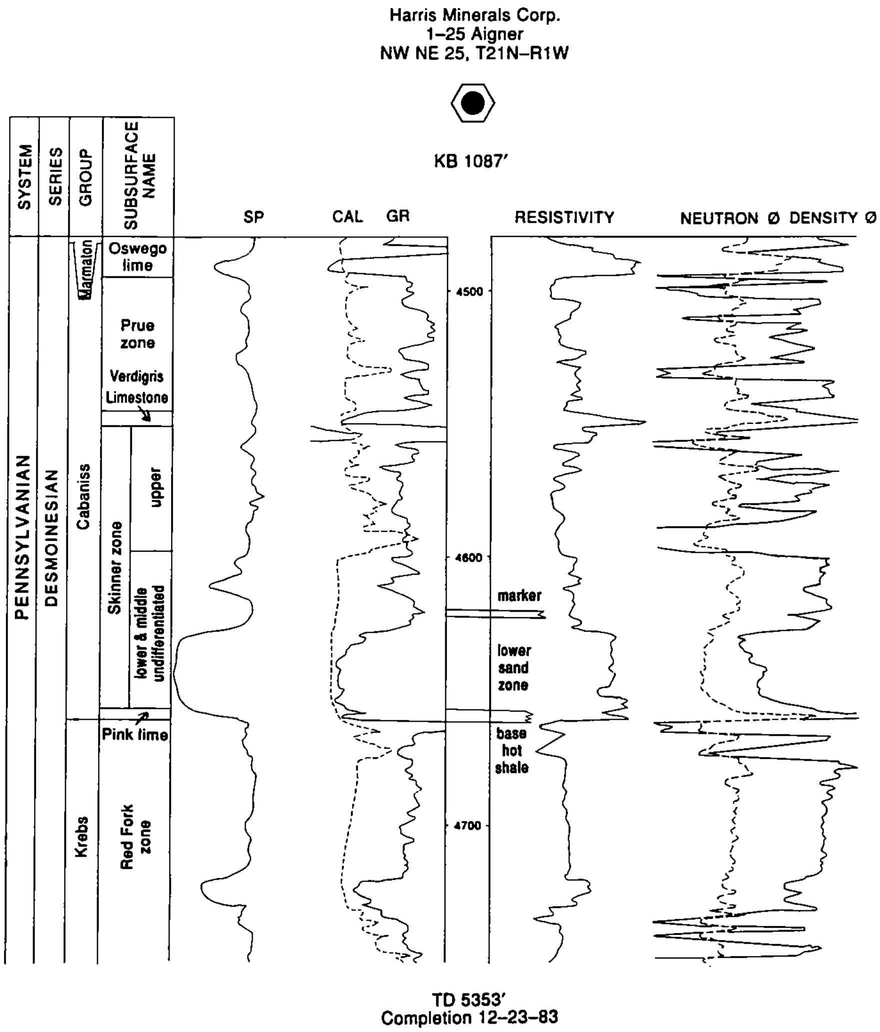


Figure 22. Perry S.E. Skinner type log. The intervals shown on the right side of the log are used in this study. The base of the thin shale marker (4,622) is the top of the sand zone in cross sections and is the top of the lower sand zone that is mapped in Figure 23. SP = spontaneous potential, CAL = caliper, GR = gamma ray.

Skinner sand is thin or absent, the sand zone isopach is thin. Figure 28 is a gross sand map of the entire study area. The contours reflect information from the Skinner zone and Pink lime–hot shale isopach maps (Figs. 23,24). The thick sand at the west side of the map is also interpreted to be a thick Skinner channel sandstone. Both channel belts (gray) are ~0.5 mi wide and both approach 30 ft in thickness. The thinner sandstone between the channels, which includes sandstone in the three wells at the west edge of the Perry S.E. unit, is interpreted to be a crevasse splay deposit based on the location (between channel deposits) and the poor performance of wells in the thinner sandstone.

Figure 26 is an isopach map of the lower Skinner net sand (log $\phi \geq 8\%$). There are few differences between the net and gross sand map that might suggest the presence of reservoir heterogeneities. The net and gross sand values are almost identical. Thus, in this reservoir, if the Skinner sand is present, it most likely will have reservoir-quality porosity.

Structure: Regional dip of the Verdigris Limestone (Fig. 16) is to the southwest at ~50 ft/mi, which is <2°. Figure 27 is a structure-contour map showing the configuration of the top of the lower Skinner sand zone. The "top of the sand zone marker" is interpreted to have been flat and horizontal at the time of deposition. This map shows that the dip of the lower Skinner sand zone within the Perry S.E. Skinner unit is to the southwest. Small closures (dashed contour lines) are mapped within the unit boundary in secs. 24 and 30. These contours were closed based on the low structural position of the No. 3-B Warren (SE¼ SE¼SE¼ sec. 24). However, the datum is low with respect to wells to the west because of differential compaction, not deformation (see cross section B–B', Fig. 21). Without knowing the importance of the relationship between zone thickness and the relative sand content, these minor closures might be attributed to tectonic folding. Other apparent structures in Figure 27 (dashed contours) are also the result of differential compaction. These apparent structures are simply a consequence of the presence of the thick channel facies adjacent to flood plain shale that experienced greater compaction.

Figure 29 is a revised structure map drawn at the top of the Skinner sand zone that incorporates the observation that the top of the Skinner sand zone is a function of the zone thickness (Fig. 23), which is a function of gross sand thickness (Fig. 28). In this map, the influence of the Skinner channel geometry is evident and the apparent structures (Fig. 27) have been replaced by structural contours that parallel the two channel trends.

Core Analysis: The core well for the field is the No. 4-A Warren (SE¼SW¼ sec. 24, T. 21 N., R. 1 W.), which is at the edge of the Skinner channel sand (Fig. 28). Core Laboratories (Oklahoma City) described the core as sand with siltstone in part, dolomitic in part, and some shale laminations. The sandstone grain density is 2.66 gm/cc. Porosity, permeability, and fluid saturations are shown in Table 2. In this core, the average sandstone porosity is 11.1% and the average permeability is 15.2 md.

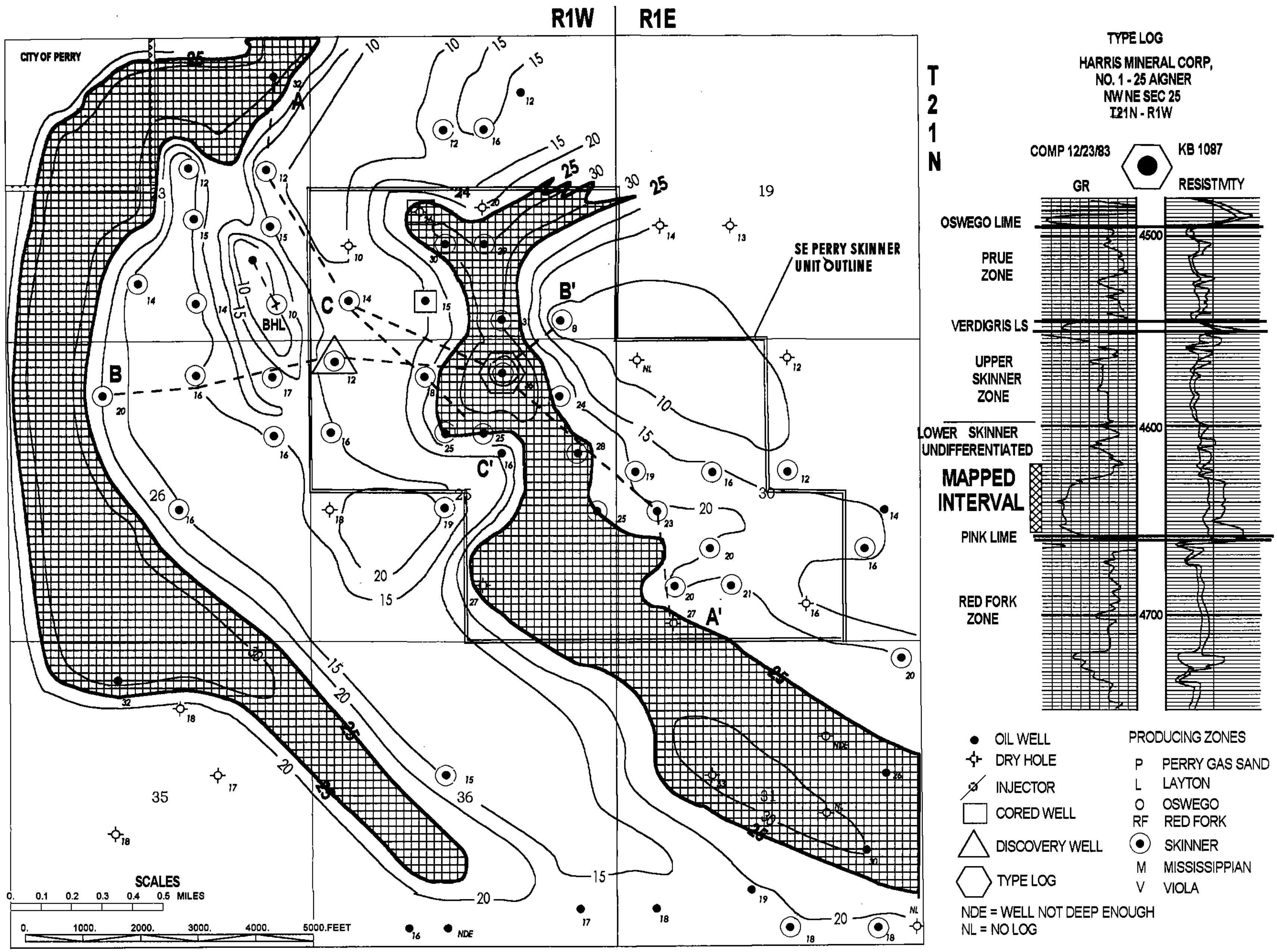


Figure 23. Isopach map of the gross lower Skinner zone for the Perry S.E. Skinner Sand Unit. Contour interval is 5 ft. Shaded areas indicate zone thicknesses ≤25 ft.

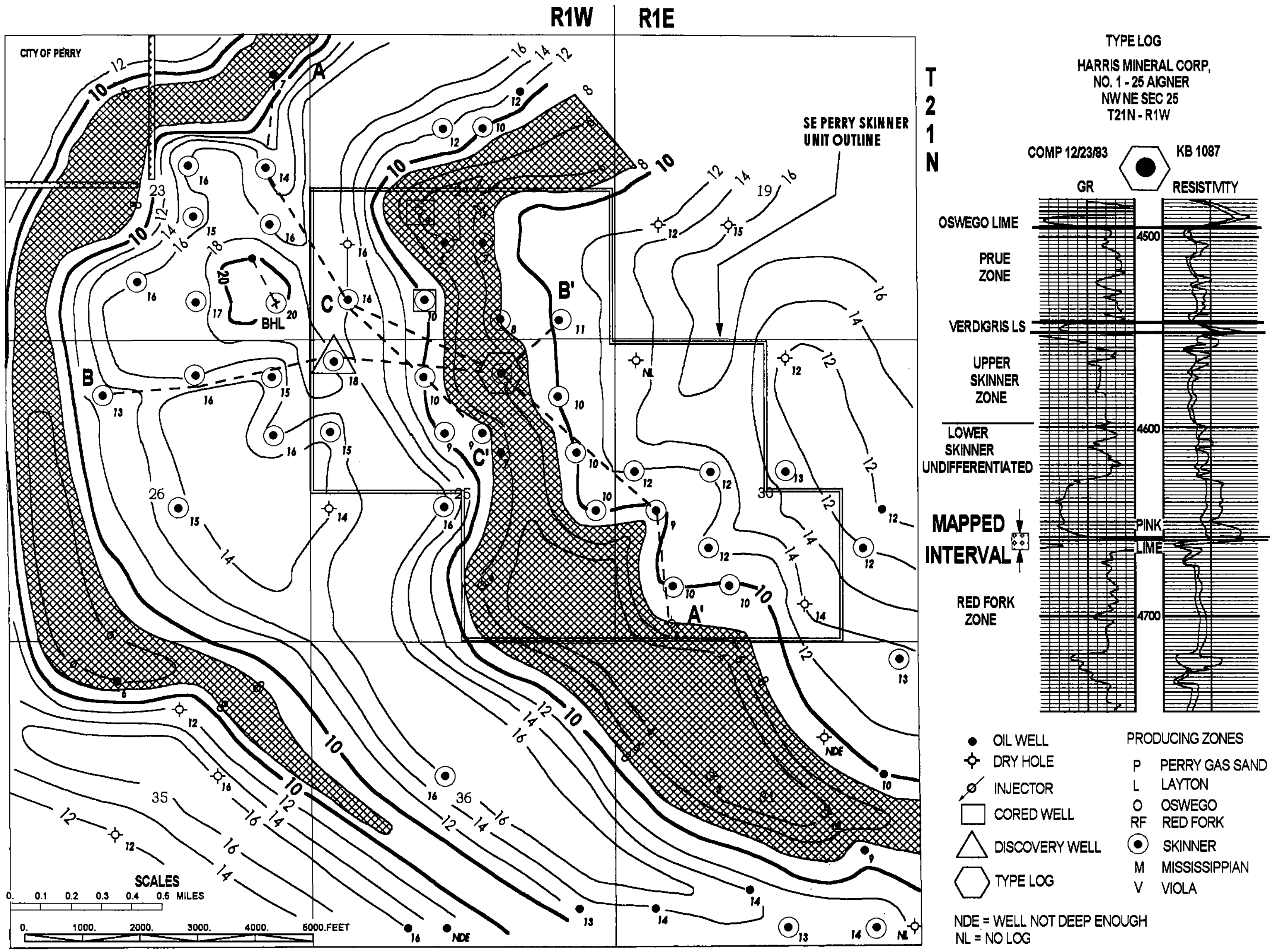


Figure 24. Isopach map of the interval between the top of the Pink limestone and base of a hot shale immediately below the Pink limestone in the Perry S.E. Skinner Sand Unit. Shaded areas indicate isopach interval ~8 ft. Contour interval is 2 ft.

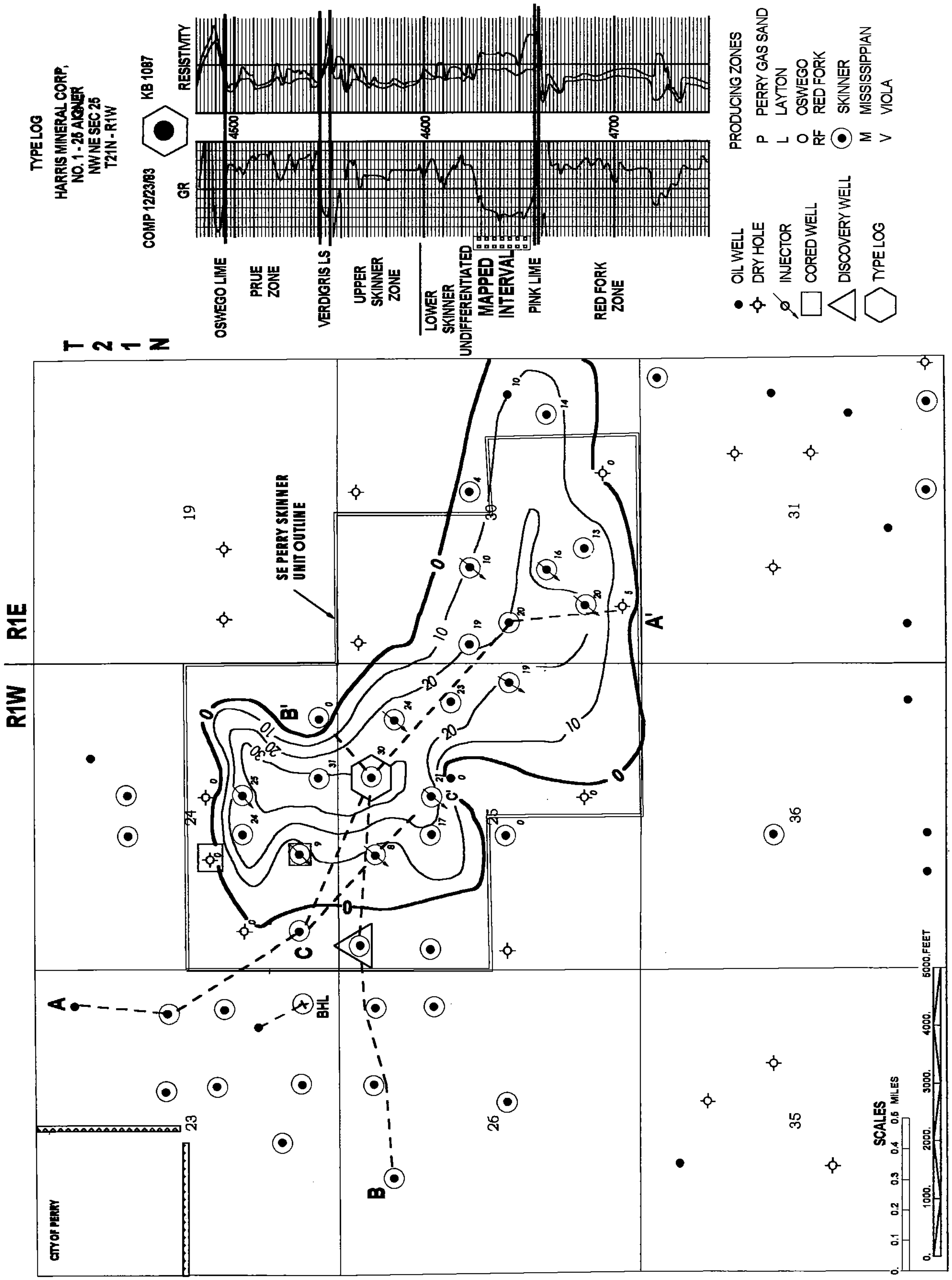


Figure 25. Isopach map of the gross lower Skinner sand for the Perry S.E. Skinner Sand Unit. Contour interval is 10 ft.

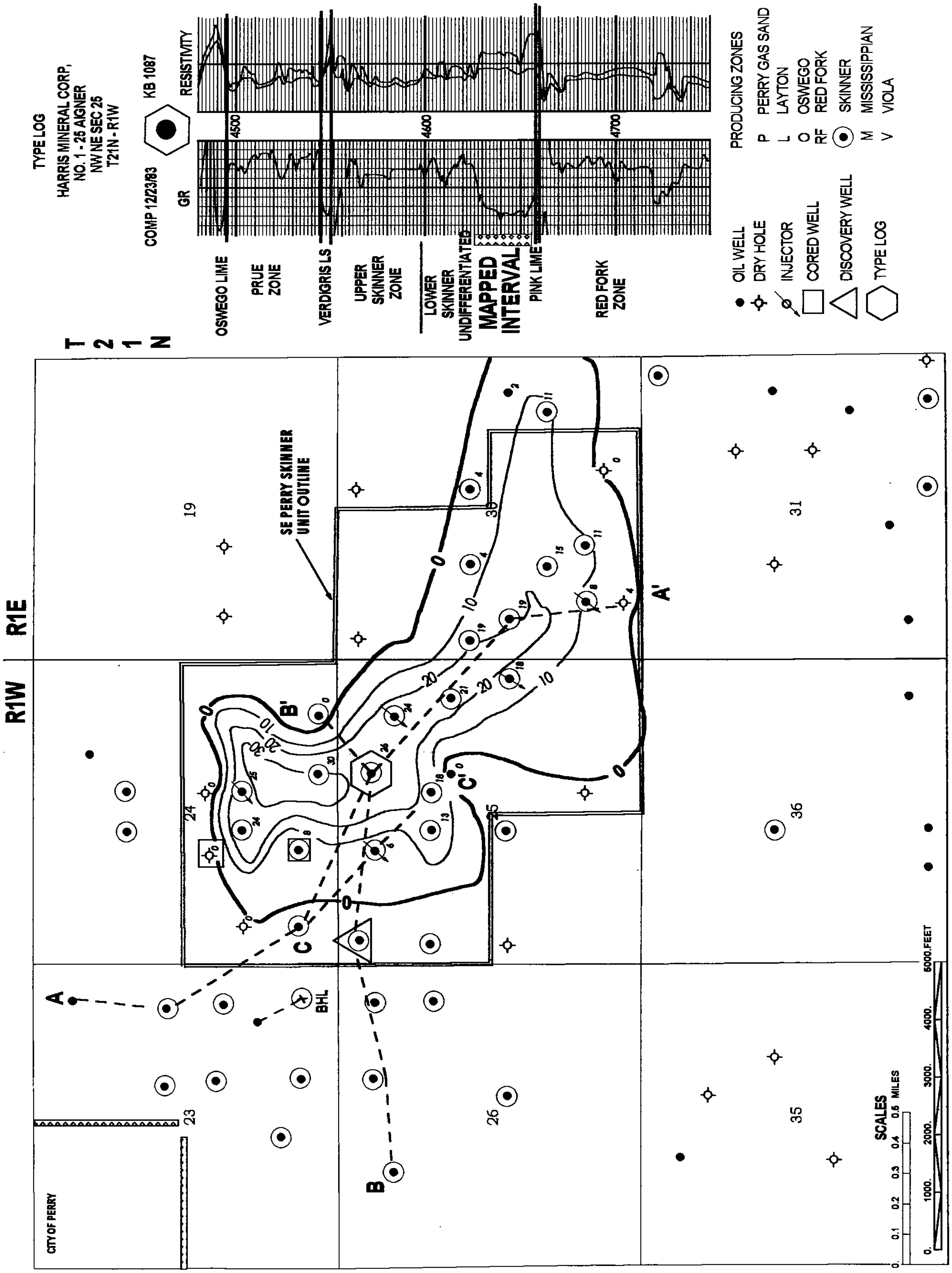


Figure 26. Isopach map of the net lower Skinner sand for the Perry S.E. Skinner Sand Unit. Contour interval is 10 ft.

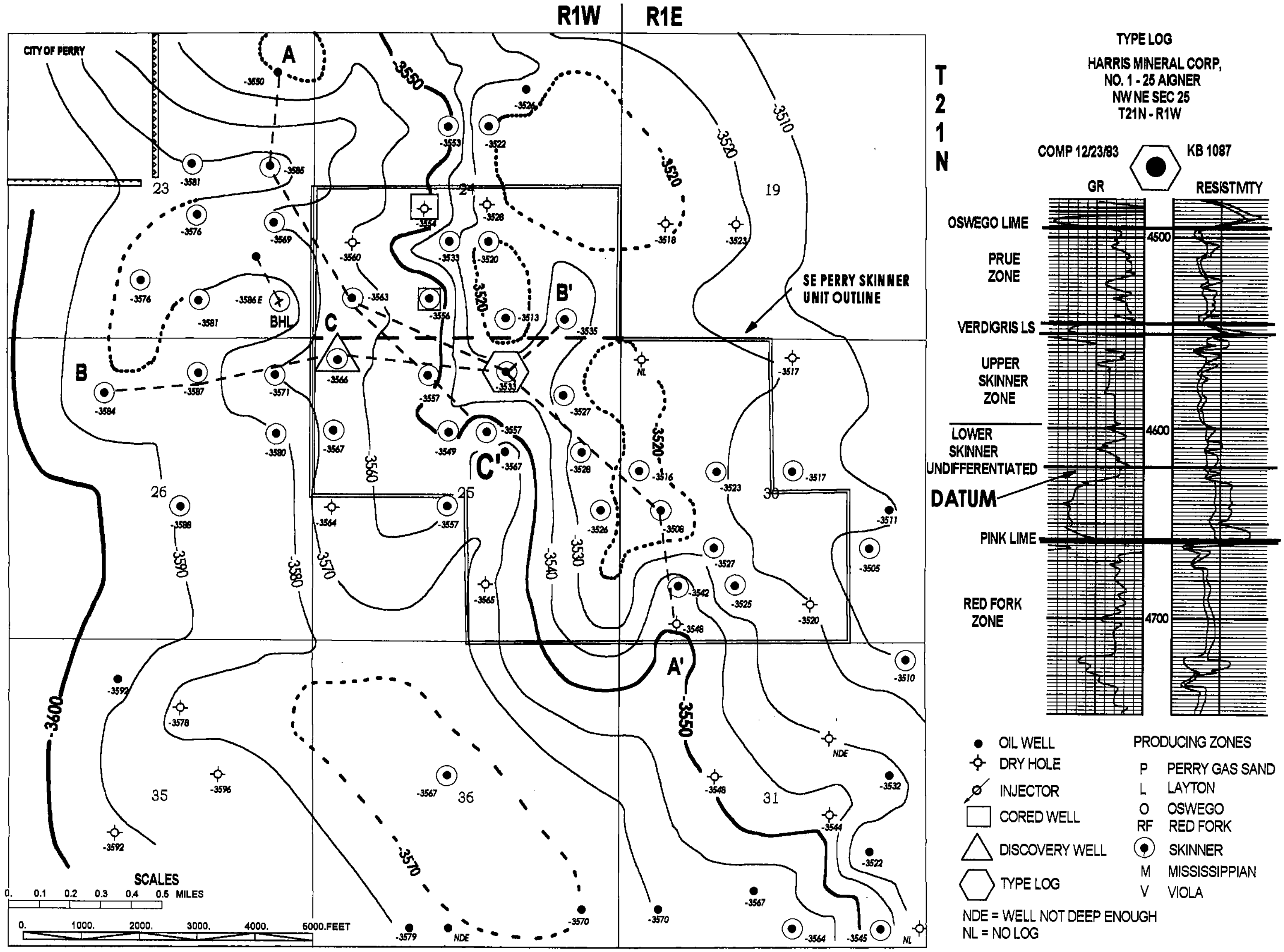


Figure 27. Structure map of the top of the lower Skinner zone for the Perry S.E. Skinner Sand Unit. Contour interval is 10 ft. Areas of apparent structure are indicated by dashed contour lines (see text for explanation).

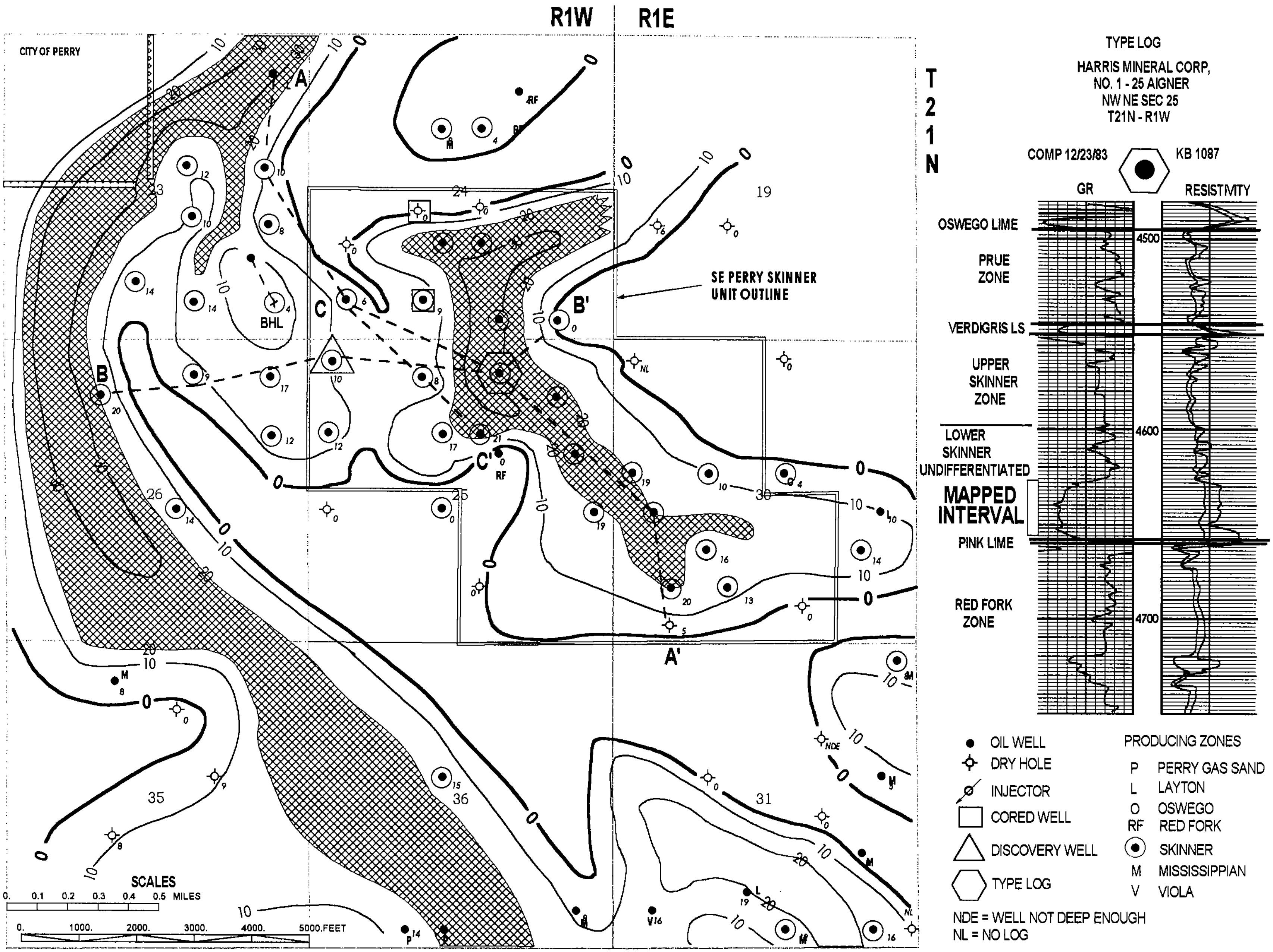


Figure 28. Isopach map of the gross lower Skinner sand for the Perry S.E. Skinner Sand Unit and surrounding area. Contour interval is 10 ft. Shaded areas indicate sand thicknesses ~20 ft. This isopach map was derived from the gross lower Skinner (zone) isopach map of Figure 23 and the Pink lime + hot shale isopach map of Figure 24.

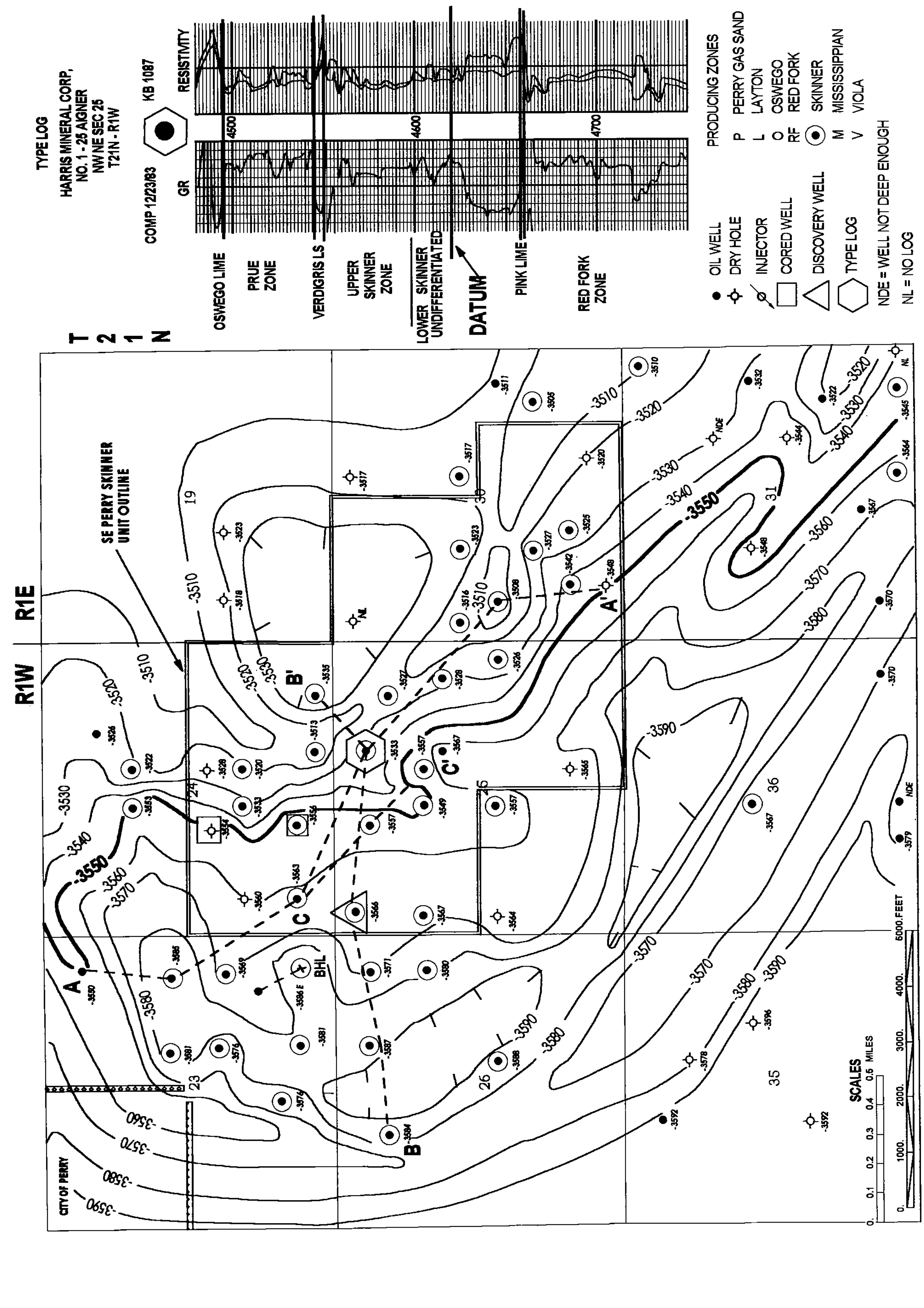


Figure 29. Revised structure map of the top of the lower Skinner zone in Perry S.E. Skinner Sand Unit and surrounding area. Contour interval is 10 ft. This structural interpretation incorporates the geometry of the lower Skinner sand mapped in Figure 28.

TABLE 2. – Core Analysis of the Skinner Sand in the MacKeller, Inc. Warren No. 4-A Well
(SE¼SW¼ sec. 24, T. 21 N., R. 1 W., Noble County, Oklahoma)

Sample Number	Depth in feet	Permeability (Kair in md) Maximum	Permeability (Kair in md) Vertical	Porosity (Helium) %	Saturation (% Pore Volume) Oil	Saturation (% Pore Volume) Water	Grain Density (gm/cc)
1	4653.0--54.0	0.11	0.012	2.4	4.4	81.5	2.76
2	4654.0--55.0	0.16	0.011	7.1	4.4	72.8	2.65
3	4655.0--56.0	0.16	0.57	10.1	3.6	67	2.65
4	4656.0--57.0	8.3	14	10.8	2.9	52.8	2.65
5	4657.0--58.0	10	10	9.3	2.2	41.8	2.66
6	4658.0-59.0	14	14	10.3	2.1	48.1	2.67
7	4659.0--60.0	9.9	4.7	12.2	3.8	57.8	2.66
8	4660.0--61.0	13	4.1	11.7	2.2	56.6	2.66
9	4661.0--62.0	51	39	13.3	7.8	45.9	2.66
10	4662.0--63.0	9.2	6.2	7.3	5.6	44.9	2.7
11	4663.0--64.0	0.27	0.336	4	6.5	57.1	2.73
12	4664.0--65.0	7.2	0.023	5.6	6.4	62.5	2.65
13	4665.0--65.5	0.01	1.78	5.6	3	76.6	3.06

TABLE 3. – Reservoir Engineering Data for the Lower Skinner Sandstone in the Perry S.E. Skinner Sand Unit, Noble County, Oklahoma

	Lower Skinner Sand
Reservoir size	610 acres
Spacing (oil)	40 acres
Oil/water contact	none
Gas/oil contact	none
Porosity (average)	15% average
Permeability (average)	15 md average
Water saturation (calculated)	36%
Initial Average Gas to Oil Ratio (GOR)	492 SCF/BO
Average Thickness (net sand $\phi \geq$ 10%)	12.5 feet
Reservoir temperature	122°F
Oil gravity	41°API
Initial reservoir pressure	~2000 PSI
Initial formation volume factor	1.24 RB/STB
Original Oil in Place (volumetric)	4,591,000 STBO
Cumulative primary oil production	639,000 STBO
Cumulative primary oil recovery	84 BO/acre-ft
Recovery efficiency (oil)	~13.9%
Cumulative primary gas production	Not determined

Reservoir Characteristics: Reservoir characteristics for the Perry S.E. Skinner Sand Unit are given in Table 3. Porosities as measured primarily from density logs average 15.0%. The lower porosities tend to occur at the edges of the reservoir, with the higher porosities in the center part of the field or where the sandstone is thicker. Permeabilities probably average 15 md in wells at the edges of the field, and are likely to be higher away from the edges. Calculated water saturations average 36%. Wells located within the Perry S.E. Skinner unit do not have an apparent oil/water contact, however the water saturations for the Skinner sand generally are higher in the wells west of the unit. The initial GOR was ~492 SCF/BBL at an estimated 2,000 psi BHP. The oil gravity was 41.0° API, and the initial formation volume factor was 1.24.

Production History: Cumulative production through the first six months of 1995 was 1,318,268 BO for the Perry S.E Skinner Sand Unit. Table 4 gives the number of active wells per year, the annual oil production, the average monthly oil production, the average daily oil production per well, and the cumulative oil production for the field. The production decline curve (Fig. 30) shows the production history for the field. The field was unitized for secondary recovery on December 1, 1989. The oil recovery factor (i.e., primary production divided by original oil in place) for the Perry S.E. Skinner Sand Unit prior to unitization was ~13.9%. Water injection started on January 1, 1990. The increase in production for 1991 (Fig. 30) was the response to water injection.

Figure 31 is an isopotential map for the Perry S.E. Skinner Sand Unit. The isopotential map is contoured to display areas of equal initial oil production potential. Three wells within the unit outline are outside of the zero net sand line of the unit (SW¼SW¼ sec. 24, NW¼ NW¼ sec. 25, and SW¼NW¼ sec. 25, T. 21 N., R. 1 W.) (Fig. 25). As discussed earlier, the sand in these wells is thinner than the channel sandstone facies, perhaps a crevasse splay deposit. The initial potential production data (Fig. 31) help support that interpretation. Figure 32 is a structural cross section from the well in the SW¼ SW¼ of sec. 24, which is in the splay deposit, to the wells in the NE¼NW¼ and NW¼SW¼SE¼ of sec. 25, which are in the channel facies. The top of the Skinner net sand in these three wells is at essentially the same elevation. However, the well in the splay deposit made water-free oil, and the two wells in the channel deposit produced oil with water (Fig. 32, in envelope). Figure 33 is an isopach of the cumulative oil production for the Perry S.E. study area. The isopach indicates that the production increases toward the center of the channel.

Secondary Recovery: The Perry S.E. Skinner Sand Unit was unitized for secondary recovery operations on December 1, 1989. Water injection began on January 1, 1990. Figure 25 illustrates the original five spot pattern that was established for the field. Shortly after injection, water breakthrough indicated that there was a strong east-west orientation of permeability, possibly controlled by the natural fracture patterns prevalent in the region. The pattern was changed to a line drive pattern, illustrated in Figure 26, to take advantage of the fracture pattern.

TABLE 4. – Oil Production Statistics for the Perry S.E. Skinner 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)
1983	4	15,351 *	11,075	92	15,351
1984	15	236,851 *	21,162	47	252,202
1985	24	256,231	21,353	30	508,433
1986	24	95,180	7,932	11	603,613
1987	24	48,640	4,053	6	652,253
1988	24	30,989	2,582	4	683,242
1989	12 **	22,667	1,889	5	705,909
1990	12	16,959	1,413	4	722,868
1991	12	258,399	21,533	60	981,267
1992	12	183,265	15,272	42	1,164,532
1993	12	84,858	7,072	20	1,249,390
1994	11	53,675	4,473	14	1,303,065
1995	11	15,203 ***	2,534	8	1,318,268

* Partial year's production

** Unitized 12/1/89; 12 producers converted to injection wells

*** 6 months of production

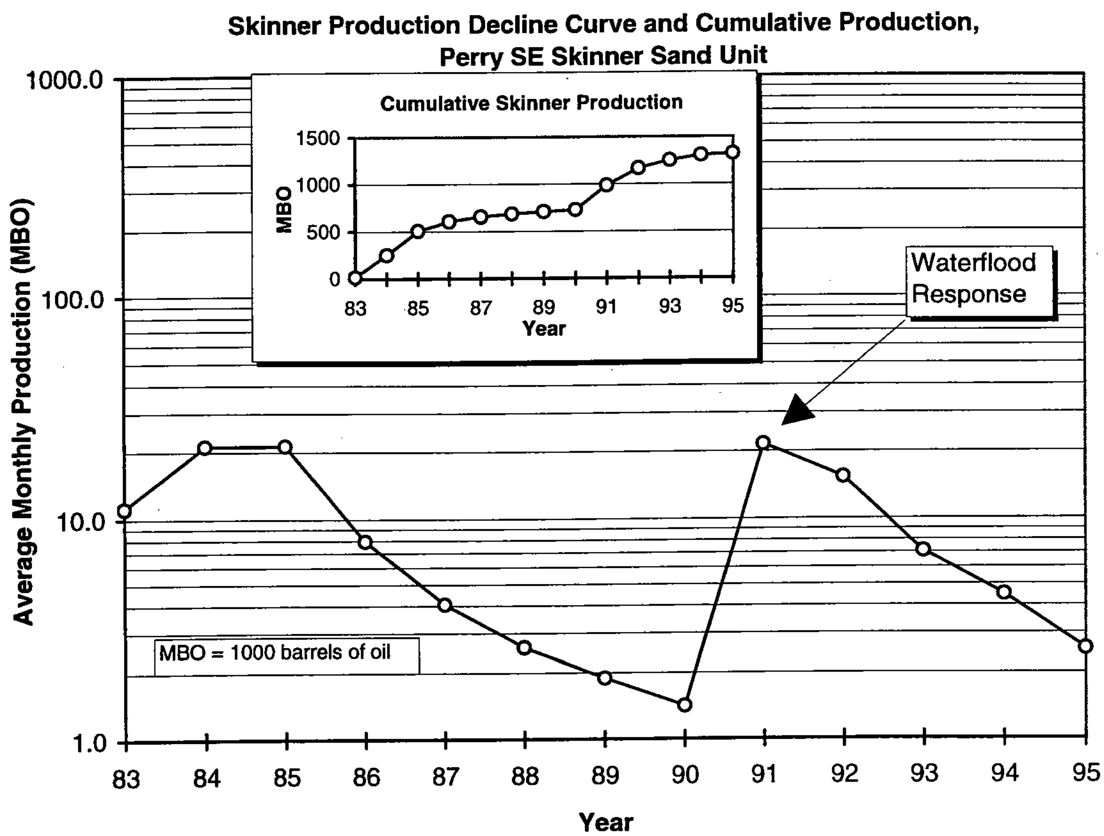


Figure 30. Oil production decline curve for the Perry S.E. Skinner Sand Unit.

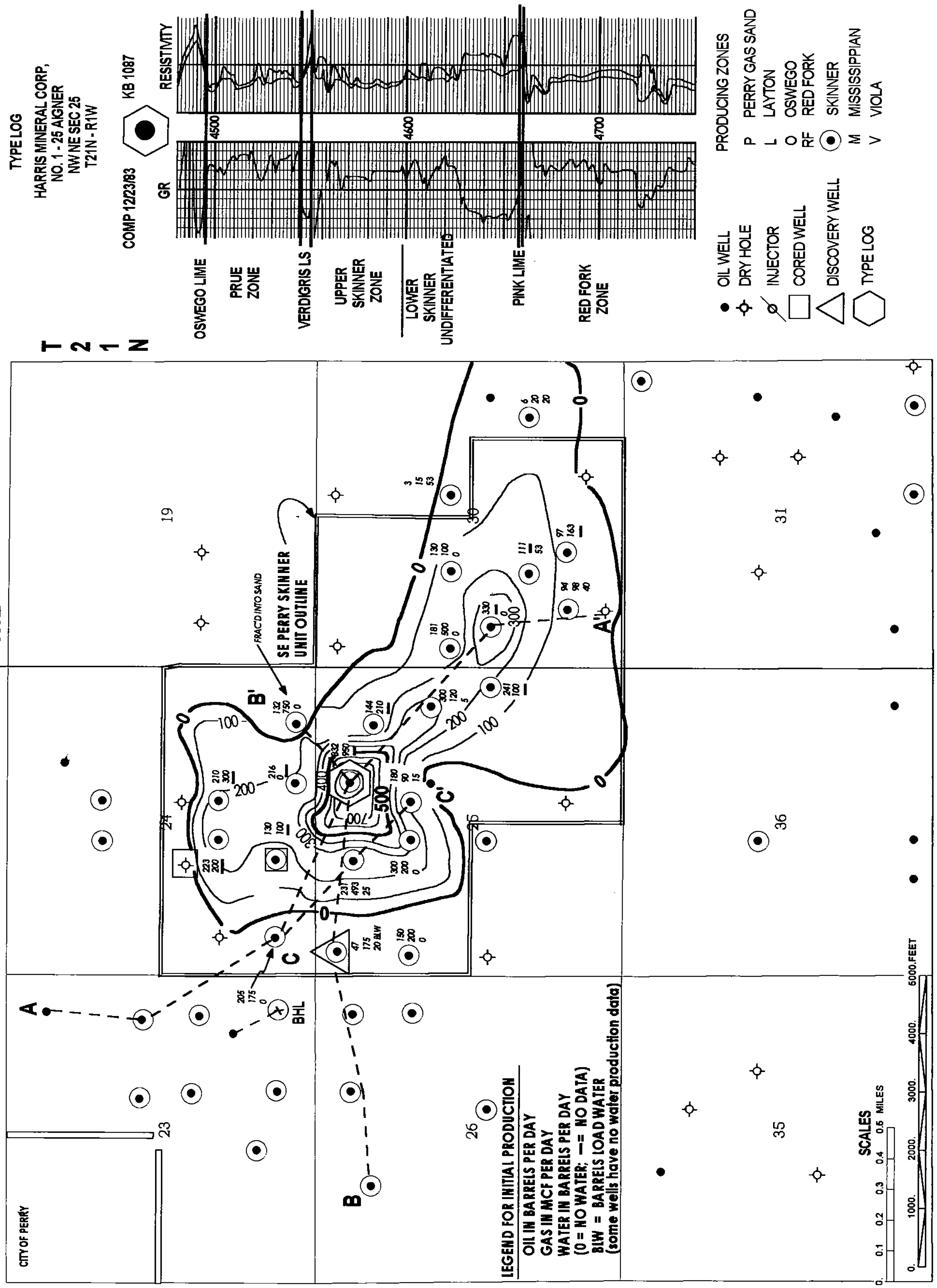


Figure 31. Isopotential map for the Perry S.E. Skinner Sand Unit. Contour interval is 100 BOPD.

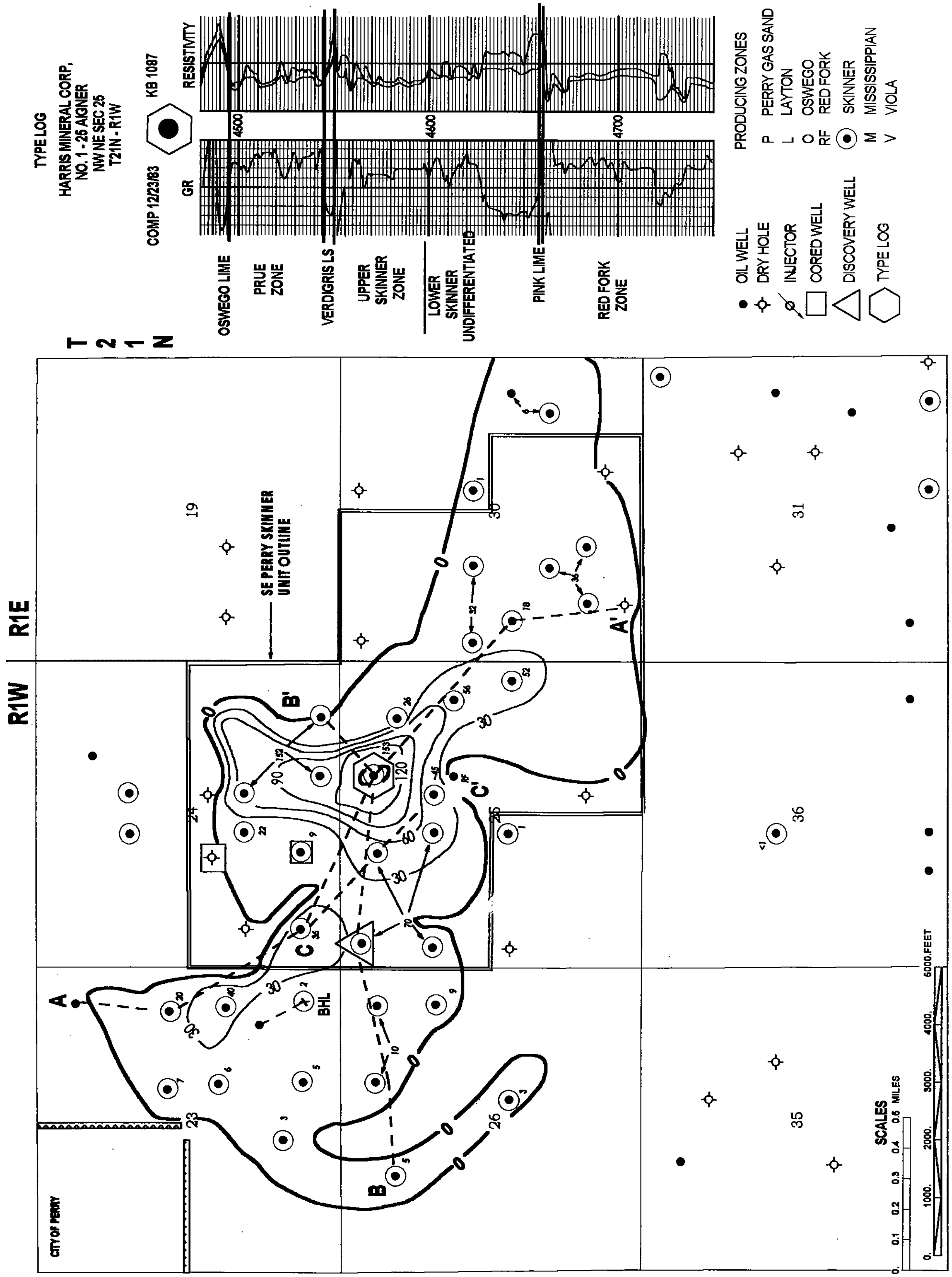


Figure 33. Map of cumulative oil production in the Perry S.E. Skinner Sand Unit. Contour interval is 30,000 BO.

Salt Fork North Field

(Skinner oil pool in sec. 19, T. 25 N., R. 3 W. and sec. 24, T. 25 N., R. 4 W., Grant County, Oklahoma)

by Richard D. Andrews

The Salt Fork North field is located in southeastern Grant County, north-central Oklahoma (Fig. 34). This area is just west of the Nemaha uplift in an area referred to as the Anadarko shelf province (Pl. 1). Production in the study area is from both the upper and lower Skinner sands; a few scattered wells also produce from the Layton sand and Mississippi lime reservoirs. A map identifying operators, well locations, well numbers, principal leases, and producing reservoirs in the study area is shown in Figure 35.

Oil and gas production was first established in Salt Fork North field in 1981 with the completion of Rincon Resources No. 1 Hall in the NW¼SE¼NE¼ of sec. 24, T. 25 N., R. 4 W. This well encountered 29 ft of upper Skinner sand. The upper Skinner sand was perforated (4,964–4,978 ft) and the initial potential flowing (IPF) was 65 BO, 200 MCFG, and 60 BW per day. Flowing tubing pressure was 125 psi and the oil gravity was 33° API. (All other wells in the field report the oil gravity to be around 42° API.) The No. 1 Hall produced ~3,445 BO and 10,649 MCFG from May 1981 through February 1984 before being shut-in. The initial GOR was 3,077:1; the GOR computed from cumulative production is 3,091:1, which is higher than that of most wells in the field. The overall gas-to-oil ratio indicates that this is a moderately gas-saturated oil reservoir and that the principal driving mechanism is solution gas expansion. To date, 15 wells have been completed in the Skinner and only a few wells have tested the underlying Mississippian section. Additional oil potential in the overlying Layton occurs in several wells within and just southeast of the study area. Salt Fork North field was developed on 40-acre spacing and is just about fully developed. The only other areas that may contain additional drilling locations are a small sand body southeast of the field or to the west, along the trend of the main sand body.

Salt Fork North field was unitized in late 1994 for the purpose of water flooding. However, water supply well problems were encountered and the flood was discontinued shortly thereafter.

Stratigraphy: The stratigraphic section in the study area is illustrated on the Salt Fork North type log (Fig. 36). The Skinner zone is divided into upper and lower sand zones by a thin shale marker bed (see gamma-ray log, Fig. 36). The stratigraphic position of this marker

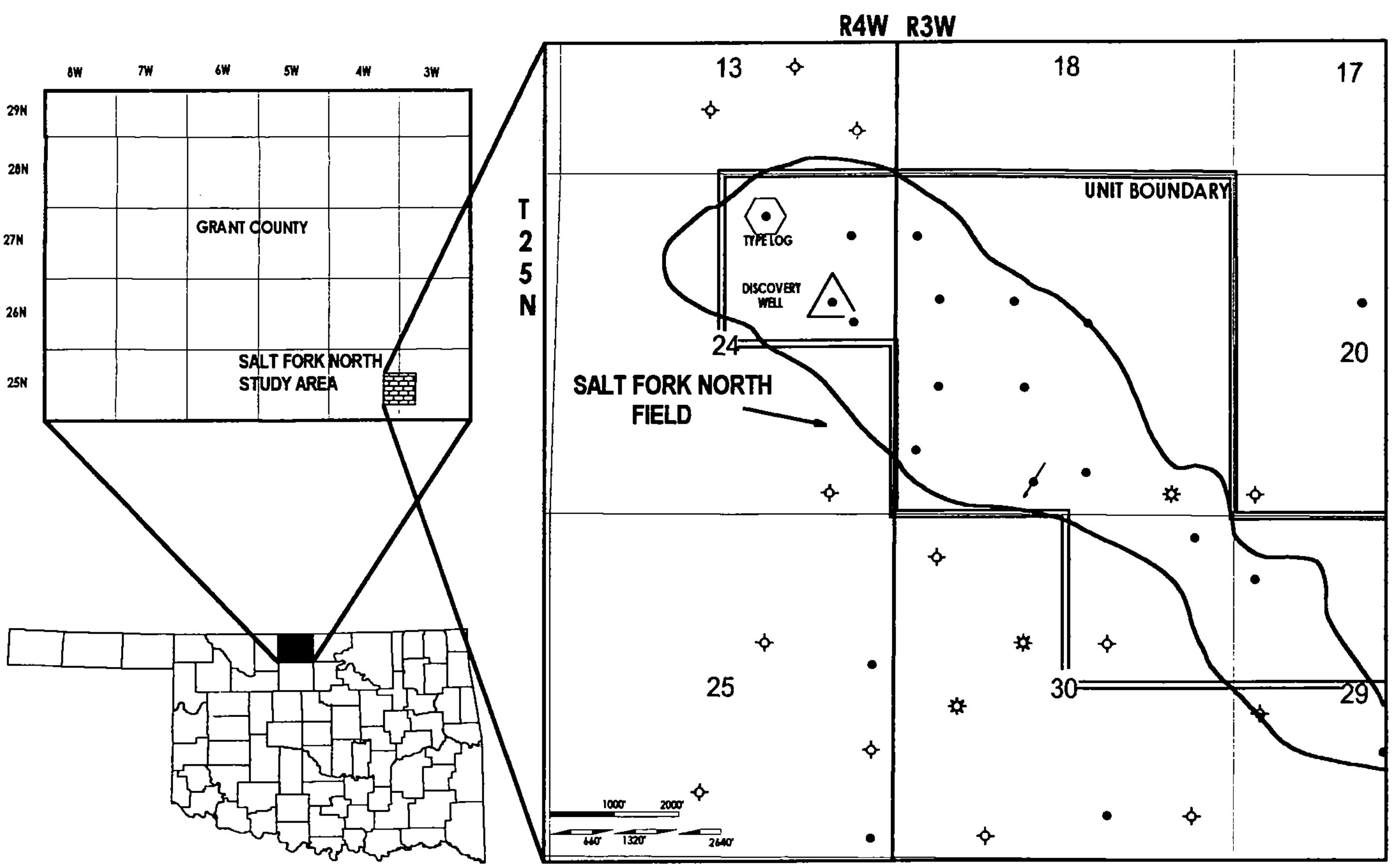


Figure 34. Generalized location map of the Salt Fork North study area in southeast Grant County, Oklahoma. The area outlined (single line) is the Salt Fork North field.

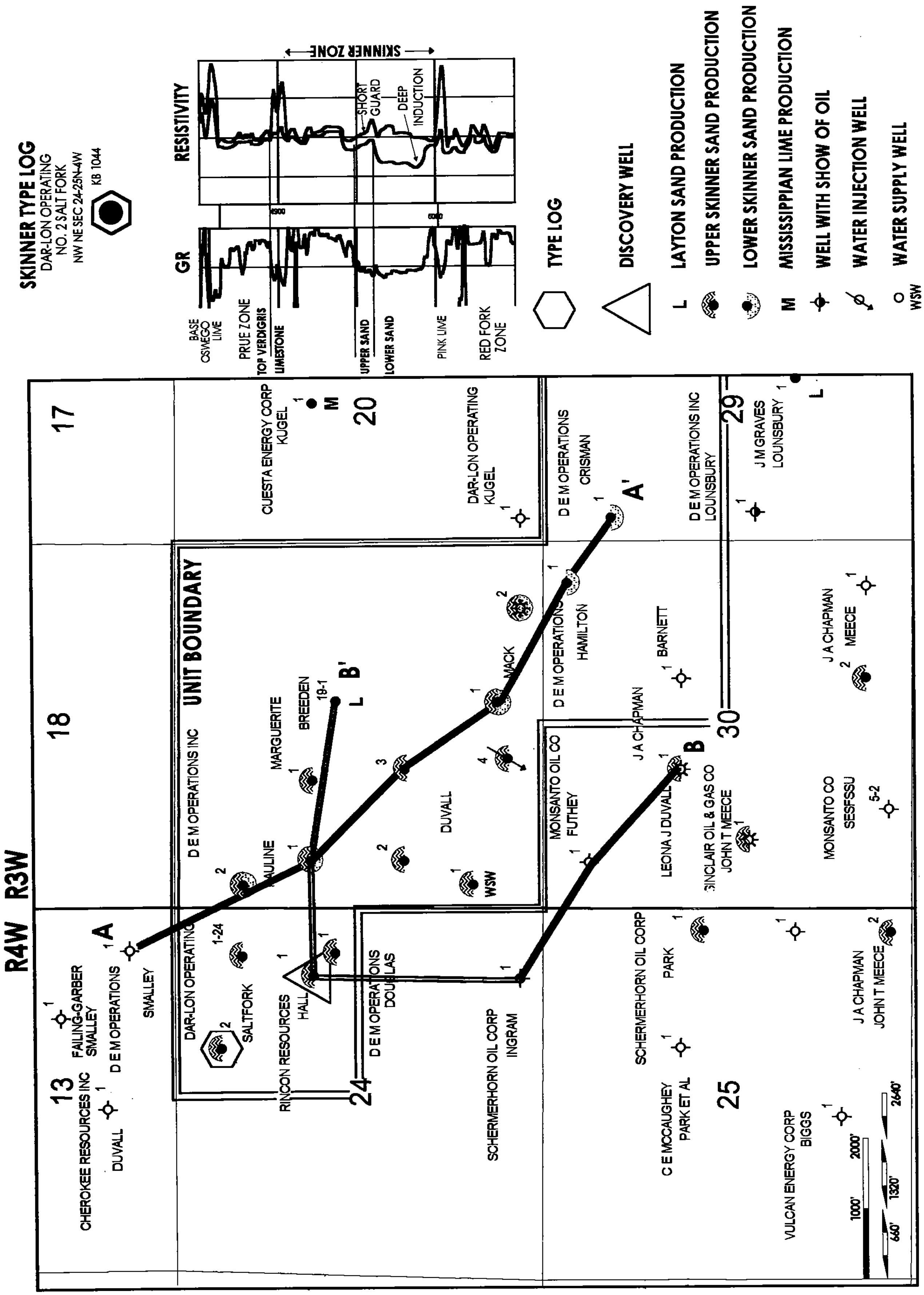


Figure 35. Well information map showing operator, lease name, well number, and producing reservoir(s) for wells in the Salt Fork North study area.

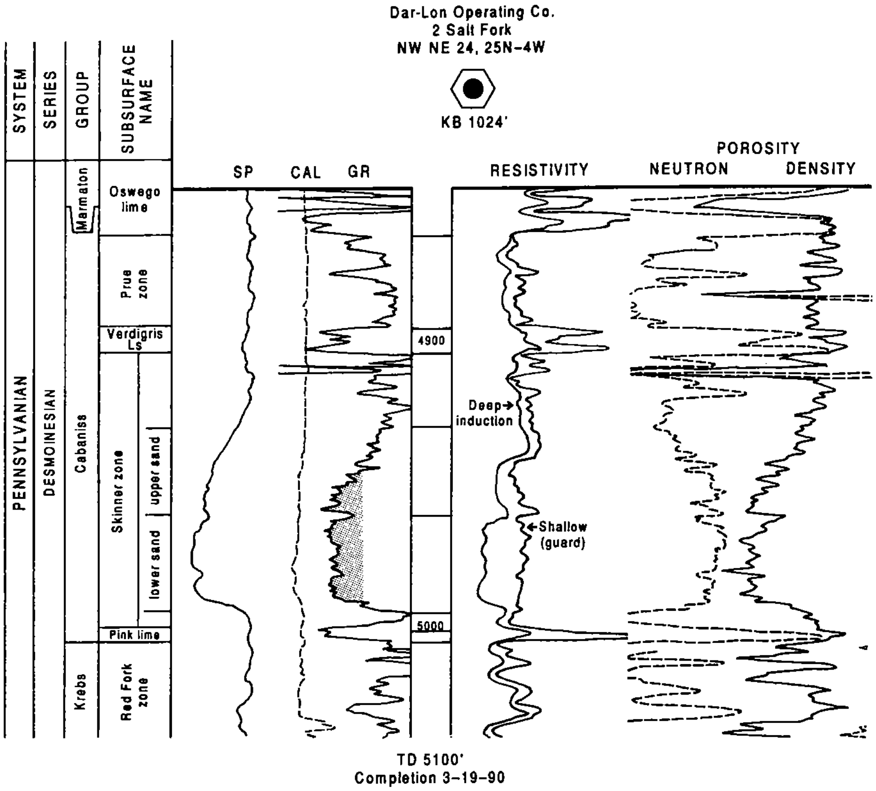


Figure 36. Salt Fork North Skinner type log showing stratigraphic markers and characteristic log signatures. The thin shale (4,964–4,966 ft) separates the Skinner interval into upper and lower zones in the study area and is the top of the lower Skinner sand zone. SP = spontaneous potential, CAL = caliper, GR = gamma ray.

bed is fairly consistent and marks the top of the lower sand zone even where sandstone is not present in the lower zone. The lower Skinner sandstone log shows a sharp contact with the underlying shale which is ~6 ft thick on the type log. Throughout the study area, the lower Skinner sandstone is underlain by this shale and does not scour into or even rest directly on the underlying Pink lime.

The type log (Fig. 36) illustrates an important difference in the upper and lower sandstones. Notice that the resistivity of the upper sand is considerably higher than that of the lower sand. Upon first examination, the resistivity shift appears to be an oil-water contact, but the shift occurs at the shale marker between the upper and lower sandstones. Also, the elevation of similar resistivity shifts in nearby wells is too variable to be an oil-water contact. Therefore, the difference in resistivity of the upper and lower sands appears to be related, at least in part, to a difference in lithology.

The upper sandstone is quite variable in thickness, however the thickness increase is mostly at the expense of shale in the upper Skinner zone rather than by deep incision into the lower Skinner zone. The upper sand apparently built upward, perhaps by vertical aggradation or possibly by lateral and vertical accretion within a flood plain.

Stratigraphy of the Skinner interval is best shown by the detailed cross sections of the field. Cross section A–A′ (Fig. 37, in envelope) is oriented northwest-southeast and shows the log character and sandstone distribution along the long axis of the field. In the No. 1 Pauline well (SW¼ NW¼ sec. 19), the thin shale that separates the Skinner into upper and lower zones is absent and the upper and lower Skinner sands are present in a stacking arrangement, making it difficult to distinguish between the two. The lower sandstone in this well has a sharp basal contact with the underlying lower Skinner shale and apparently is incised into the surrounding shale. The blocky gamma-ray profile of the lower Skinner sand is interpreted to be indicative of a channel-fill sandstone composed of fluvial (longitudinal?) sand bars that accumulated mainly by vertical aggradation rather than by lateral accretion. The apparent absence of delta-front deposits in the lower Skinner zone suggests that the channel sandstone is not a distributary channel and that it was probably deposited in a subaerial coastal flood plain in response to a lowering of sea level.

Unlike the lower Skinner sand, the upper sand in the study area is characterized by different gamma ray profiles. The gamma ray profile of the upper sand in the Pauline well appears to coarsen or become less shaly upward. Yet, other gamma ray logs have distinct fining upward profiles (e.g., Fig. 36) or blocky vertical profiles. In addition, the resistivity of the upper sand is considerably higher than that of the lower sand. Upon first examination, the resistivity shift appears to be an oil-water contact, but the elevation of similar resistivity shifts in nearby wells is too variable. Therefore, the difference in resistivity of the upper versus the lower sand appears to be related, at least in part, to a difference in lithology. Water saturations calculated using resistivity of the lower sand are commonly >50%, yet there is no discrete oil-water contact in wells that produce from the lower sand.

Southeast of the No. 1 Pauline, in the No. 3 Duvall well (NE¼SW¼ sec. 19), the upper Skinner sand is thicker than in the No. 1 Pauline and has a more channel-like log profile. Farther southeast, in the No. 1 Mack well (W½SW¼SE¼ sec. 19), the same upper Skinner sandstone appears on the gamma ray log to coarsen or become less shaly upward. The different log patterns of the upper sandstone in this cross section indicate variations in lithologies and, perhaps, different depositional facies. The upper Skinner in this cross section typifies that of the whole study area. Despite certain differences in lithology and sand distribution, the

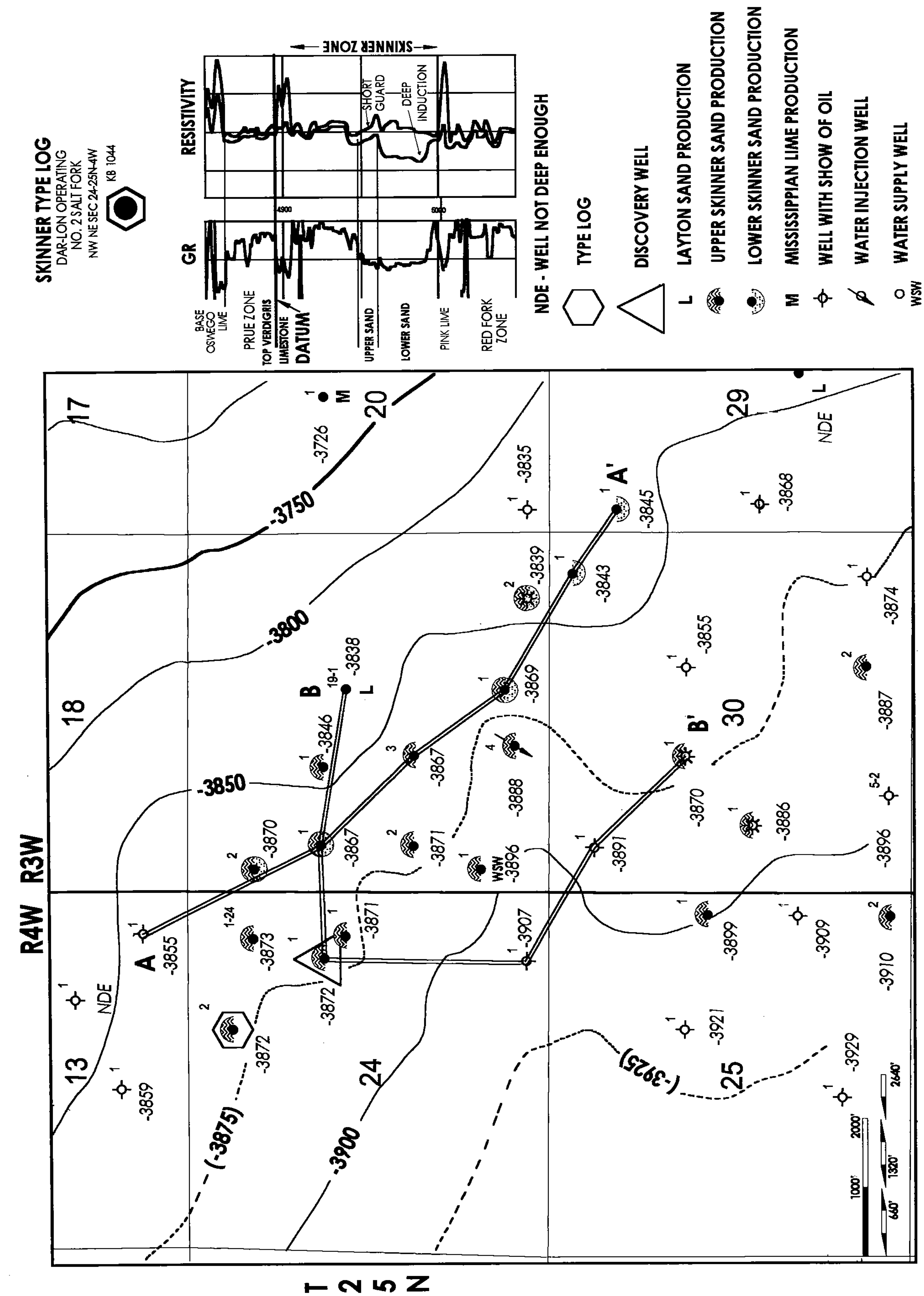


Figure 39. Structure map of the top of the Verdigris Limestone, Salt Fork North study area. Contour interval is 50 ft; intermediate contours are dashed.

upper and lower Skinner sandstones are probably related in depositional origin, perhaps deposited at different times in different subenvironments of one fluvial system (Pl. 1).

The stratigraphic variations along a line perpendicular to the channel complex is shown by the right half of cross section B–B′ (Fig. 38, in envelope). Most apparent are the blocky gamma ray signature and changes in thickness of the lower Skinner sandstone. The lower sandstone is ~40 ft thick in the No. 1 Pauline well, which is located in about the center of the field, and is absent in logs adjacent to the Pauline log in B–B′. The upper Skinner sandstone is almost 20 ft thick in the No. 1 Pauline and is ~30 ft thick in the log of the No. 1 Hall, which is only ~1,650 ft to the west (Fig. 38).

Cross section B–B′ (Fig. 38) also shows the lateral relationship of Salt Fork North Skinner sands to productive Skinner sands ~0.5 mi south of the study area in the Salt Fork S.E. field. It is believed that Skinner sands in these two fields are not in communication with each other.

Structure: Regionally, the Verdigris Limestone in the study area dips gently to the southwest (Fig. 16). The structure in this area is a result of subsidence of the Anadarko basin and has also been affected by the Nemaha uplift, which lies several miles to the east. Technical discussion of the effects of the Nemaha uplift is contained in the regional analysis of the Skinner play preceding this field study. A local structure map of the Verdigris Limestone in the Salt Fork study area indicates a gentle southwesterly dip of about 100–150 ft/mi (~1.5°) (Fig. 39). In addition, Figure 39 shows that Salt Fork North field is oriented roughly parallel to to strike. Because of this parallelism, drape folding over the thick sandstone surrounded by shale (differential compaction) would not be manifest as a structural nose over the sand body. Instead, drape folding, if present, would result in changes in amount, not direction, of dip and would be evident as changes in contour line spacing, increased spacing on the updip side, and decreased spacing on the downdip side of the sand body. In Figure 39, over the field, an increase in spacing can be seen between the –3,850 ft and –3,875 ft contour lines and a decrease in spacing between the –3,850 ft and –3,900 ft contour lines.

Lower Skinner Structure and Isopach Maps: The lower Skinner sand is limited in areal extent in the study area but is very productive in the few areas where it is sufficiently above the oil-water contact. The narrow, sinuous sand body has log characteristics that strongly indicate a fluvial, channel-fill origin (blocky gamma ray profile and sharp basal contact). Lateral changes from sandstone to shale also are abrupt rather than gradual (Figs. 37,38). Figure 40 is an isopach map of the lower Skinner gross sandstone. The areal distribution pattern indicates a fluvial origin with a maximum meander length and amplitude of about 1.4 and 0.9 mi, respectively. The actual channel width is only ~2,000 ft, but the sand thickness is nearly 40 ft in the northwest part of the field. These dimensions are indicative of a relatively large channel; therefore, from the thick sand in the NW¼ of sec. 19, the contours were extended into the SE¼ of sec. 24 rather than forcing the sand trend diagonally between the wells with no sand in sec. 19. The lower Skinner sand is absent north of Salt Fork North field, and very little sand is apparent in the lower Skinner zone in Salt Fork S.E. wells to the south (Fig. 40).

Figure 41 is a structure-contour map that shows the configuration of the top of the lower Skinner sand zone in the area inside the zero-sand isopach line (Fig. 40). The somewhat hummocky pattern of contours primarily reflects the distribution of sandstone within the lower zone. Areas of thickest sand (Fig. 40) occur where the top of the sand zone is low, which is opposite of what one might expect. This may have been caused by depositional loading (i.e., increased subsidence of the thick lower Skinner sand body).

Based upon resistivity log interpretations and field-wide production trends of the lower Skinner sand, an oil-water contact is estimated to be at about –3,950 ft. Above this elevation, water saturations are relatively high, but the sand is clearly oil productive. The distinction of a truly wet zone would probably be in sands having <2 ohm-meters of deep resistivity. However, no sharp contrasts in true resistivity below –3,950 were found, making definition of an oil-water contact very difficult.

The lower Skinner net sand (log porosity ≥10%) isopach map, as shown in Figure 42, closely approximates the gross sand map (Fig. 40). This indicates that wherever lower Skinner sand is present, it generally has porosity that is much greater than the 10% cutoff used for this map. The oil-water contact generally lies at or very near the upper bed boundary in the northwest part of the field so that only the central and southeast portions of Salt Fork North field have sufficient reservoir above water to account for significant oil reserves.

Upper Skinner Isopach and Structure Maps: Of the two Skinner sandstones, the upper sand is the most significant in terms of oil and gas production and in areal extent. The upper Skinner sand is also productive in several nearby fields along a trend that extends west and then southward into the Anadarko basin (Pl. 1). The upper Skinner sand has log characteristics that strongly suggest a fluvial origin especially in the northwest part of Salt Fork North field. This includes a blocky to fining-upward gamma ray profile (Fig. 36), which is typical of point bars or longitudinal channel-fill bars. However, in the central and southeastern part of the field (cross section A–A′, Fig. 37) gamma ray logs have blocky to coarsening-upward profiles which suggest depositional processes more attributable to river mouth bars rather than river channel deposits. However, the regional distribution pattern (Pl. 1) strongly supports a genetic relationship to fluvial deposition.

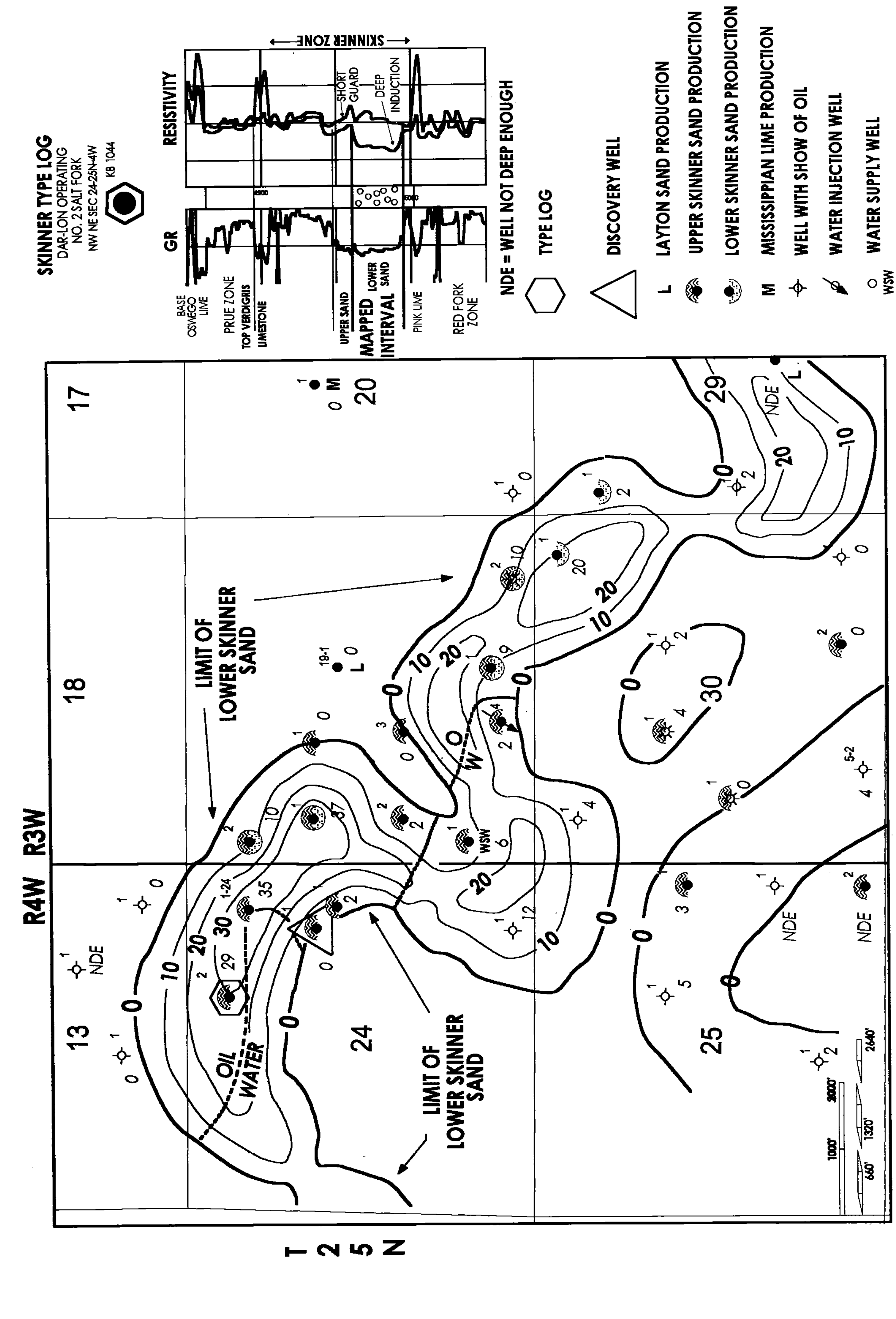


Figure 40. Lower Skinner gross sand isopach map, Salt Fork North field. Contour interval is 10 ft.

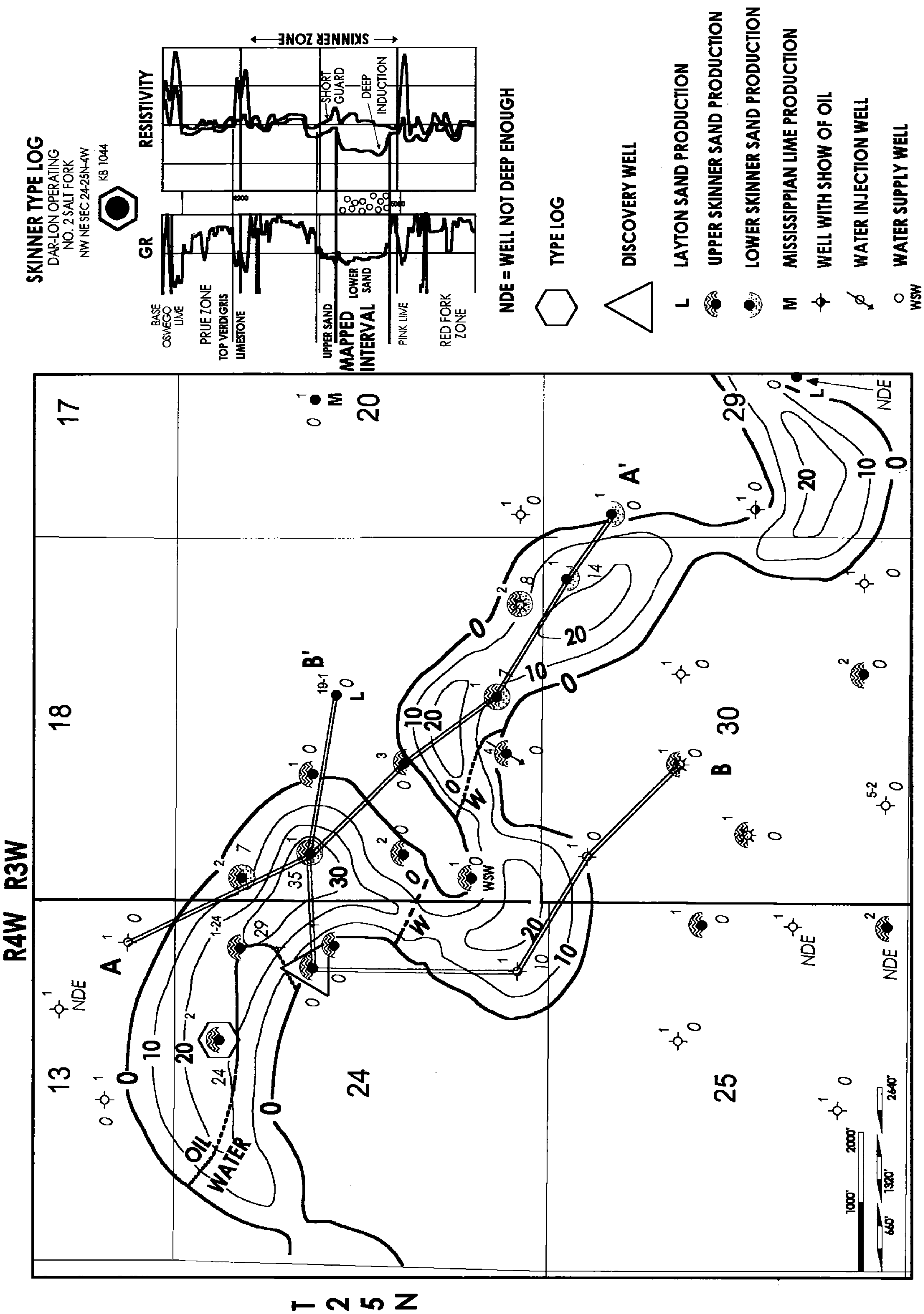


Figure 41. Structure-contour map showing the configuration of the top of the lower Skinner sand or sand zone, Salt Fork North field. Contour interval is 10 ft.

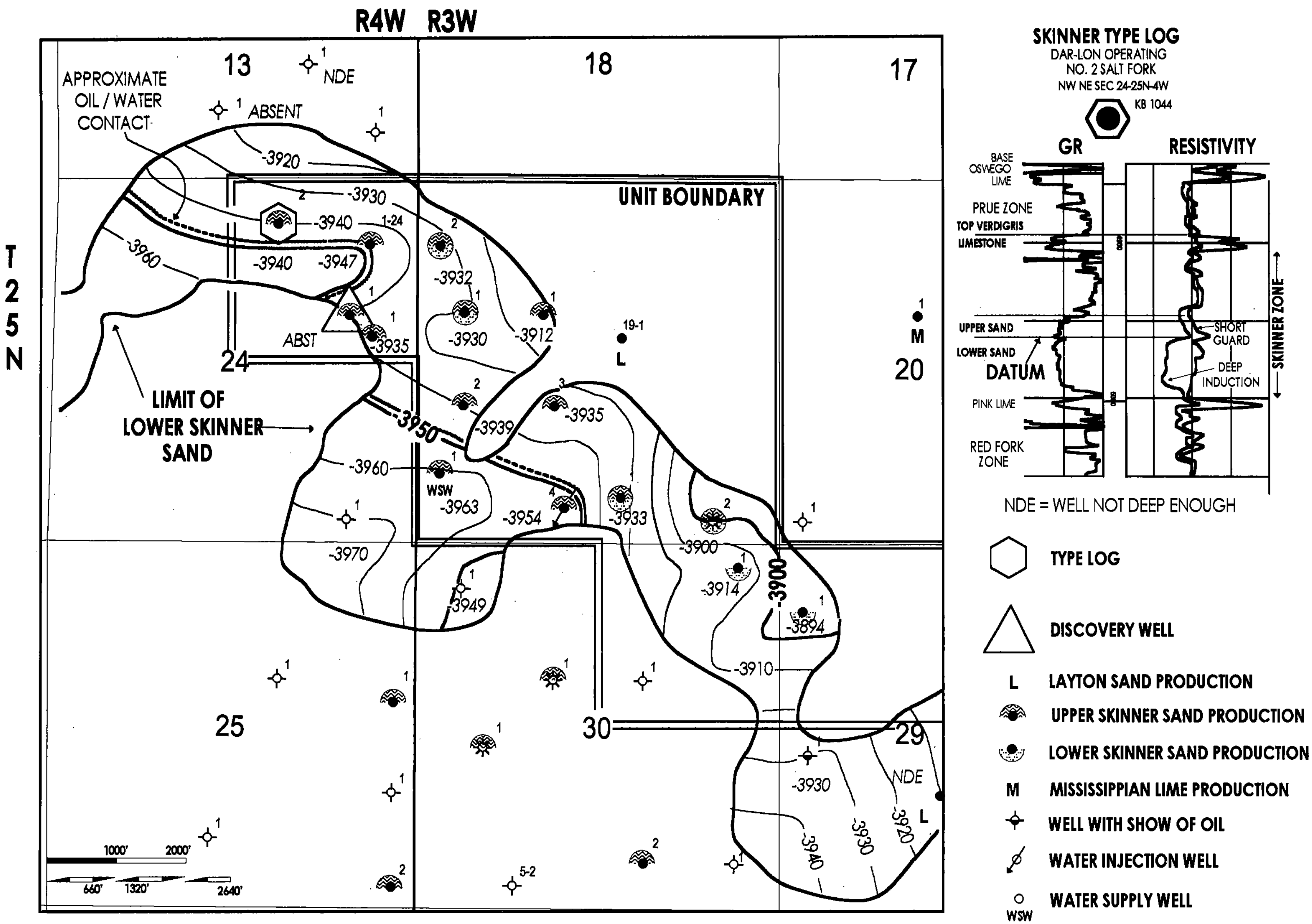


Figure 42. Lower Skinner net sand isopach map, Salt Fork North field. Net sand = sand with log $\phi \geq 10\%$. Contour interval is 10 ft.

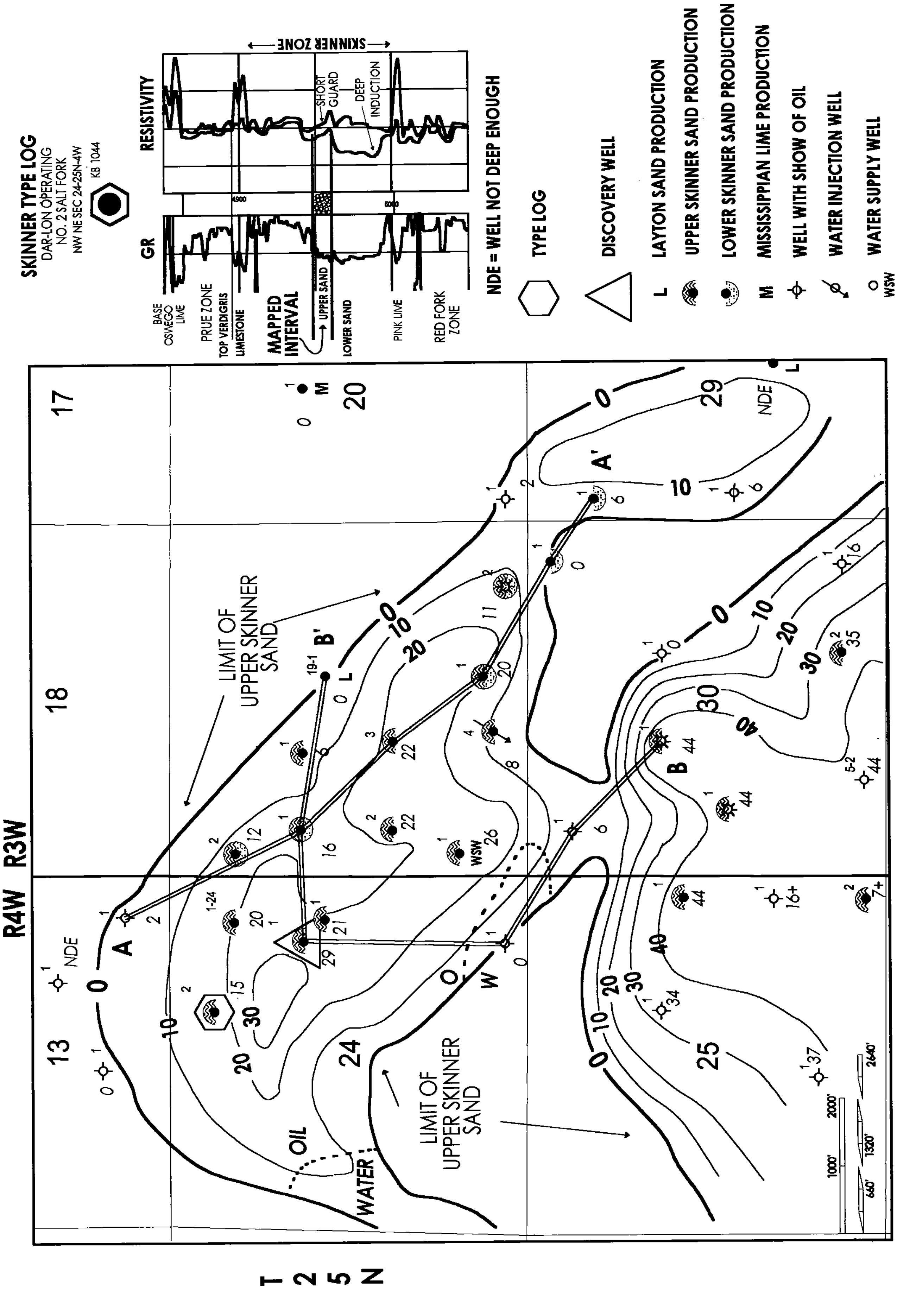


Figure 43. Upper Skinner gross sand isopach map, Salt Fork North field. The upper gross sand interval is 4,947–4,962 (15 ft) on the type log (Fig. 36). Contour interval is 10 ft.

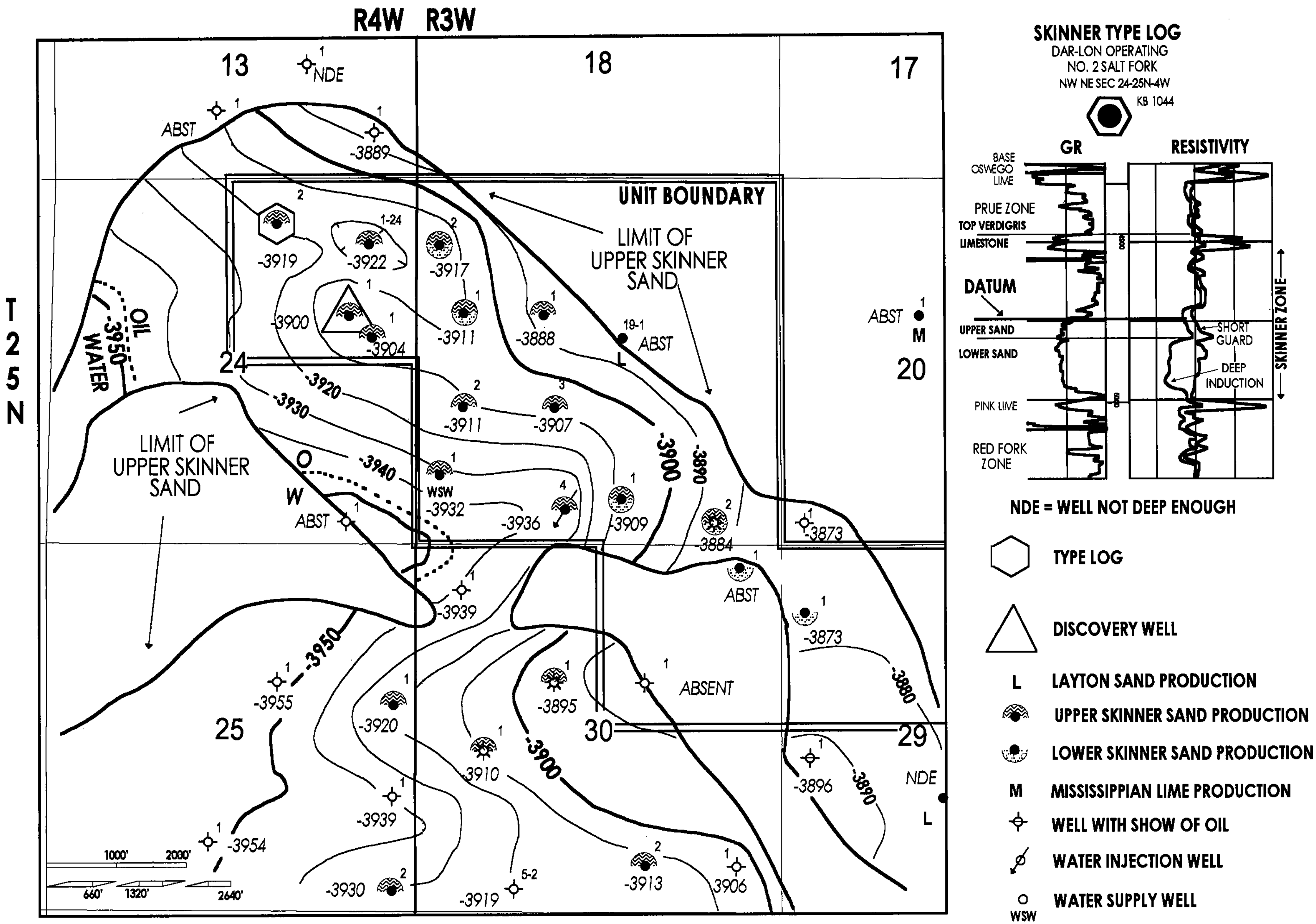


Figure 44. Structure-contour map showing the configuration of the top of the upper Skinner sand or sand zone, Salt Fork North field. In the type log (Fig. 36), the datum is at 4,943 ft. Contour interval is 10 ft.

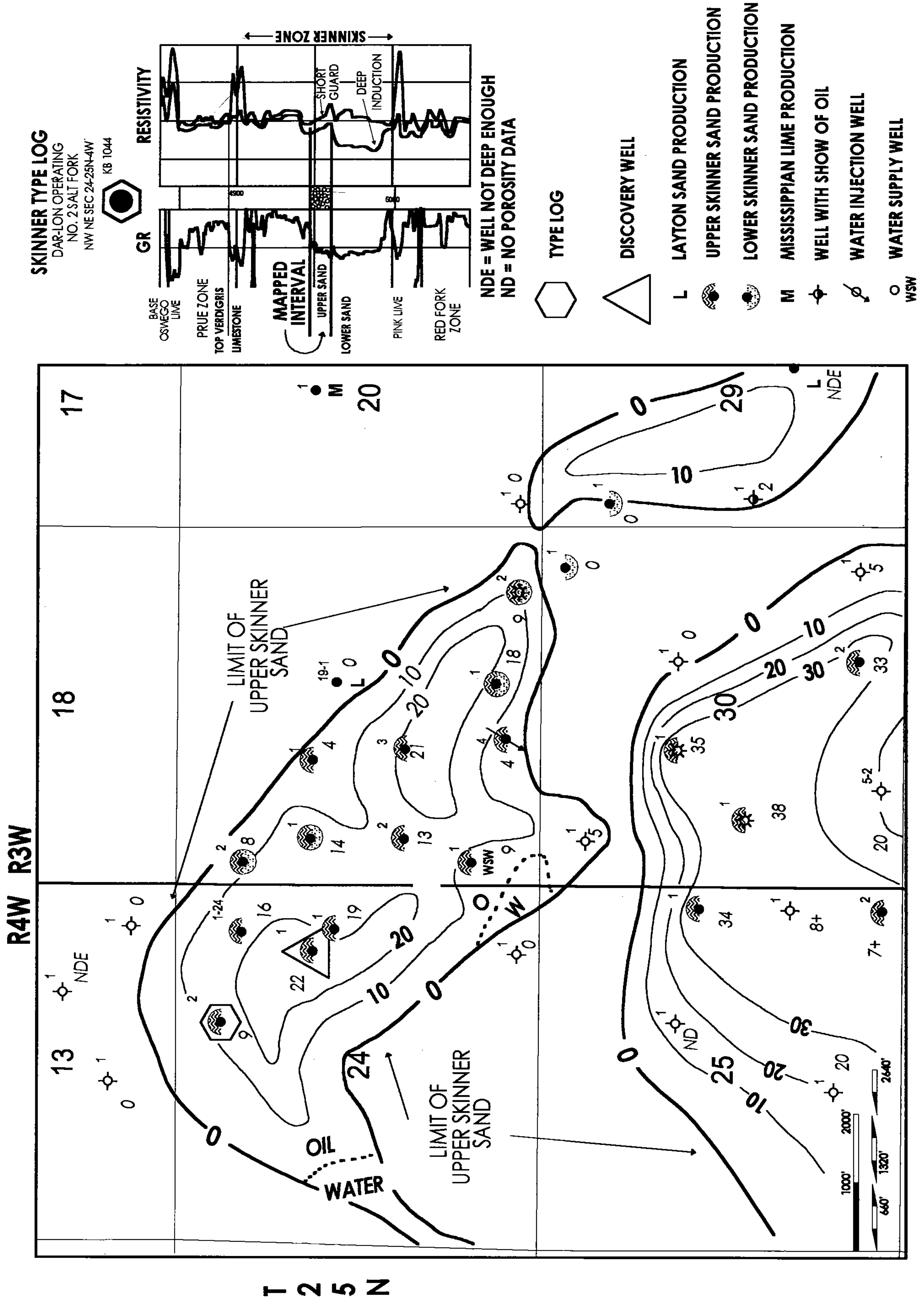
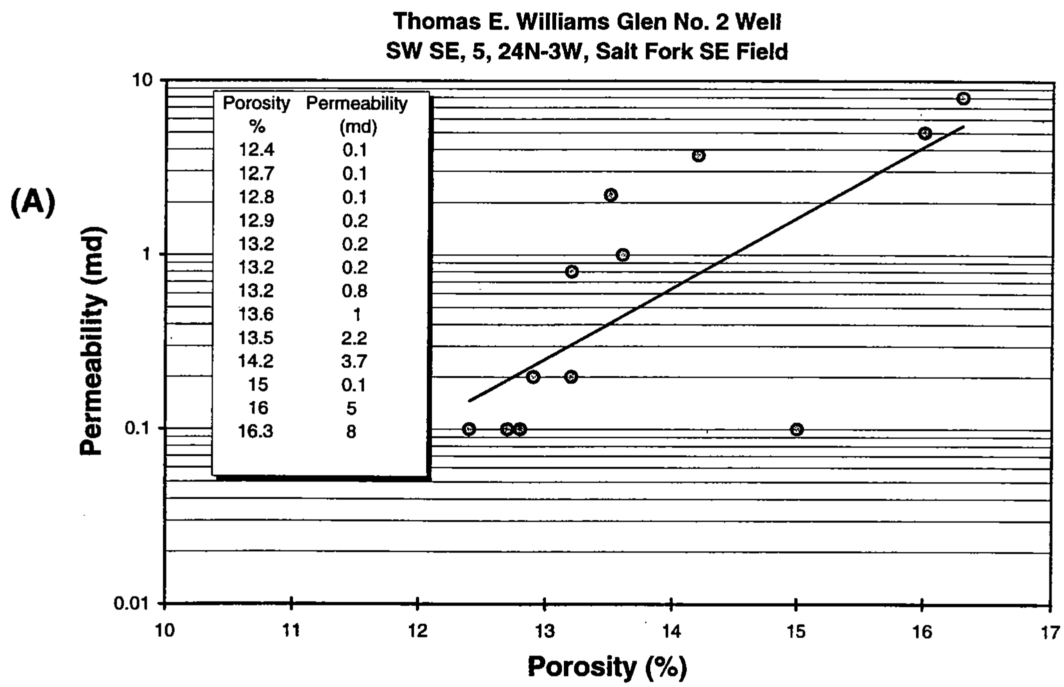


Figure 45. Upper Skinner net sand isopach map, Salt Fork North field. Net sand is sand with log $\phi \geq 10\%$. Contour interval is 10 ft.

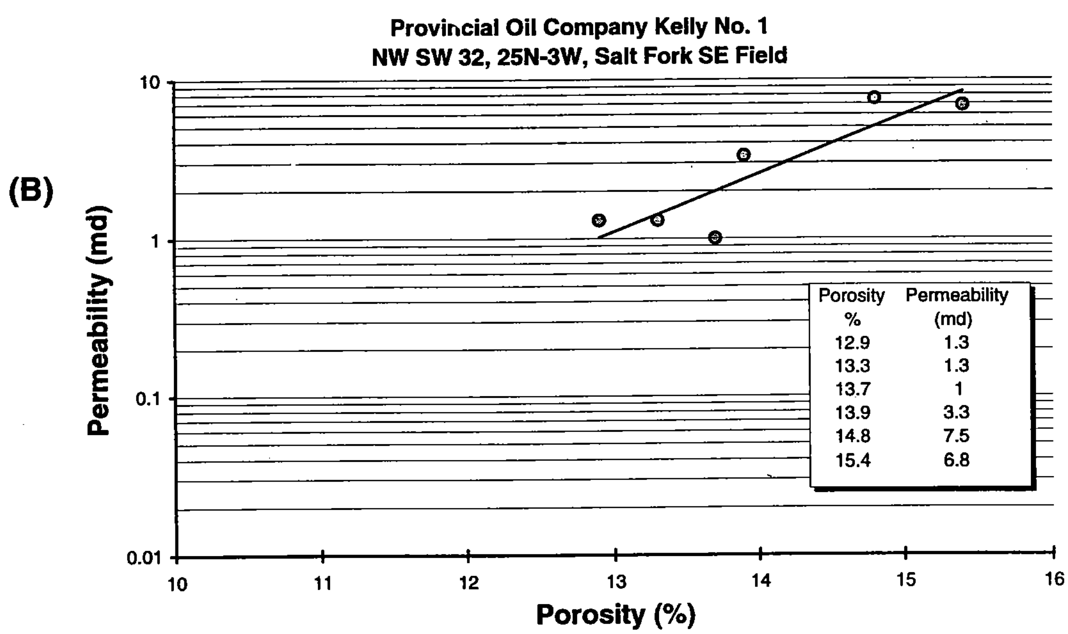
Figure 43 is an isopach map of the upper Skinner gross sandstone in Salt Fork North field. The sand body is elongate parallel to structural strike and has a maximum width of ~0.8 mi. The area defined by the thickest gross sand (>20 ft) has a definite meandering pattern and is interpreted to extend to the southeast and possibly to the west beyond the area mapped.

Figure 44 is a structure-contour map showing the configuration of the top of the upper Skinner sand zone. On this map, structural nosing is very evident in the western part of sec. 30, possibly caused by the presence of thick upper Skinner sandstone in the Salt Fork S.E. field. A pronounced nose in the SE¼NE¼ sec. 24 may be due to a combination of factors: drape folding over the thick upper sand in the SE¼NE¼ of sec. 24 and depositional loading in adjacent areas caused by lower Skinner sand. Based on field-wide production patterns of the upper Skinner sand and resistivity log interpretations, a generalized oil-water contact is estimated above −3,950 ft. However, this boundary is not clearly seen on any of the resistivity logs in the field.

An isopach map of the upper Skinner net sand (sand



Porosity %	Permeability (md)
12.4	0.1
12.7	0.1
12.8	0.1
12.9	0.2
13.2	0.2
13.2	0.2
13.2	0.8
13.6	1
13.5	2.2
14.2	3.7
15	0.1
16	5
16.3	8



Porosity %	Permeability (md)
12.9	1.3
13.3	1.3
13.7	1
13.9	3.3
14.8	7.5
15.4	6.8

Figure 46. Core porosity and permeability data from two wells in Salt Fork S.E. field.

TABLE 5. – Reservoir Engineering Data for the Skinner Sandstones in Salt Fork North Field, Southeastern Grant County, Oklahoma

	Lower Skinner Sand	*Upper Skinner Sand*
Reservoir size	~375 acres	~645 acres
Spacing (oil)	40 acres	40 acres
Oil/water contact	~ -3950	above ~ -3950
Gas/oil contact	undetermined	undetermined
Porosity	10-18% (avg 12%)	10-19% (avg 13%)
Permeability[1]	0.25-8 md (avg 4 md)	0.25-8 md (avg 4 md)
Water saturation (calculated)	26-60% (avg 41%)	33-50% (avg 43%)
Thickness[2] (net sand $\phi \geq$ 10%)	10-20 ft (avg 16 ft)	10-35 ft (avg 12 ft)
Reservoir temperature	125°F	125°F
Oil gravity	40-42° API	40-42° API
Initial reservoir pressure	1,826 PSI	1,826 PSI
Initial formation volume factor	1.3 RB/STB	1.3 RB/STB
OOIP (volumetric est) (original oil in place)	2,376,000 STBO	3,137,000 STBO
Cumulative primary oil prod.	73,337 STBO (est)	159,313 STBO (est)
Recovery efficiency (oil)	3.1%	5.1%
Cumulative gas[3] production	336,044 MCF	1,286,000 MCF

[1]Based on permeabilities measured in cores from two Skinner wells located a few miles south of the Salt Fork North study area (see Fig. 46).
[2]Entire sand bed thickness. In places, adjacent to the oil-water contact, the thickness of net sand above the oil-water contact is somewhat lower than the entire sand bed thickness.
[3]Not including produced gas used for on-site power generation.

with log $\phi \geq$10%) (Fig. 45) shows that the thickest sand is in two main lobes separated by a narrow zone of thinner sand near the east line of sec. 24. This may indicate reservoir compartmentalization. Most of the reservoir-grade upper Skinner sand in Salt Fork North field is 10–20+ ft thick and is above the oil-water contact. Also, the upper Skinner reservoir in the Salt Fork North field is not in communication with the upper Skinner reservoir in secs. 25 and 30 (Salt Fork S.E. field). Therefore, the oil-water contact that generally lies at or very near the base of the upper Skinner sand is only relevant to Salt Fork North field.

Core Analysis: Cores from two wells in Salt Fork S.E. field in secs. 5 and 32, T. 25 N., R. 3 W. (just outside the study area) are believed to be representative of the upper Skinner throughout the general area. The porosity-permeability plots (Fig. 46) show that both wells are relatively tight. Even so, both produced oil from the upper Skinner sand. The No. 2 Glen well (Fig. 46A) initially produced 129 BO + 369 BLW from 10 ft of oil-saturated sand following a sand frac. The permeabilities in the productive zone of this well are only 2.0–3.7 md with corresponding porosities of 13.5%

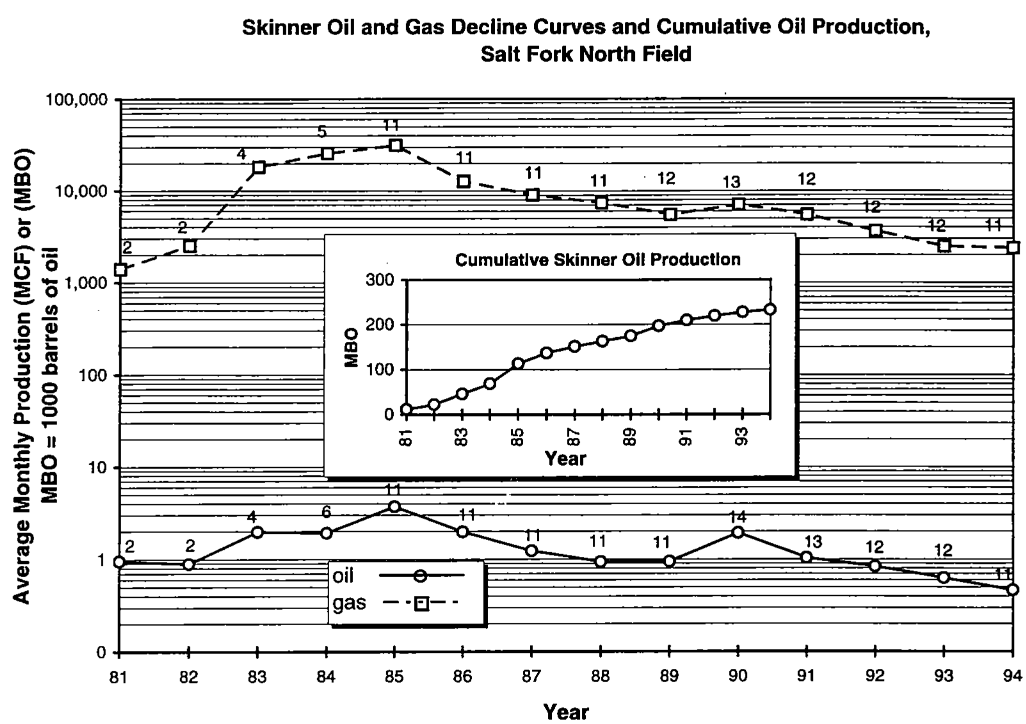


Figure 47. Upper and lower Skinner combined oil and gas production decline curves, Salt Fork North field. Number of oil wells that produced is indicated by the number above the oil data points. Inset plot shows cumulative oil production from the upper and lower Skinner sands combined.

TABLE 6. – Oil and Gas Production Statistics (upper and lower Skinner combined), Salt Fork North Field

Oil Production Statistics, Salt Fork North Field

Year	Number of Oil Wells (est.)	Annual Oil Production (Barrels)	Average Monthly Oil Production (Barrels)	Average Daily Oil Production Per Well (BOPD)	Cumulative Oil Production (Barrels)
1981	2	11,478	957	16	11,478
1982	2	10,672	889	15	22,150
1983	4	23,628	1,969	16	45,778
1984	5	22,964	1,914	13	68,742
1985	11	44,304	3,692	11	113,046
1966	11	23,519	1,960	6	136,565
1987	11	14,765	1,230	4	151,330
1988	11	11,274	940	3	162,604
1989	11	11,288	941	3	173,892
1990	14	22,932	1,911	4	196,824
1991	13	12,389	1,032	3	209,213
1992	12	10,034	836	2	219,247
1993	12	7,560	630	2	226,807
1994	10	5,558	463	2	232,365

Gas Production Statistics, Salt Fork North Field

Year	Number of Gas Wells (est.)	Annual Gas Production (MCF)	Average Monthly Gas Production (MCF)	Average Daily Gas Production Per Well (MCF)	Cumulative Gas Production (MCF)
1981	2	16,841	1,403	23	16,841
1982	2	30,024	2,502	41	46,865
1983	4	219,165	18,264	150	266,030
1984	5	307,177	25,598	168	573,207
1985	11	376,850	31,404	94	950,057
1986	11	152,825	12,735	38	1,102,882
1987	11	108,460	9,038	27	1,211,342
1988	11	88,708	7,392	22	1,300,050
1989	12	65,756	5,480	15	1,365,806
1990	13	84,877	7,073	18	1,450,683
1991	12	65,644	5,470	15	1,516,327
1992	12	43,460	3,622	10	1,559,787
1993	12	29,516	2,460	7	1,589,303
1994	12	28,378	2,365	6	1,617,681

and 14.2%. The No. 1 Kelly well (Fig. 46B) initially produced 240 BO from 10 ft of oil-saturated sand also following a sand frac. Permeabilities in the production zone of the Kelly well ranged from about 1.0 to 7.5 md; porosities ranged from 12.9% to 15.4% (Fig. 46B). Cumulative production of the Kelly well was 30,493 BO from June 1956 through September 1972, which verifies that significant oil production can be attained from relatively tight Skinner sands.

Reservoir Characteristics: Descriptive rock analysis was not performed in the previously mentioned core analysis, but other similar Skinner deposits have been examined by the author and other investigators such as Lojek (1984) and Hanke (1967). The Skinner in the Salt Fork area is expected to be fine to very fine grained, although basal portions of the interval may contain coarse-grained material such as mud clasts. Framework components are mostly quartz and lesser amounts of rock fragments and some mica. Interstitial authigenic constituents consist mostly of clays (kaolinite, illite, and minor chlorite), carbonate cements, and iron oxides, which tend to impart a brownish coloration. The relatively high clay, mica, and rock fragment content causes a "dirty" gamma ray profile such as shown by the type log (Fig. 36).

Porosity in productive intervals of both the upper and lower Skinner sands, primarily from log analysis, is in the 10–19% range and averages about 12–13%. Based on permeabilities measured in the Salt Fork S.E. cores (Fig. 46), permeability in the Salt Fork North field is expected to be low and should be in the 1–10 md range, averaging about 3–5 md. Such low values necessitate fracture treatment in all wells in order to establish oil production. The inset tables included in Figure 46 show that permeability doesn't vary more than a few millidarcies. Nevertheless, because of natural or induced fracturing brought on by well completion practices, the upper and lower Skinner sands in certain portions of the field are expected to have zones of preferred fluid (and gas) mobility. Although the reservoir as a whole appears to be somewhat uniform in terms of average permeability, certain zones undoubtedly have enhanced permeability which can lead to unpredictable production characteristics such as water breakthrough. Additionally, isopach mapping consistently shows rapid thickness variations along trend in both the upper and lower, which indicates compartmentalization. A summary of reservoir and engineering data for the Skinner sandstones in Salt Fork North field is given in Table 5.

Formation Evaluation: Skinner sandstone in the Salt Fork area is easily identified on any wire line logs commonly used today. Although the gamma ray reading is somewhat higher ("dirtier") than in very pure quartz sandstones, it is much "cleaner" (i.e., lower) than that observed in most Prue sand sections. Skinner sand resistivity logs are very diagnostic for the Skinner sands. The deep reading is about 5–10 ohm-meters in productive zones (sometimes as much as 15 ohm-meters). Lower (and presumably wetter) zones commonly have deep resistivity readings of about 2–3 ohm-meters, although a field-wide oil-water contact in each sand is difficult to identify because production is often attributable to the low resistivity sand zones as well. The separation between the short normal and deep resistivity measurements is usually about 7–12 ohm-meters, less separation indicates a greater oil saturation or that the sand is tight. Porosity logs are usually combination density-neutron logs, and there is little gas effect (see type log, Fig. 36). A few wells have density-neutron cross-over of 2–5 porosity units, but higher values are uncommon.

TABLE 7. — Annual Primary Oil Production by Lease (upper and lower Skinner production combined), Salt Fork North Field

Well Information										Primary Oil production in barrels															Cumulative Oil
S3	S2	S1	SEC	TWP	RGE	Status	Lease name and Well #		Comp date yr-mo-day	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995 (to April)	Production by Well (barrels)
NW	SE	NE	24	25N	04W	OIL	HALL	1	81-06-01	2,709	1,029	197	139	0	0	0	0	0	0	0	0	0	0	0	3,935
NW	SW	SW	19	25N	03W	OIL	DUVALL *	1	81-07-03	8,769	9,643	10,849	11,385	8,370	4,450	2,304	2,601	1,779	1,397	1,079	1,200	1,082	718	0	65,626
	NW	SW	19	25N	03W	OIL	DUVALL	2	83-09-01			Production combined with Duvall #1, NWSWSW													
	NE	SW	19	25N	03W	OIL	DUVALL	3	84-10-10				Production combined with Duvall #1, NWSWSW												
SE	SE	SW	19	25N	03W	OIL	DUVALL	4	85-09-15					Production combined with Duvall #1, NWSWSW											
	SW	NW	19	25N	03W	OIL	PAULINE	1	83-05-13			12,582	10,080	3,908	1,947	1,400	1,275	827	158	0	0	0	0	0	32,177
S2	SE	NE	24	25N	04W	OIL	DOUGLAS	1	84-04-24				1,360	968	542	176	185	0	172	88	0	0	0	0	3,491
W2	SW	SE	19	25N	03W	OIL	MACK	1	84-12-15					15,499	3,030	1,979	1,137	515	653	311	325	156	0	0	23,605
SW	SE	SE	19	25N	03W	GAS	MACK	2	85-09-19					Combined with Mack #1, SWSE											
W2	SE	NW	19	25N	03W	OIL	MARGUERITE	1	85-04-02					3,287	1,967	1,049	808	645	494	419	428	261	170	0	9,528
N2	NE	NE	30	25N	03W	OIL	HAMILTON	1	85-04-27					11,001	6,578	4,298	3,245	2,231	1,829	1,345	1,385	920	988	0	33,820
SW	NW	NW	29	25N	03W	OIL	CRISMAN	1	85-10-09					1,271	5,005	3,559	2,023	1,364	993	755	732	545	462	0	16,709
S2	NE	NE	24	25N	04W	OIL	SALT FK 1-24	1-24	89-10-03									3,927	10,727	4,575	3,081	2,450	1,626	301	26,687
	NW	NE	24	25N	04W	OIL	SALT FORK	2	90-04-18										2,877	1,599	1,221	1,043	811	123	7,674
SW	NW	NW	19	25N	03W	OIL	PAULINE	2	90-04-25										3,632	2,218	1,662	1,103	783	0	9,398
* Duvall #1 converted to a water supply well in 1995 **																									
** Duvall #4 converted to injector well late in 1995										Cumulative Primary Oil Production for field 6/1/81 to 4/30/95 →															232,650
Cumulative Annual Production (BO) →										11,478	10,672	23,628	22,964	44,304	23,519	14,765	11,274	11,288	22,932	12,389	10,034	7,560	5,558	424	
Number of producing wells →										2	2	4	6	11	11	11	11	11	14	13	12	12	11	10?	

Water saturation (S_w) was calculated using the Archie equation ($S_w = \sqrt{(F \times R_w / R_t)}$ with $R_w = 0.35$, $F = 0.81/\phi^2$, porosity log ϕ, and deep resisitivity (R_t). Calculated water saturation in productive zones ranges from about 26% to 60% (average 41%) in the lower Skinner sand and from 33% to 50% (average 43%) in the upper Skinner sand.

Oil Production and Well Completion: Cumulative Skinner production from Salt Fork North field from June 1981 through December 1994 was 232,365 BO and 1,617,681 MCF gas (Table 6) plus an estimated 67,410 MCF used for on-site power generation. Annual production data is shown in the decline and cumulative production curves (Fig. 47) and compiled in Table 6, which also shows average per month and average per well. Annual oil and gas production by lease are shown in Tables 7 and 8.

Most of the production was from the upper Skinner, which is areally more extensive than the lower Skinner sand (159,000 BO and 1,286,000 MCFG, estimated); only 6 of 13 wells produced from the lower Skinner. The lower Skinner sand has excellent reservoir characteristics, but the water saturation is high in many wells since the sand is at or very near the oil-water contact (Fig. 41). Production from the lower Skinner sand is therefore estimated at 73,000 BO, most if not all of which came from three wells in the southeast part of the field. Overall, water production within the field is estimated to be twice the oil production (Don Muegge, field owner and operator, personal communication), but no exact values are known.

Cumulative Skinner oil produced from individual wells and leases is highly variable, ranging from about 3,000 to 34,000 BO (Table 7). Cumulative gas production is also erratic, ranging from only a few thousand MCF to >368,000 MCF in the No. 1 Pauline well (SW¼NW¼ sec. 19) (Table 8). Cumulative oil and gas and the production period are plotted on the map in Figure 48. The best gas producers generally produce from the upper Skinner sand. The good oil producers in the upper and lower sands are those with lower water saturations (Fig. 49).

Some wells are shown to have production from both Skinner zones, even though log analyses indicate that this condition is sometimes unlikely. This situation is best

TABLE 8. – Annual Gas Production by Lease (upper and lower Skinner production combined), Salt Fork North Field

Well Information										Associated Gas production in MCF															Cumulative Gas
S3	S2	S1	SEC	TWP	RGE	Status	Lease name and Well #		Comp date yr-mo-day	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995 (to April)	Production by Well (MCF)
NW	SE	NE	24	25N	04W	OIL	HALL	1	81-06-01	489	8,325	2,668	0	0	0	0	0	0	0	0	0	0	0	0	14,150
NW	SW	SW	19	25N	03W	OIL	DUVALL *	1	81-07-03	16,352	21,699	[illegible]	137,067	33,313	9,499	16,666	22,481	13,887	11,658	9,156	5,966	4,832	568		393,381
	NW	SW	19	25N	03W	OIL	DUVALL	2	83-09-01			Combined with Duvall #1, NWSWSW													
	NE	SW	19	25N	03W	OIL	DUVALL	3	84-10-10				Combined with Duvall #1, NWSWSW												
SE	SE	SW	19	25N	03W	OIL	DUVALL **	4	85-09-15					Combined with Duvall #1, NWSWSW											
	SW	NW	19	25N	03W	OIL	PAULINE	1	83-05-13			126,260	139,073	62,909	16,367	9,480	7,152	5,806	1,700	0	0	0	0	0	368,747
S2	SE	NE	24	25N	04W	OIL	DOUGLAS	1	84-04-24				31,037	36,752	29,286	22,215	15,905	12,600	8,061	10,586	6,101	5,137	5,832	456	183,968
W2	SW	SE	19	25N	03W	OIL	MACK	1	84-12-15					188,620	62,482	32,268	18,554	10,472	9,095	5,168	2,916	1,946	1,028	162	332,711
SW	SE	SE	19	25N	03W	GAS	MACK	2	85-09-19					Combined with Mack #1, SWSE											
W2	SE	NW	19	25N	03W	OIL	MARGUERITE	1	85-04-02					32,569	20,382	12,736	11,586	7,225	4,407	3,174	2,932	1,744	2,088	126	98,969
N2	NE	NE	30	25N	03W	OIL	HAMILTON	1	85-04-27					22,300	9,862	8,292	7,461	6,076	4,761	3,684	3,376	2,328	2,959	238	71,337
SW	NW	NW	29	25N	03W	OIL	CRISMAN	1	85-10-09					387	4,947	6,803	5,569	4,431	3,725	6,137	4,294	2,402	3,298	68	42,061
S2	NE	NE	24	25N	04W	OIL	SALT FORK 1-24	1-24	89-10-03									5,259	26,835	17,461	11,029	7,047	7,840	553	76,024
	NW	NE	24	25N	04W	OIL	SALT FORK	2	90-04-18										0	0	0	0	0	0	0
SW	NW	NW	19	25N	03W	OIL	PAULINE	2	90-04-25										14,635	10,278	6,846	4,080	4,765	92	40,696
										Cumulative Associated Gas Production (MCF) for field 6/1/81 to 4/30/95 →															1,622,044
* Duvall #1 converted to a water supply well in 1995																									
** Duvall #4 converted to injector well late in 1995																									
Cumulative Annual Production (MCF) →										16,841	30,024	219,165	307,177	376,850	152,825	108,460	88,708	65,756	84,877	65,644	43,460	29,516	28,378	1,695	
Number of producing wells →										2	2	4	5	11	11	11	11	12	13	12	12	12	12	12?	

shown in the No. 1 Pauline well in the SW¼NW¼ sec. 19, which was one of the earliest wells to be drilled in sec. 19. Shortly after drilling this well, the well-site geologist recognized that mostly gas was produced during flow testing, so he recommended that the lower Skinner be perforated in order to enhance oil production, maintain reservoir pressure, and avoid producing a potential gas cap. The well was perforated and fracture treated in a low resistivity lower Skinner sand zone and over a seven-year period, produced about 32,000 BO and 368,238 MCFG. This proved to be one of the best wells in the field. However, formation evaluation indicates that the lower Skinner zone is fairly wet (S_w = 50%), and the porosity log shows no gas effect in the upper Skinner sand. The initial GOR for this well was 4,417:1, and the cumulative production GOR is only 11,500:1, which may mean that the Pauline well was at or very close to bubble point when penetrated but that the reservoir contained basically a gas-saturated oil. Cumulative production values indicate that the No. 1 Pauline is a gas well, a situation similar to many Skinner wells in the field. When fluid communication between the upper and lower Skinner sands was enhanced due to an aggressive frac job, oil and associated gas was probably forced into the well bore through perforations in the lower part of the Skinner section due to the high initial pressure within the upper Skinner reservoir (1,826 psi) and gas expansion during pressure depletion. Thus, it is likely that much of the production from the No. 1 Pauline came from the upper Skinner sand rather than the lower sand in which the well is perforated. It is also possible that the upper Skinner sand may not be fully exploited because it is not in direct contact with well bore perforations and that most of the reservoir energy is depleted.

Some of the leases in the field have more than one well, in which case, reserve allocation was attempted in order to characterize individual well performance. This

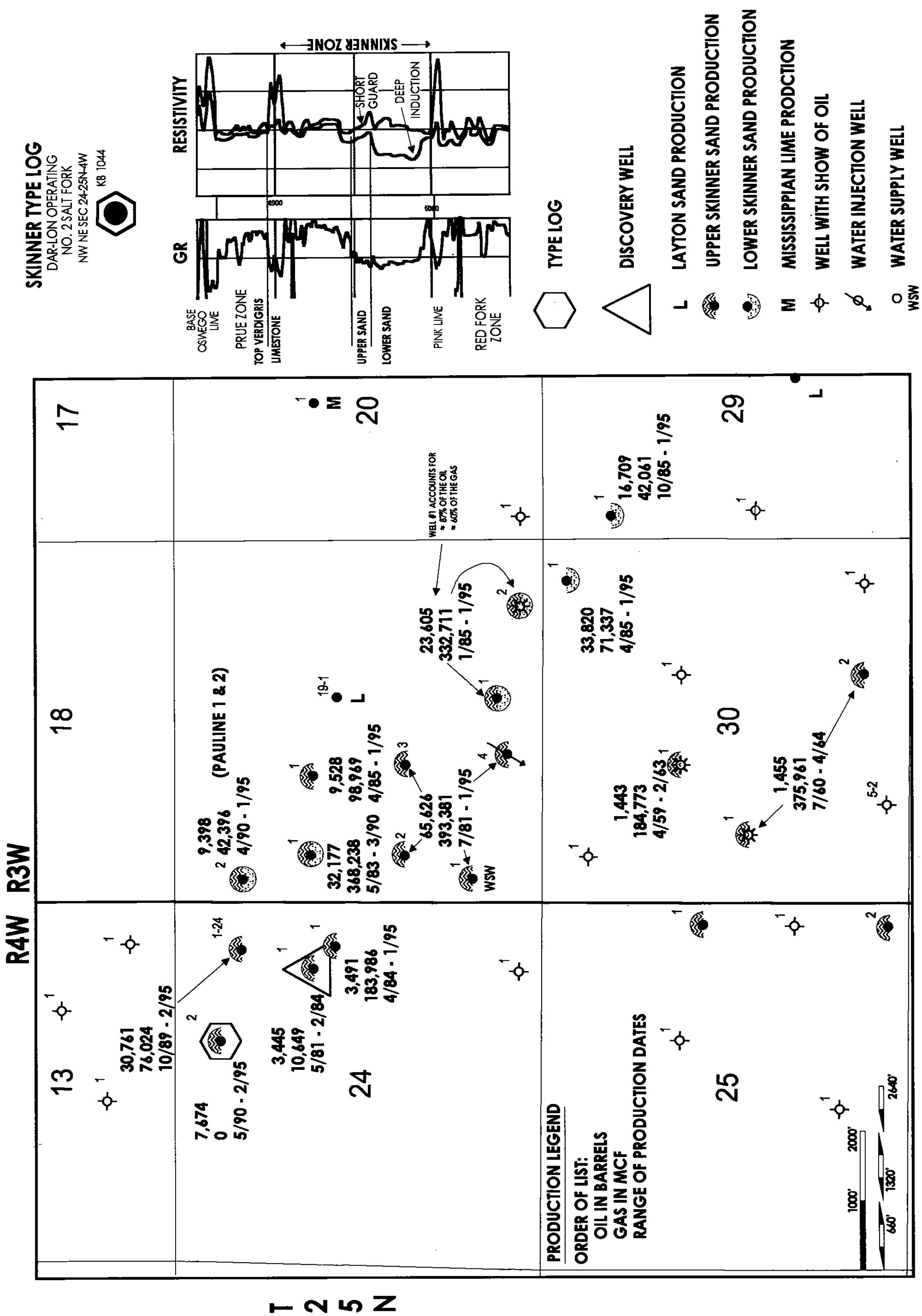


Figure 48. Map showing cumulative oil and gas production and producing time periods for leases in the Salt Fork North study area. See Figure 35 for well names.

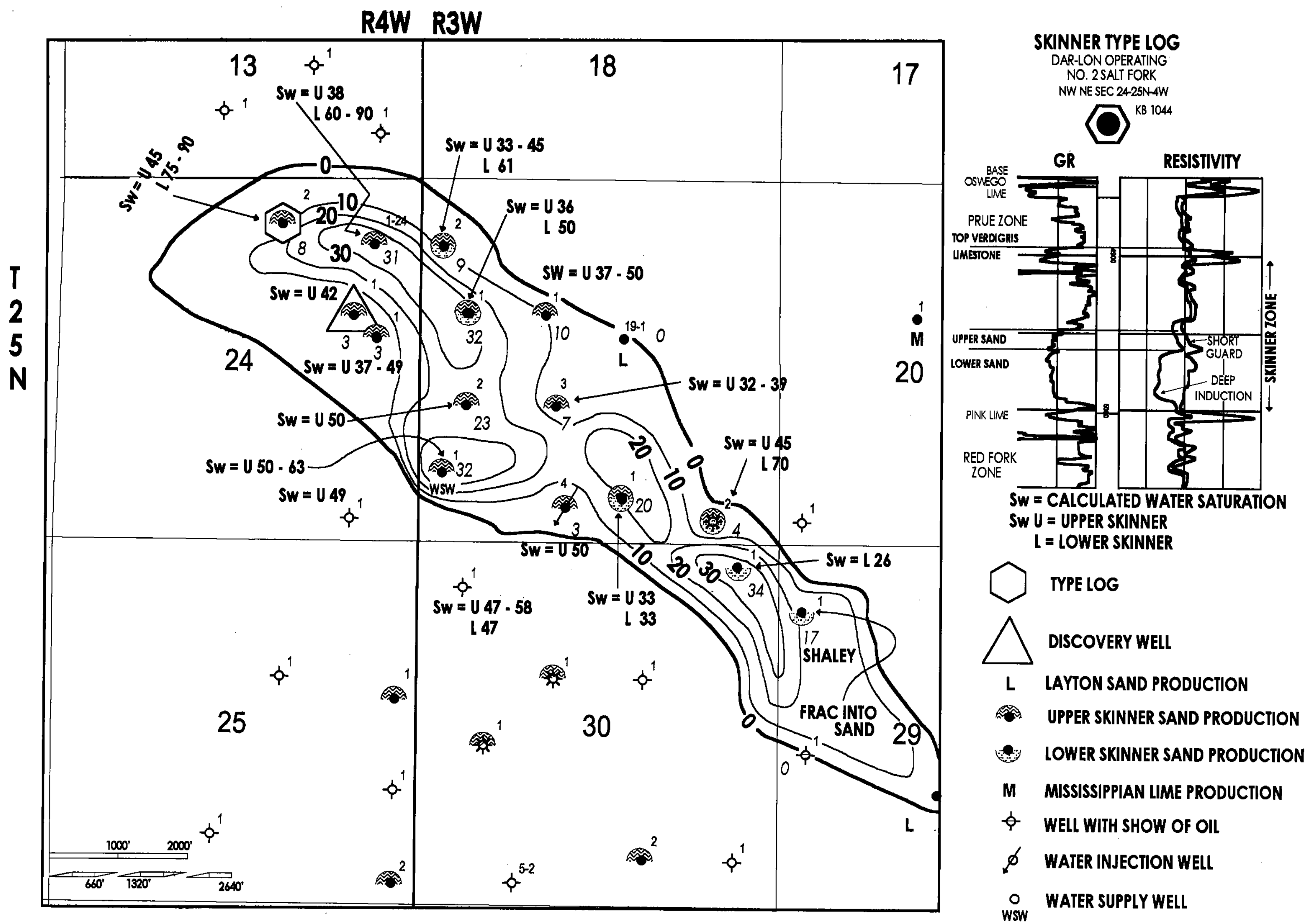


Figure 49. Cumulative oil production in thousands of barrels (MBO) from upper and lower Skinner sands combined. Representative water saturations (S_w) are also shown. S_w was calculated using the Archie equation with $R_w = 0.035$ ohm-meters, and $F = 0.81/\phi^2$. Contour interval is 10 MBO.

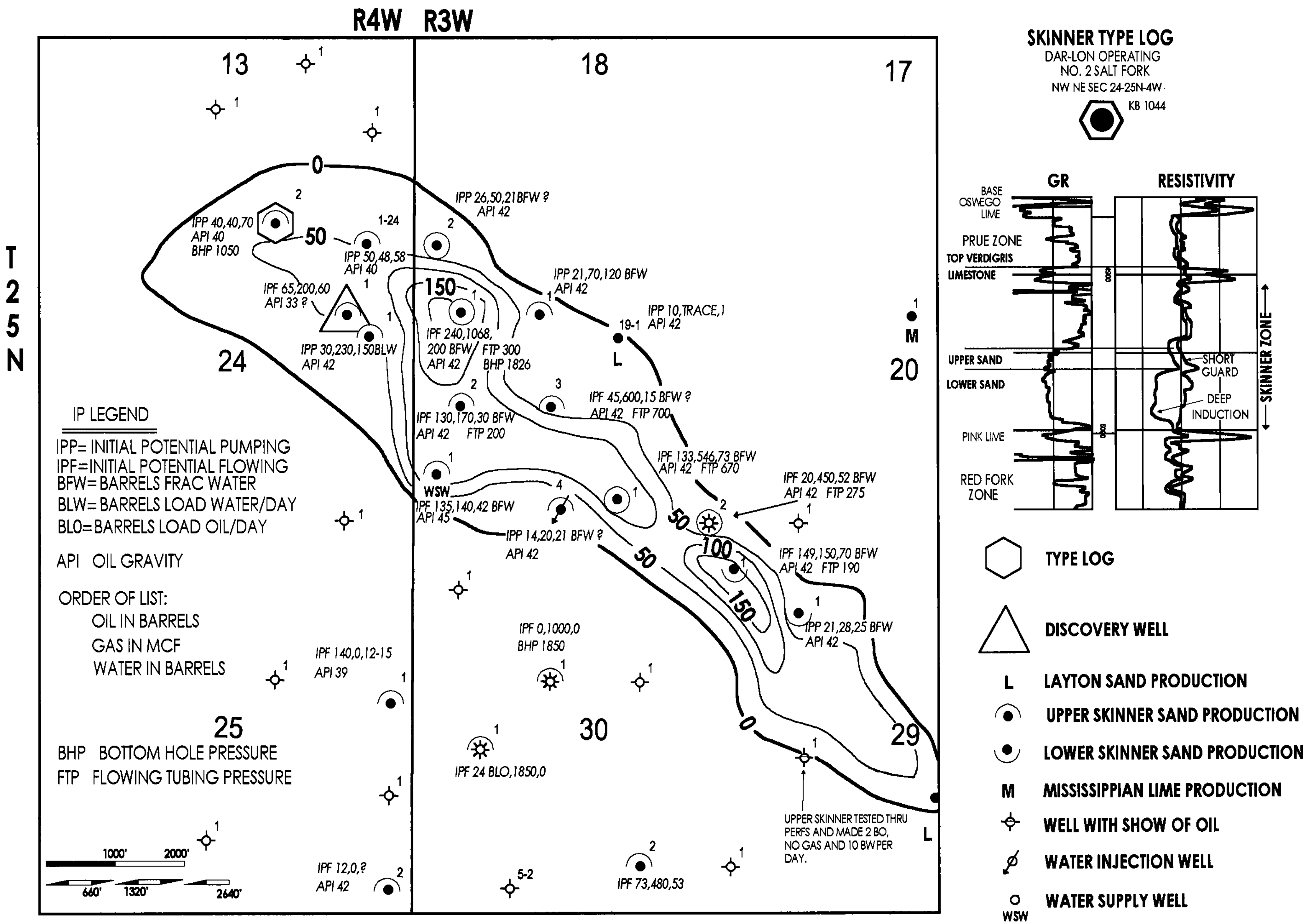


Figure 50. Initial production data (oil, gas, and water) and oil isopotential map for Salt Fork North field. Contour interval is 50 BO. Where known, oil gravity and pressures are also shown.

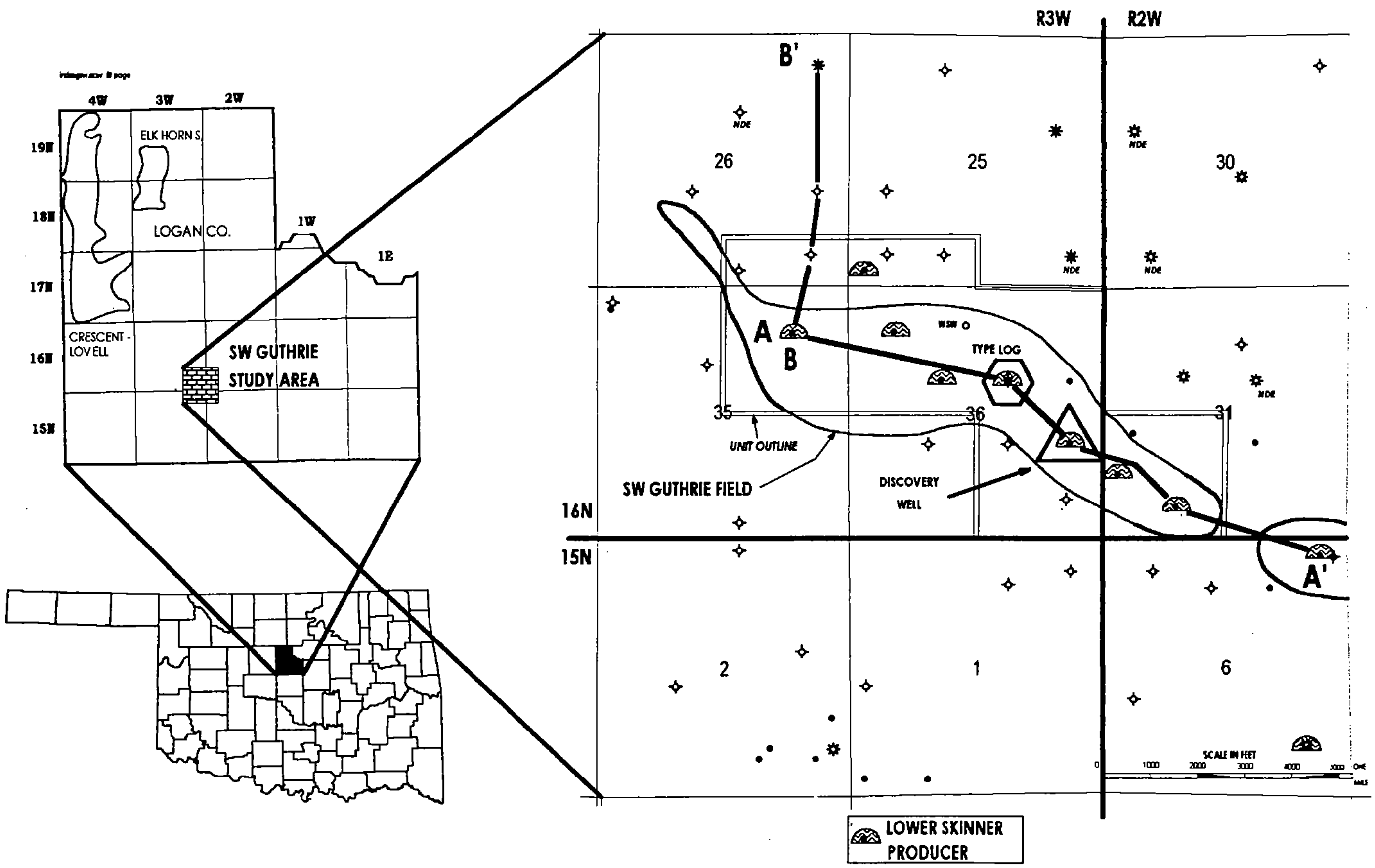


Figure 51. Generalized location map of Guthrie S.W. field study area in southern Logan County, central Oklahoma.

was completed by using relative production estimates of the operator in addition to formation evaluation of individual sands from well logs. The resulting cumulative oil production isopach map shows the estimated well production and calculated water saturations of each Skinner sand zone (Fig. 49).

Recently drilled wells were perforated through 4.5-in. production casing that was set at or very near bottom of the hole. Older wells used 5.5-in. production casing. Wells completed in the Skinner were stimulated with a large fracture treatment utilizing about 50,000–80,000 pounds of sand as a proppant and Skinner formation water as the mobilizing medium. No fresh water was used for fracturing purposes. Acid was used only for well bore cleanup because most wells did not have a good initial response following stimulation. The well was then swabbed immediately to prevent formation damage and put on-line. Initial production tests were highly variable and ranged from 14 BOPD + 20 MCFGPD (pumping) to 240 BOPD + 1068 MCFGPD (flowing) (Fig. 50). Flowing tubing pressure generally ranged from 100 to 300 psi, which indicates the relative tightness of this reservoir. Most wells initially produced frac water; overall, the amount of formation water produced was about twice the amount of oil. An oil gravity of 40°–42° API was reported from all wells except from the No. 1 Hall (NW¼SE¼NE¼ sec. 24), which reportedly produced 33° API oil.

Secondary Recovery: Salt Fork North was unitized for purposes of water flooding in December 1994. In preparation for a preliminary water flood attempt, the No. 1 Duvall (NW¼SW¼SW¼ sec. 19) was recompleted in the Layton (Cottage Grove) sand and converted to a water supply well. The No. 4 Duvall (SE¼SE¼SW¼ sec. 19) was converted to an injector probably in hopes of banking oil to the east-northeast within the upper Skinner sand reservoir. However, the No. 1 Duvall experienced water supply problems such as rapid drawdown and water storage tanks were not available to handle the amount of water needed for injection. Because of these factors, the water flood was temporarily suspended after injecting only ~800 bbl of water. No additional secondary recovery of oil was obtained. At last communication with the operator, the water flood operation was again put on-line in mid-November, injecting about 200–250 BWPD. Don Muegge, owner and operator of the field, indicated that a response had occurred in the No. 1 Mack well (W½SW¼SE¼ sec. 19), which lies only ~800 ft east of the nearest injector. An increase in water production to ~70 BWPD and decrease in gas production was noted within a period of only three or four weeks after water injection resumed. At this writing, it is too early for conclusions to be made except that water breakthrough occurred much earlier than anticipated and prior to completion of modeling of this reservoir.

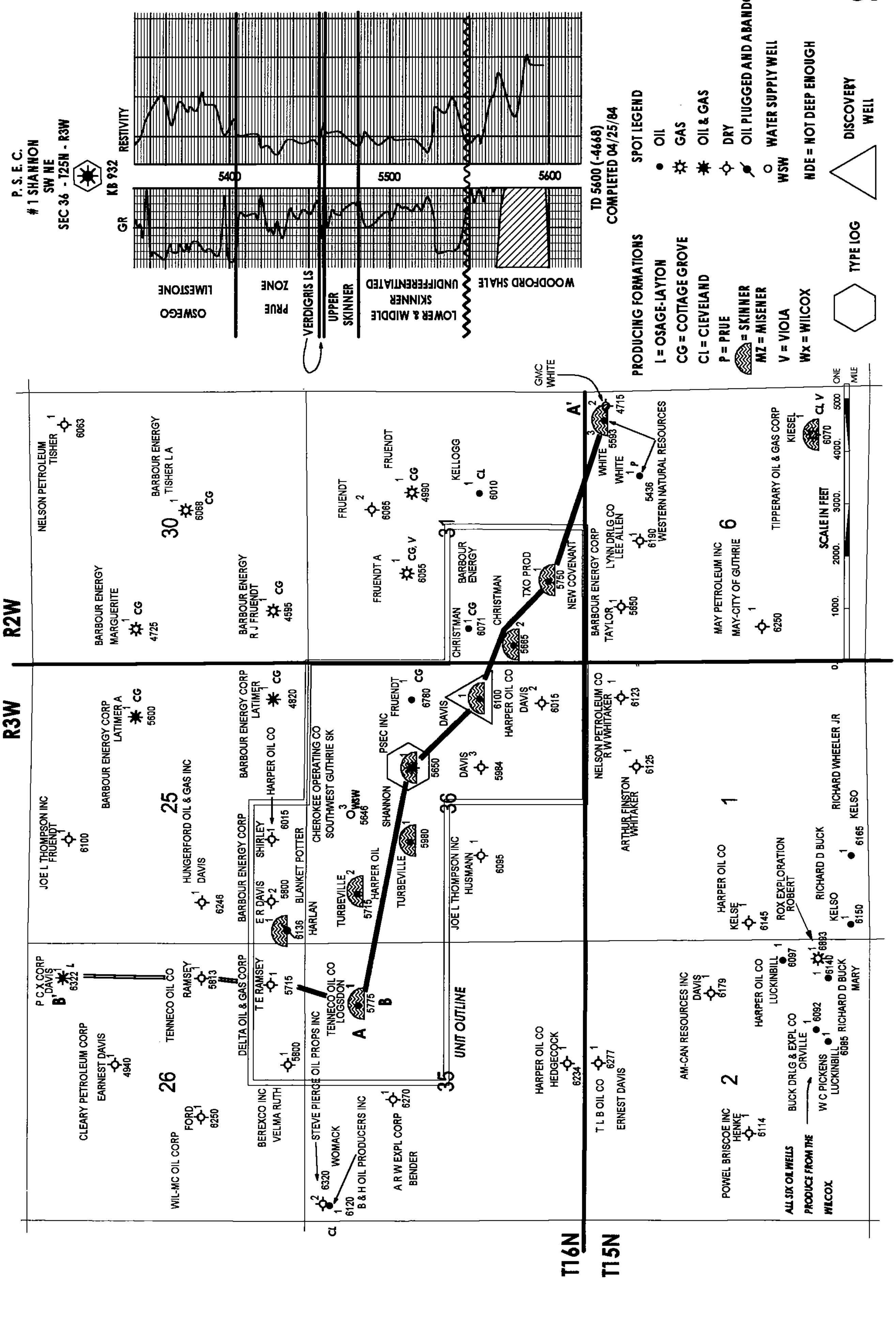


Figure 52. Well information map showing operator, lease name, well number, and producing formation for wells in the Guthrie S.W. study area.

Guthrie S.W. Field Area

(Lower Skinner oil pool in secs. 35 and 36, T. 16 N., R. 3 W., and sec. 31, T. 16 N., R. 2 W., Logan County, Oklahoma)

by Kurt Rottmann

Guthrie S.W. field is located in southern Logan County in central Oklahoma (Fig. 51). Regionally, the field is just east of the Nemaha fault zone in the region between the Cherokee platform to the east and the Anadarko basin and shelf provinces to the west (Pl. 2). Most of the production from the Guthrie S.W. study area is from the lower Skinner sandstone. In this area, the Skinner rests on the unconformity at the base of the Pennsylvanian, so it is often referred to locally as an "unconformity sand." Figure 52 shows well locations, lease names, well numbers, and producing formations for wells in the study area.

The first oil well in the study area was noncommercial. In 1963, the No. 1-25 Daisy Harlan dry hole (SW¼ SW¼SW¼ sec. 25, T. 16 N., R. 3 W.) (Fig. 52) was reentered and completed in the lower Skinner sandstone. It produced 8,065 BO from the Skinner and was abandoned. Commercial production was established with the completion on January 4, 1983, of the Harper Oil Co. No. 1 Davis well in the NE¼SE¼ sec. 36, T. 16 N., R. 3 W. (Fig. 52). The initial potential flow reported was 38 BOPD and 442 MCFGD from the lower Skinner sand. The field was fully developed within three years by the completion of seven lower Skinner oil wells. Mickey Canaday, formerly with Cherokee Operating Co., now with Mid-Continent Energy, had previously installed the West Guthrie Skinner Sand Unit (~3 mi north of the study area) and in 1990 began purchasing interests in the Guthrie S.W. field. In 1992, sufficient leases had been acquired, and the wells were unitized by Mid-Continent Energy to form the Guthrie S.W. Skinner Sand Unit. Sincere appreciation is extended to Mr. Canaday for his cooperation in providing information for the analysis of this field.

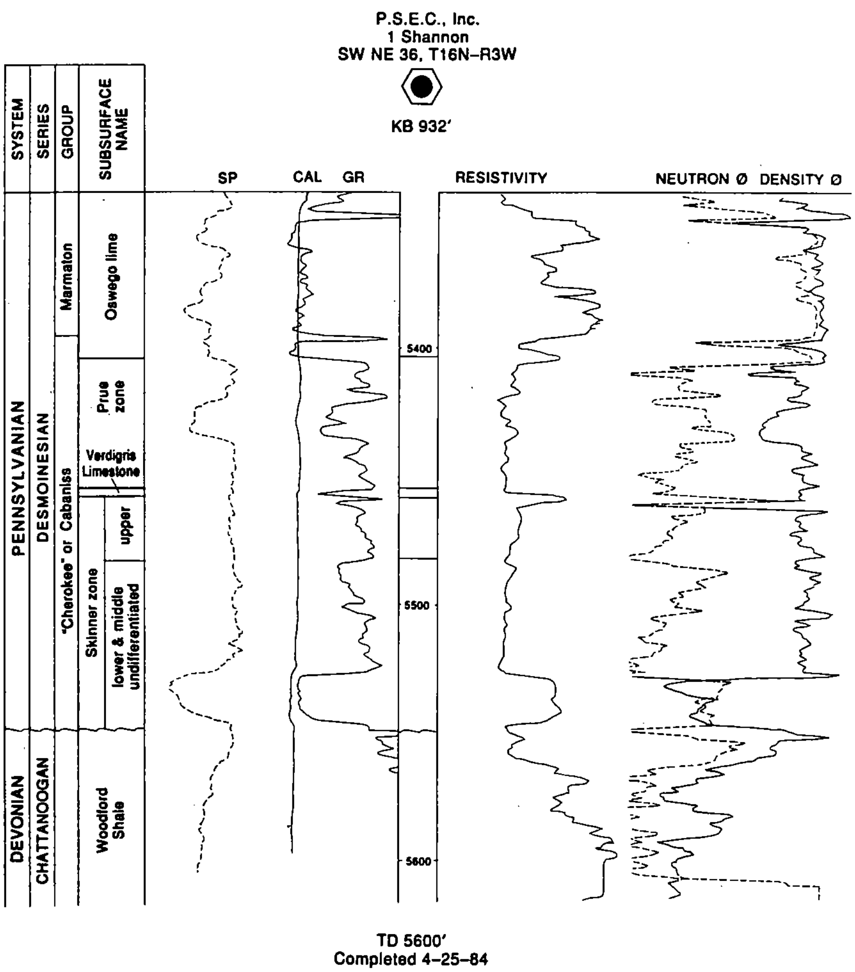


Figure 53. Guthrie S.W. field Skinner type log. The base of the Skinner zone in the study area is the unconformity at the base of the Pennsylvanian. The thin shale at about 5,480–5,482 ft separates the upper Skinner zone from the lower Skinner zone (lower–middle undifferentiated on the regional cross sections [Pl. 4]). SP = spontaneous potential, CAL = caliper, GR = gamma ray.

Stratigraphy: During Early Pennsylvanian time, the Nemaha fault zone was a north-south structural feature with position elements along much of its extent in central and northern Oklahoma. Exposure of these uplifted areas resulted in erosion of the early Pennsylvanian, Mississippian, and older sediments. This uplift separated the Anadarko basin and shelf from the basin in northeastern Oklahoma. The study area is on the east side of this uplift. "Cherokee" sediments were supplied to this area from the north; however, gradual burial by "Cherokee" sediments resulted in westward onlapping onto the uplift by progressively younger units. In the S.W. Guthrie study area, the Bartlesville and Red Fork sandstones and the Pink lime are absent, and lower Skinner sandstone and shale lie on the unconformity that truncates underlying Mississippian rocks and Woodford Shale. The Skinner is the oldest Pennsylvanian unit present within the study area.

The stratigraphic section in the study area is illustrated by the Guthrie S.W. field type log (Fig. 53) which is from the PSEC, Inc. No. 1-36 Shannon (SW¼NE¼ sec. 36, T. 16 N., R. 3 W.). The Pink limestone, which generally defines the base of the Skinner zone, is absent in the study area. So, the Skinner zone is the interval from the base of the Verdigris Limestone to the unconformity, which, in this well, is at

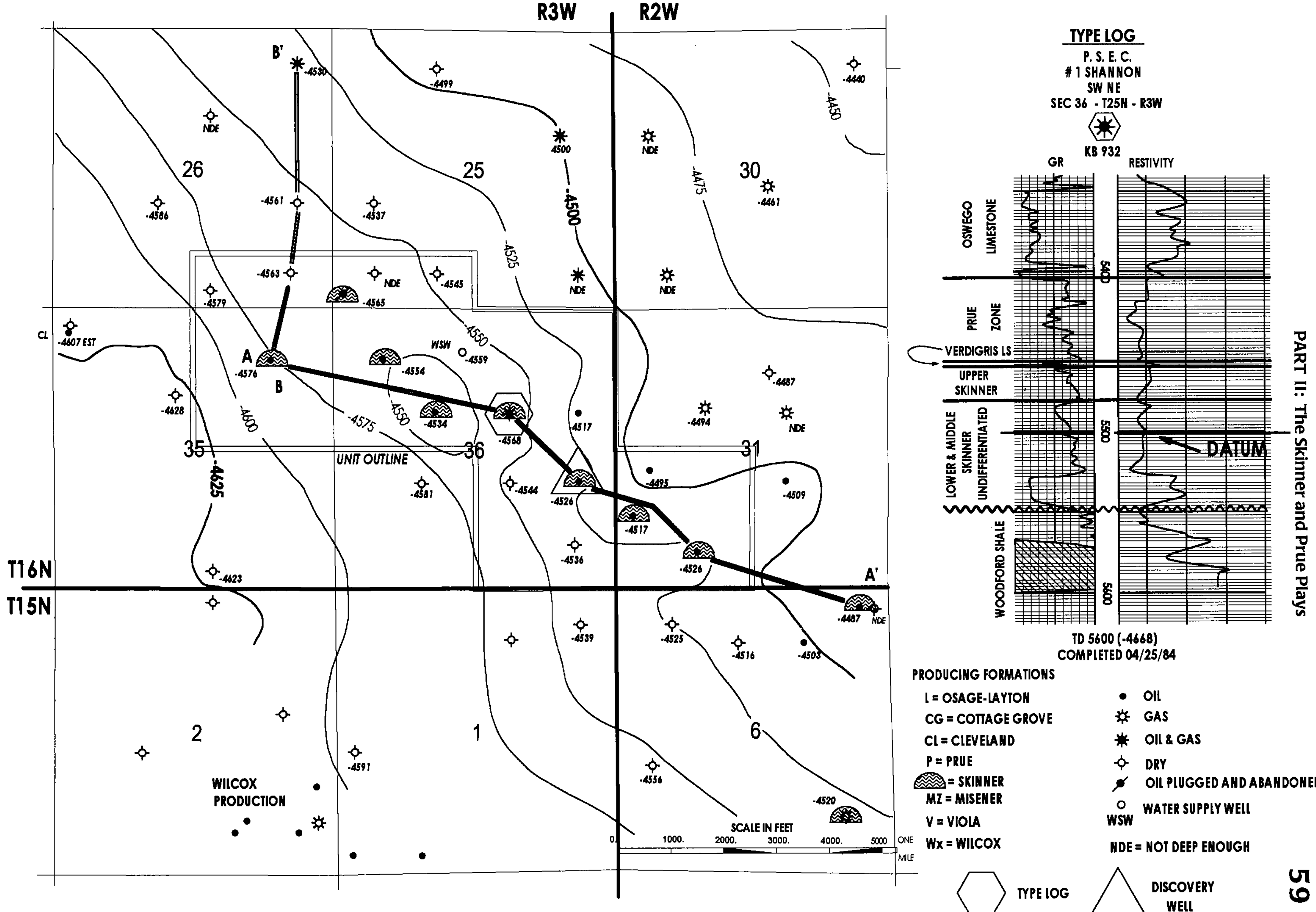


Figure 56. Structure-contour map of the Guthrie S.W. study area. Datum is the "Skinner structure marker" bed shown in Figures 54 and 55. Contour interval is 25 ft.

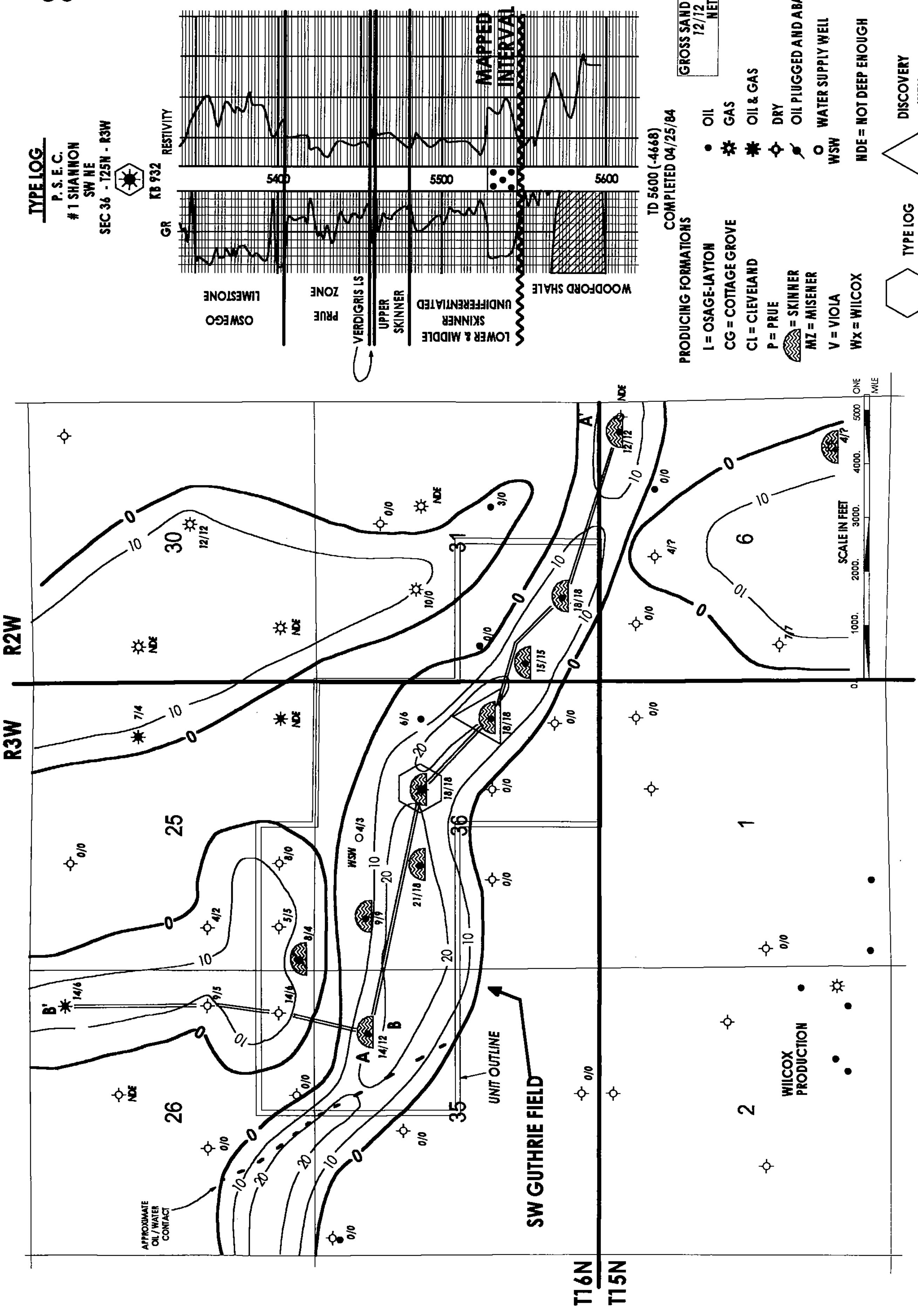


Figure 57. Isopach map of the lower Skinner gross sand in the Guthrie S.W. study area. Contour interval is 10 ft.

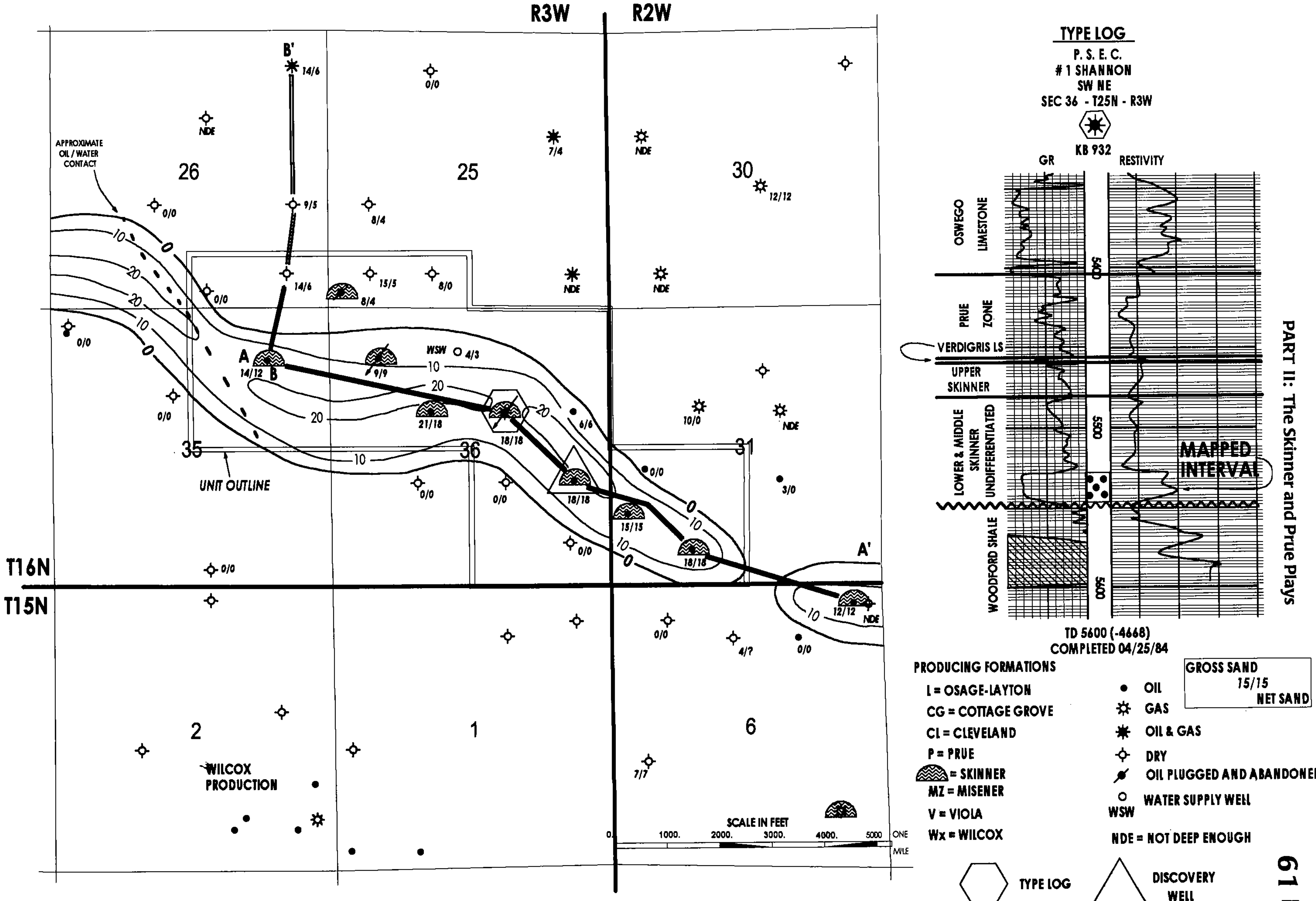


Figure 58. Isopach map of the lower Skinner net sand for the Guthrie S.W. Skinner Sand Unit. The two water injection wells are shown for the unit. Contour interval is 10 ft.

TABLE 9. – Reservoir Engineering Data for the Guthrie S.W. Skinner Sand Unit

	Lower Skinner Sand
Reservoir size	583 acres
Spacing (oil)	40 acres
Oil/water contact	~-4625 feet
Gas/oil contact	none
Porosity (average)	15%
Permeability	Not determined
Water saturation (calculated)	20%
Average Gas to Oil Ratio (GOR)	
Initial	800 SCF/BO
Final	4808 SCF/BO
Average Thickness (net sand $\phi \geq 8\%$)	6.8 feet
Reservoir temperature	128°F
Oil gravity	42°API
Initial reservoir pressure	~2367 PSI
Initial formation volume factor	1.4 RB/STB
Original Oil in Place (volumetric)	2,467,000 STBO
Cumulative primary oil production	312,761 STBO
Cumulative primary oil recovery	79 BO/acre-ft
Recovery efficiency (oil)	~12.6%
Cumulative primary gas production	~1.5 BCF

the top of the Woodford Shale (Fig. 53). On the type log, ~4 ft of Skinner shale are present between the Skinner sandstone and the Woodford Shale. On the gamma ray log, the sandstone contacts with shale above and below are sharp; the upper contact is slightly less sharp and suggests a fining upward texture.

Cross section A–A′ (Fig. 54, in envelope) is a structural-stratigraphic cross section through the Guthrie S.W. Skinner Sand Unit and is approximately parallel to regional strike. The log signature of the sandstone is very similar in all the wells in the cross section and suggests that this could be a channel facies of a fluvial depositional environment. The Skinner sand within the reservoir approaches 20 ft in thickness in the center of the channel. Also note the apparent gas effect seen on the density-neutron porosity log over the interval 5,530–5,536 in the No. 1-36 Shannon well.

Cross section B–B′ (Figure 55, in envelope) shows the stratigraphic and structural relationships between the Skinner sandstone in the field and the nonproductive wells north of the field. The sandstone log signature of the No. 1-35 Logsdon well (NE¼ sec. 35) is significantly different from those to the north in cross section B–B′. In logs of wells north of the Logsdon well, the Skinner sandstone rests directly on Mississippi lime (not on Skinner shale). In addition, the sandstone is much thinner, less porous, and toward the base of the sandstone, the gamma ray increases, suggesting that the sandstone becomes finer or shalier downward.

Regionally, the Verdigris Limestone in the study area dips very gently (<1°) to the west-southwest (Fig. 16). A structure-contour map of the study area was constructed on the top of a persistent thin, resistive bed in the upper part of the lower Skinner zone. The top of this bed is at 5,500 ft in the type log (Fig. 53) and is the "Skinner structure marker" that is correlated in cross sections A–A′ and B–B′ (Figs. 54,55). The structure map shows gentle dip to the southwest (~75 ft/mi) (Fig. 56). The southwesterly dip is slightly interrupted in the vicinity of the productive wells and a small closure is

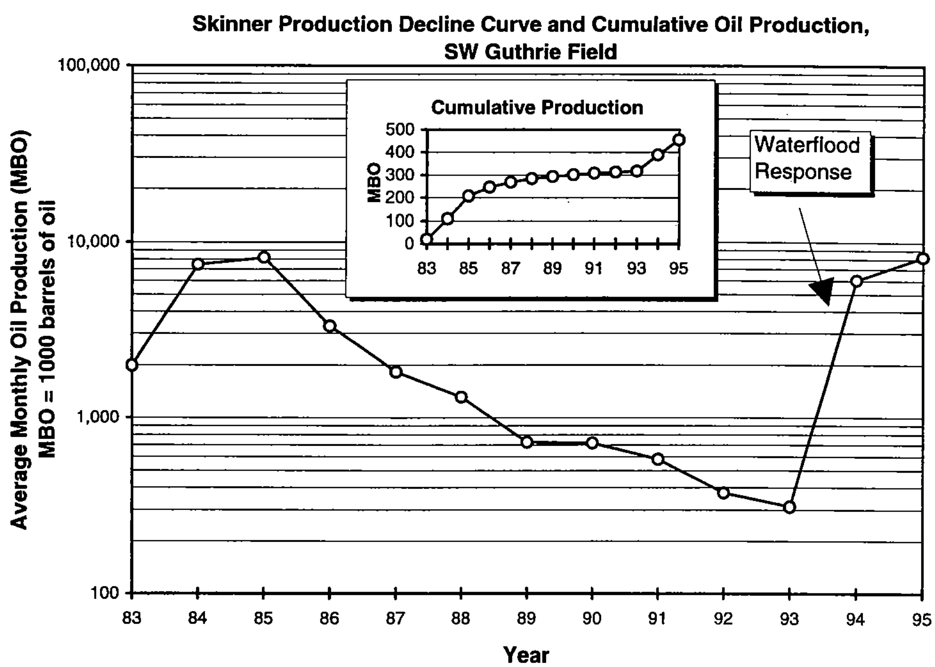


Figure 59. Guthrie S.W. Skinner Sand Unit production decline and cumulative oil production.

TABLE 10. – Oil Production Statistics for the Skinner Sand, Guthrie S.W. Skinner Sand Unit, Logan 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)
1983	1	19,781 *	1,978	66	19,781
1984	3	89,283	7,440	83	109,064
1985	6	97,842	8,154	45	206,906
1986	7	39,542	3,295	16	246,448
1987	7	21,832	1,819	9	268,280
1988	7	15,782	1,315	6	284,062
1989	7	8,677	723	3	292,739
1990	7	8,594	716	3	301,333
1991	7	6,961	580	3	308,294
1992**	5	4,467	372	2	312,761
1993	5	3,741	312	2	316,502
1994	5	72,391	6,033	40	388,893
1995	5	65,949 ***	8,244	55	454,842

* 10 months of production
** unitized Feb. 1, 1992, 2 producers were converted to water injection wells
*** 8 months of production

mapped in the SE¼NW¼ of sec. 36. This closure may be the result of differential compaction (i.e., less compaction of sand-rich intervals compared to adjacent sand-poor intervals).

Because of water production from the No. 1-35 Logsdon well in sec. 35, which is the lowest well in the unit at the west end of the field, an oil-water contact downdip from the well is inferred to be at about –4,600 ft. However, there does not appear to be an active water drive or partial water drive, which suggests that the net sandstone does not extend much farther west beyond the area mapped.

Isopach Mapping: Figure 57 is a lower Skinner gross sand isopach for the Guthrie S.W. field area. The gross sand trends west-northwest and is ~0.5 mi wide and continues beyond the area mapped. The narrow, winding geometry and the blocky log signature indicates that the sandstone was deposited in a channel of some kind.

Gross sand thickness within the unit ranges from 9 to 21 ft. Two sand lenses are present on the north side of the main sand body and one on the south. These three lenses are interpreted to be separate from main sand body. Cross section B–B′ (Fig. 55) shows the relationship between the Skinner sandstone in the field (No. 1-35 Logsdon in sec. 35) and the sandstone north of the field. Although structurally higher than the No. 1-35 Logsdon well, the water saturation in wells to the north is higher (35–50%). Water saturation in the No. 1-35 Logsdon is ~20%. The other two lenses of Skinner sand that are structurally even with or updip from the productive wells also have high water saturations. This indicates the presence of barriers to fluid flow between the Guthrie S.W. field sandstone and the three sand lenses outside the field.

The origin of the three sand lenses is not known. They may have been deposited before the Guthrie S.W. Skinner sandstone or perhaps by other processes at about the same time.

Figure 58 is an isopach of the lower Skinner net sand. The net sand is sand with log porosity ≥8%. There is very little difference in the appearance of net and gross sand maps. For six of the eight wells that produce from the Skinner, the gross and net sand thicknesses are equal (Figs. 57,58). A permeability barrier probably exists to the east of the No. 1 New Covenant well in the E½SE¼SW¼ sec. 31. This barrier is suggested by the very poor productive performance of the well compared to the production of wells with similar reservoir sandstone thicknesses.

Reservoir Characteristics: Reservoir characteristics of the Guthrie S.W. Skinner Sand Unit are given in Table 9. One well in the field was cored. The Cherokee Operating Co. No. 3 Turbeville (NE¼SE¼NE¼NW¼ sec. 36) cored the Skinner interval from 5,544 to 5,557 ft and recovered only 3 ft of Skinner sandstone; the core analysis was not available. Porosity, determined primarily from compensated neutron-density logs, generally ranges from the net sand porosity cut-off of 8–19%; the average for the unit is 15%. The water saturations for the productive wells average 20%. The initial potential GOR was about 800:1. The produced GOR is approximately 4,800:1.

Production History: Cumulative oil production through January 1992 was ~312,000 BO. Table 10 shows annual oil production, average monthly production, number of producing wells, average daily oil production per well, and cumulative oil production. Two producing wells were converted to water injection wells in February 1992, hence the decrease from seven producers in 1991 to five producers in 1992 (Table 10).

Production decline and cumulative production curves for the field are shown in Figure 59. Production in 1983 was from one well, and the 1983 average monthly production was ~2,000 BO/month. In 1984, production was from four wells, and average monthly production increased to ~7,500 BO/month. The increase in 1994 production over that in 1993 was the response to water injection. Completion techniques varied from well to well, but generally consisted of setting casing through the Skinner, cementing the casing, and

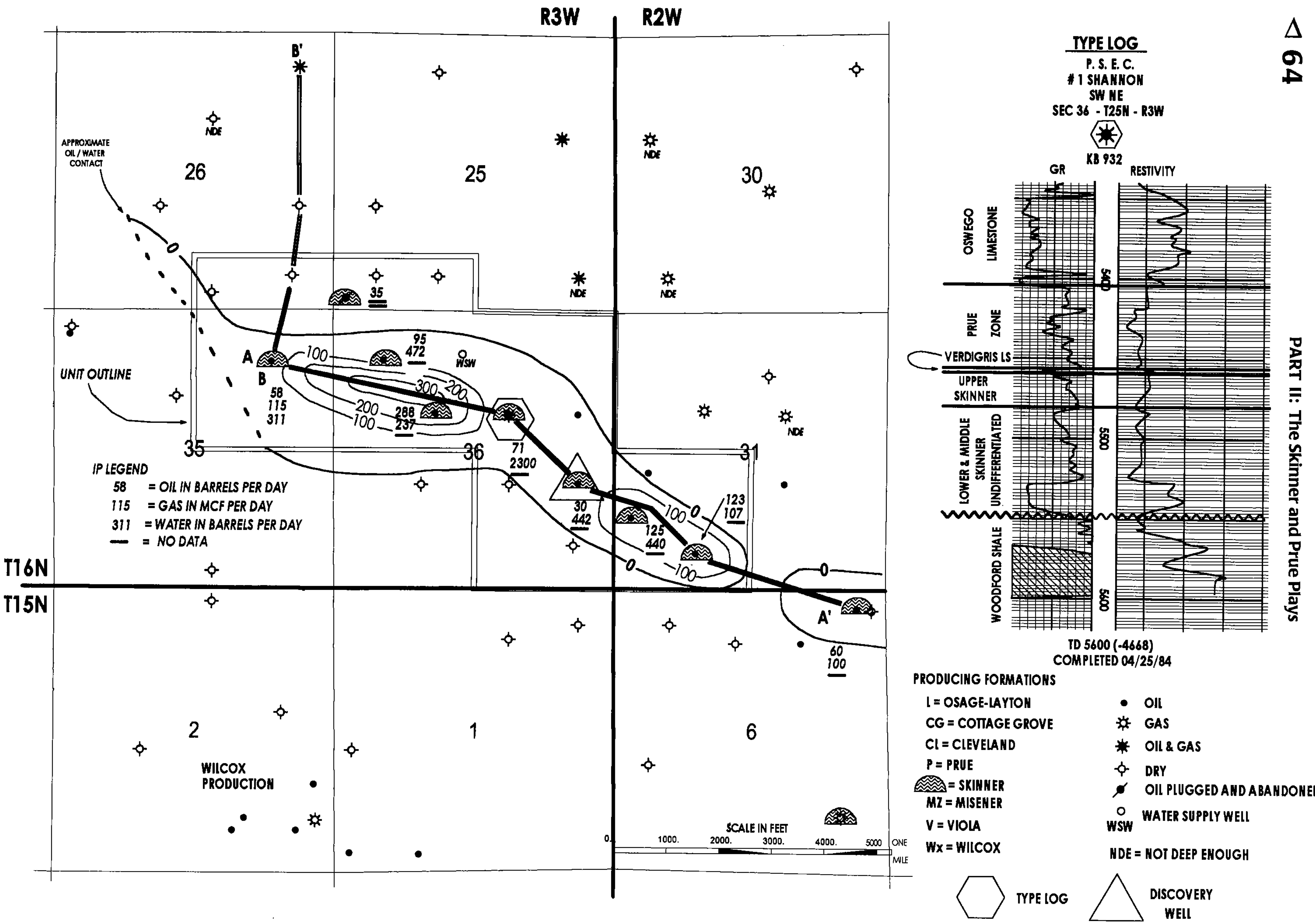


Figure 60. Initial potential production data for the Guthrie S.W. Skinner Sand Unit. Contour interval is 100 BOPD. See Figure 52 for well names.

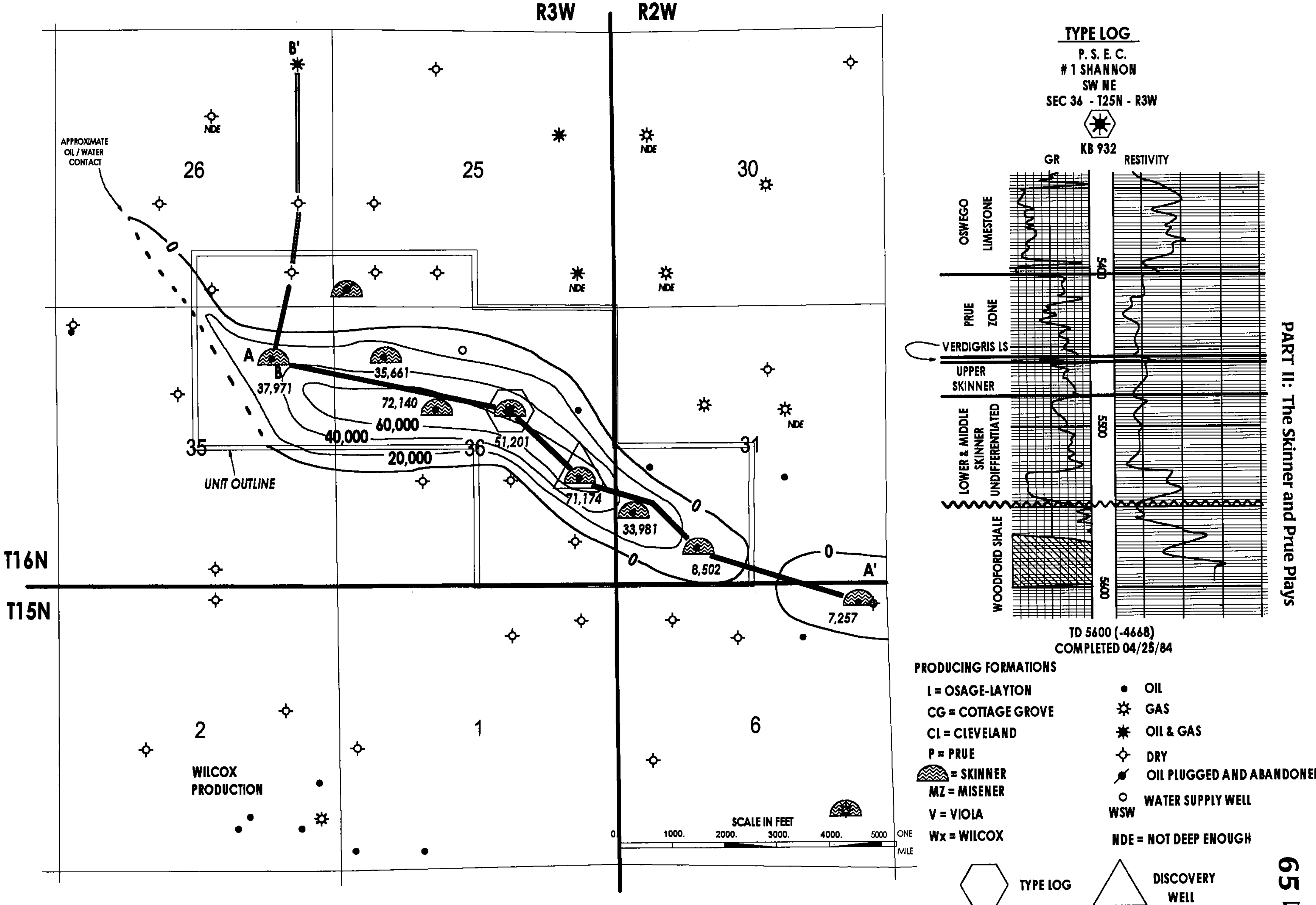


Figure 61. Map of cumulative lower Skinner oil production for wells in the Guthrie S.W. Skinner Sand Unit. Contour interval is 20,000 BO. See Figure 52 for names of wells.

perforating, acidizing, and fracture treating the sandstone.

Initial production data for wells in the unit is shown in Figure 60; initial potential oil production is contoured. The No. 1 Davis discovery well (SE¼ sec. 36) and its northeast offset, the No. 1-36 Shannon (SW¼ NE¼ sec. 36), which was drilled more than a year later, had the highest initial potential gas-to-oil ratios (GOR), 14,733:1 and 32,394:1, respectfully, in the field. The initial potential GOR was <1,000:1 in only two wells, the No. 1 Turbeville (SE¼NW¼ sec. 36) and the No. 1 New Covenant (E½SE¼SW¼ sec. 31). Cumulative lower Skinner oil production for each well prior to unitization is shown in Figure 61. The greatest amount of production was from the central part of the field.

Secondary Recovery: The Guthrie S.W. field was unitized on February 1, 1992. An alternate pattern of producer-injector wells was established by converting the No. 2 Turbeville (NE¼ sec. 36) and the No. 1-36 Shannon (NW¼ sec. 36) into water injection wells (Fig. 58). The No. 1-36 Shannon was selected as an injector to fill the small gas cap that was interpreted on the compensated neutron-density log from 5,530 to 5,536 ft (Fig. 53). The origin of this gas cap is unclear. Structurally, the No. 1-36 Shannon is one of the lowest wells in the field. Two possible scenarios could explain the presence of this gas effect. First, the gas could be in a local trap in the top of the sandstone characterized by differential relief, which caused differences in sandstone thickness. Secondly, the No. 1-36 Shannon was drilled approximately 14 months after the No. 1-36 Davis discovery well which is a diagonal offset. This gas effect could be a secondary gas cap that formed during depletion of the reservoir and the possible formation of a secondary gas cap. The average injection rate is ~500 BWPD for each injection well. Response to water-injection occurred in May 1994 with an increase in the average daily field production from 13 to 55 BOPD. The peak average monthly production rate of 444 BOPD was attained in November 1994. As of August 1995, secondary production totaled 146,548 BO, which is ~47% of primary production. By extrapolating the decline curve for the field to the economic limit, the operator is anticipating a greater than 1:1 recovery factor of secondary to primary production (Mickey Canaday, personal communication).

Conclusions: The Guthrie S.W. field area, at first glance, appears to be a straightforward example of a typical Skinner field. However, a detailed analysis of the field indicates that this reservoir is complex and has several facets that the geologist or engineer must recognize to fully exploit similar reservoirs. These facets include the following two observations:

• Recognition of an intermediate to slightly oil wet reservoir phase within the vicinity of water wet lenses of sand. The No. 1-35 Logsdon is 11 ft structurally lower than the No. 1-25 Daisy Harlan; however, the deep resistivity of the Skinner zone is ~40 ohm-meters versus 15 ohm-meters for the No. 1-25 Daisy Harlan. Using an estimated porosity value for the No. 1-25 Daisy Harlan of 14.5% and R_w of 0.035, this equates to a water saturation of 33% versus 20% for the No. 1-35 Logsdon using the same porosity and R_w.

• Most of the initial potential gas to oil ratios for the Guthrie S.W. field area were high. The discovery well, the No. 1-36 Davis and the field's first offset, the No. 1-36 Shannon, had initial potential gas to oil ratios of 14,733:1 and 32,394:1, respectively, and could be classified as gas wells. For the professional evaluating this reservoir for secondary potential, the initial GOR would be misleading and indicate that this would not be an attractive property. However the cumulative gas to oil ratio for the field was 4,800:1, which is more indicative of an oil reservoir.

THE PRUE-CALVIN PLAY

INTRODUCTION

Prue

The Upper "Cherokee" Prue sandstone was first referenced in 1921 by White and Green from its occurrence in the Prue field, T. 21 N., R. 10 E., Osage County, Oklahoma (Jordan, 1957). During the early 1900s, Prue oil production was quickly exploited in northeast Oklahoma, particularly on structural closures where it was often the shallowest productive "Cherokee" reservoir. However, many stratigraphic Prue oil pools were not recognized during this general time period because of poor formation evaluation techniques that led operators to believe that the Prue was wet, too shaly, or inconsequential as an oil producer. This situation, of course, permitted opportunities for later development of the Prue.

The Prue sandstone is confined to the Cherokee platform and shallow shelf areas of the Anadarko basin (Pl. 7, in envelope). In the northern part of this area, Prue sandstones are primarily fluvial; however, they become increasingly more marine southward. In a northeast-southwest zone that approximates the Cherokee platform/Arkoma basin hinge line, Prue sands are entirely marine or are absent. It is in this area where the Prue merges with the Calvin Formation and results in stratigraphic nomenclature changes that complicate correlations of the entire Senora Formation.

Prue reservoirs primarily produce oil and relatively small amounts of associated gas, although perhaps a quarter of the completions are classified as gas wells (Pl. 8, in envelope). Many Prue wells are completed in nonchannel facies such as small river mouth bars(?), which are discontinuous and susceptible to stratigraphic trapping. Prue channel sands also make excellent reservoirs and often have a high degree of porosity and permeability. However, channel sands that are continuous over relatively large areas are more likely to be wet. Hydrocarbon production from major channel sands is generally best where structural closure occurs.

Prue oil production is commonly commingled with production from other reservoirs, making statistical compilations of production misleading. This is illustrated in Table 1 and the accompanying production plot in Figure 14 that shows the annual Prue oil production since 1979. Overall, Prue oil production is characterized by moderate annual fluctuations and has ranged from about 0.75–2 MMBO over the past 10 years, with a moderate decline since 1987.

Since the mid-1980s, annual Prue oil production was consistently about 0.75–1.0 MMBO less than that from the Skinner.

Calvin

The Calvin Sandstone was first named in 1901 by Taff for exposures near the town of Calvin, T. 6 N., R. 10 E., Hughes County, Oklahoma (Jordan, 1957). Use of this terminology in the subsurface persists into the northern part of Seminole and Pottawatomie Counties (to about T. 11–12 N., R. 5–10 E.), where the stratigraphic relationships of the Prue and Calvin become complex. This area also coincides approximately with the Wilzetta fault zone and is characterized by rapid thinning of the Calvin interval and by lithologies consisting of marine shale (prodelta?) and detached offshore bars.

The Calvin Formation occupies a relatively small areal extent within the western margin of the Arkoma basin (Pl. 7). Production is concentrated in Seminole and northern Pontotoc Counties and consists primarily of oil and relatively small amounts of associated gas. A small percentage of wells, mostly located in northern Hughes and southern Okfuskee Counties, were completed as gas wells (Pl. 8). Sandstones in the gas producing areas in Hughes and Okfuskee Counties are predominantly of marine origin and are more tightly cemented and finer grained than many of the fluvial deposits. In a manner similar to the Prue, many sandstones in the Calvin Formation that are of fluvial origin are wet and nonproductive due to a lack of stratigraphic or structural trapping.

STRATIGRAPHY

Prue

Prue sediments are Middle Pennsylvanian in age and belong to the Upper "Cherokee" (Cabaniss) Group (Fig. 12). Sandstones in this section are usually about 10–50 ft thick and fine to very fine grained. Prue sandstones can sometimes be distinguished from older "Cherokee" sandstones by lithology. Prue sands have a tremendous amount of interbedded mica and matrix clay. The clay is also visible as small aggregates within a clastic framework consisting predominately of quartz and lesser amounts of rock fragments. The Prue zone generally extends ~100 ft beneath the overlying Oswego lime and is stratigraphically the highest productive unit in the Senora Formation of the Cherokee platform. In many places, two sandstones are present and separated by shale or a thin coal bed within the Prue interval. In other places, the Prue sandstones are stacked upon one another in an amalgamated sequence that may approach 100 ft in thickness.

The Prue is an informal subsurface name that is used primarily by the oil and gas industry for sandstones below the Ft. Scott or Oswego lime and above the Verdigris. Locally, Prue sands are also referred to as the Squirrel, Perryman, and other names as shown in Figure 12. Formal surface nomenclature for the Prue is the Lagonda Sandstone, but few geologists would even recognize this terminology on a scout card. In many places, however, the Verdigris Limestone is absent, in which case the boundary between the Prue and underlying Skinner zone is a thin "hot" shale that underlies the Verdigris Limestone.

Regional stratigraphy of the Prue interval is best shown on the regional stratigraphic cross sections accompanying this report. Cross section A–A′ (Pl. 4) is oriented in an east-west direction across major producing areas of both the Prue and Skinner. This line of section best shows the stratigraphic and lateral characteristics of the Prue interval across the Nemaha fault zone both to the west and east. Although structural adjustments of the Nemaha fault zone primarily affected the lower and middle "Cherokee" section, the Prue interval was also affected, but to a much smaller degree. Evidence of this is seen in the interval thinning that occurs above the Nemaha fault zone and by the relatively thin nature of sands that persist to the west. As seen on the regional Prue sand trend map (Pl. 7), most of the Prue FDD system lies east of the Nemaha fault zone. The only major fluvial-deltaic deposits west of the Nemaha fault zone are in southern Oklahoma and Canadian Counties.

Regional cross section B–B′ (Pl. 4) is a north-south line situated mostly west of the Nemaha fault zone. It is positioned to intersect major producing areas of both the Prue and Skinner and shows the character of sandstones along the distal edge of the Prue FDD system. In the northern part of this cross section, the Prue zone is very thin and composed entirely of marine shale. The Prue thickens basinward to the south and contains several channel deposits at various stratigraphic horizons. In the far southern part of this cross section, the Prue zone apparently develops into a fluvial-deltaic sequence such as shown in the Ratliff No. 34-2 well in SW¼NW¼ sec. 34, T. 11 N., R. 4 W. In northern Cleveland County, this same zone appears to be dominantly shale that is interpreted to be marine prodelta deposits.

Regional cross section C–C′ (Pl. 4) is a north-south tie line illustrating stratigraphic changes that occur within the Prue-Calvin interval between the Cherokee platform and Arkoma basin. Log profiles that are typical of fluvial-deltaic sequences within the Calvin Formation are also shown. The thicker section of sediments that characterizes the Calvin Formation is primarily due to a steeper basinward slope along the depositional edge of the prograding Calvin delta.

Calvin

In the Arkoma basin, the Calvin Formation is stratigraphically equivalent to the Prue interval as illustrated in the nomenclature cross section of Figure 15. In the subsurface, the Calvin Formation typically is ~250 ft thick and is stratigraphically bounded by younger shale of the Wewoka Formation and underlain by shale belonging to the upper Senora Formation. Stratigraphic thickening of the Calvin interval and the entire Desmoinesian Series in the Arkoma basin occurred because of foreland basin subsidence and mountain front faulting in the adjacent Ouachita uplift. The Calvin, therefore, appears to be sourced from the Ouachita uplift to the southeast.

The Calvin Formation is informally subdivided into an upper and lower zone, as determined by the relative stratigraphic position of sandstone and shale interbeds. Each zone has several discrete sandstone horizons about 10–50 ft thick. Amalgamated sandstone sequences in the shallow subsurface or at outcrop are often 200–350 ft thick (Weaver, 1952), making the distinction between upper and lower Calvin difficult. Sandstones are fine- to coarse-grained and massive to thinly bedded. They commonly have contorted bedding, fluvial scour, chert fragments, and appear brownish-orange when weathered (Weaver, 1952). According to Jordan (1957), the lower Calvin interval was historically called the Wanette sand. The northernmost area of Calvin deposition is characterized by sand bodies having a coarsening upward (marine?) textural profile as interpreted from gamma-ray logs. Farther to the south, Calvin sands occur in stratigraphic sequences consisting of coarsening upward lithologies (delta front?) overlain by fining upward sand bodies (channels?). This vertical and lateral relationship of inferred depositional environments is indicative of a prograding deltaic complex. Still farther to the south and southeast, many sandstones at outcrop belonging to the Calvin Formation appear to have sedimentary structures and log patterns primarily of channel deposits such as point bars. This may indicate a subaerial coastal plain (flood plain) or upper delta plain depositional environment.

Stratigraphy of the Calvin Formation is best illustrated in the southern half of regional cross section C–C′ (Pl. 4). In this line of section, the Calvin Formation is informally divided into an upper and lower unit because of the presence of two unique assemblages of interbedded sandstone and shale. Both zones have stratigraphic sequences that are indicative of deltaic progradation (i.e., marine [or delta front] sands overlain by fluvial channel deposits). This sequence persists northward ~40 mi from the outcrop where sandstone facies become entirely marine, as shown in the Wil-Mc No. 2 Blumenthal well in S½ NW¼SW¼ sec. 5, T. 11 N., R. 7 E.

DEPOSITIONAL MODEL

Prue

Sandstones in the Prue interval originated from a major fluvial system that advanced across much of the Cherokee platform in a southwest direction (Fig. 62). Based on prevailing depositional patterns and the fine-grained nature of clastic material, the predominant clastic source area was probably cratonic areas far to the northeast. Sediment transport occurred in a mixed load depositional system and included large amounts of suspended clay, silt, and very fine grained sand. Bed load material was mostly fine grained sand consisting chiefly of quartz with lesser amounts of very small rock fragments. Large amounts of organic material such as leaves and wood fragments are also included within the sandstones of both fluvial and marginal marine origin.

Areal distribution patterns of Prue sandstones appear to be controlled mostly by the attitude of the Cherokee platform and the Nemaha fault zone (Nemaha uplift). As shown in Figure 63, the regional iso-

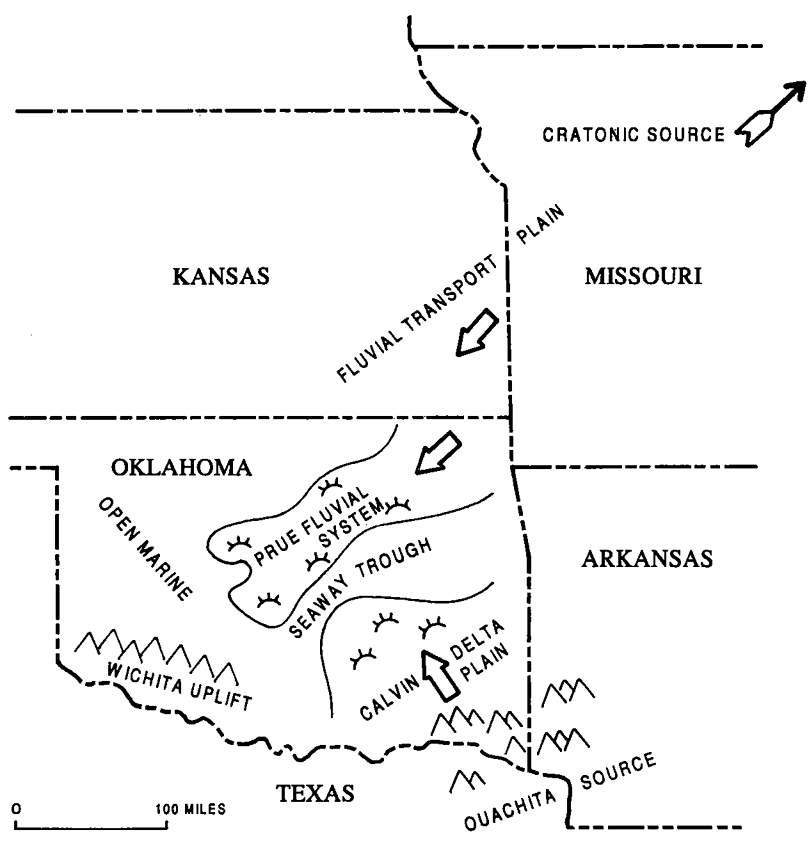


Figure 62. Paleogeography of the central Midcontinent region during deposition of Prue and Calvin sandstones (modified from Krumme, 1981).

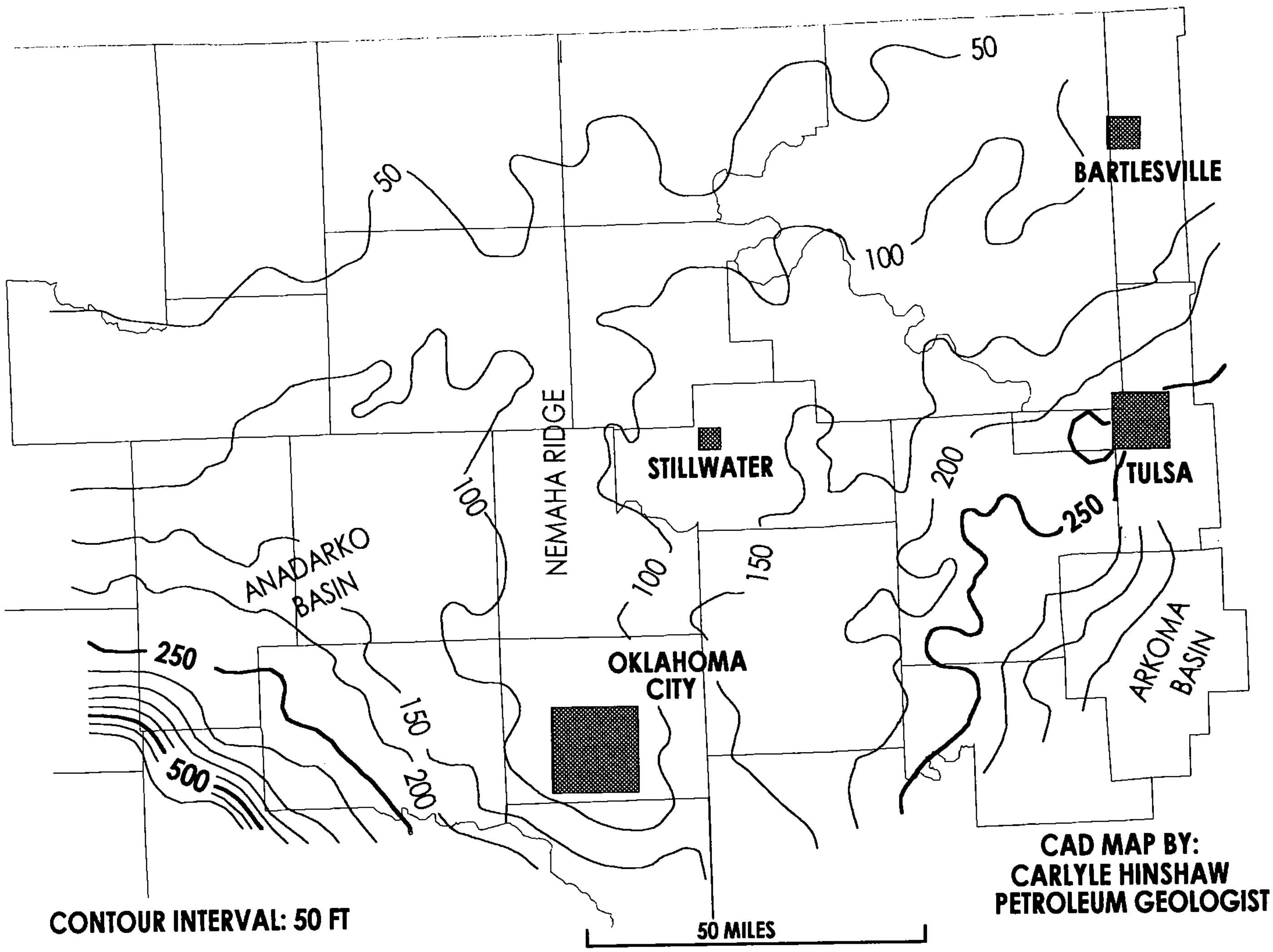


Figure 63. Regional isopach map of the interval from the top of the Verdigris Limestone to the top of the Pink lime, Oklahoma. This interval includes the Skinner + Verdigris Limestone. Contour interval is 50 ft.

pach map of the combined Skinner and Verdigris interval shows very little thickness variation throughout the Cherokee platform province. This indicates the presence of a relatively low depositional gradient as compared to the Arkoma basin, which thickens considerably to the southeast. Although fluvial deposition extends west of the Nemaha fault zone, thinning does occur within the Prue interval as shown in cross section A–A′ (Pl. 4). This indicates that Prue deposition was significantly attenuated west of the Nemaha fault zone, since portions of this fault zone in northern Oklahoma remained structurally high during much of Prue deposition. Because of this, fluvial systems in the upper and lower Prue zones were redirected farther to the south where structural uplift along the central Oklahoma fault zone was not appreciable during Prue time. This contributed to the development of the west-trending Prue-Skinner channel complex in the Airport trend, located in southern townships of Oklahoma and Canadian Counties (about T. 10–11 N., R. 3–7 W.). The present structure of upper "Cherokee" in central Oklahoma is shown in Figure 16, which is contoured on top of the Verdigris Limestone. From this map, structural adjustments of the Nemaha fault zone are primarily recognized north of Stillwater.

Many geologists consider Prue sands to be part of a prograding depositional system typical of a constructive, lobate delta. However, morphologic and stratigraphic relationships of Prue sand bodies are indicative primarily of a subaerial coastal plain environment with distal segments consisting of small deltaic sequences and marine delta-front or interdistributary facies. As interpreted in this study, the deposition of Prue sands was brought about primarily by downward fluctuations of eustatic sea level in a manner similar to the deposition model shown in Figure 17. Most channel deposits are incised directly into shale and form the thickest Prue sandstones within the Cherokee platform area. However, in terms of areal distribution, nonchannel sandstone deposits are more common. These types of sandstones have coarsening upward textures and are prevalent in the vicinity of channel deposits within the same general stratigraphic horizon. Many of the nonfluvial sands may simply be previously deposited fluvial sands that were redistributed very near or at the shoreface. Progradational sequences consisting of channel sands over delta front sediments (Fig. 7) are not everywhere common.

Throughout the Cherokee platform, basinward dip along the leading edge of the Prue fluvial system was simply too small to permit the buildup of a thick, prograding deltaic sequence. However, the Prue play in northeastern Oklahoma extends to the southwest for >150 mi, primarily from only a few major channel systems. Assuming a relatively heavy sediment load entrained within major channels, it seems unlikely that a deltaic distributary channel could prevail so far without repeated abandonment and bifurcation. Therefore, the concept of a regressive subaerial fluvial system merging with very near-shore marine conditions is a plausible environmental interpretation. Near-shore dispersal of fluvial sediment may have led to the formation of offshore bars and small, marginal marine river-mouth or distributary mouth bars. These types of sand bodies generally have a coarsening upward texture rather than a blocky or fining upward textural profile that characterizes fluvial deposits. The nonchannel facies, however, contain large amounts of terrestrial material such as carbonaceous material and mica and have sedimentary structures indicative of distributary mouth bar facies. The abundance of these features indicates a fluvial relationship and proximity of terrestrial environments.

Calvin

The depositional origin of the Calvin Formation is more closely related to fluvial-deltaic environments than that of the Prue. Fluvial systems originating in the Ouachita uplift area (Fig. 62) carried sediments to the northwest into what is now the Arkoma basin. Basinward dip along the leading edge of this deposition system was probably much greater and resulted in a clastic assemblage two to three times thicker than the Prue interval. Depositional phases that characterize a prograding deltaic sequence are found in both the upper and lower Calvin intervals. As shown in cross section C–C′, (Pl. 4), these consist of sandstones having coarsening upward textural profiles (delta front?) overlain by sandstones having sharp basal contacts and fining upward textural profiles (channel deposits). Basinward, sandstones in both Calvin intervals have log characteristics over a large area that are suggestive of shallow marine bars. These are interpreted by the consistent coarsening upward textural profile of sand bodies that are stratigraphically bounded above and below by marine shale. The trend of these marine sand bodies is northeast-southwest, as opposed to the orientation of channel deposits that is northwest-southeast.

FDD IN THE PRUE AND CALVIN

The regional distribution of sandstone and interpretation of depositional facies is shown on Plate 7. Two prominent fluvial depositional systems are mapped and include the Prue trend in the northern half of the map and the Calvin trend located in the southeastern part of the map. These two systems are generally separated by a marine seaway or trough where deposition consisted largely of shale or detached offshore bars. Areas identified as sandstone within each trend contain primarily fluvial and marginal marine deposits including delta-front sediments. As used throughout this paper, marginal marine implies nonfluvial deposition in a delta plain, or very near-shore depositional environment such as a distributary mouth bar. Reference to marine sand bodies or offshore bars in this paper refers to detached sand bars originating in a shallow marine shelf environment.

Oil and gas producing areas attributable to either the Prue or Calvin FDD trends are illustrated on the field map (Pl. 9, in envelope). Any field that has produced at least 5,000 bbl of oil or at least 3 BCF of gas since 1979 from the Prue and/or Calvin is included on this plate. Field names and boundaries are consistent with field designations by the Oklahoma Nomenclature Committee of the Mid-Continent Oil and Gas Association. In some cases, Prue-Calvin production is from only part of the field; in other cases, Prue-Calvin production is from wells outside of the formal field boundaries. This occurs because the effort to formally extend field boundaries lags behind the extension of producing areas.

Long Branch Field

(Prue oil pool in secs. 10 and 11, T. 18 N., R. 4 E., Payne County, Oklahoma)

by Richard D. Andrews

Long Branch field is located in southern Payne County in north-central Oklahoma (Fig. 64). The field is in the western part of the Cherokee platform province and is ~45 mi east of the Nemaha fault zone (Pl. 7). Several different reservoirs are productive within Long Branch field and surrounding areas; however, only the Prue oil pool is studied in this report. A map identifying well locations, operators, lease names, well numbers, and producing formations in the study area is shown in Figure 65.

Oil production was first established in the Long Branch field in 1926 with the completion of the Deep Rock No. 1 Cole Misener well, NW¼SE¼NE¼ sec. 10, T. 18 N., R. 4 E. This well only produced a few thousand barrels of oil from the Misener sand before being abandoned. In 1949, other wells drilled nearby were completed in the Peru (or Wayside) sand and in the Mississippian with little apparent commercial oil potential. All of these wells penetrated oil-saturated Prue sandstones, but log calculations indicated that it was wet. The actual opener for the Prue pool was the Advent Oil and Operating Co. No. A-1 Barker in the NE¼NW¼ sec. 11, T. 18 N., R. 4 E. This well was a dual Prue-Peru

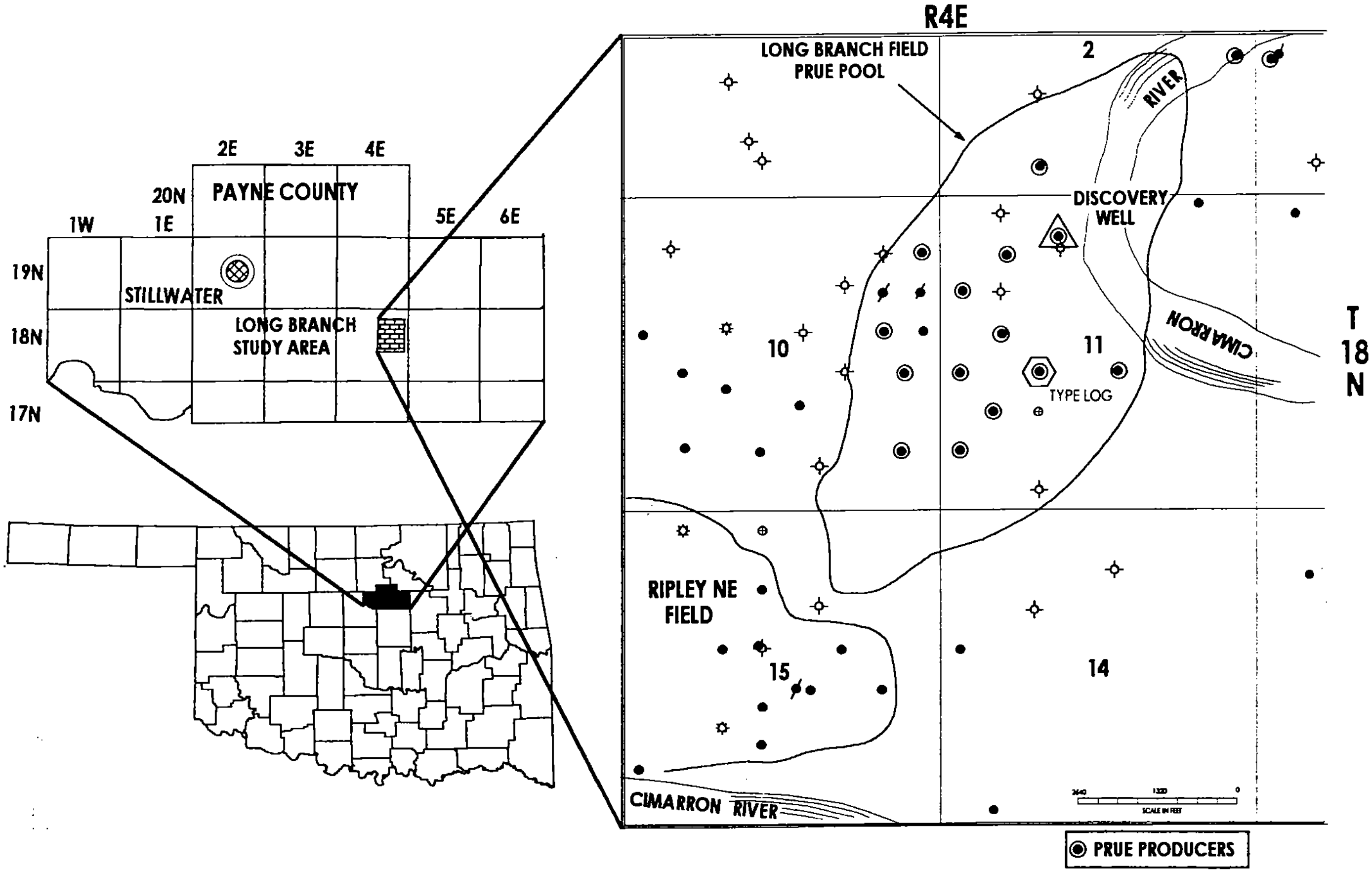


Figure 64. Location map showing the location of the Long Branch field Prue oil pool, Payne County, Oklahoma.

completion that reported an initial potential pumping of 15 BOPD, 45 MCFGPD, and 250 BW. As with all wells in this field, initial oil production rates are not representative, since they were taken very shortly after an aggressive fracture treatment. Primarily because the Cimarron River is immediately east of the Prue discovery well, development drilling progressed to the southwest (Fig. 65). In the Long Branch study area to date, 14 wells have been completed in the Prue pool, and, to the west, additional reservoirs have been discovered in upper Skinner, Red Fork, and Bartlesville sandstones (Fig. 65). Development drilling is ongoing, and the operator will probably develop the field on 40- or 20-acre spacing which would facilitate water-flooding.

Stratigraphy: The stratigraphic section in the study area is illustrated by the Long Branch field type log (Fig. 66). The Prue zone is the interval from the base of the Oswego limestone to the top of the Verdigris Limestone. In the study area the Verdigris is very thin and absent in some wells, so the black shale and coal beneath the Verdigris Limestone (the Henryetta Coal) defines the base of the Prue zone. In the type log, this is shown as the Verdigris/Henryetta horizon.

The type log (Fig. 66) shows that the Prue zone is separated into upper and lower zones by a thin coal or shaly coal marker bed. The upper Prue zone in the type log and throughout the study area is shaly. The sandstone in the lower Prue zone is relatively continuous throughout the Long Branch field, except along the channel margins where the sandstone becomes discontinuous abruptly.

Stratigraphically, the lower Prue sandstone lies just above the Verdigris limestone. Where the sandstone is very thick, the Verdigris is usually absent, although deep scouring into the underlying Skinner interval does not occur.

Stratigraphy of the Prue interval in the study area is shown in the detailed structural-stratigraphic cross sections of the field. North-south cross section A–A′ (Fig. 67, in envelope) is oriented diagonally across the channel, and, most importantly, shows the log-characteristics and lateral relationships of channel and nonchannel facies. At the the north end of the cross section, the lower Prue zone in the No. 1 Wilson (SW¼ NE¼SW¼ sec. 2) contains no sandstone. This log is characteristic of the "nonchannel facies" in the study area. Note the log signature from 3,224 to 3,226 ft, a gamma-ray "kick" to the left and a small resistivity "kick" to the right. This log signature is always present where channel facies are absent. The same abrupt change from channel to nonchannel facies is seen between the last two logs at the southern end of cross section A–A′. In this area, channel facies are composed

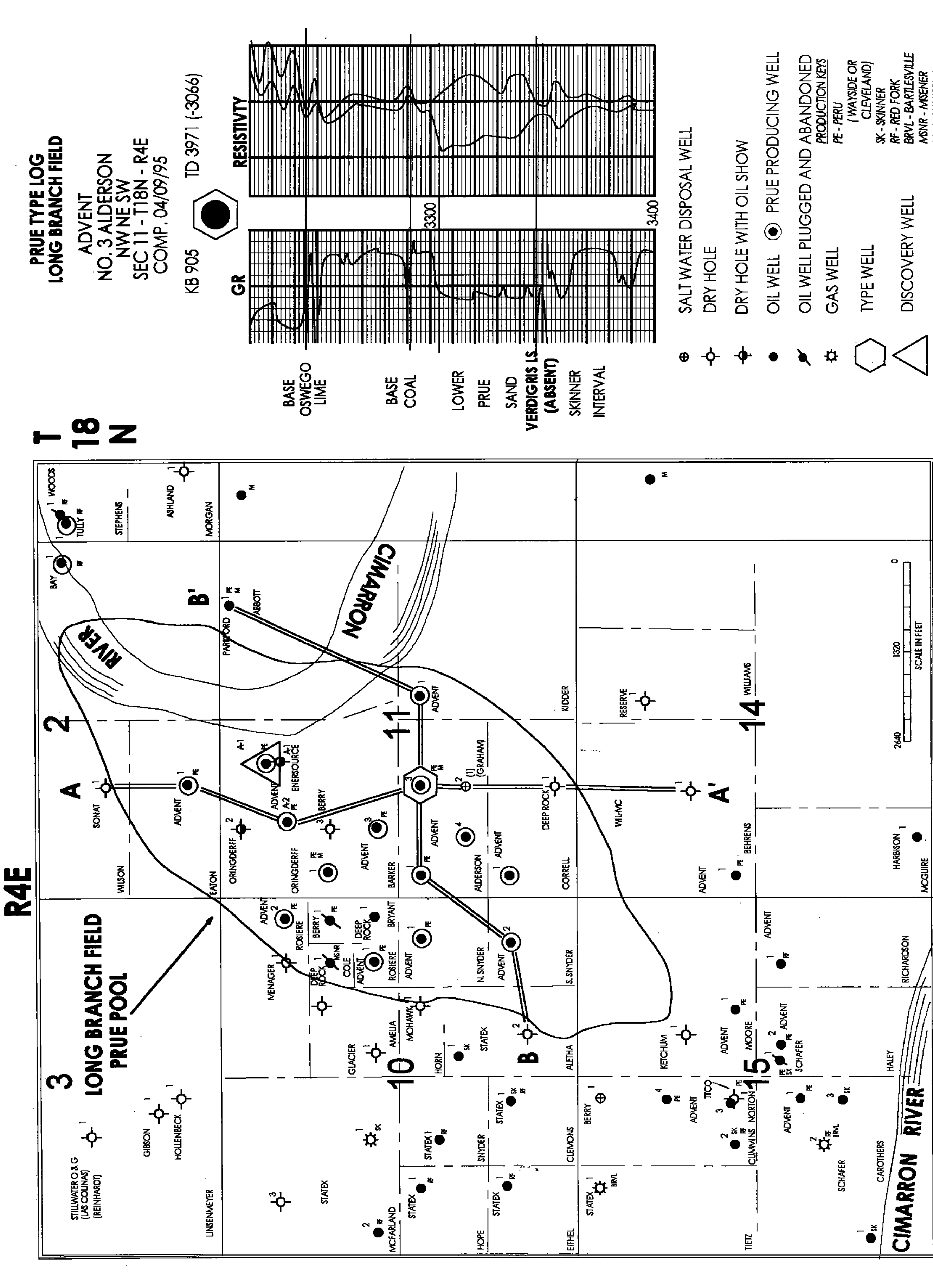


Figure 65. Well information map showing lease name, well number, operator, and producing formation for wells in the Long Branch field study area. SP = spontaneous potential, CAL = caliper, GR = gamma ray.

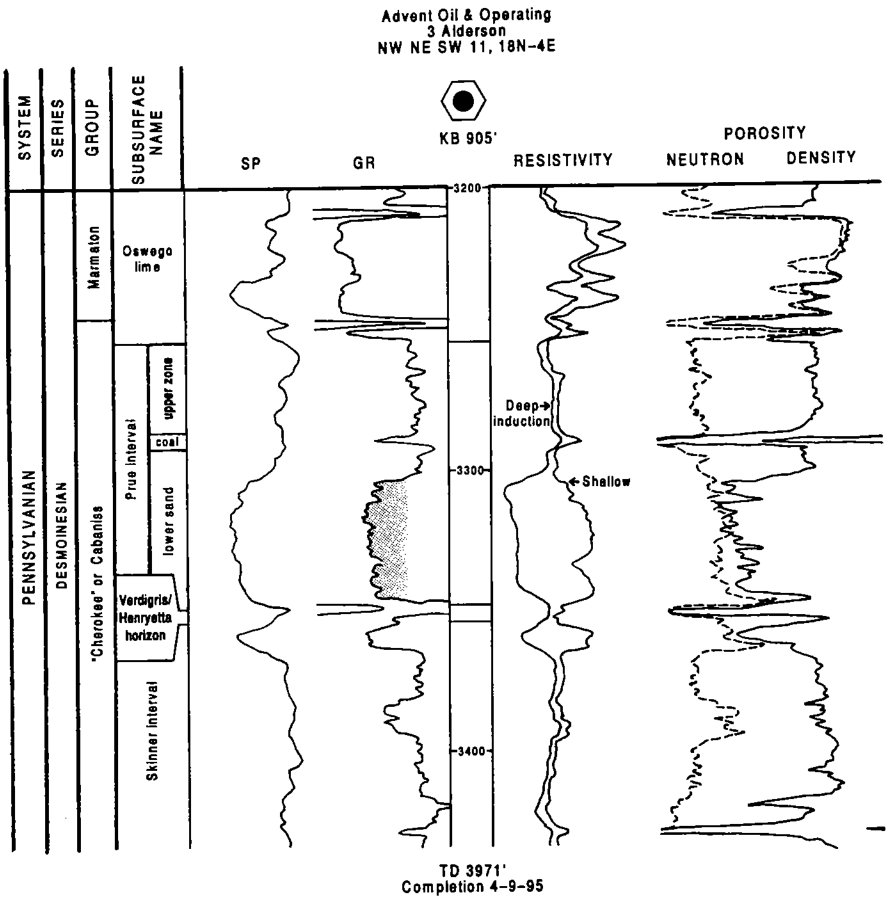


Figure 66. Long Branch field Prue type log showing log patterns of spontaneous potential (SP), gamma ray (GR), resistivity, neutron porosity, and density porosity.

mostly of abandoned channel-fill material which includes thin layers of sandstone and interbedded shale. Whether or not sandstone is present, the channel facies can be distinguished from nonchannel facies by virtue of their characteristic log signatures.

Other important features that are shown in cross section A–A′ include the blocky to multi-layer stacking arrangement of sandstones and the presence of interbedded shaly zones as interpreted from gamma-ray logs. Also evident is the sharp basal contact of the channel sandstone with the underlying "hot" shale of the Verdigris horizon. The Verdigris is present in the two wells that do not have Prue channel facies. Generally, where the Prue sandstone is very thick, the Verdigris Limestone is absent. Also shown is the coal marker that separates the upper shaly Prue zone from the lower sandy zone.

Cross section B–B′ (Fig. 68, in envelope) is oriented in a southwest-northeast direction approximately along the long axis of the field. Along the western margin of the field, the same abrupt change from channel to nonchannel facies is identified from characteristic log signatures. Northward, the sandstone thickens to >40 ft then thins to ~4 ft thick in the end well (No. 1 Abbot, NW¼NE¼NE¼ sec. 11). At this location, the lower Prue is interpreted to be shaly channel fill because the log signature and marker that are considered to be diagnostic of nonchannel facies is absent.

Structure: Local mapping in the Long Branch field area indicates a gentle basinward dip to the west-southwest at ~100 ft/mi (~1°). This trend is modified by a small but pronounced nose in secs. 10 and 11, T. 18 N., R. 4 E. that also plunges to the southwest (Fig. 69). Contoured on the base of the coal marker bed at the top of the lower Prue zone, the structure map probably reflects the effects of differential compaction (i.e., drape folding over the thick Prue channel sands). With a smaller contour interval, a small closure might be interpreted in the SW¼NW¼ of sec. 11.

Another structure-contour map was prepared using the top of the Prue sandstone as a datum (Fig. 70). This map shows the configuration of the top of the Prue sandstone and clearly shows closure in the NW¼ sec. 11. The closure is not a fold; it is caused by the shape of the sand body, which is controlled by the sand thickness. Although variations in resistivity of the Prue sandstone are very small, it is felt that a gradational oil-water "contact" may exist below –2,475 ft (Fig. 70).

Isopach Mapping: The lower Prue sand is the only reservoir within the Prue interval that occurs in Long Branch field. Because of this, correlations are very simple and depositional processes appear to be related to channel infilling (vertical aggradation) rather than point bar lateral accretion. Therefore, lateral continuity within the sand body is expected to be relatively good, as opposed to the more discontinuous, compartmentalized point bar sand accumulations. Overall, the Prue sandstone within Long Branch field appears stratigraphically similar to stacked longitudinal river bars or even to a distributary channel, although no delta front sediments are interpreted to occur in this immediate area. As in most other places within the Cherokee platform, the Prue sandstone appears to have a somewhat suppressed gamma ray response in "clean" sandstones. This is generally attributed to relatively large amounts of interstitial clay and interbedded mica.

The gross thickness of the lower Prue sandstone in the Long Branch study area area is shown in Figure 71. The main channel is about a mile wide and trends northeast-southwest in the study area and extends several miles in both directions beyond the area mapped.

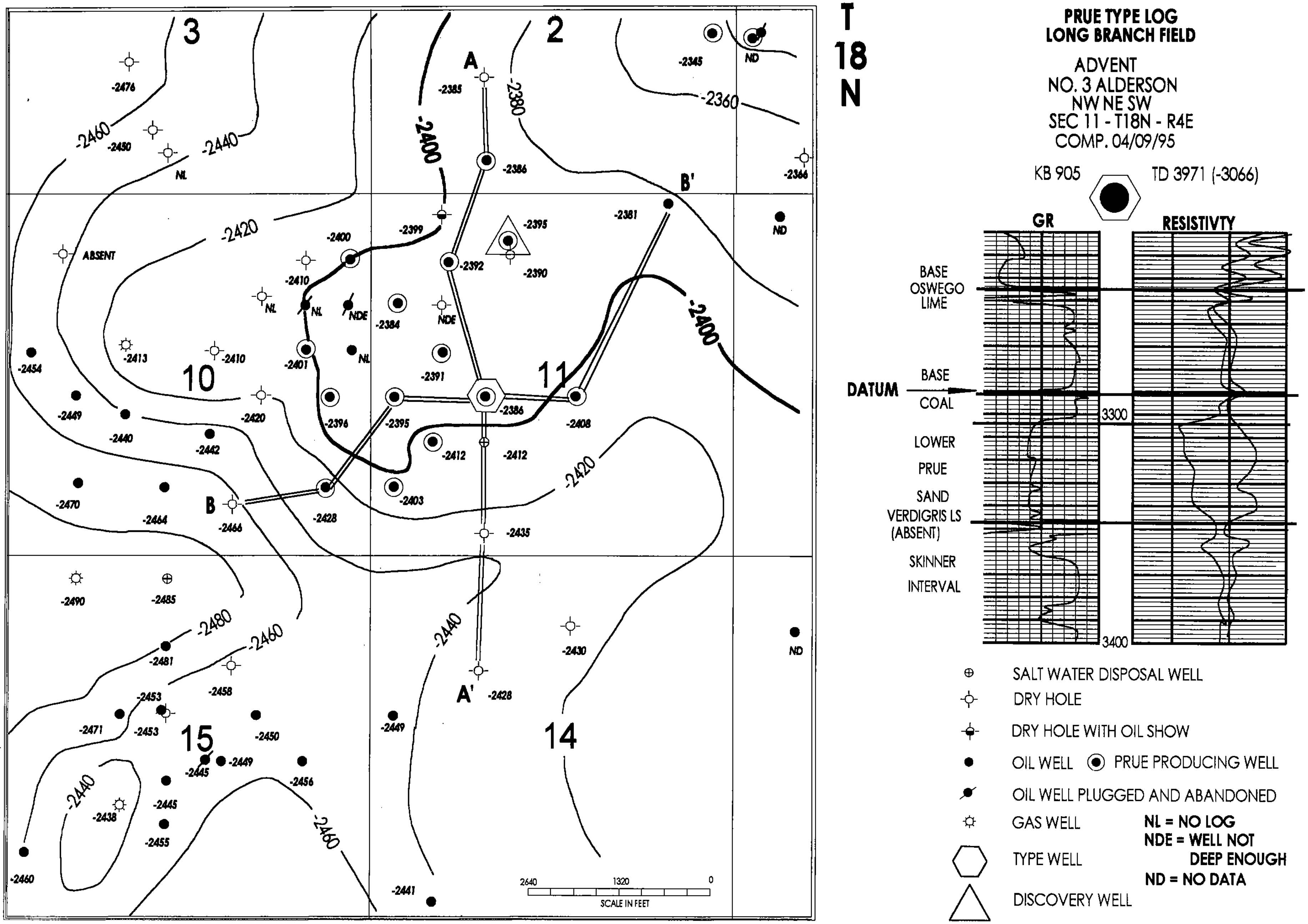


Figure 69. Structure-contour map of the base of the Prue coal marker/top of the lower Prue zone (Fig. 53), Long Branch field, Payne County, Oklahoma. Contour interval is 20 ft.

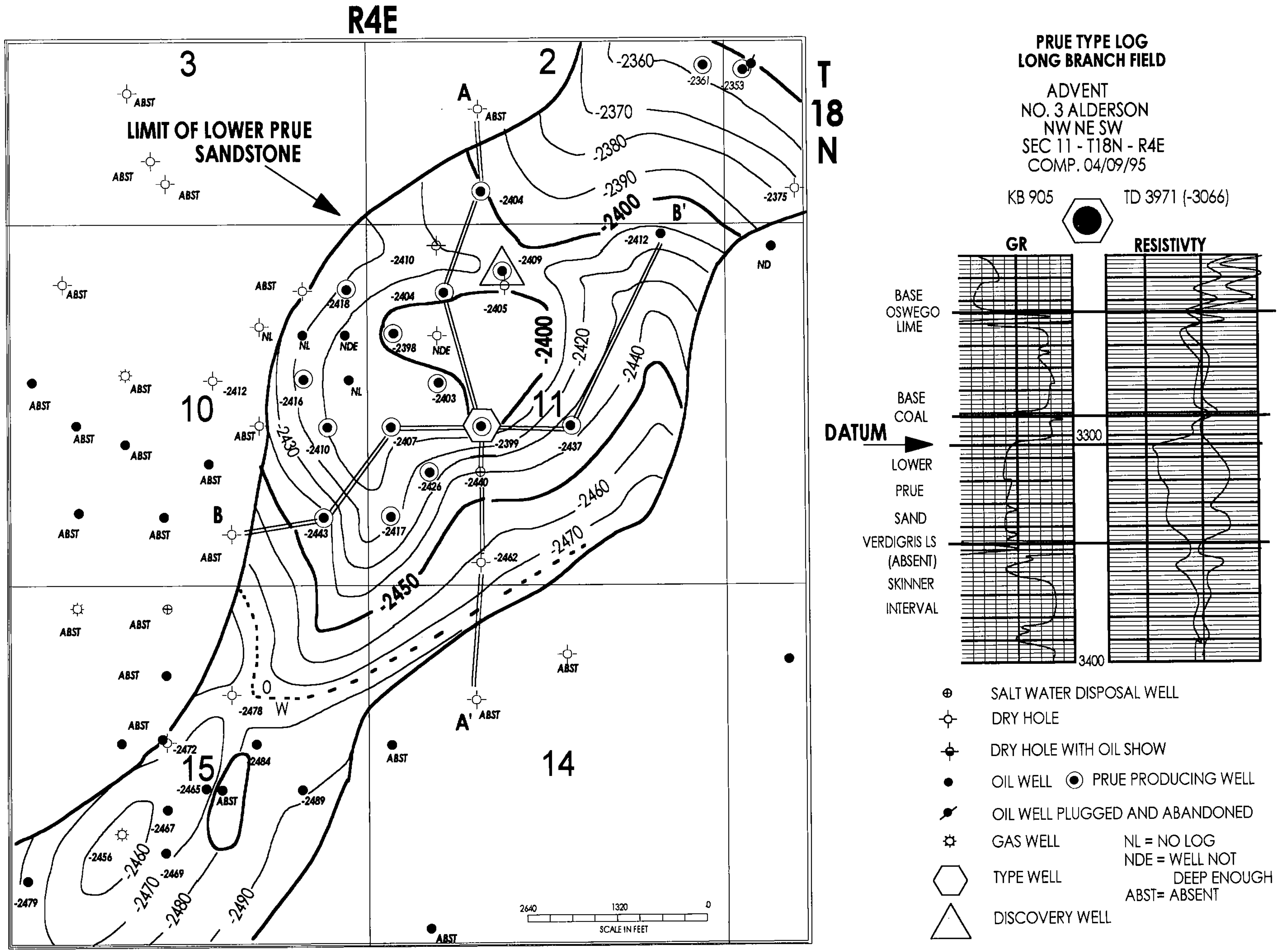


Figure 70. Structure-contour map of the top of the lower Prue sandstone, Long Branch field, Payne County, Oklahoma. Contour interval is 10 ft.

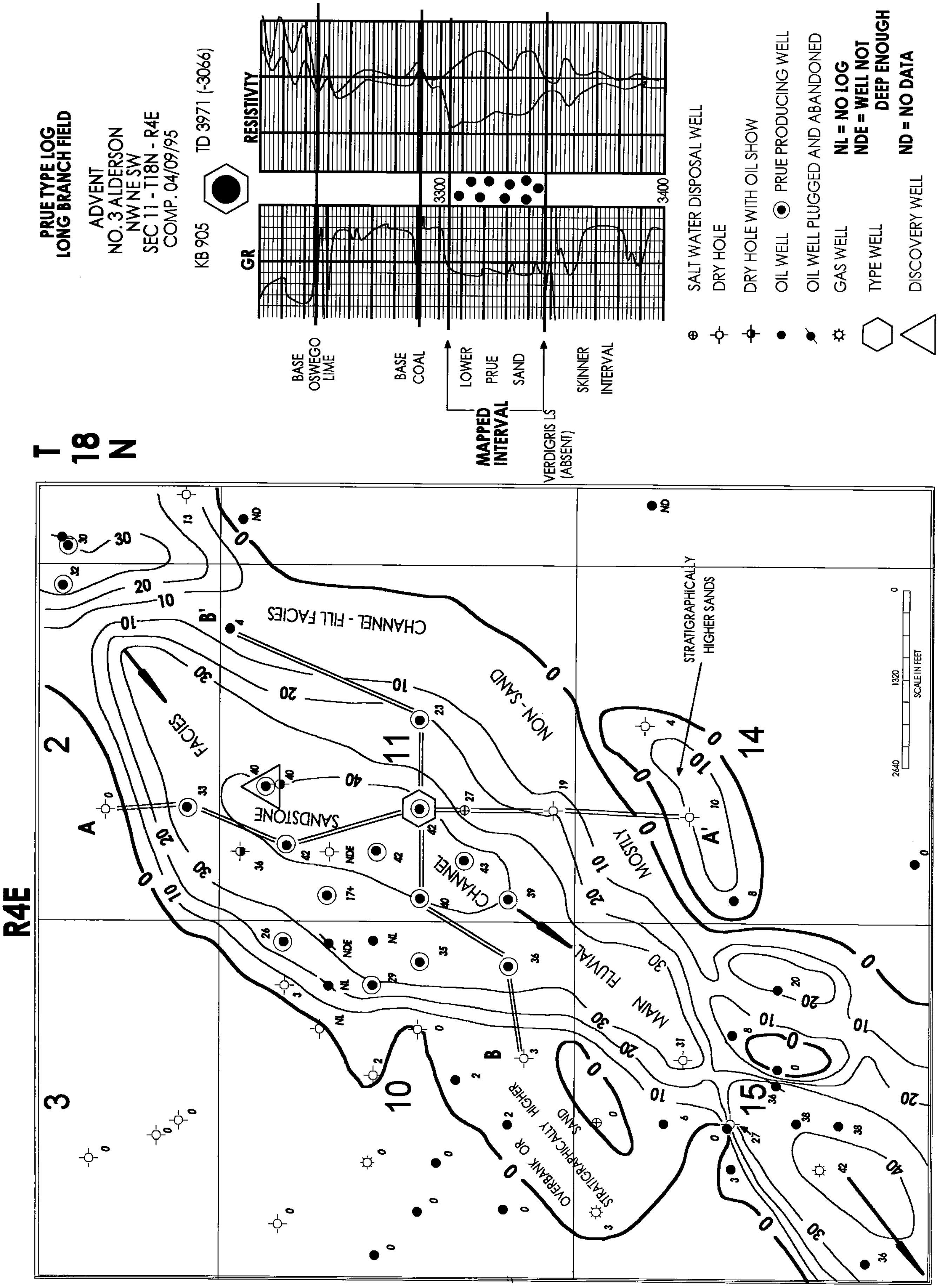


Figure 71. Lower Prue gross sand thickness, Long Branch field, Payne County, Oklahoma. Contour interval is 10 ft.

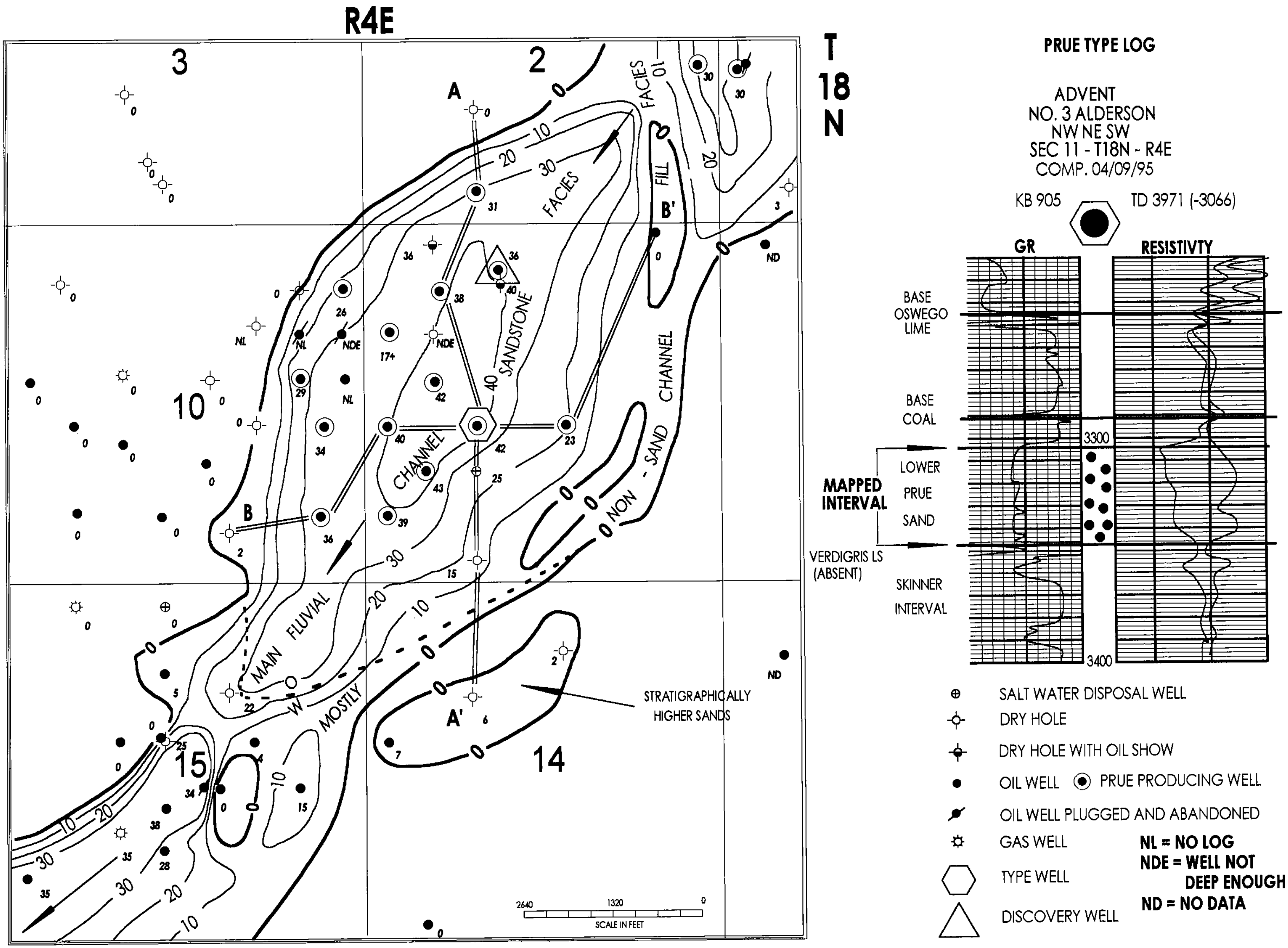


Figure 72. Lower Prue net sand thickness, Long Branch field, Payne County, Oklahoma. Net sand = sand with log porosity ≥10%. Contour interval is 10 ft.

TABLE 11. – Geological/Engineering Data for the Prue Sandstone in Long Branch Field, Payne County, Oklahoma

	Lower Prue Sand
Reservoir size	~ 800 acres
Spacing (oil)	20-40 acres
Oil/water contact	~ -2475 feet
Gas/oil contact	none
Porosity	10-22% (avg. ~ 16%)
Permeability[1]	10-63 md (avg. ~ 23md)
Water saturation (calculated)	44-60%
Average Gas to Oil Ratio (GOR)	probably < 1000 SCF/BO
Thickness (net sand $\phi \geq 10\%$)	15-42 feet (avg. ~27feet)
Reservoir temperature	108°F
Oil gravity	40-41°API
Initial reservoir pressure	NA
Initial formation volume factor	1.25 (est. from GOR, BHT, oil gravity)
Original oil in place (volumetric)	10,725,000 STBO
Cumulative primary oil production (field)	undetermined, commingled with Peru
Estimated cumulative primary oil per well	15,000 - 30,000 BO
Recovery efficiency (oil)	undetermined, probably < 10%
Cumulative gas production	undetermined, commingled with Peru

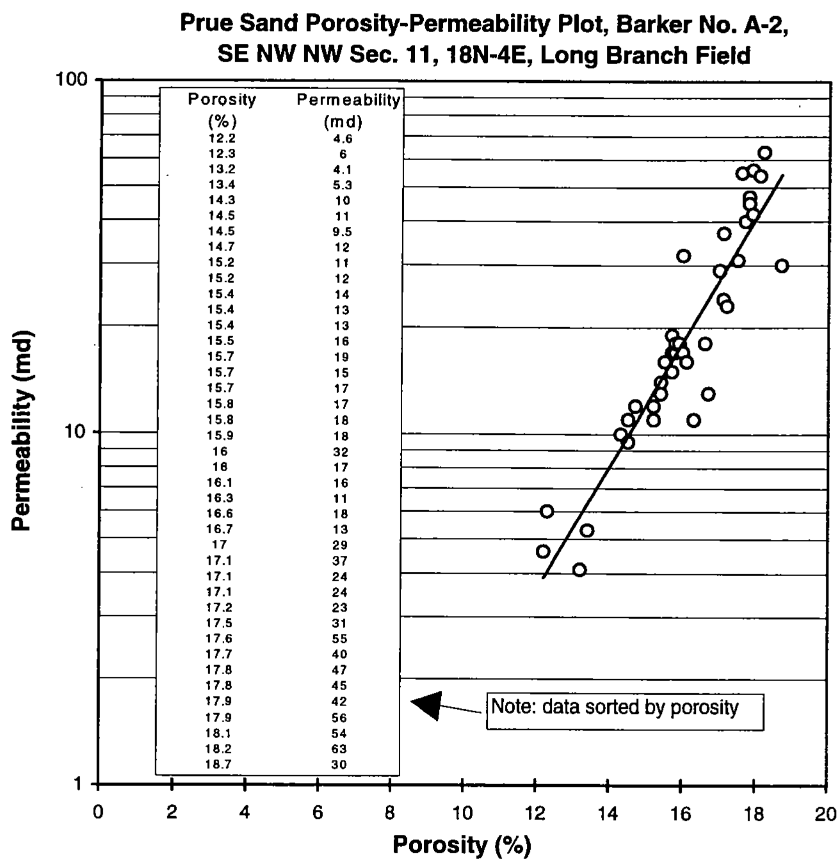
[1]All wells have been fracture treated, possibly resulting in preferentially oriented enhanced permeability.

Figure 72 is a net sand isopach map of the same Prue sandstone. It is nearly identical to the gross sand map of Figure 71 and clearly shows that if sand is present in the lower Prue zone, it generally has excellent porosity. Although a 10% porosity cutoff was used, porosity is much higher in most wells. A possible updip stratigraphic barrier is interpreted in the northeast portion of the map (E½ of secs. 2 and 11) as this appears to represent the sand-poor abandoned channel-fill facies. The net sand trends to the southwest into sec. 15 where oil shows were noted in most wells having lower Prue sand. However, subtle differences in resistivity (or conductivity) may indicate the presence of a water leg beginning in the NE¼ of the section.

Core Analysis: Advent Oil and Operating Co. cut a 47-ft core in the No. A-2 Barker well, SE¼NW¼NW¼ sec. 11, T. 18 N., R. 4 E. The entire Prue sandstone section was recovered and analyses indicate that it is tan in color, moder-

The edge of the channel is indicated by the zero contour line (except in part of sec. 10). The edge of the channel is a very sharp transition from channel to nonchannel facies and would very likely be mapped more abruptly with closer well control. Near the center of sec. 15, two wells ~330 ft apart have 36 ft and 0 ft gross sand. On the other side of the sand body, a well and its twin have 27 ft and 0 ft of gross sand. It appears that fluvial sediments of the lower Prue zone literally filled a small ravine. Narrow areas within the channel facies that contain little or no sand are interpreted to be nonsand channel fill and possibly deposited in an abandoned channel. The nonsand channel-fill facies may be an updip stratigraphic trapping component of the Long Branch Prue pool (Fig. 71).

Several wells along the margin of the main channel contain thin sands that lie just below the coal marker bed in the lower Prue zone and probably originated as some form of flood plain deposit. These sands are identified on the gross sand as "overbank" or "stratigraphically higher floodplain sands" and are also present in the southernmost well in cross section A–A′ and the westernmost well in cross section B–B′ (Figs. 67,68).

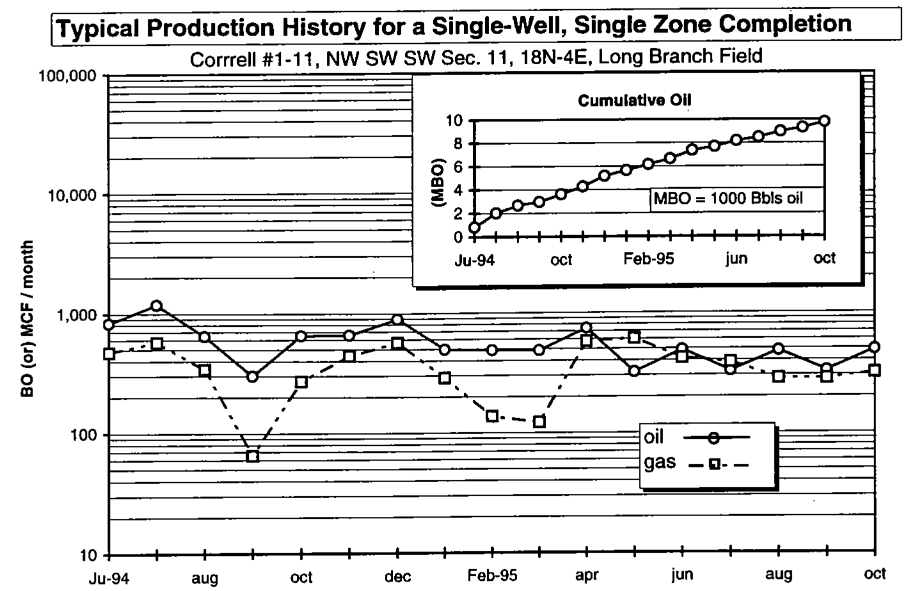


Porosity (%)	Permeability (md)
12.2	4.6
12.3	6
13.2	4.1
13.4	5.3
14.3	10
14.5	11
14.5	9.5
14.7	12
15.2	11
15.2	12
15.4	14
15.4	13
15.4	13
15.5	16
15.7	19
15.7	15
15.7	17
15.8	17
15.8	18
15.9	18
16	32
16	17
16.1	16
16.3	11
16.6	18
16.7	13
17	29
17.1	37
17.1	24
17.1	24
17.2	23
17.5	31
17.6	55
17.7	40
17.8	47
17.8	45
17.9	42
17.9	56
18.1	54
18.2	63
18.7	30

Figure 73. Core porosity and permeability data for the Prue reservoir in Long Branch field, Payne County, Oklahoma.

ately well sorted, fine-grained, slightly calcareous, micaceous, and has numerous thin carbonaceous laminations. The grain density ranged from about 2.66 to 2.74 for sandstones having porosities of 12–18%. Permeability varied from about 10 to 63 md and averaged about 36 md. Helium porosity ranged from about 12 to 19%. There were a few shaly zones interbedded within the sandstone, but, overall, the section was mostly sand. Whole rock analysis was not performed, but inferring from other Prue cores in the area and log analysis, it probably consists mostly of quartz with a relatively high proportion of detrital and authigenic clay. In most Prue samples, small particles of clay dispersed within a framework of quartz grains are discernible to the unaided eye. This core was donated to the School of Geology at Oklahoma State University (Stillwater) but never studied in detail. The large volume of core made handling of it logistically impractical, so it is not displayed at this workshop. Instead, representative core of a thinner Prue fluvial channel is provided for observation (Appendix 5).

Reservoir Characteristics: Prue sands are some of the dirtiest sands in the upper "Cherokee" section and in the Long Branch field, containing visible amounts of mica, dark minerals, and very small interstitial clay aggregates (other than clay clasts) that weather brown. The porosity, as measured from electric logs or from cores, can be quite high and in productive wells is often 10–22%, averaging ~16%. Permeability in the field gen-



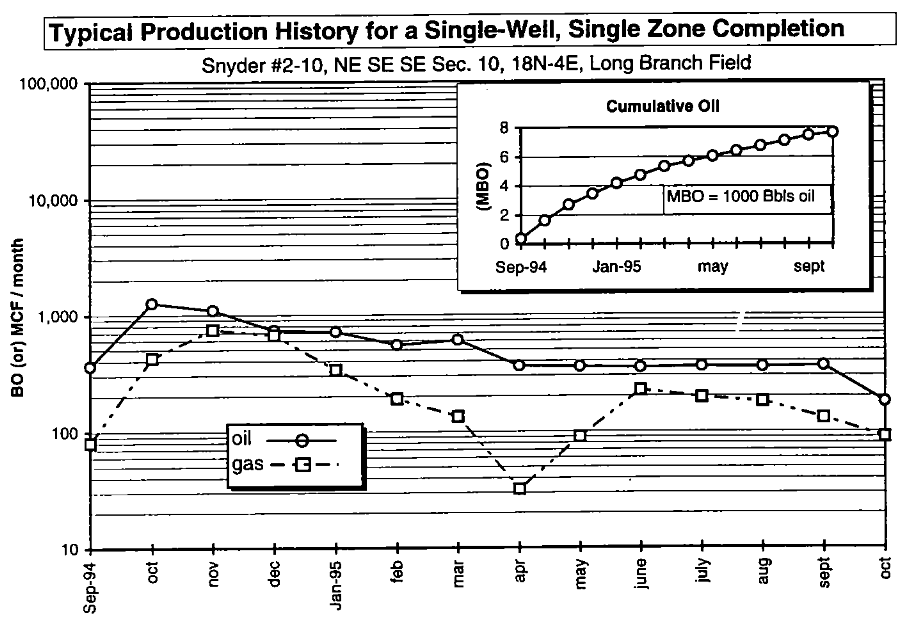


Figure 74. Single-zone Prue oil and gas production decline curves and cumulative oil production curves of two wells in the Long Branch field.

TABLE 12. – Oil and Gas Production Statistics for Two Wells That Produce Only from the Prue Sandstone, Long Branch Field, Payne County, Oklahoma

Snyder # 2-10, NE SE SE Sec. 10, 18N-4E, Long Branch Field

	Oil Production			Gas Production		
Date Month & Year	Oil Production (Barrels)	Average Daily Oil Production (BOPD)	Cumulative Oil Production (Barrels)	Gas Production (MCF)	Average Daily Gas Production (MCF)	Cumulative Production (MCF)
Sep-94	363	12.1	363	81	2.7	81
Oct	1,261	42.0	1,624	427	14.2	508
Nov	1,095	36.5	2,719	747	24.9	1,255
Dec	732	24.4	3,451	669	22.3	1,924
Jan-95	714	23.8	4,165	338	11.3	2,262
Feb	549	18.3	4,714	190	6.3	2,452
Mar	603	20.1	5,317	134	4.5	2,586
Apr	359	12.0	5,676	32	1.1	2,618
May	354	11.8	6,030	90	3.0	2,708
Jun	347	11.6	6,377	223	7.4	2,931
July	356	11.9	6,733	194	6.5	3,125
Aug	352	11.7	7,085	179	6.0	3,304
Sept	361	12.0	7,446	130	4.3	3,434
Oct	178	5.9	7,624	90	3.0	3,524

Correll # 1-11, NW SW SW Sec. 11, 18N-4E

	Oil Production			Gas Production		
Date Month & Year	Oil Production (Barrels)	Average Daily Oil Production (BOPD)	Cumulative Oil Production (Barrels)	Gas Production (MCF)	Average Daily Gas Production (MCF)	Cumulative Production (MCF)
Jun-94	829	27.6	829	473	15.8	473
Jul	1,184	39.5	2,013	573	19.1	1,046
Aug	645	21.5	2,658	342	11.4	1,388
Sep	301	10.0	2,959	65	2.2	1,453
Oct	649	21.6	3,608	271	9.0	1,724
Nov	658	21.9	4,266	441	14.7	2,165
Dec	893	29.8	5,159	565	18.8	2,730
Jan-95	495	16.5	5,654	288	9.6	3,018
Feb	486	16.2	6,140	137	4.6	3,155
Mar	482	16.1	6,622	122	4.1	3,277
Apr	736	24.5	7,358	577	19.2	3,854
May	318	10.6	7,676	604	20.1	4,458
Jun	486	16.2	8,162	417	13.9	4,875
July	324	10.8	8,486	382	12.7	5,257
Aug	477	15.9	8,963	282	9.4	5,539
Sept	326	10.9	9,289	280	9.3	5,819
Oct	486	16.2	9,775	312	10.4	6,131

erally varies from about 10 md to 63 md and averages ~36 md. This relatively low average permeability is due mainly to large amounts of interstitial clay originating from detrital sources as well as authigenic alterations of framework constituents such as rock fragments. The relationship of porosity and permeability in the Prue reservoir in Long Branch field is shown in Figure 73 and indicates that when log porosity reaches ~10%, the sand should have slightly >1 md permeability, which is considered minimal for oil production. Core analysis indicates that the Prue sand is slightly calcareous and contains numerous, thin carbonaceous laminations. Thin, shaly zones are also detected in core and in log analysis. The reservoir as a whole does not appear to have "breakout" zones or paths of exceptional permeability as in certain other Pennsylvanian lithologies. This may prove to be an advantageous attribute in water flooding programs of this sand unit. A summary of reservoir and engineering data for the Prue sandstone in Long Branch field is given in Table 11.

Formation Evaluation: The identification and evaluation of Prue sandstones can often be misleading, particularly when interpreting sandstones of fluvial origin. The relatively high clay content and presence of interstitial mica suppresses the gamma-ray response, resulting in poorer bed resolution. In addition, the often high content of formation (connate) water results in S_w (water saturation) calculations to be discouraging for well completions. In fact, this was the case in Long Branch field, where in the S½NE¼NW¼ sec. 11, the Enersource No. A-1 Barker well was abandoned due to this interpretation. After recognizing the oil potential from sample and detailed log analysis, independent geologist Greg Riepl encouraged Advent Oil to twin the No. A-1 Barker, which resulted in the discovery of the Long Branch Prue oil pool.

"Deep" or true resistivity measurements in productive intervals of the lower Prue sand zone have relatively low values of only about 1.5–3 ohm-meters. A very strong separation of about 20–30 ohm-meters exists between the shallow and deep resistivity readings, which indicates, in addition to some degree of permeability, that the zone is fairly wet (which is also true). Deep resistivity measurements in non-hydrocarbon producing Prue zones farther downdip in sec. 15 likewise are in the 1–3 ohm-meter range, so the distinction of an oil-water contact is not very clear.

Calculated water saturation ($S_w = \sqrt{(F \times R_w / R_t)}$) in productive zones varies from about 44% to 60%, assuming a R_w (resistivity of formation water) of 0.035 ohm-meters at formation temperature and using a modified equation for formation factor ($F = 0.81/\phi^2$). R_t (true resistivity) is determined from the deep resistivity log curve. Porosity (ϕ) is determined from any porosity measuring tool or core analysis.

Oil Production and Well Completion: Cumulative oil production of the Prue reservoir cannot be accurately determined since nearly all oil production is

TABLE 13. – Oil and Gas Production Statistics for the Barker Lease* in the NW¼ sec. 11, T. 18 N., R. 4 E.

Well No. 1 Oringderff and Nos. 1, 2, 3 Barker

	Oil Production			Gas Production		
Year/ Month	Oil Production (Barrels)	Average Daily Oil Production (BOPD)	Cumulative Oil Production (Barrels)	Gas Production (MCF)	Average Daily Gas Production (MCF)	Cumulative Production (MCF)
		(#1 Oringderff on-line)				
1979	926	3	926	No gas production reported prior to 1993		
1980	841	2	1,767			
1981	766	2	2,533			
1982	381	1	2,914			
1983	799	2	3,713			
1984	623	2	4,336			
1985	574	2	4,910			
1986	775	2	5,685			
1987	539	1	6,224			
1988	367	1	6,591			
1989	374	1	6,965			
1990	470	1	7,435			
1991	349	1	7,784			
1992	176	0	7,960			
1993	13,339	37	21,299	3,610	10	3,610
Jan	0	0		0	0	
Feb	0	0		0	0	
Mar	159	5	(Barker A-1 on-line)	0	0	
Apr	704	23		0	0	
May	165	6		0	0	
Jun	2,169	72	(Barker A-2 on-line)	0	0	
Jul	1,654	55		0	0	
Aug	1,447	48		0	0	
Sep	1,134	38		0	0	
Oct	1,149	38		669	22	
Nov	1,154	38		817	27	
Dec	3,604	120		2,124	71	
1994	24,633	67	45,932	32,376	89	35,986
Jan	2,900	97		3,120	104	
Feb	2,071	69		2,258	75	
Mar	2,741	91		3,062	102	
Apr	2,635	88		3,206	107	
May	2,623	87		3,260	109	
Jun	2,013	67		3,215	107	
Jul	1,933	64		3,161	105	
Aug	1,818	61		2,850	95	
Sep	1,497	50		2,429	81	
Oct	1,578	53		2,299	77	
Nov	1,480	49		1,843	61	
Dec	1,344	45		1,673	56	
1995	21,305	70	67,237	34,707	114	70,693
Jan	1,250	42		1,278	43	
Feb	1,300	43		1,022	34	
Mar	1,485	50		1,651	55	
Apr	2,786	93		2,953	98	
May	3,351	112		3,793	126	
Jun	2,482	83	(Barker A-3 on-line)	5,467	182	
July	2,349	78		5,533	184	
Aug	2,357	79		4,792	160	
Sept	2,063	69		4,207	140	
Oct	1,882	63		4,011	134	
		TOTAL =	67,237		TOTAL =	70,693

*This lease has four producing wells that were developed over the past 45 years and includes production from the Mississippi lime, and the Prue and Peru sands.

commingled with the younger "Peru" reservoir. Additionally, Prue oil production has been established for only about two years, so there are no long-term production trends available in the field. There are, however, three wells which produce entirely from the Prue reservoir, and two of these have produced oil and gas for about 1½ years. These are the No. 2 Snyder in the NE¼SE¼SE¼ sec. 10 and the No. 1 Correll in the NW¼ SW¼SW¼ sec. 11. The other Prue producer is the Kidder well in the NW¼ NW¼SE¼ sec. 11, which was completed in July 1995 and has no reported production history as yet.

Production decline curves for the No. 2 Snyder and No. 1 Correll wells are shown in Figure 74. The No. 2 Snyder has production data for nine months, during which time production declined ~70%. The No. 1 Correll well has production data for 12 months, during which time production declined ~60%. If these wells are any indication of the majority of Prue producers, the cumulative primary production per well could be about 10–20 MBO. This can be envisioned by extrapolation of the cumulative oil production curve (inset plot) included with each decline curve. Assuming an average GOR per well of 500:1, gas reserves per well could be 5,000–10,000 MCF. Production data for these two wells is presented separately in Table 12, which also calculates the average daily production rate of each well.

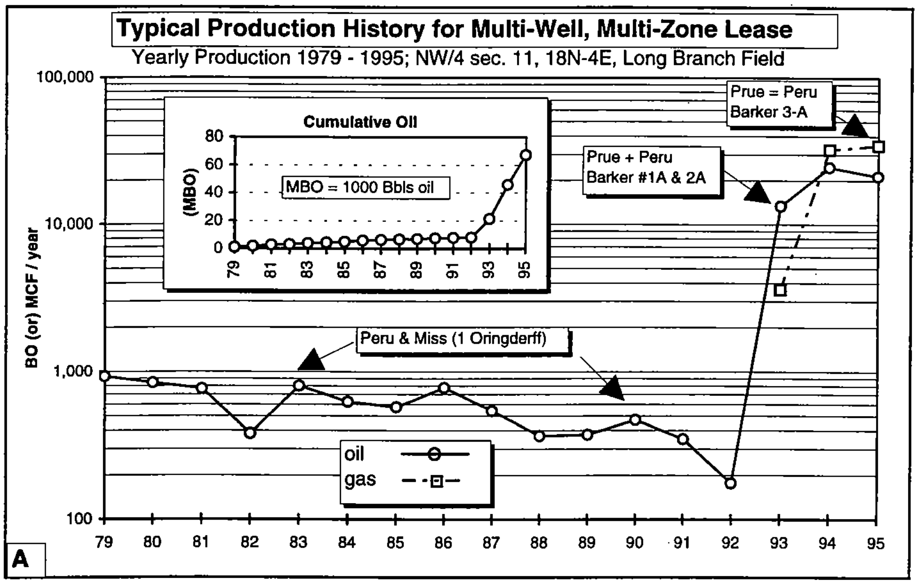
Production in most cases is reported by lease, which usually includes more than one well. In addition, most wells in the field produce from both the Prue and "Peru" sands simultaneously. A typical production decline curve of one lease involving three wells, each a dual producer, is shown in Figure 75A, and the actual production data is included in Table 13. The steep jump in production in 1993 is due to field development of the Prue and "Peru" interval. Figure 75B shows a more detailed production history of the lease wells during the last two years, which corresponds primarily to Prue + "Peru" production. In such a complicated scenario, a decline rate per well is difficult to determine.

Oil and gas production by well or lease is always useful information to judge the performance and overall economic potential of a field. This is shown in Figure 76, which indicates the cumulative oil and gas production through October 1995, the well completion date, producing formations, and well lease assignments, if any.

Wells completed in the Prue sand were generally stimulated with a massive fracture treatment utilizing ~50,000 pounds of sand as a proppant per producing horizon (i.e., 100,000 pounds sand for a dual Prue-"Peru" completion). In utilizing this technique, there was little concern for water encroachment since the reservoir has no oil-water contact in current producing areas. The wells were perforated through production casing, acidized to clean out the well bore, and brought on-line. Initial production as indicated in completion reports was usually measured shortly after fracture treatment and, therefore, is not a realistic gauge of actual well performance. Consequently, reported IPs in the range of 20–30 BOPD, 30–50 MCFGPD, and 200 BW represent unstabilized production estimates and are deceptive and erroneous. Using the first full month of production data, the initial daily production rate of a well can be approximated at 40–50 BOPD. Additionally, few if any Prue wells had reliable pressure measurements available.

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, the Geo Information Systems research unit at the University of Oklahoma, and the OU School of Petroleum and Geological Engineering. Special recognition is given to Dr. Charles Mankin, director of the Oklahoma Geological Survey (OGS), and to Mary Banken, director of Geo Information Systems (GeoSystems), who orig-



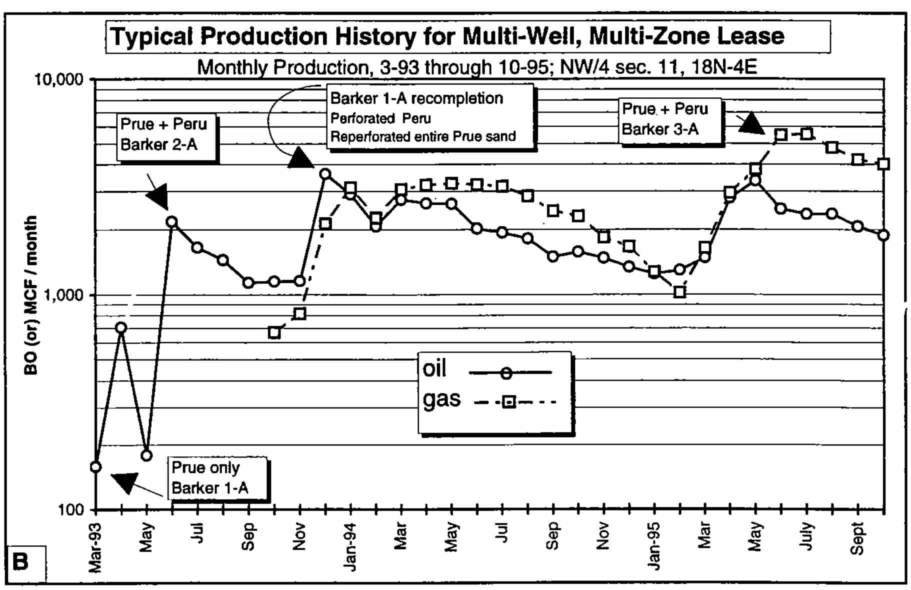


Figure 75. Oil and gas production decline curves for the Barker lease in the NW¼ sec. 11, T. 18 N., R. 4 E. (A). This lease has four producing wells that were developed over the past 45 years and involve production from the Mississippi lime and the Prue and Peru sands. Detailed monthly production (B) shows the production trend of this lease over the past 32 months, which consists primarily of Prue + Peru oil and gas production.

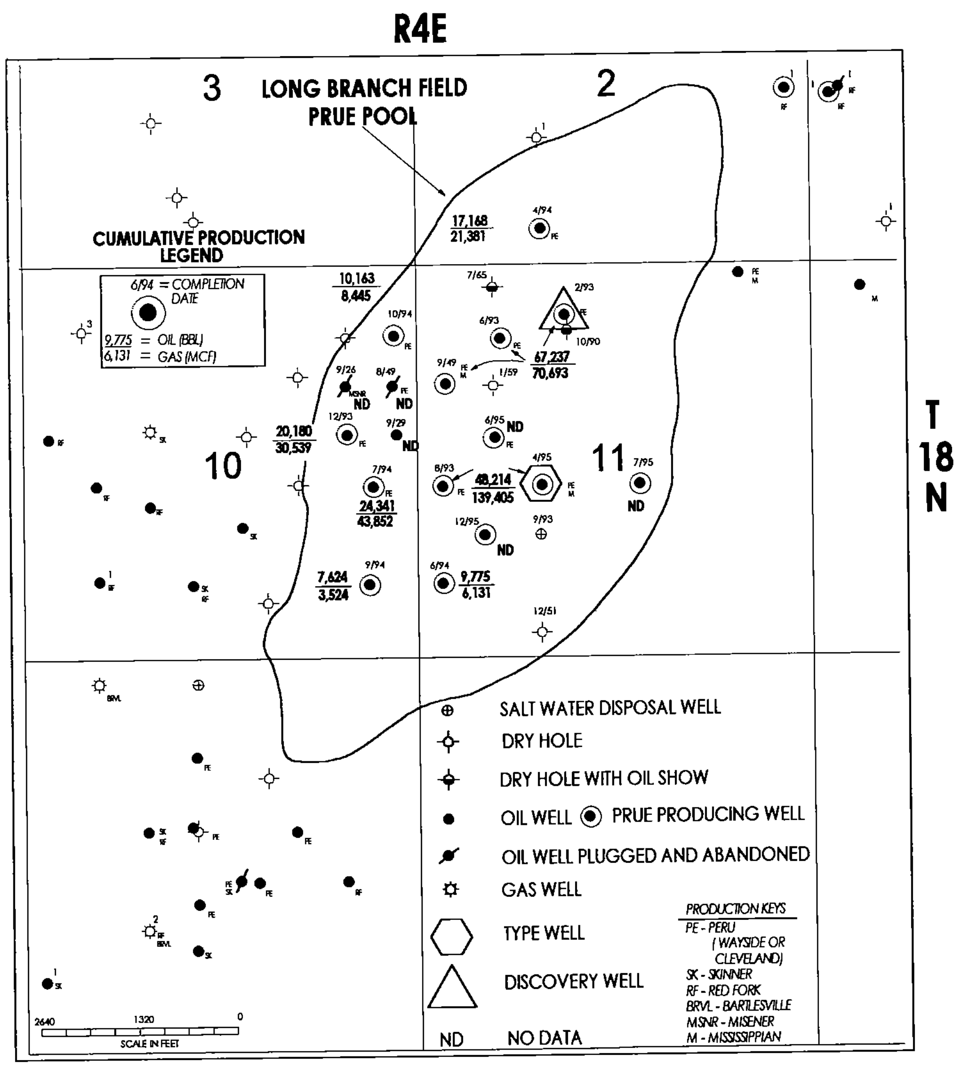


Figure 76. Oil and gas production map of Long Branch field, Payne County, Oklahoma, showing completion date, producing formation, and cumulative oil + gas production (through October 1995). Since production is reported by lease, cumulative production values may represent more than one well as indicated. Furthermore, Prue production in most wells is commingled, usually with production from the Peru (Wayside or Cleveland?) sands.

inated concepts for this program and provided overall leadership. Both the OGS and GeoSystems also provided funding for this cooperative project.

Several consulting geologists in the Oklahoma City area contributed greatly to this project by providing technical information, field and well log data, cores, and interpretations. These include Kurt Rottmann, Greg Riepl, Jay Lackey, and Robert Northcutt. Kurt Rottmann also completed work on the Perry S.E. and Guthrie S.W. field studies. Donald Muegge, operator of Salt Fork North field, was instrumental in providing field information for the reservoir simulation and waterflood modeling that was completed by Dr. Roy Knapp and Zahid Bhatti. X. H. Yang assisted in the reservoir simulation study for the Long Branch field.

Much of the technical support for computer map preparation, core preparation, technical editing, and computer graphics was completed by David Brown, GeoSystems technical project coordinator; Scott March, GeoSystems geotech; Carlyle Hinshaw, GeoSystems petroleum geologist; and Melanie Jackson, GeoSystems technical support. Core examination and slabbing was made possible by Walter Esry and Larry Austin of the OGS Core and Sample Library. Cartographic drafting, visual-aid preparation, and computer drafting was completed by Carlyle Hinshaw, GeoSystems petroleum geologist; Wayne Furr, OGS manager of cartography; Jim Anderson and Charlotte Lloyd, cartographic drafting technicians; and Gary Leech, Greg Taylor, Ron Klein, and Julieta Rachel, contract drafting technician. Technical review and publication editing was completed by)Robert Northcutt, OGS consulting geologist; Carlyle Hinshaw, GeoSystems petroleum geologist; Dorothy Swindler, contract technical editor; Christie Cooper, OGS editor, and Tracy Peeters, OGS editorial assistant. Publication printing was made possible 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.

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.

Baharloui, Abdolhossein, 1964, Quantitative study of electrical parameters, Prue sand (Pennsylvanian), southern Creek County, Oklahoma: University of Oklahoma unpublished M.S. thesis, 173 p.

Bass, N. W., and others, 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.

____ 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.

Baumann, D. K.; Peterson, M. L.; and Hunter, L. W., 1983, History of development and depositional environment [of] upper Cherokee Prue sand, Custer and Rogers Mills Counties, Oklahoma [abstract]: American Association of Petroleum Geologists Bulletin, v. 67, p. 420–421.

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.

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. F., Jr., 1979, Deltaic sandstone facies of the Midcontinent, *in* Hyne, N. J. (ed.), Pennsylvanian sandstones of the Midcontinent: Tulsa Geological Society Special Publication 1, p. 35–63.

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.

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.

Chandler, 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 [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.

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.

____ 1969, Cherokee Group, east flank of the Nemaha Ridge: Shale Shaker, v. 19, no. 8, p. 134 [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.
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 northwestern Tecumseh field, Pottawatomie County, Oklahoma: University of Tulsa unpublished M.S. thesis, 91 p.
____ 1987, Red Fork and lower Skinner sandstones in northwestern 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.
Dillard, W. R., 1941, Olympic pool, Hughes and Okfuskee Counties, Oklahoma, *in* Stratigraphic type oil fields: American Association of Petroleum Geologists Bulletin, p. 456–472.
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.
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.
Greig, P. B., Jr., 1959, Geology of Pawnee County, Oklahoma: Oklahoma Geological Survey Bulletin 83, 188 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., 1984, The Red Fork sandstone, Cherokee Group (Pennsylvanian) of the southeast Thomas field, Custer County, Oklahoma: Shale Shaker, v. 35, no. 3, p. 50–58.
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.
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.
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 plates.
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].
McDade, L. B., 1953, The sedimentation and petrology of the lower Calvin sandstone of Hughes County, Oklahoma: Tulsa Geological Society Digest, v. 21, p. 182–200.
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 Wood 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.
Page, K. G., 1955, The subsurface geology of southern Noble County, Oklahoma: Shale Shaker, v. 5, no. 10, p. 5–25.
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, Steve 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., 1979, Subsurface stratigraphic and structural analysis, Cherokee Group, Pottawatomie County, Oklahoma: Shale Shaker, 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, v. 8, no. 7, p. 10.
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.

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.

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.

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

Shaarawy, M. A. R., 1962, Quantitative geophysical study of the Prue sand reservoir (Pennsylvanian) in a portion of Lincoln County, Oklahoma: University of Oklahoma unpublished M.P.E. thesis, 145 p.

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, Oklahoma, 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.

Stiles, W. E., 1957, Olympic pool water flood: Journal of Petroleum Technology, February, p. 29–35.

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* Structure of typical American oil fields: 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.

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.

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: American Association of Petroleum Geologists Bulletin, v. 2, p. 396–406.

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* Stratigraphic type oil fields, a symposium: American Association of Petroleum Geologists, Tulsa, p. 386–407.

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].

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

W Water injection (input) well

W Abandoned water injection well

G Gas injection (input) well

G Abandoned gas injection well

WSW Water supply well

WSW Abandoned water supply well

X 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. **Southport Exploration No. 1-21 Shively**
   N½NW¼NW¼ sec. 21, T. 19 N., R. 3 E.
   Lower Skinner, fluvial channel
   Cored interval: 3,877–3,914 ft

2. **Jeron Oil and Gas Company No. 2 Fisher**
   NE¼NE¼NW¼ sec. 20, T. 19 N., R. 4 E.
   Lower Skinner, nonchannel facies
   Cored interval: 3,639–3,670 ft

3. **TXO Production Company No. 17-1 Payne**
   SW¼SE¼ sec. 17, T. 10 N., R. 5 E.
   Middle Skinner, fluvial channel facies
   Cored interval: 8,646–8,671 ft

4. **Sullivan and Company No. 1 Diamond "L"**
   SW¼SW¼SW¼ sec. 4, T. 16 N., R. 2 E.
   Prue, fluvial channel
   Cored interval: 4,320–4,362 ft

Southport Exploration Shively No. 1-21

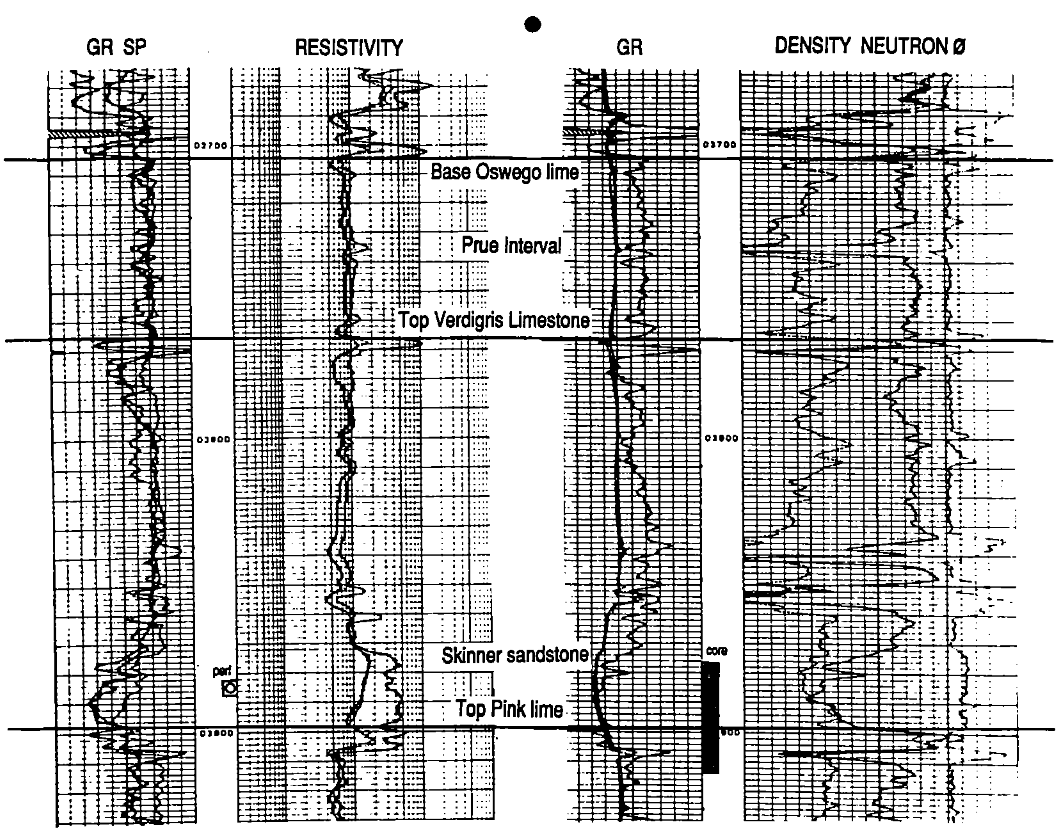
N½NW¼NW¼ sec. 21, T. 19 N., R. 3 E.

Lower Skinner Sandstone Core

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

Core depth *(in feet)*	Lithology and sedimentary structures
3,877–3,878	***Upper channel facies.*** Sandstone, very fine grained, wavy to horizontal bedding, interbedded with shale laminae. Very minor mica on bedding surfaces.
3,878.7–3,880	Sandstone, fine to very fine grained, faint shale laminae, horizontal to wavy bedding, some inclined bedding, excellent porosity.
3,880–3,884.5	***Middle to lower channel facies.*** Sandstone, fine to very fine grained, slightly micaceous, occasional elongate mud clasts 0.1–0.5 in. in diameter, horizontal to slightly inclined bedding, excellent porosity.
3,884.6–3,885.2	Shale and laminated shale and very fine grained sandstone (with clay drape?).
3,885.2–3,888.7	Sandstone, fine grained, poorly bedded to massive, a few mud clasts suspended in sandstone, excellent porosity.
3,888.7–3,888.9	Shale.
3,889–3,891	***Lower channel facies.*** Sandstone, fine grained, occasional mud clasts, possible flowage.
3,892–3,898	Sandstone, fine grained, highly inclined to horizontal bedding, some cross-stratification, a few elongate mud clasts, excellent porosity. ***Base of channel*** sandstone.
3,898–3,899	Shale, black.
3,899–3,906	***Pink lime.*** Upper part brownish-gray, fossiliferous limestone with interbedded black fossiliferous shale. Lower part pinkish-gray, stylolitic, micritic.
3,906.5–3,909	Shale, dark gray, very crumbly, samples mostly missing.
3,909–3,914	***Red Fork sandstone,*** very fine grained, silty, green with reddish-brown (hematitic) specks, noncalcalreous. Distinct scour and fill structures, no fossils, numerous thin shale laminae.

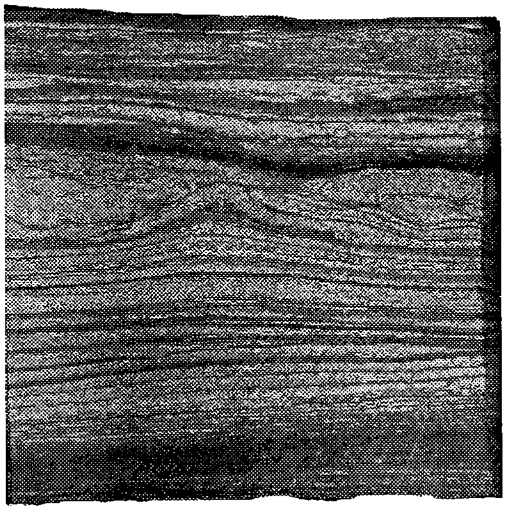
Reservoir: Lower Skinner sandstone — Depositional environment: Fluvial channel



T.D.: 4,448 ft
Completion date: 3/17/85
Perforated: 3,882–3,888 ft

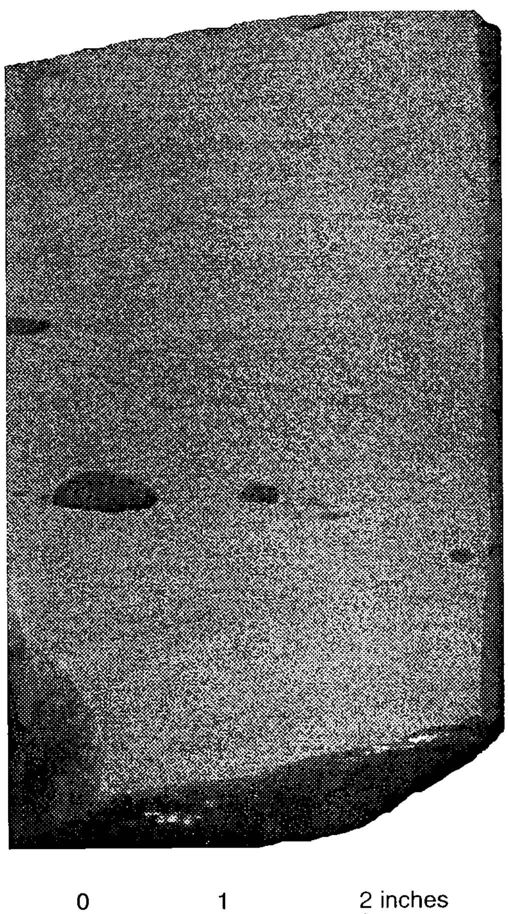
IPP (Skinner) 100 BOPD + 1 unit gas
Cored depth interval: 3,877–3,914 (actual depth)

Southport Exploration Shively No. 1-21



Log and core depth: ~3,878 ft

Upper channel facies. Sandstone, very fine grained, wavy to horizontal bedding. Numerous interbedded shale laminae with minor mica on bedding surfaces. This core is above the main Skinner reservoir and represents the uppermost channel facies.



Log and core depth: ~3,881–3,881.5 ft

Lower to middle channel facies. Sandstone, fine to very fine grained. Faint horizontal to slightly inclined bedding. Occasional deformed mud clast oriented along bedding plane. This sand interval may be part of a stacked channel sequence thereby accounting for the relatively high stratigraphic position of mud clasts. This core interval can be related to the well logs accompanying this report.

Jeron Oil and Gas Company Fisher No. 2

NE¼NE¼NW¼ sec. 20, T. 19 N., R. 4 E.

Lower Skinner Sandstone Core

Log depth ≈ Core depth –10 to 14 ft — Described by: Richard D. Andrews

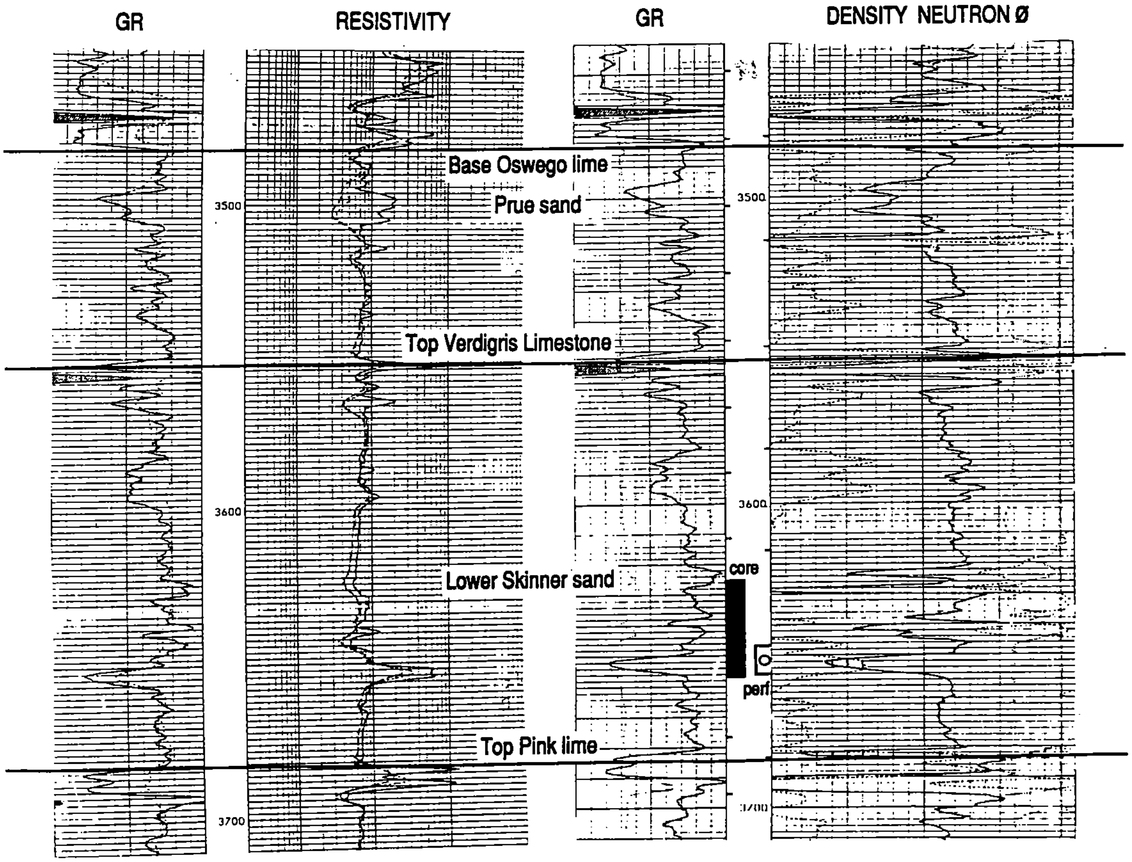
Core depth *(in feet)*	Description of selected core intervals
3,639–3,640	Shale, dark gray.
3,640.5–3,641	*Coal*, black, fractured.
3,643.5	Mudstone and shale, medium gray, waxy in part, with carbonaceous laminae and debris, minor contorted bedding, no fossils.
3,645.5	Shale, dark gray to black, pyrite lenses, micaceous interbeds; no fossils or carbonaceous laminae, small carbonized twig. Well laminated (very thin, horizontal).
3,648	Shale, black to drab olive, slightly carbonaceous, no fossils or pyrite.
3,650–3,651	*Limy mudstone*, black, very fossiliferous (mostly gastropods, some brachiopods, randomly oriented).
3,652–3,655	Marine shale, black to drab olive, brachiopod at 3,653 ft.
3,655–3,656	*Limy mudstone*, mottled black to dark olive green, very fossiliferous, mostly gastropods, some brachiopods.
3,656–3,657	Sandstone, very fine grained, silty, bioturbated? with shell fragments, grades downward to black shale interbedded with siltstone? laminae and a few small shell fragments.
3,660–3,660.5	Sandstone, very fine grained, with thin shale interbeds, wavy bedding, small-scale scour and fill structures, and ripples. Small amount of mica and carbonaceous material on some bedding surfaces.
3,660.5–3,661	Silty sandstone with sharp base. Contains scattered 0.25–0.75 in. diameter mud clasts in the lower part (*transgressive lag*) and grades upward into laminated shale possibly bioturbated with small (<0.2 in. diameter) mud clasts.

Core depth *(in feet)*	Description of selected core intervals
3,661–3,662	Shale.
3,662	Sandstone, very fine grained; slightly inclined, discontinuous and indistinct (bioturbated?) bedding; numerous shale partings.
3,663	Interlaminated shale and siltstone, dark gray to drab olive, pyritized shell fragment in upper half, leaf imprints in lower half.
3,664	***Top of reservoir sandstone.***
3,664–3,667	***Upper bar facies***, coarsening upward sequence. Sandstone, coarsens upward from very fine grained to fine grained. Very porous and permeable. Mostly horizontal bedding, some slightly inclined. Center part of unit has wavy and/or rippled beds with carbonaceous debris and laminae every few inches. Near top, fine grained with carbonized twig; lower part is very fine grained with apparent scour and fill structures.
3,667–3,668.1	Sandstone, very fine to fine grained, very porous and permeable with medium-inclined to horizontal bedding; near base, rippled bedding and more abundant carbonaceous layers. Base is sharp, scoured into silty, tight sandstone below. 3,668.1 is ***base of reservoir sandstone.***
3,668.1	***Lower bar facies.*** Sandstone, very fine grained (upper part) scours into lower part which is silty, very fine grained sandstone, highly deformed (flowage), frequent carbonaceous shale laminae, tight.
3,669–3,670	Sandstone, very fine grained with interbedded silty shale laminae and minor amounts of carbonaceous material, and slightly inclined to indistinct bedding.
3,670	Claystone, tan, massive with carbonaceous and woody debris.

Jeron Oil and Gas Company Fisher No. 2

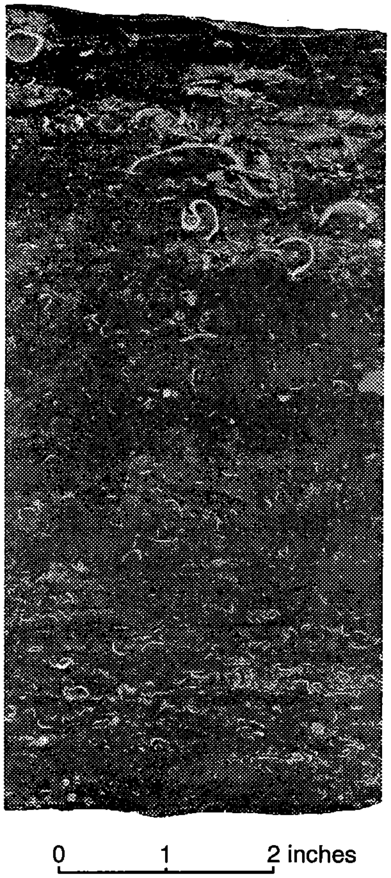
Reservoir: Lower Skinner sandstone
Depositional environment: Nonchannel facies, possible distributary mouth bar or shoreface?

Interval cored (log depth): 3,625–3,658 ft
Reported core interval (core depth): 3,639–3,670 ft



T.D.: 4,165 ft
Completion date: 9/2/93
Perforated: 3,646–3,656 ft
IPF (lower Skinner) 150 BOPD, 300 MCFGPD, no water

Jeron Oil and Gas Company Fisher No. 2

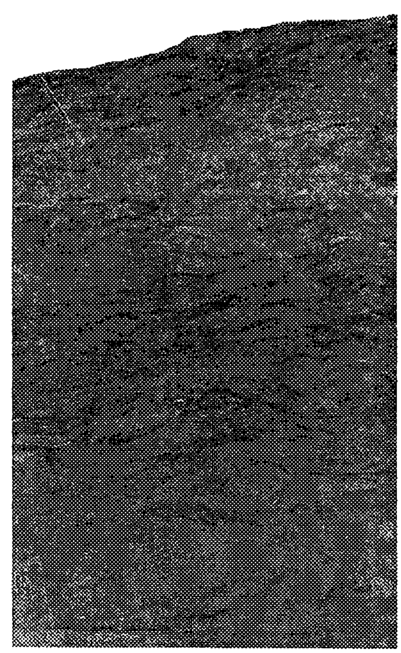


Core depth: 3,655.5–3,656 ft
Log depth: ~3,641–3,641.5 ft

Shallow marine. Fossiliferous shale, black to mottled dark olive green, abundant randomly oriented gastropods and some brachiopods.

Core depth: 3,660.5–3,661 ft
Log depth: ~3,646.5–3,647 ft

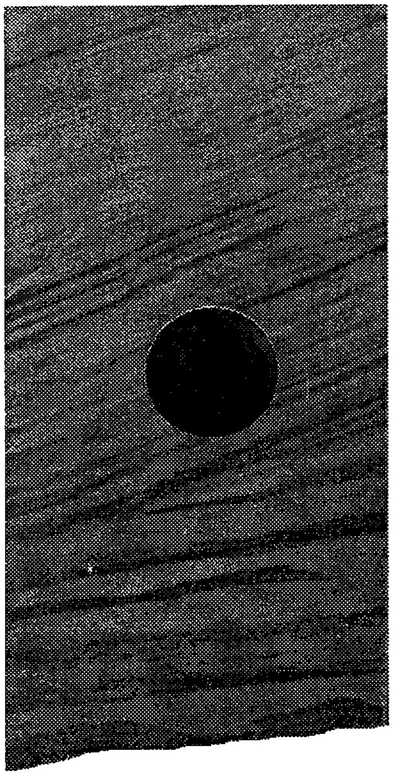
Transgressive lag. Sharp basal contact with shale; 0.25–0.75 in. diameter mud clasts in silty sand matrix. This horizon lies just above a thin, bioturbated sandstone (see picture below).



Core depth: 3,662 ft
Log depth: ~3,648 ft

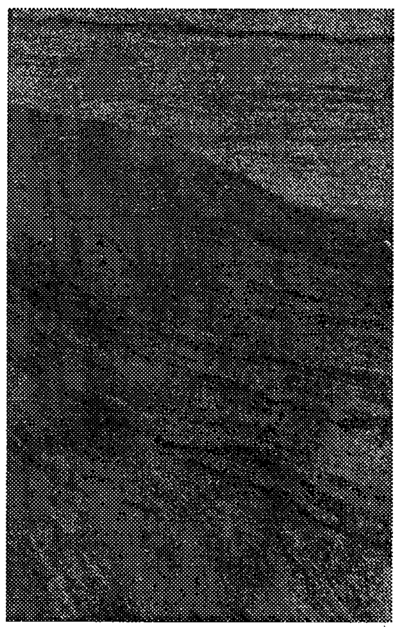
Marginal marine sandstone, very fine grained with indistinct, discontinuous bedding (bioturbated?) and numerous thin shale partings. Grades downward to shale with leaf imprints and pyrite.

Jeron Oil and Gas Company Fisher No. 2



Core depth: 3,667–3,667.5 ft
Log depth: ~3,652–3,653 ft

Middle bar facies. Very fine to fine grained cross-bedded sandstone. Very porous and permeable. Possible ripple bed and carbonaceous layer at base of sample.



Core depth: 3,668–3,668.5 ft
Log depth: 3,654–3,654.5 ft

Lower bar facies. Sandstone, very fine grained, (upper part) scoured into silty, very fine grained, tight sandstone having contorted bedding (lower part). This interval is not considered part of the reservoir.

TXO Production Corporation Payne No. 17-1

SW¼SE¼ sec. 17, T. 10 N., R. 5 W.

Middle Skinner Sandstone Core

Log depth ≈ Core depth + 10 ft

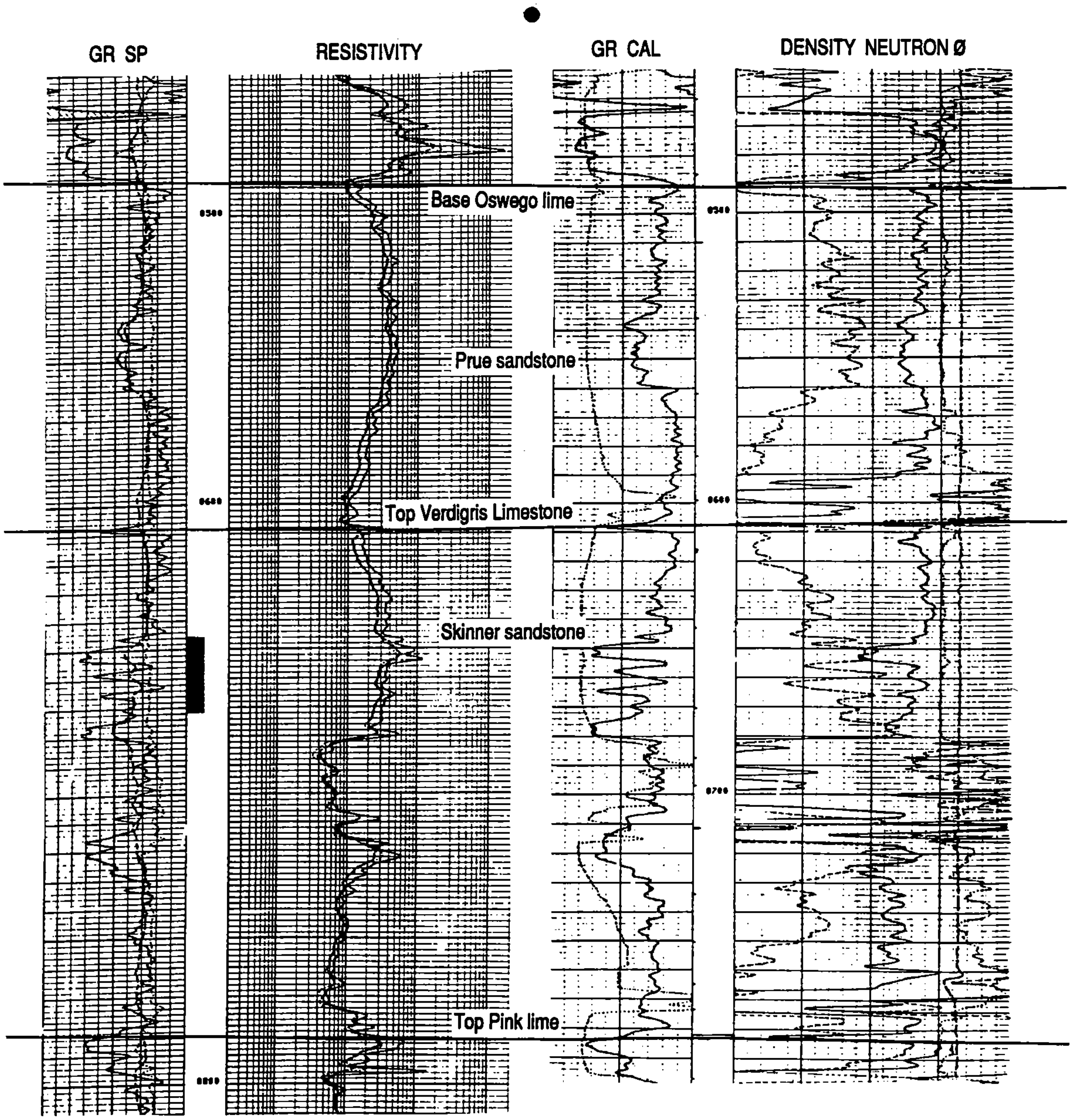
Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
8,646–8,653	Not described.
8,653.5	Shale with interbedded, very fine grained sandstone, wavy bedding, occasional micro cross bedding.
8,654	***Top of thin channel.*** Sandstone, very fine to fine grained, shale laminations, micro cross bedding. Most shale laminations truncate sandstone layers.
8,654.5	Sandstone, fine to very fine grained, wavy bedding, occasional shale laminae, visible porosity.
8,655–8,656	Sandstone, fine grained, occasional mud clasts and carbonaceous/micaceous layers and interbedded carbonaceous debris. Horizontal to wavy bedding. ***Base of thin channel.***
8,656–8,664	***Upper channel facies*** (***main channel***). Sandstone, very fine grained with carbonaceous shale interbeds as much as 0.5 in. thick. Numerous carbonaceous shale laminae with mica. Sandstone layers 0.5–0.4 in. thick often with micro cross bedding or wavy bedding.
8,664.5–8,667	***Middle channel facies.*** Sandstone, fine grained, contorted bedding (flowage) grading downward into high-angle bedding and, at 8,667 ft, to horizontal bedding. Uniform grain size, very few carbonaceous shaly laminae.
8,667.5–8,669	Sandstone, fine grained, mostly horizontal bedding, few carbonaceous laminae.
8,669.5–8,670.5	***Lower channel facies.*** Sandstone and mud rip-up clast conglomerate. Interval contains two graded-bed sets with deformed mud clasts (0.1–0.5 in. diameter) that grade upward into fine grained sandstone. Occasional carbonaceous debris. ***Base of channel assemblage.***
8,670.5–8,671	Shale.

TXO Production Corporation Payne No. 17-1

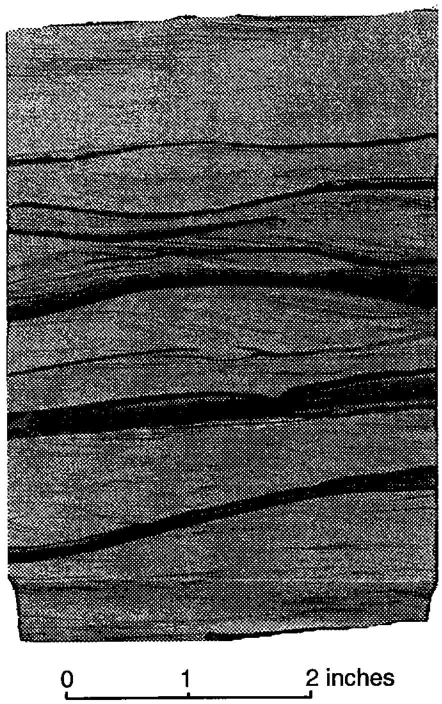
Cored interval: Middle Skinner
Depositional environment (Skinner): Fluvial-channel assemblage

Interval cored (log depth): 8,656–8,681 ft
Reported core interval (core depth): 8,646–8,671 ft



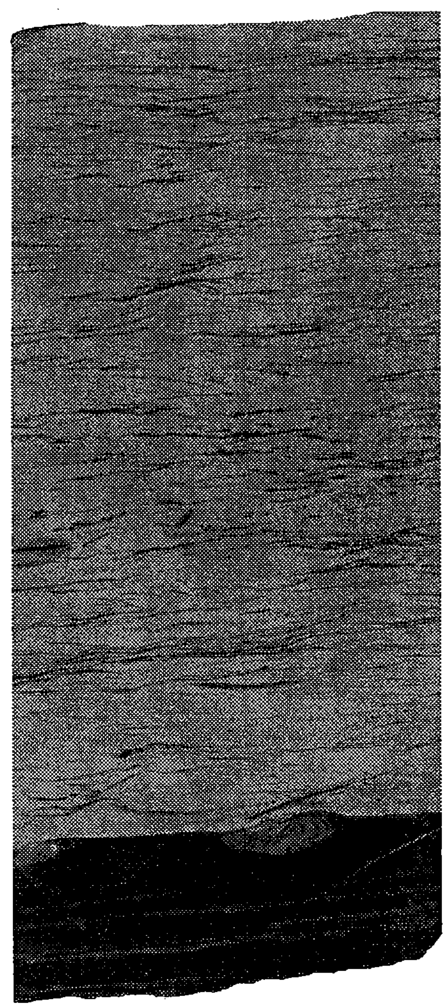
T.D.: 9,148 ft
Completion date: 6/21/85
Perforated (Mayes) lime: 9,040–9,072 ft
IPF (Mayes) not reported

TXO Production Corporation Payne No. 17-1



Core depth: 8,657–8,657.5 ft
Log depth: ~8,667–8,667.5 ft

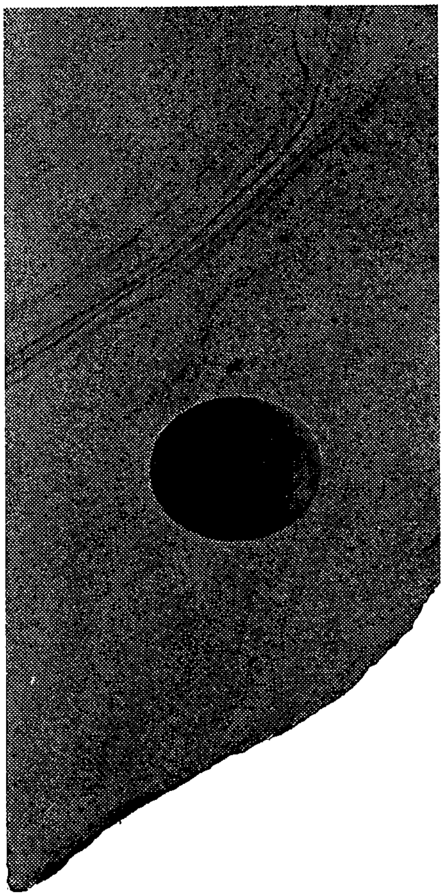
Upper channel facies. Very fine grained ripple-laminated sandstone with interbedded shale (clay drapes).



Core depth: 8,663–8,663.5 ft
Log depth: ~8,672–8,672.5 ft

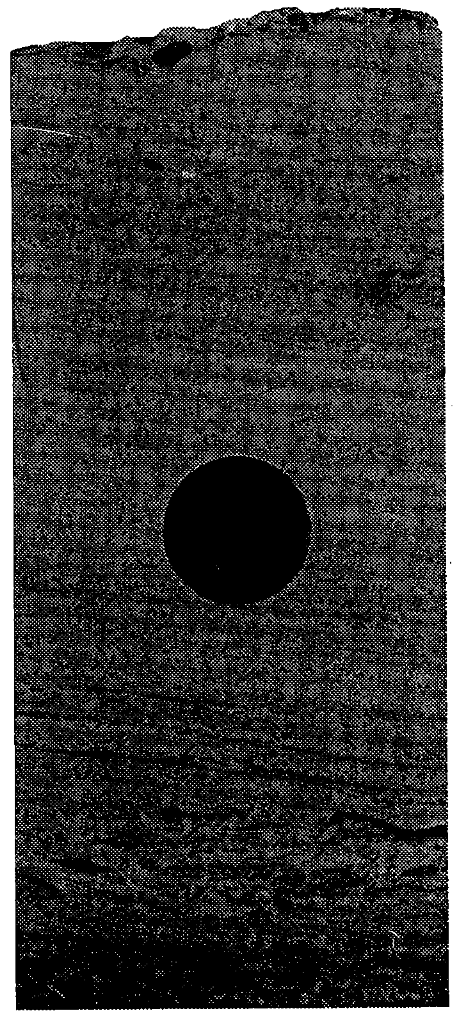
Upper channel facies. Very fine grained ripple-laminated sandstone with very thin, discontinuous clay laminae (mud flasers?). Contact with underlying shale is sharp.

TXO Production Corporation Payne No. 17-1



Core depth: 8,665–8,665.5 ft
Log depth: 8,675–8,675.5 ft

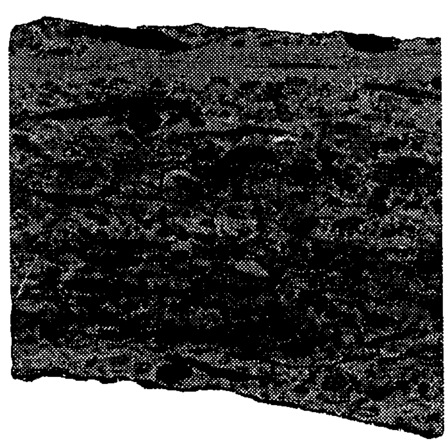
Middle channel facies. Fine grained sandstone with contorted bedding (flowage). Carbonaceous material present on the high-angle (deformed) bedding surface at base of sample. Contorted bedding and carbonaceous laminae are common in the middle parts of point bar deposits.



Fine grained sandstone

Core depth: 8,669–8,670 ft
Log depth: 8,679–8,680 ft

Lower channel facies. Basal mud clast conglomerate grades abruptly upward into fine grained sandstone.



Mud clast conglomerate

Sullivan and Company Diamond "L" No. 1

SW¼SW¼SW¼ sec. 4, T. 16 N., R. 2 E.

Prue Sandstone Core

Log depth ≈ Core depth – 8 ft   Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
4,320–4,330	Not described.
4,331–4,333	***Upper channel facies.*** Interbedded sandstone, very fine grained and black silty shale. Sandstone lenses as much as 1 in. thick with micro scour and fill. Pyritic wood fragments and carbonaceous debris interbedded with black shale common.
4,334–4,336	Sandstone, very fine to fine grained, interbedded with shale laminae, wavy to faint ripple bedding. Brown specks of aggregated clay throughout sandstone. Interbedded sandstone has micro scour to slightly inclined bedding. Shale interbeds highly carbonaceous with abundant mica. Sand layers become thicker with depth.
4,336–4,338	***Middle channel facies.*** Sandstone, fine to very fine grained, slightly inclined to horizontal bedding. Carbonaceous laminae less abundant, mica still present. Occasional suspended compressed mud clasts. Brown colors are fine aggregates of clay.
4,338–4,339	Sandstone, fine to very fine grained, horizontal to high-angle cross bedding.
4,340–4,342	Sandstone, very fine grained, slightly to moderately inclined bedding, eroded bedding surfaces, tight.
4,342–4,345	Sandstone, fine to very fine grained, occasional visible porosity, slightly to moderately inclined cross bedding, few carbonaceous interbeds, some woody material, tight.
4,346–4,348	***Lower channel facies.*** Sandstone, very fine to fine grained, moderately to highly cross bedding, occasional mud clasts, occasional inclined carbonaceous/micaceous shaly interbeds <0.5-in. thick. Woody fragments commonly visible within shaly interbeds.
4,349	Sandstone, fine grained, numerous mud clasts (0.1–0.25 in. diameter), moderately inclined bedding. ***Base of channel.***
4,350	Shale, black, heavy, highly carbonaceous with carbonized wood fragments, no fossils. ***Conglomeratic lag*** horizon ~2 in. thick with clay clasts 0.1–0.5 in. in diameter. Clay clasts are flattened and oriented parallel to bedding. Micro scour and fill within this zone. Possibly caused by a storm event or change in relative sea level?
4,351–4,362	Not described.

Sullivan and Company Diamond "L" No. 1

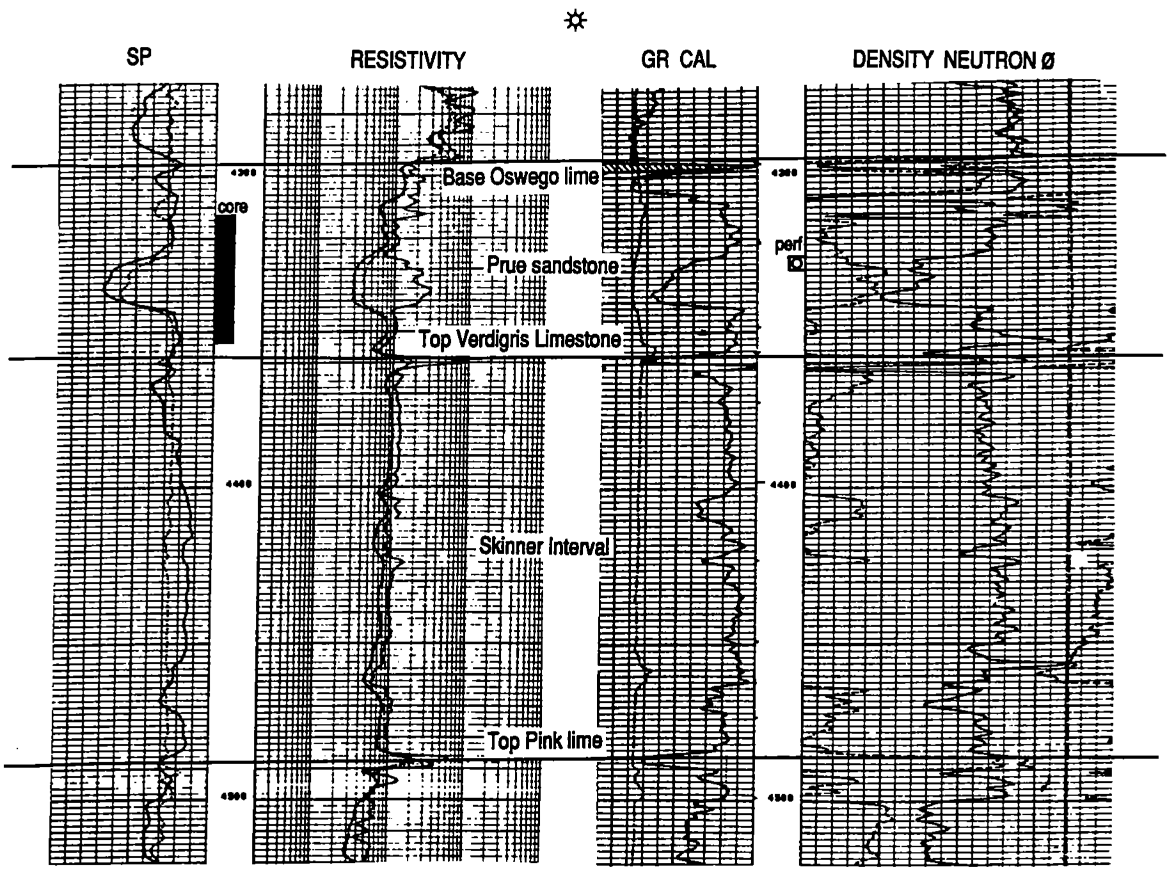
Reservoir: Prue sandstone

Depositional environment: Fluvial-channel, possibly point bar in a subaerial coastal or flood plain?

Interval cored (log depth): 4,312–4,354 ft

Reported core interval (core depth): 4,320–4,362 ft

Log Depth: ~8 ft above reported core depth



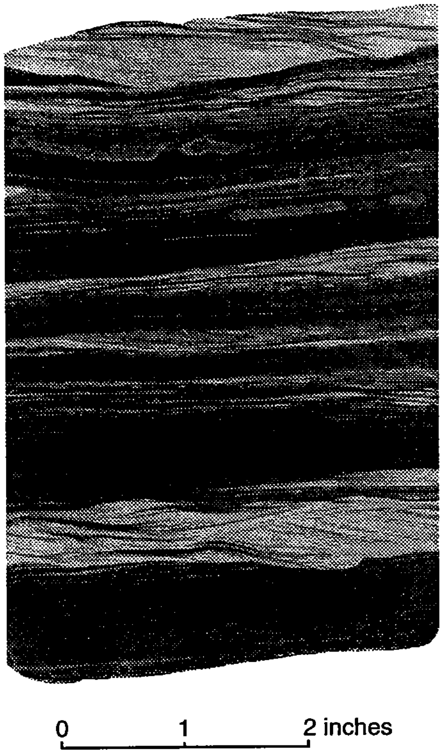
T.D.: 4,648 ft

Completion date: 5/12/81

Perforated (Prue): 4,326–4,331 ft

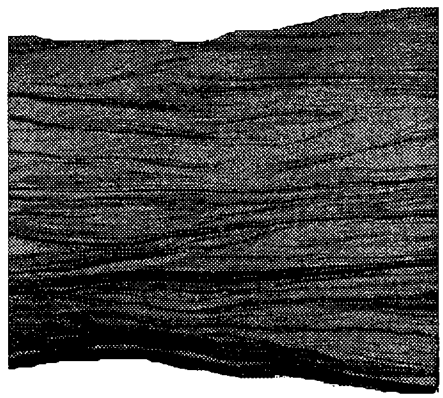
IPF (Prue) 325 MCFGPD + 67 BW

Sullivan and Company Diamond "L" No. 1



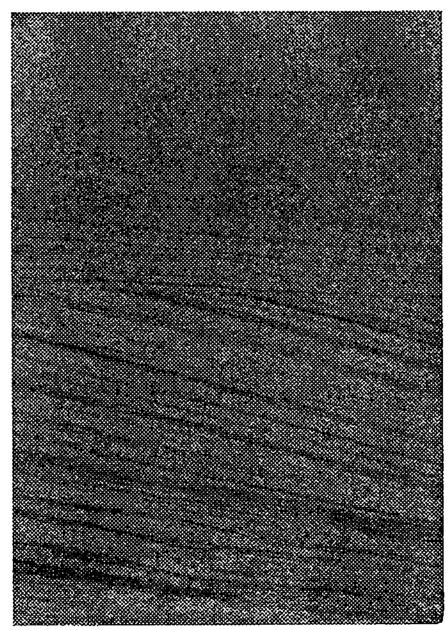
Core depth: 4,332–4,332.5 ft
Log depth: 4,325–4,325.5 ft

Upper channel (or flood plain) deposits. Interbedded black silty shale and very fine grained sandstone. Thin sand layers have small-scale cross bedding. Shale layers have pyrite lenses and interbedded carbonaceous debris. This core sample is above the main channel sandstone.



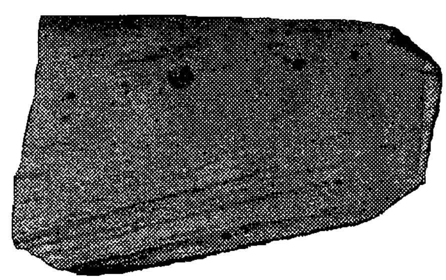
Core depth: 4,335.2–4,335.5 ft
Log depth: ~4,328 ft

Upper channel facies. Sandstone, very fine to fine grained, wavy bedding, occasional small-scale cross bedding and interbedded shale laminae. Carbonaceous debris on bedding surfaces.



Core depth: 4,341–4,341.5 ft
Log depth: ~4,334–4,334.5 ft

Middle channel facies. Sandstone, very fine to fine grained, moderate to high-angle tabular cross bedding.



Core depth: 4,349 ft
Log depth: ~4,341 ft

Lower channel facies. Sandstone, fine grained, occasional mud clasts, cross stratified with carbonaceous debris and mica on foresets.

Oklahoma Geological Survey
Supplement to Special Publication 96-2

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Skinner and Prue Plays

PART III

Reservoir Simulations

◁ CONTENTS ▷

LIST OF ILLUSTRATIONS

Figures

Tables

RESERVOIR SIMULATION OF A SKINNER RESERVOIR, SALT FORK NORTH FIELD, GRANT COUNTY, OKLAHOMA

Z. N. Bhatti and R. M. Knapp
School of Petroleum and Geological Engineering
University of Oklahoma

INTRODUCTION

The Salt Fork North field is located in secs. 19, 29, and 30, T. 25 N., R. 3 W., and sec. 24, T. 25 N., R. 4 W., Grant County, Oklahoma (Fig. 34, Part II). Production is from the upper and lower Skinner sandstones, which are separated by a thin, widespread shale bed (Fig. 36, Part II). The field was discovered in 1981 by Rincon Resources Hall No. 1 well in the NW¼SE¼NE¼ sec. 24, T. 25 N., R. 4 W. (Fig. 34, Part II). The Salt Fork North reservoir is at a depth of about 5,000 ft (–3,850 ft subsea). The field has been developed on 40 acre spacing and is almost fully developed.

Fifteen Skinner wells have been completed in the Salt Fork North field. Thirteen wells have penetrated the upper Skinner reservoir, which has an average net thickness of 15 ft and a productive area of 645 acres (Fig. 45, Part II). The lower Skinner has been perforated in six wells, four of which were completed in both the upper and lower Skinner. The lower Skinner has an average net thickness of 18 ft and 375 acres of productive area (see p. 43, Part II). The lithology of the upper Skinner is not as uniform as that of the lower Skinner (Part II).

The estimated initial oil in place in the Salt Fork North field is 3.4 MMSTB; only 7% had been recovered as of January 1996.

FIELD DEVELOPMENT AND PRODUCTION PERFORMANCE

Development of the Salt Fork North field began in May 1981 with the completion of Rincon Resources Hall No. 1 in the upper Skinner from 4,964 ft to 4,978 ft. The flowing initial potential (IP) reported was 65 BOPD, 200 MCFPD, and 60 BWPD. The Pauline No. 1, drilled by DEM Operations in May 1983, penetrated both the upper and lower Skinner, and reported a flowing IP of 240 BOPD, 1,068 MCFPD, 200 bbl of fracture water. Information about the individual wells in the Salt Fork North field is provided in Table 14.

Nine wells were drilled in the Salt Fork North field from May 1981 to May 1985 (Table 14). Production from the field peaked in May 1985 at 150 BOPD and 1,600 MCFPD. Three more wells were completed by the end of 1985 (Table 14); however, the wells could not sustain the field production rate and by September 1989, the production had declined to only 20 BOPD and 270 MCFGPD. Three wells drilled during 1989–90 increased the field production rates to 72 BOPD and 560 MCFGPD. A total of 15 wells have been completed in the upper and lower Skinner.

The most productive lease has been the Duvall lease, which has produced >65 MSTB of oil from four wells. The Pauline No. 1 has been the best well, with a cumulative production of just over 32 MSTB of oil and 370 MMSCF of gas through December 1990. The Hall No. 1 well was abandoned in 1984 after almost three years of production with a cumulative oil production of 4,074 STB.

Insight into water production was obtained from the field operator, Don E. Muegge. His estimates of the amount of water produced by each well in the field range from no water (from the Douglas No. 1) to a water-to-oil ratio of 2:1 for the Salt Fork No. 2 well. Most of the wells in the field were fractured with 50,000–80,000 lb of sand. One can imagine that big fractures have been created, but it is not possible to predict the extent and direction of the fractures. Some wells have produced water since they were completed, located wells located relatively high structurally. This can be explained in part by the high water saturations in the lower Skinner; however, it is evident that induced fractures have extended downward into the lower water-bearing zones.

In late 1994, the Duvall No. 1 was completed in another formation as a water supply well, and the Duvall No. 4 was converted to a water injection well. Water injection into the Duvall No. 4 well began in late 1994 but was temporarily discontinued because of water supply well problems after only 800 bbl had been injected. Injection was restarted by mid-November 1995. Unfortunately, water breakthrough in the Mack No. 1 occurred within less than a month. As of December 1995, 19,200 bbl of water had been injected into the Duvall No. 4. The average field water cut (water as a percentage of total fluid produced) was 55%.

The reservoir oil likely was initially saturated. Wells completed above –3,900 ft subsea had initial gas-oil ratios above 3,000 SCF/STB, while wells completed well below that depth had initial gas-oil ratios below 1,000 SCF/STB. The common correlation used to estimate solution gas-oil ratio gave a value of 650 SCF/STB at the initial pressure of 1,995 PSIA. The aquifer associated with the reservoir is probably less that half the reservoir's size, and water influx has not been an important source of reservoir energy. The three gas caps are small, they have been partially depleted by gas

TABLE 14. – Skinner (Upper and Lower) Sandstone Wells, Salt Fork North Field

Operating Company / Map Identification	Well Location T25N	Initial Production Date	Cumulative Production Since 1981	Formation Top-Bottom ft	Perforation Top-Bottom ft
Rincon Resources / Hall #1	C SW SE NE 24 R 3W	6-1-81	4367 STB	4964-4978	4964-4978
DEM Operations / Duvall #1	NW SW SW 24 R 3W	7-3-81	39726 STB	4988-5016	4990-5006
DEM Operations / Pauline #1	SW NW 19 R 3W	5-13-83	35845 STB 357496 MCF	4952-5008	4970-5000
DEM Operations / Duvall #2	C NW SW 19 R 3W	9-1-83	17959 STB	4960-4982	4960-4980
DEM Operations / Douglas #1	S2 SE NE 24 R 4W	4-24-84	185409 MCF	4946-4962	4949-4960
DEM Operations / Duvall #3	NE SW 19 R 3W	10-10-84	188624 MCF	4952-4974	4954-4972
DEM Operations / Mack #1	C W½ SW SE 19 R 3W	12-15-84	25074 STB	4952-4986	4954-4982
DEM Operations / Marguerite	C E½ W½ SE NW 19 R 3W	4-2-85	9386 STB	4934-4949	4934-4949
DEM Operations / Hamilton #1	C N NE NE 30 R 3W	4-27-85	34336 STB	4958-4982	4960-4980
DEM Operations / Duvall #4	NW SE SE SW 19 R 3W	9-15-85	1754 STB	4982-5000	4983-4998
DEM Operations / Mack #2	SW SE SE 19 R 3W	9-19-85	150524 MCF	4919-4942	4920-4941
DEM Operations / Crisman #1	SW NW NW 29 R 3W	10-9-85	17447 STB	4932-4942	4932-4942
DAR-LON Operating / Salt Fork #1	NE NE 24 R 4W	10-3-89	28525 STB	4956-5020	4956-4986
DEM Operations / Salt Fork #2	C NW NE 24 R 4W	4-18-90	8194 STB	4942-4994	4942-4960
DEM Operations / Pauline #2	C SW NW NW 19 R 3W	4-25-90	10156 STB	4948-4996	4948-4972

wells, and the low reservoir permeability has limited the effectiveness of the gas caps as sources of primary reservoir energy. In late 1995, before water injection was resumed, the reservoir pressure was quite low, and it is believed that the dominant source of primary reservoir energy was solution gas expansion.

MODEL DEVELOPMENT

The most reliable data for the Salt Fork North field were obtained from well logs. No wells in the field were cored. However, core analysis reports from the Glen No. 2 in sec. 5, T. 24 N., R. 3 W. and the Kelly No. 1 in sec. 32, T. 25 N., R. 3 W. (~0.5 mi and 1 mi south of the study area, respectively) in the Salt Fork S.E. field were available. Porosity and permeability plots from the core analyses are shown in Figure 46 (Part II). The Skinner sandstone in the Salt Fork S.E. field is correlated to the upper Skinner in the study area and is interpreted to have been deposited in the same depositional environment as the Skinner in the study area (Part II). The core reports were helpful in estimating the absolute permeability distributions for both the upper and lower Skinner. Higher permeabilities were used in simulator blocks near wells in order to represent the effects of fracturing.The average permeabilities for the upper and lower Skinner were estimated to be 7 md and 12 md, respectively.

TABLE 15. – Average Reservoir Properties for the Skinner Reservoir

Average Properties	upper Skinner	lower Skinner
Porosity	11 %	12 %
Permeability	7 md	12 md
Gross Pay	20 ft	22 ft
Net Pay (ϕ > 10%)	15 ft	18 ft
Reservoir Temperature	155 °F	155 °F
Specific Gas Gravity	0.8	0.8
Oil Gravity	41 °API	41 °API
Initial Water Saturation	45 %	45%
Initial Bottom Hole Pressure	1990 psia	1990 psia
Initial Solution Gas Oil Ratio	386 SCF/STB	386 SCF/STB
Initial Oil Formation Volume Factor	1.37 RB/STB	1.37 RB/STB
Initial Oil in Place	1964 MSTB	1466 MSTB

From the well logs and scout tickets, Richard Andrews prepared structure and isopach maps of the field. Regional dip is ~1° to the southwest (Fig. 39, Part II). The structure map of the top of the upper Skinner sand is shown on p. 46 (Part II). The upper Skinner net sandstone isopach map is shown on p. 47, Part II. The structure map of the top of the lower Skinner is shown on p. 44 (Part II). The upper Skinner net sandstone isopach map is shown on p. 47 (Part II). These maps were digitized and form part of the data file describing the reservoir model.

Water saturations calculated from logs range from 32% to 50% for the upper Skinner and from 26% to 90% for the lower Skinner (Fig. 49, Part II). An average connate water saturation value of 45% was chosen for both zones after careful analysis. The well logs available for porosity determination were the neutron and density porosity logs. The spontaneous potential and gamma ray logs also were used to estimate percent shale for a shale correction for the density logs. The porosity of the upper Skinner ranges from 10% to 16% and averages ~12%. The porosity of the lower Skinner ranges from 8% to 15%, and averages ~13%.

Relative permeabilities were estimated using Honarpour's method (Honarpour and others, 1986). Capillary pressures were calculated using the Smith (1991) method. The oil gravity ranged from 39° to 42°API, except at the discovery well, Hall No. 1, where it was measured at 33°API. The Duvall No. 3 and the Mack No. 2 reported high initial production gas-to-oil ratios of 13,333 SCF/STB and 22,500 SCF/STB, respectively. These wells are relatively high structurally and penetrated the initial gas cap. Initial production gas-to-oil ratios reported for the other wells in the field ranged from 933 to 4,450 SCF/STB.

A single set of fluid properties estimated from Standings correlations (Craft and others, 1991) was used for the upper and lower Skinner. The initial formation volume factor was estimated to be 1.37 RB/STB. Dead oil viscosity of 3.97 cp and density of 51.56 lb/ft^3 at 60°F and water density of 71.79 lb/ft^3 were measured in the laboratory on a fluid sample from Salt Fork North field. The viscosity of the oil at initial reservoir conditions was estimated to be 0.77 cp from the Standing correlations. The gas gravity was assumed to be 0.8 and the average reservoir temperature reported was 155°F. The average reservoir and fluid properties used for the Salt Fork North field are listed in Table 15.

It is worth noting that actual production of oil, water, and gas from the individual wells are data necessary for accurate model development. Sales of oil and gas may not reflect actual production timing and should be adjusted because the actual withdrawals are important. Other data that are important include initial well tests and well pressures measured on a regular basis to aid in identifying sources of primary reservoir energy.

HISTORY MATCHING

The reservoir model was tested by history-matching runs for each well. The history-matching process entails adjustment of the reservoir description in order to bring the simulated gas and water production rates into close concert with the observed production rates. The operator's estimates of December 1995 field pressures were another target for matching. Oil production rates were chosen as the control parameter for most of the wells. Gas production rates were used as the control parameter for the four wells that were classified as gas wells.

A good history match is interpreted to be an indication that the reservoir model adequately represents the reservoir and can therefore be used to predict future performance. For the Salt Fork North field, the parameters that were adjusted to obtain the history match were structural tops between wells, porosity, permeabililty, and relative permeabilities to oil and gas.

The initial oil in place estimated from volumetric integration of the simulation model is 3.4 MMSTB. The estimate, lower than that given in Table 5 (Part II), results from including the effects of the gas caps, a slightly higher assumed connote water saturation, and using more detail to represent the oil-leg of the reservoir. Cumulative production at the end of 1995 was 239 MSTB, or 7% of the original oil in place. Based on the estimated initial oil saturation of 55% and residual oil saturation of 15%, the maximum oil recovery could be as much as 2.5 MMSTB, leaving 0.9 MMSTB unrecoverable.

Based on the production histories of individual wells and depth contraints placed on oil-water and gas-oil contacts by production from individual wells, the reservoir model contains three regions, two in the upper Skinner and one in the lower Skinner. Oil-water contacts in the upper Skinner are at –3,946 ft and –3,948 ft, and the gas-oil contacts are –3,910 ft and –3,894 ft. The lower Skinner oil-water contact is at –3,952 ft, and the gas-oil contact is at –3,880 ft.

ALTERNATIVE EXPLOITATION SCHEMES

The cumulative oil recovery of 239 MSTB at the end of 1995 represented only 7% of the estimated 3.4 MMSTB of original oil in place. The theoretical maximum recovery, which is based on the estimated initial oil saturation of 55% and residual oil saturation of 15%, could be as much as 2.5 MMSTB of oil, which provides the incentive to improve the apparent recovery factor of the reservoir. The reservoir model was used to predict the behavior of the reservoir under different reservoir management strategies. The following are four out of several options that were examined. The options are (1) to continue the current waterflood operation, (2) to expand the waterflood with existing wells, (3) gas injection, and (4) gas injection followed by waterflood.

Current Waterflood Operation

In 1995, the operator completed the Duvall No. 1 in another formation as a water supply well and began injecting water into the Duvall No. 4 well. At that time, the Marguerite and Douglas wells had been temporarily abandoned. Of the 15 Skinner wells in the field, 11 wells are being produced, one is a water injection well, one is a water supply well, and two are not being produced under the current waterflood operation. In the simulation, production wells were operated at a low constant bottomhole pressure, water was injected into the Duvall No. 4 well at a rate of 200 BPD, and producing wells that exceeded the economic limit of 80% water cut were shut in. This case was simulated for 10 years, January 1996 through December 2005. The results of the simulation are listed below:

1) An increase in production was observed after seven years of water injection.

2) A total of 710 MSTB of water was injected into the Duvall No. 4 well; cumulative field water production was 26 MSTB.

3) The Mack No. 1 was shut in after a few months and the Mack No. 2 was shut in during year 5 when water production reached the economic limit of 80% water cut.

4) The reservoir pressure did not increase.

5) The field production rate peaked at 18 BOPD in the ninth year of water injection and decreased to 17 BOPD by year 10.

6) In 10 years (1996 through 2005) 34 MSTB, or 1% of the estimated 3.4 MMSTB original oil in place (OOIP), were produced bringing cumulative production for the field to 273 MSTB or 8% of OOIP (Fig. 77).

Expanded Waterflood

Several different waterflood designs were investigated in order to identify one that would increase the production rate and reservoir pressure more rapidly than the current operating program. The most efficient design used six existing wells for water injection and eight existing producers. The Duvall No. 1, Duvall No. 4, Mack No. 1, Marguerite, Pauline No. 1, and Salt Fork No. 2 wells were used as water injectors, and, except for the Hall No. 1, the remaining wells were employed as producers.

In the simulation, bottomhole pressure was controlled in the production wells, and the water injection rate for each injection well was 200 BWPD. The economic limits were set from 80% to 90% water cut, depending on the location of the producing well. The following results were obtained from a 15-year simulation:

1) Oil and gas production rates began to increase during year 2.

2) At the end of 15 years, 2.7 MMSTB of water had been injected and the field water cut was ~70%.

3) The Mack No. 2, Pauline No. 2, and Duvall No. 3 wells reached the 80% or 90% water cut limit and were shut in during years 4, 6, and 13, respectively.

4) The reservoir pressure should rapidly increase, and, at the end of 15 years, the average reservoir pressure should be close to 2,400 PSIA.

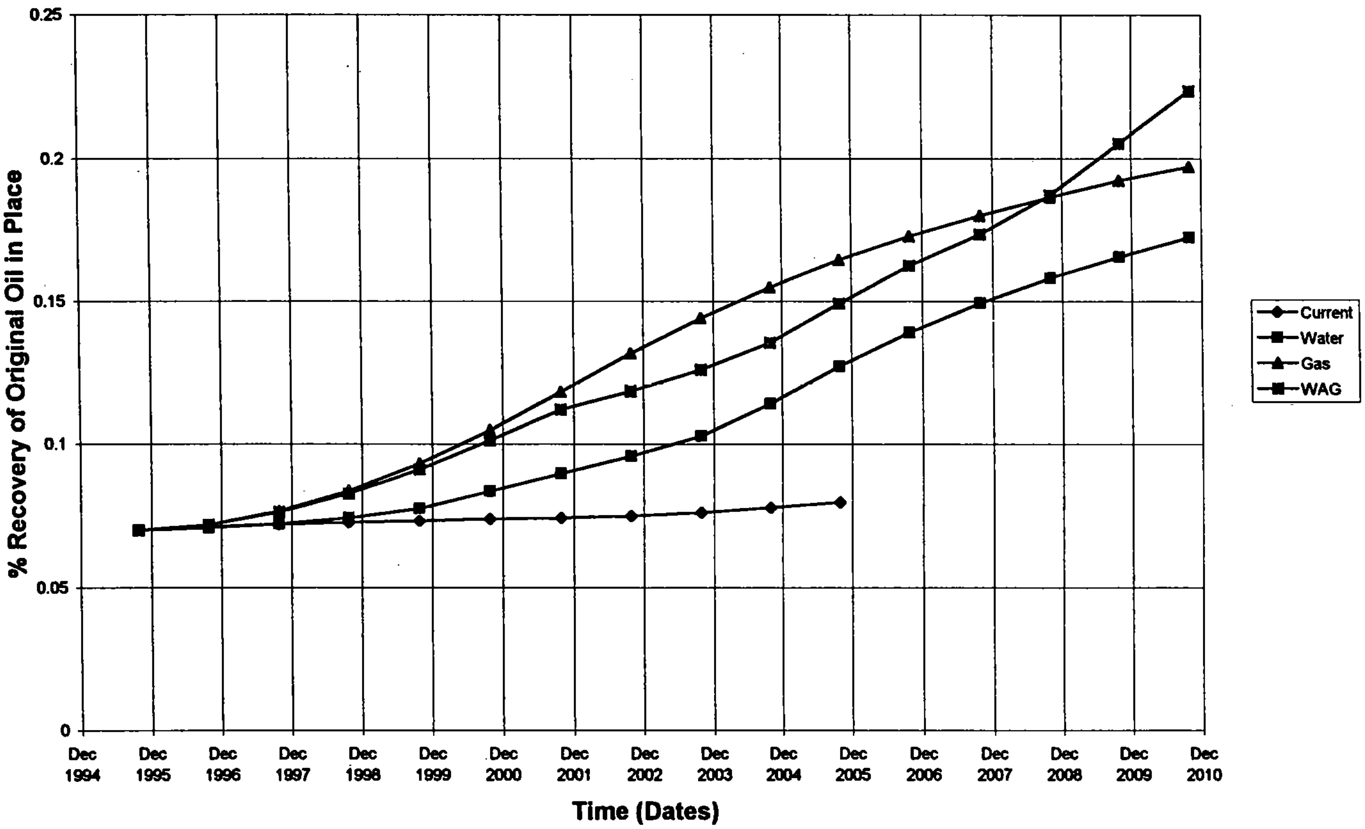


Figure 77. Predicted outcome of exploitation schemes from 1996 to 2010, based on simulation results.

5) The oil production rate peaked during year 9 at 120 BOPD and had dropped to 63 BOPD at the end of year 15.

6) In 15 years, 352 MSTB, or 10% of the estimated OOIP, were produced, bringing the cumulative field production to 591 MSTB, or 17% of OOIP (Fig. 77).

7) The most successful wells in the field are expected to be the Douglas, Salt Fork No. 1, and Duvall No. 3. The Crisman No. 1 well, on the southeastern edge of the lower Skinner zone, did not produce much additional oil.

Immiscible Gas Injection

Different gas injection strategies to increase reservoir pressure and reduce oil viscosity were considered. The most effective design used seven gas injection wells in a line drive pattern. The six wells used in the water injection case were used for gas injection using an injection rate of 350 MCFPD per well. In addition, the Crisman No. 1 well was used to inject gas in the lower Skinner. Another production well in NE¼SE¼ NE¼ sec. 30 was completed in the lower Skinner interval to enhance volumetric sweep (see Fig. 41, Part II).

The gas-oil ratio economic limit range for producing wells was 400–700 MCF/STB for the first two years and 100 MCF/STB for the next 13 years. It was necessary to do this because 1996 pressures in the reservoir were quite low and some of the wells were already producing at high gas-oil ratios. They would instantly have been shut in if the economic limit was kept low. Wells were produced at constant pressure for 15 years. The following results were obtained from this run:

1) An increase in production rate occurred after one year of injection.

2) The cumulative gas injection in the field should be ~12.5 MMMCF, with an incremental gas production of 10.5 MMMCF.

3) Field water production rates should increase, as occurred in the primary production case. However, the water cut in the field should decrease to 30%.

4) The average field pressure should peak seven years into the gas flood at just under 1,700 PSIA. Following the peak, the average field pressure should decrease slowly, and, after 15 years, be ~1,500 PSIA.

5) The field oil production rates should peak at 130 BOPD during year 5 and decrease to 41 BOPD at the end of year 15.

6) The 15-year cumulative incremental oil recovery with this strategy is expected to be 440 MSTB, for an incremental oil recovery of 13% and a total of 20%, as shown in Figure 77.

7) The Mack No. 2 well is quite near the Mack No. 1 injection well. It quickly started producing gas and was shut in by the end of year 2. Two wells, the Pauline No. 2 and Duvall No. 3, were shut in 14 years into the flood.

8) The Salt Fork No. 1 and Douglas wells should be the best production wells in the field, with a cumulative oil production of 220 MSTB.

Alternating Gas with Water Injection

The idea of alternating gas and water injection is to take advantage of the repressuring and viscosity reduction benefits of the gas, followed with inexpensive water injection with favorable mobility. Several runs were made with different numbers of injection wells and also with different injection times for the gas and water. The case discussed here had more promising results than the other runs.

Gas was injected in the same six wells used in the expanded waterflood plan for 5.5 years at a rate of 350 MCFPD per well. For the next 9.5 years, water was injected at a rate of 200 BWPD per well, with two exceptions. After 1.5 years of water injection at 200 BWPD, the Mack No. 1 injection rate was decreased to 120 BWPD. After the 1.5 years of water injection at 200 BWPD, the Duvall No. 4 injection rate was increased to 240 BWPD for a better sweep. In year 7, the upper Skinner in the Mack No. 2 well was shut in because of high water cut; the lower Skinner production continued.

This recovery protocol was also simulated for 15 years. Economic limits were the same as those used in the waterflood simulation (80–90% water cut) and in the gas injection simulation (100 MCF/STB). The following results were obtained from this run:

1) An increase in production rates occurred after one year of gas injection.

2) Cumulative gas injected was 4.2 MMMCF, and 3.7 MMMCF of gas was produced; 2,234 MSTB of water was injected, and 350 MSTB was produced.

3) Water production decreased during gas injection and increased during water injection. The field water cut at the end of 15 years was 50%.

4) The average field pressure peak was just over 1,500 PSIA and occurred at the end of the gas flood. The average field pressure decreased with the start of water injection. After fill-up (after about one year of water injection), the pressure should steadily increase and, at the end of 15 years, should be >2,000 PSIA.

5) The oil production rate increased to 110 BOPD by year 5 and dropped to 53 BOPD two years later. After one year of water injection, following "fill-up," the oil production rate started increasing again. At the end of the 15 years, the field production rate was 170 BOPD and had not yet leveled off. Note that the oil production rate for this case is 2.5 times greater than for the simple waterflood case at the end of the 15-year simulation.

6) The field gas production rate should increase rapidly during the gas flood, but only solution gas will be produced during the water injection phase.

7) In the 15 years simulated, more than 500 MSTB of oil was produced, 15% of OOIP (Fig. 77).

8) The Douglas, Salt Fork No. 1, and Duvall No. 3 wells were the most productive wells in the field with simulated cumulative production of 380 MSTB.

9) The Mack No. 2 well, located quite near the Mack No. 1 injection well, started producing gas and was shut in by the end of year 2 and was re-opened at the beginning of the water injection phase. The Pauline No. 2 well was shut in after 11 years because of water breakthrough.

CONCLUSIONS AND RECOMMENDATIONS

The conclusions drawn and recommendations made about the reservoir simulation model study are as follows:

- On the basis of the exploitation schemes discussed above, the gas injection followed by water injection strategy seems to be the best. After 15 years, this scheme should recover 3% and 5% more oil than the gas and water injection cases, respectively. In addition, at the end of the 15-year simulation, the oil production rate is at its maximum and had not yet leveled off.
- The main reasons for low productivity are low permeability and limited reservoir energy, which results in low pressures, high oil viscosity, and low mobility.
- The water cut problems in some wells result from the large well fracture treatments.
- In the management plans studied, shutting in production wells for pressure buildup did not appear to be beneficial.
- The reservoir should be studied to determine the continuity of the reservoir, flow units, and fluid and rock properties. This can be done by conducting well tests and tracer tests. A fresh core studied in the laboratory would yield valuable insight.

ACKNOWLEDGMENTS

Rick Andrews provided the field geological data, developed the structural and isopach maps, and provided frequent counsel about the behavior of the reservoir model. Don E. Muegge, the field operator, and his staff provided valuable insight into the water production levels and behavior of the wells in the field.

RESERVOIR SIMULATION OF A PRUE RESERVOIR, LONG BRANCH FIELD, PAYNE COUNTY, OKLAHOMA

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

INTRODUCTION

The Prue oil reservoir in the Long Branch field is located in secs. 2, 10, and 11, T. 18 N., R. 4 E., Payne County, Oklahoma (Fig. 64, Part II). The Prue sand in this field is at depths of 3,300 ft (–2,400 ft subsea). A complete discussion of the Long Branch Prue reservoir, including petrology, depositional environment, and exploration strategy, can be found in Part II of this volume. Production is from the lower Prue sandstone, which was deposited in a northeast-southwest–trending fluvial channel. The channel deposit extends to the northeast and to the southwest (below the oil-water contact) beyond the Prue pool. The thickness of the reservoir is 27 ft with an areal extent of 800 acres (see Fig. 72, Part II).

The major objective of this study was to use existing data to develop a reservoir simulation model of the Prue pool of the Long Branch field for use in BOAST 3 (Mathematical & Computer Services, Inc., 1995). BOAST 3 software is a three-dimensional, three-phase black oil applied simulation tool (simulator), which is available to the public from the U.S. Department of Energy. The reservoir model developed can be used to analyze past field performance and to identify potential strategies to improve oil recovery.

OVERVIEW OF THE FIELD DEVELOPMENT

The Prue reservoir simulated in this study contains 14 production wells. The Prue discovery well in Long Branch field was the Barker No. A-1 (NE¼NW¼ sec. 11, T. 18 N., R. 4 E.; Fig. 65, Part II). The Barker No. A-1 was completed in February 1993 in the Prue and Peru sandstones; the reported initial pumping potential was 15 BOPD, 45 MCFGPD, and 250 BWPD. From May 1993 through June 1995, 13 more wells were completed in the lower Prue; nine were dual completions (Fig. 65, Part II).

The three-year production history of the study area is shown in Figure 78. The field oil production rate declined from the peak rate of 380 BOPD from 12 wells in the spring of 1995 (700–850 days, Fig. 78) to 220 BOPD in January 1996 (1,036 days, Fig. 78). The field water cut was ~80% in January 1996. The water cut in the Eaton No. 1-2 (Fig. 65, Part II) has reached 92%. The average initial pressure was 1,660 PSIA, and the oil is believed to have been initially undersaturated. Based on production data, the main recovery mechanism in this field is probably natural water drive. However, the areal extent of the aquifer is not known. Current average values of shut-in bottom-hole pressure are unknown. Almost all of the wells have had constant gas-oil ratios and the reservoir may still have been undersaturated as of January 1996. Through January 1996, total production from the Long Branch Prue reservoir is 217,300 STB of oil, 382,000 MCF of gas, and 880,000 STB of water (Greg Riepl, unpublished data).

DATA AVAILABILITY

Data used for reservoir characterization and simulation include depth to top of the lower Prue sandstone, net sandstone thickness ($\phi \geq 10\%$), porosity, permeability, initial gas-to-oil ratio (GOR), initial water saturation, and depth of the oil-water contact were obtained from Richard Andrews (see Part II). His maps of the depth to the top of the lower Prue sandstone (Fig. 70, Part II) and the net sandstone thickness (Fig. 72, Part II) were digitized and are part of the data file that defines the reservoir. Greg Riepl, independent petroleum geologist, provided oil, gas, and water production records, including estimates of Prue production from wells with commingled Peru production. The initial GOR for all 14 wells was estimated from production data. Data that are useful for reservoir studies but were unavailable for this study include (1) reservoir pressures at several times during production, and (2) capillary pressure and relative permeability data.

ROCK DATA AND FLUID PROPERTIES

The average porosity, permeability, and water saturation values used in the reservoir simulation model (Table 16) are based on data provided by Andrews and reported in Table 11 (Part II). Wells completed in the Prue sand were generally stimulated with fracture treatment so that permeabilities of 100 md were assumed for the simulation blocks containing wells. The elevation of the original oil-water contact interpreted from geophysical logs was –2,475 ft (Table 11, Fig. 70, Part II). An average 56.0% initial water saturation was used above the oil-water contact. Residual oil saturation of 20% was estimated from Bradley (1987). Capillary pressures were estimated using the method of Smith (1991). Initial relative permeabilities were estimated using Honarpour's method (Honarpour and others, 1986).

The average reservoir temperature reported from well logs was 108°F. The oil gravity averaged 41°API.

From reported production, initial GOR ranged from 100 to 3,000 SCF/STB; 600 SCF/STB was chosen as a representative value. Oil and gas fluid properties were estimated with the Standing correlations (Craft and others, 1991) using data reported by Andrews (Table 11, Part II). A specific gas gravity of 0.8 (air = 1.0) was used to match the average initial gas-oil ratio. The original saturation pressure (bubble-point) estimated from the Al-Marhoun correlation (McCain, 1990) was 1,580 PSIA. The estimated average initial oil formation-volume factor was 1.30 RB/STB, and oil viscosity at reservoir conditions was 0.53 cp. Average reservoir properties are listed in Table 16.

TABLE 16. – Average Reservoir Properties of the Prue Reservoir in Long Branch Field, Payne County, Oklahoma

Estimated Properties	Lower Prue Sand
Porosity	16%
Permeability	36 md
Average Net Pay	27 ft
Initial Water Saturation	56%
Initial Bottom-Hole Pressure	1,660 PSIA
Initial Gas-Oil Ratio	560 SCF/STB
Initial Formation-Volume Factor	1.30 RB/STB
Reservoir Temperature	108° F
Oil Gravity	41°API
Specific Gas Gravity	0.8
Initial Oil in Place	10.70 MMSTB

HISTORY MATCHING

To be confident that the reservoir model adequately represents the reservoir, the model was tested by matching the model-predicted production to the actual production (estimated in the case of commingled production) for each of the 14 wells in the study area. For the history-match simulations, the actual oil production rates were specified, because they were considered to be the most reliable data available. The targets for the history match were cumulative gas and water production. The history-matching process entails adjustment of uncertain parameters in the reservoir description so that the simulated production history matches the actual production history. There were no pressure or production data that would make it pos-

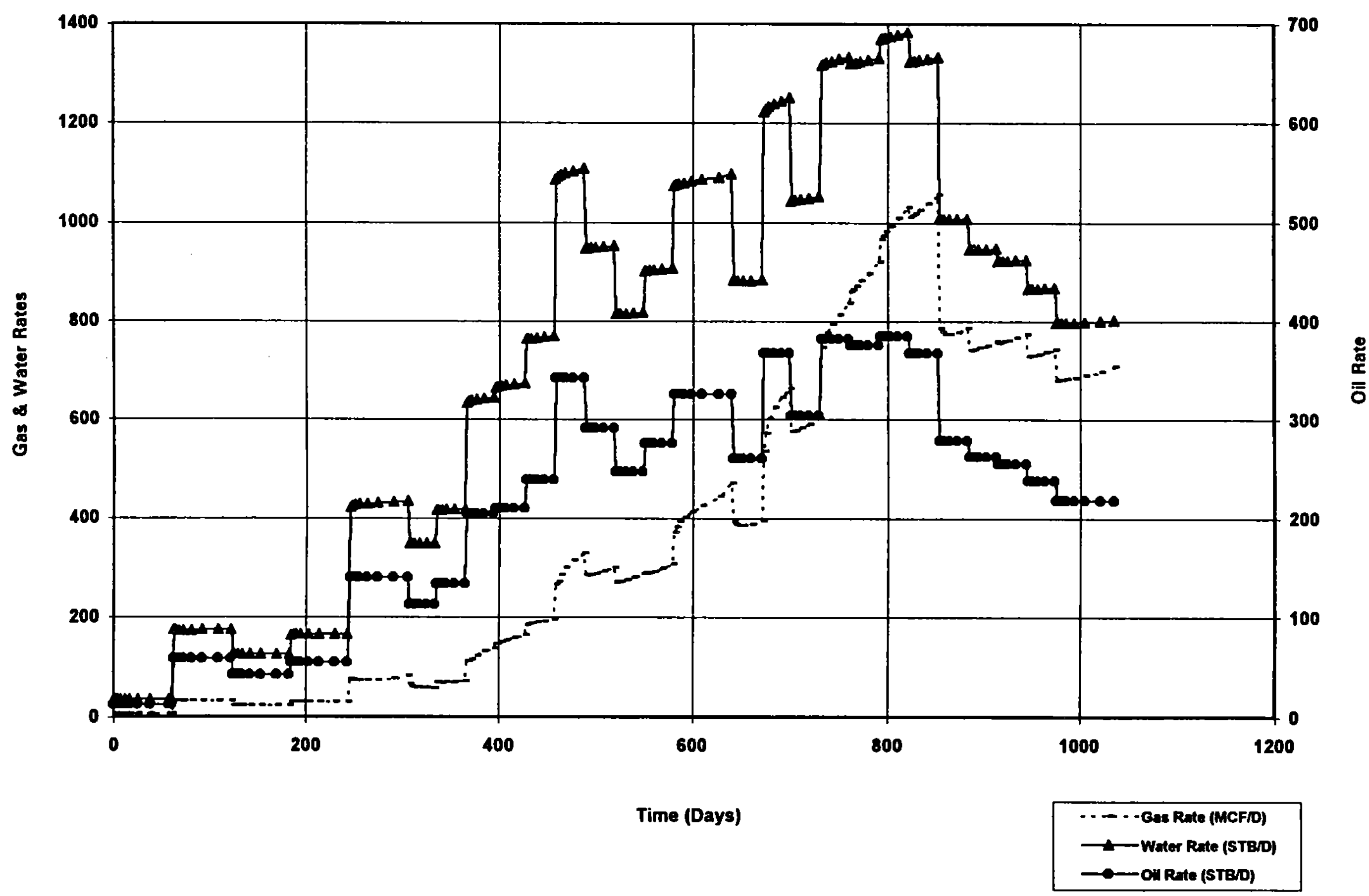


Figure 78. Prue oil, gas, and water production rates from May 1993 through January 1996, Long Branch field, Prue pool. Figure from Greg Riepl (unpublished data) includes estimates of Prue production from wells with dual completions.

sible to spatially vary reservoir properties. Therefore, for the Long Branch Prue reservoir, parameter adjustments were confined to properties that affected the entire reservoir. The model used average porosity and permeability. Properties that were adjusted were: (1) the water and oil relative permeability functions were modified to effect higher water and lower oil mobilities; (2) the initial oil and water saturations were raised to the upper part of Andrews' range (Table 11, Part II) to match high initial water production; (3) a 2% critical gas saturation, the minimum saturation for "free" gas flow, was selected to match historical gas production; and (4) to match the water production history, the initial oil-water contact was lowered 5 ft, and an external aquifer 30 times the volume of the oil reservoir was required. Figures 79 and 80 show the simulated gas and water production curves and the actual gas and water production curves for the Barker No. A-1 and Rosiere No. 1-10 wells. Good matches of cumulative and estimated cumulative gas and water production were obtained for most wells.

ESTIMATION OF RESERVES AND OIL RECOVERY FACTOR

The estimated total original oil in place in the Prue pool is 10.7 MMSTB. With the estimated residual oil saturation of 20%, the theoretical maximum recovery could be as much as 5.8 MMSTB, or 54% of OOIP. The estimated unrecoverable immobile oil is 4.9 MMSTB. The primary oil production from the Prue reservoir through January 1996 is ~217,290 STB (Greg Riepl, unpublished data), which leaves ~5.6 MMSTB (52% of OOIP) of unproduced mobile oil and a target for recovery.

EVALUATION OF FUTURE DEVELOPMENT OPPORTUNITIES

Three reservoir management strategies were simulated for 10 years: (1) current operations, (2) waterflood with existing wells, (3) waterflood with infill wells. The results predicted by the three strategies are shown in Table 17.

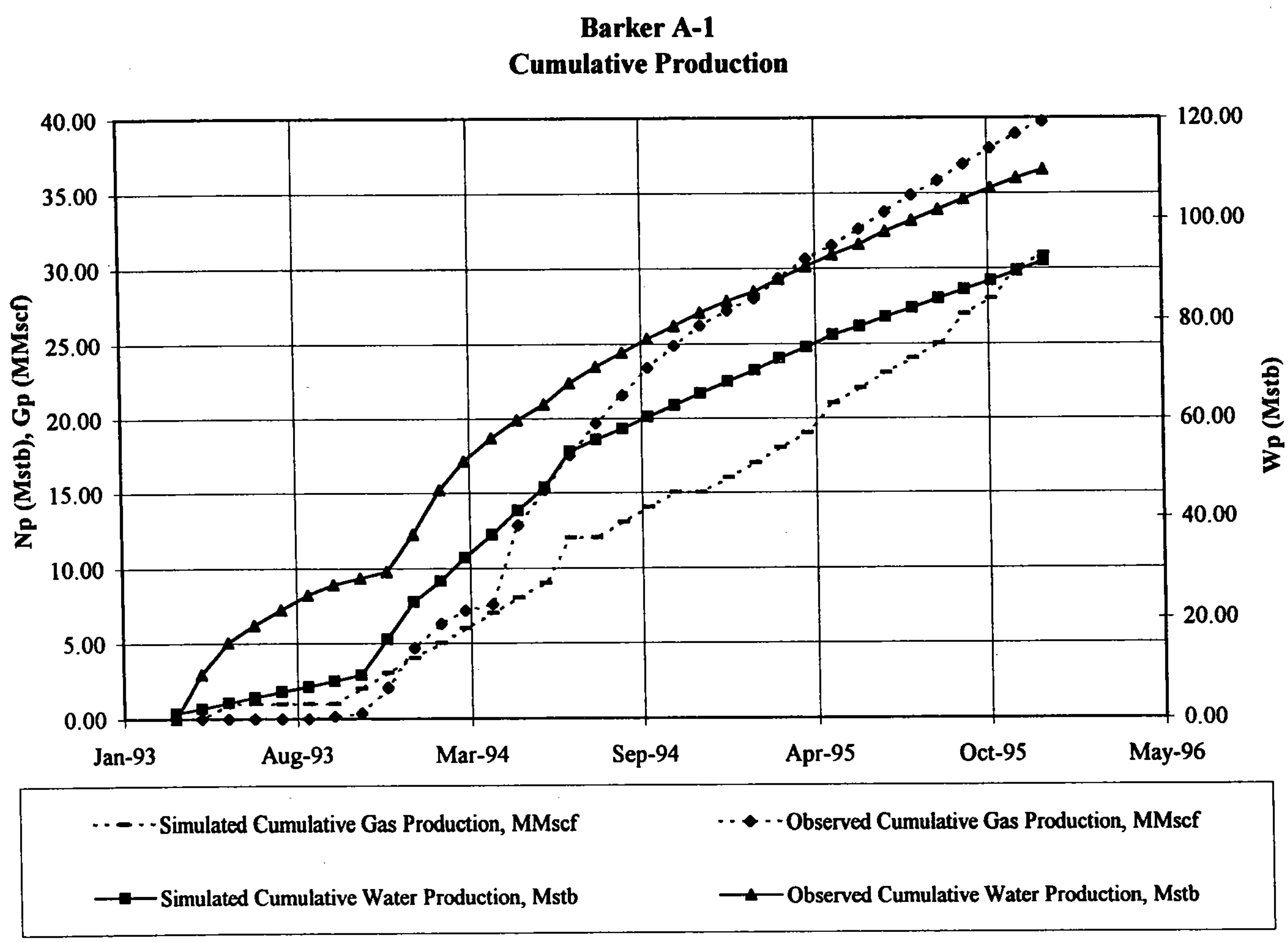


Figure 79. Simulated and observed cumulative gas and water production history match for the Barker No. A-1 well. Observed cumulative gas and water production are estimates of the Prue contribution to Prue and Peru commingled production (from Greg Riepl, unpublished data). Well location is shown on Figure 65, Part II.

TABLE 17. – Ten-Year Production Forecast Based on Reservoir Simulations

	Current operations	Waterflood with existing wells	Waterflood with infill wells
Cumulative oil production (mstb), 1/01/96	210	210	210
Expected cumulative oil production (mstb), 1/01/06	460	1,800	2,150
Incremental recovery from waterflood (mstb)	*	1,340	1,700
Cumulative water production (mstb), 1/01/06	1,700	12,000	15,250
Cumulative water injected (mstb), 1/01/06		14,350	18,100
Cumulative gas production (mmscf), 1/01/06	1,660	6,900	8,400
Maximum field oil production rate (stb/d)	70	700	900
Time at maximum oil rate (date)	1/01/06	2/01/00	5/01/00
Oil production rate (stb/d), 1/01/06	70	250	275

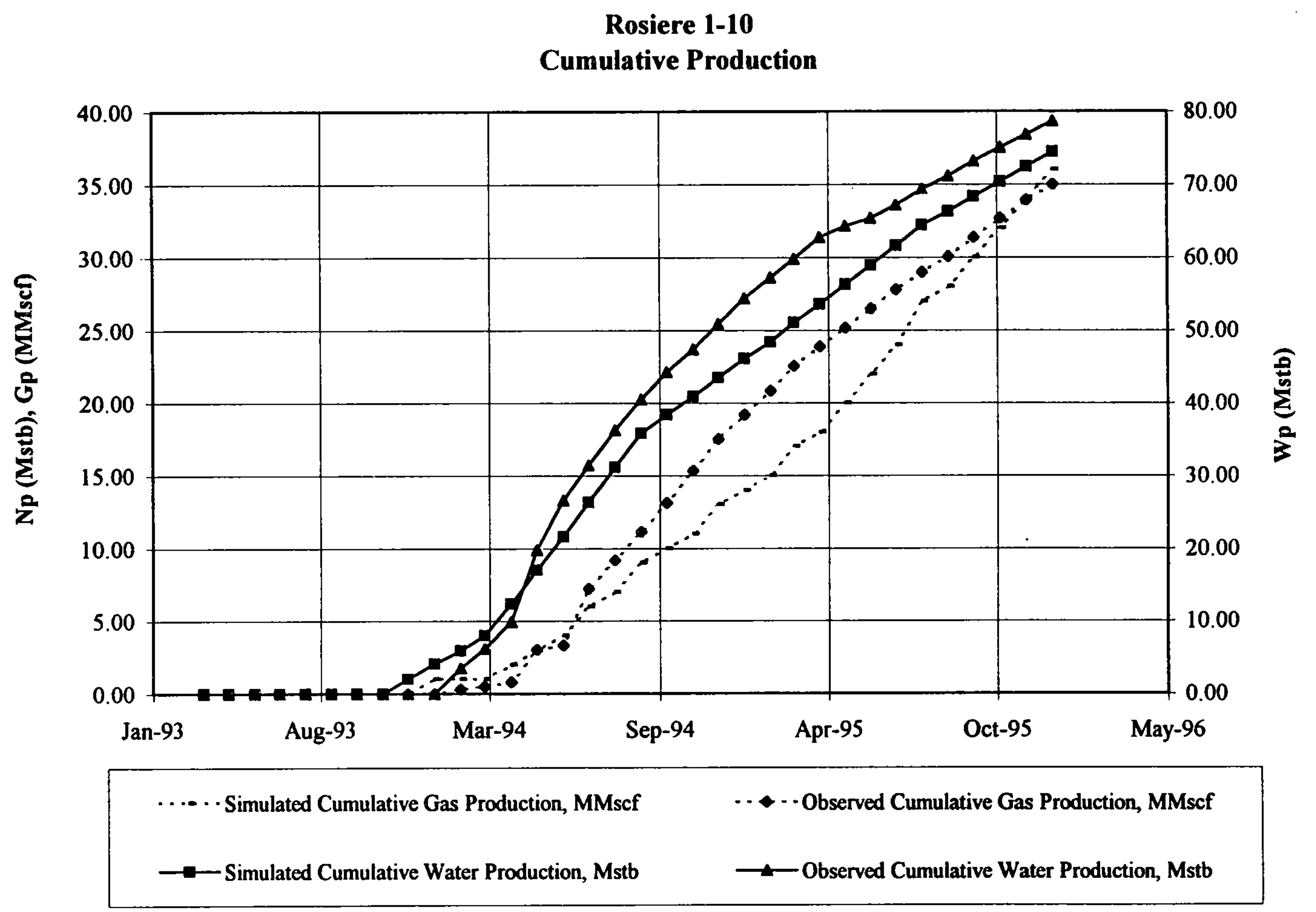


Figure 80. Simulated and observed cumulative gas and water production history match for the Rosiere No. 1-10 well. Observed cumulative gas and water production are estimates of the Prue and Peru commingled production (from Greg Riepl, unpublished data). Well location is shown on Figure 65, Part II.

Current Operations

The simulation of current operations assumes that there are no changes in the January 1996 well configuration and well operating conditions (i.e., BHPs). In 10 years, 250 MSTB, 2.3% of OOIP, was produced. Simulation results are shown in Table 17.

Waterflood with Existing Wells

For this case, four production wells, the Snyder No. 2-10, Correll No. 1-11, Alderson No. 1-11, and Alderson No. 3-11, were converted into water injection wells. Well locations are shown in Figure 65, Part II. Water produced from the other wells was injected at a constant bottom-hole pressure of 2,400 PSIA. The bottom-hole pressures of the oil wells were held constant at their estimated January 1996 values. In 10 years of the simulated waterflood, 1.6 MMSTB of oil was produced, 15% of OOIP. Water cut is expected to be ~90% at the end of 10 years. Simulation results are shown in Table 17.

Waterflood with Infill Wells

The third design modeled is the same configuration as the waterflood described above, with the addition of two infill wells. A new production well was drilled close to the mapped top of the structure, in the NE¼SE¼ NW¼ sec. 11 (see Fig. 70, Part II). An injection well was drilled in the S½NW¼NE¼ sec. 11, close to the oil-water interface predicted for January 1996. The BHP for the production well was specified to be 1,100 PSIA, and the BHP for the injection well was 2,400 PSIA. The other wells were operated using the same controls as for the waterflood case. The simulated production in 10 years was 1.94 MMSTB, or 18% of OOIP. Water cut is expected to be ~90% at the end of 10 years. Simulation results are shown in Table 17.

SUMMARY

The estimated original oil in place (OOIP) in the Prue pool of the Long Branch field is 10.7 million bbl of oil. Only about 2% of that amount has been recovered during three years of primary production. The estimated volume of unproduced mobile oil is ~5.6 million bbl (~52% of OOIP), which is a strong incentive for considering future oil recovery opportunities.

The results of 10-year model simulations show that, of the three development alternatives considered, the waterflood with infill well plan would result in the greatest recovery over the next 10 years: 18% of OOIP or 1,940,000 bbl of oil, which is about 8 times the amount that would be recovered by continuing the current operating conditions for 10 years. The total recovery for both primary and secondary production could be as much as 2,151,000 bbl of oil, more than 20% of the OOIP.

SELECTED REFERENCES

Bradley, H. B., 1987, Petroleum engineering handbook: Society of Petroleum Engineers, Richardson, TX.

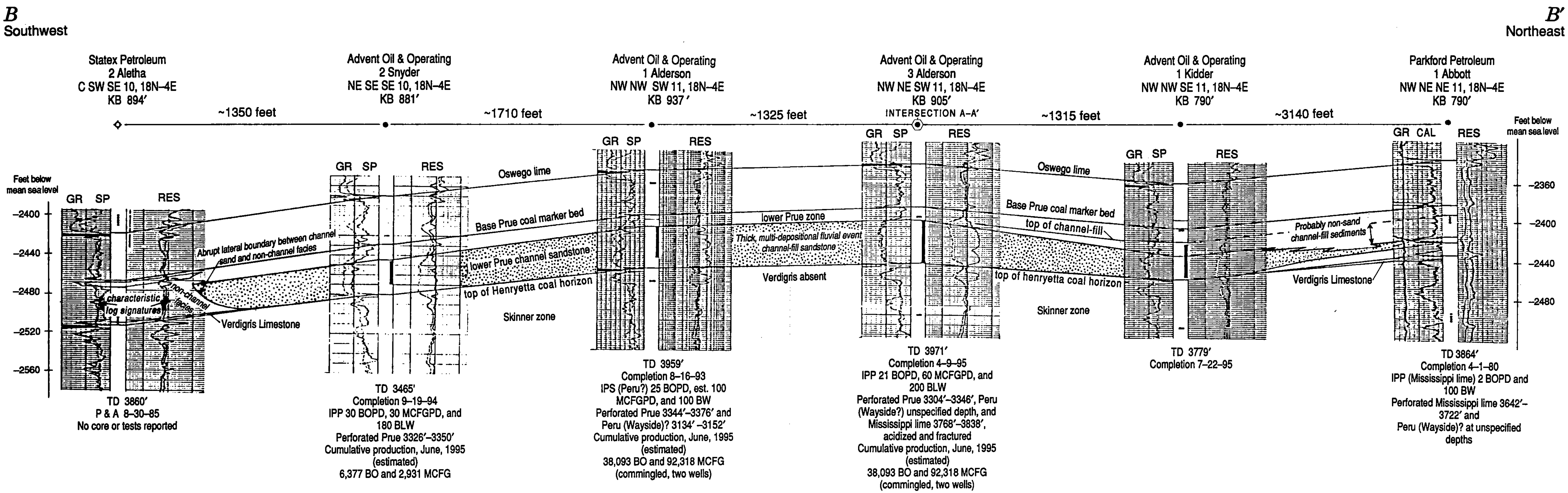
Craft, B. C.; Hawkins, M.; and Terry, R. E. (eds.), 1991, Applied petroleum reservoir engineering [2nd edition]: Prentice Hall, Englewood Cliffs, NJ, p. 9–55.

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

Mathematical & Computer Services, Inc., 1995, BOAST 3, A modified version of Boast II with post processors B3PLOT and COLORGRID, 63 p.

McCain, W. D., Jr., 1990, The properties of petroleum fluids: Pennwell Publishing Co., Tulsa, OK, 548 p.

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



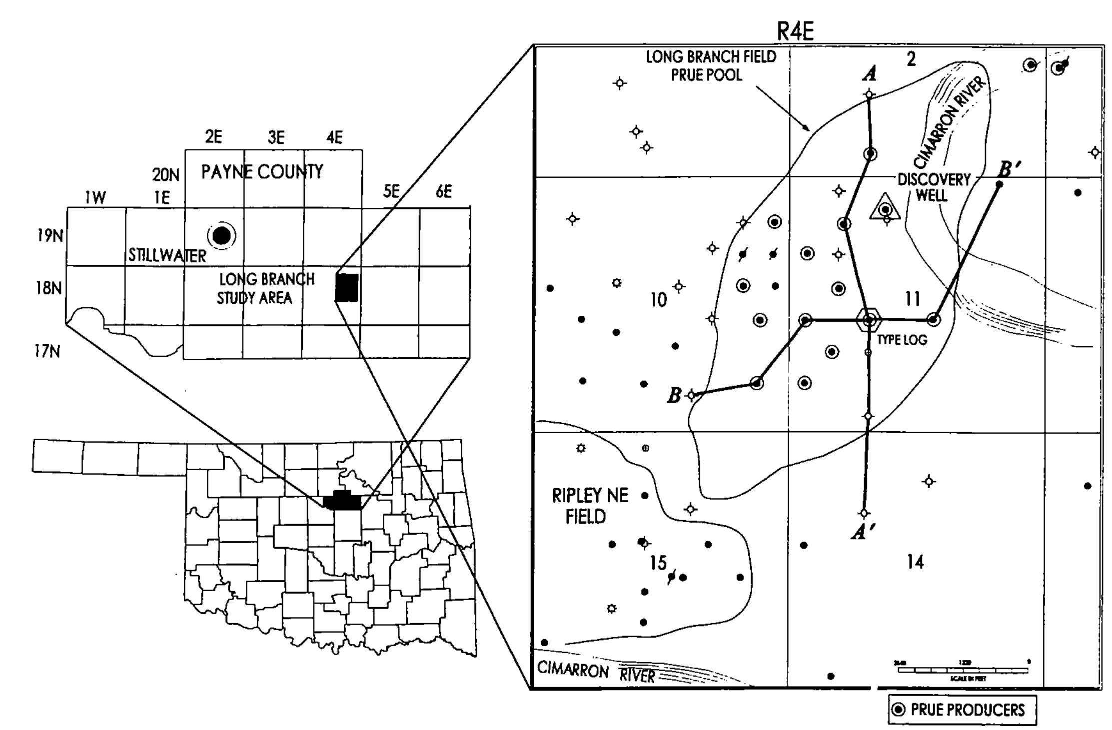


Figure 68. Structural and stratigraphic cross section B–B′, Long Branch field, Payne County, Oklahoma. (Datum: Sea Level, no horizontal scale)

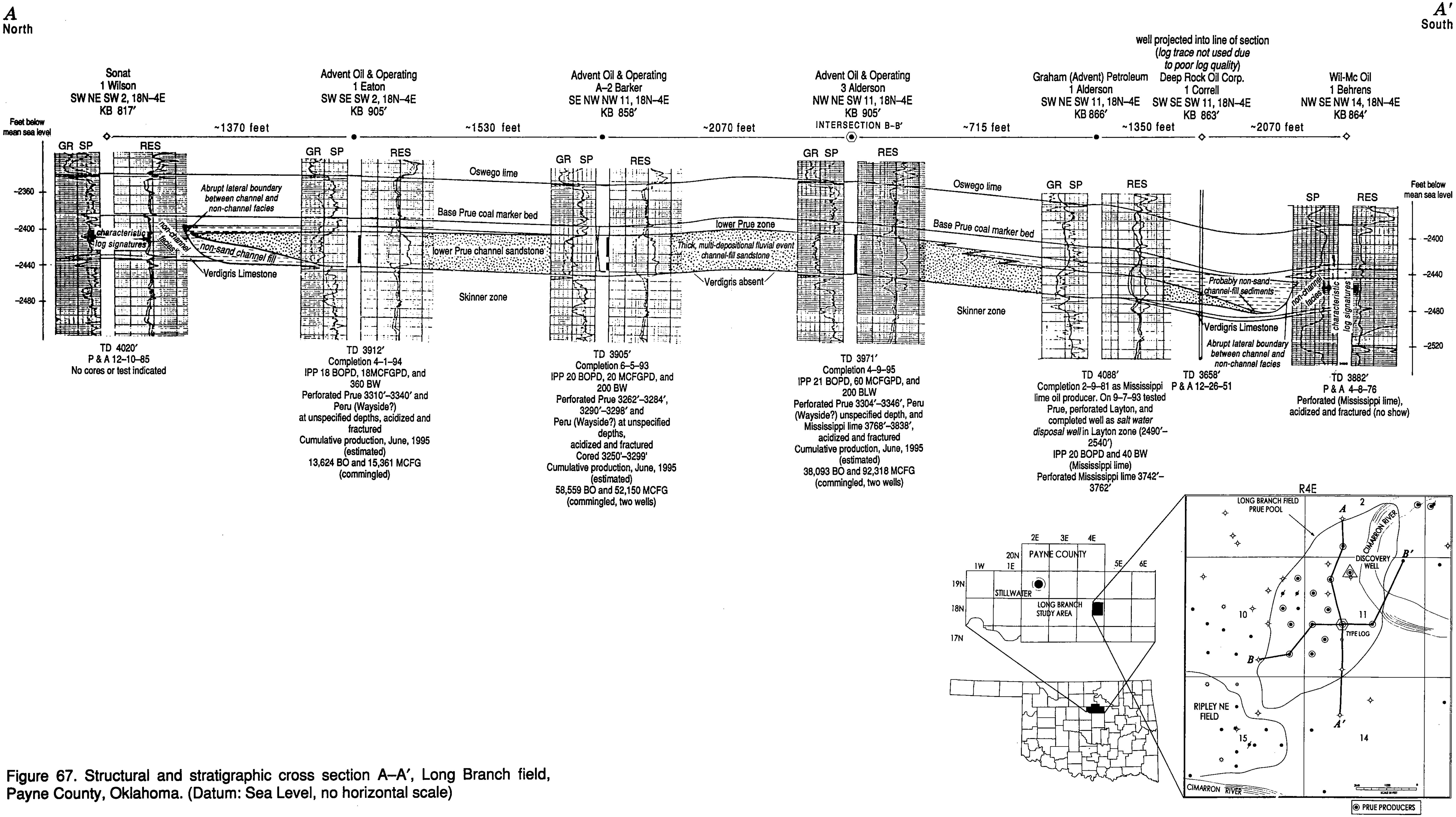


Figure 67. Structural and stratigraphic cross section A–A′, Long Branch field, Payne County, Oklahoma. (Datum: Sea Level, no horizontal scale)

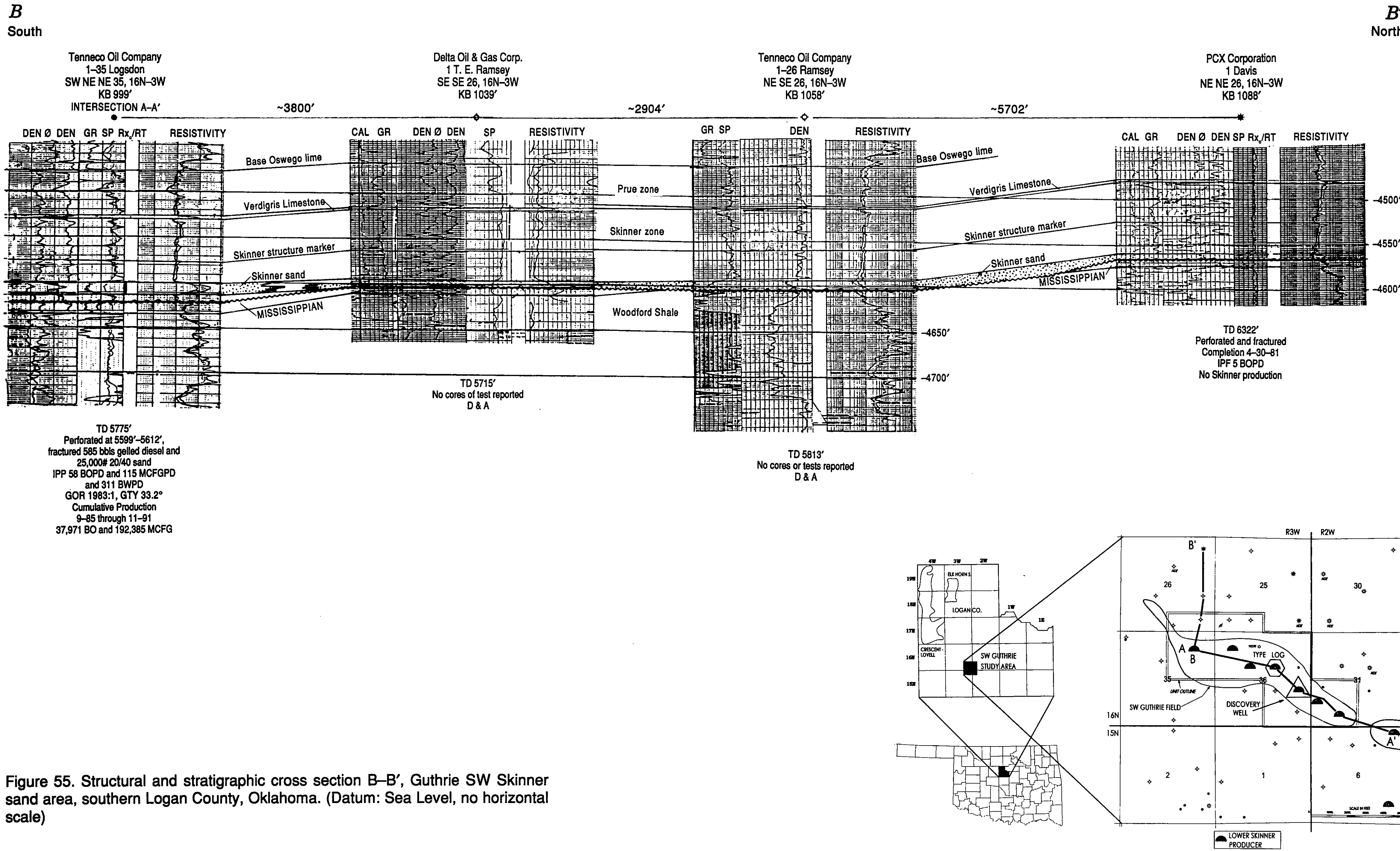
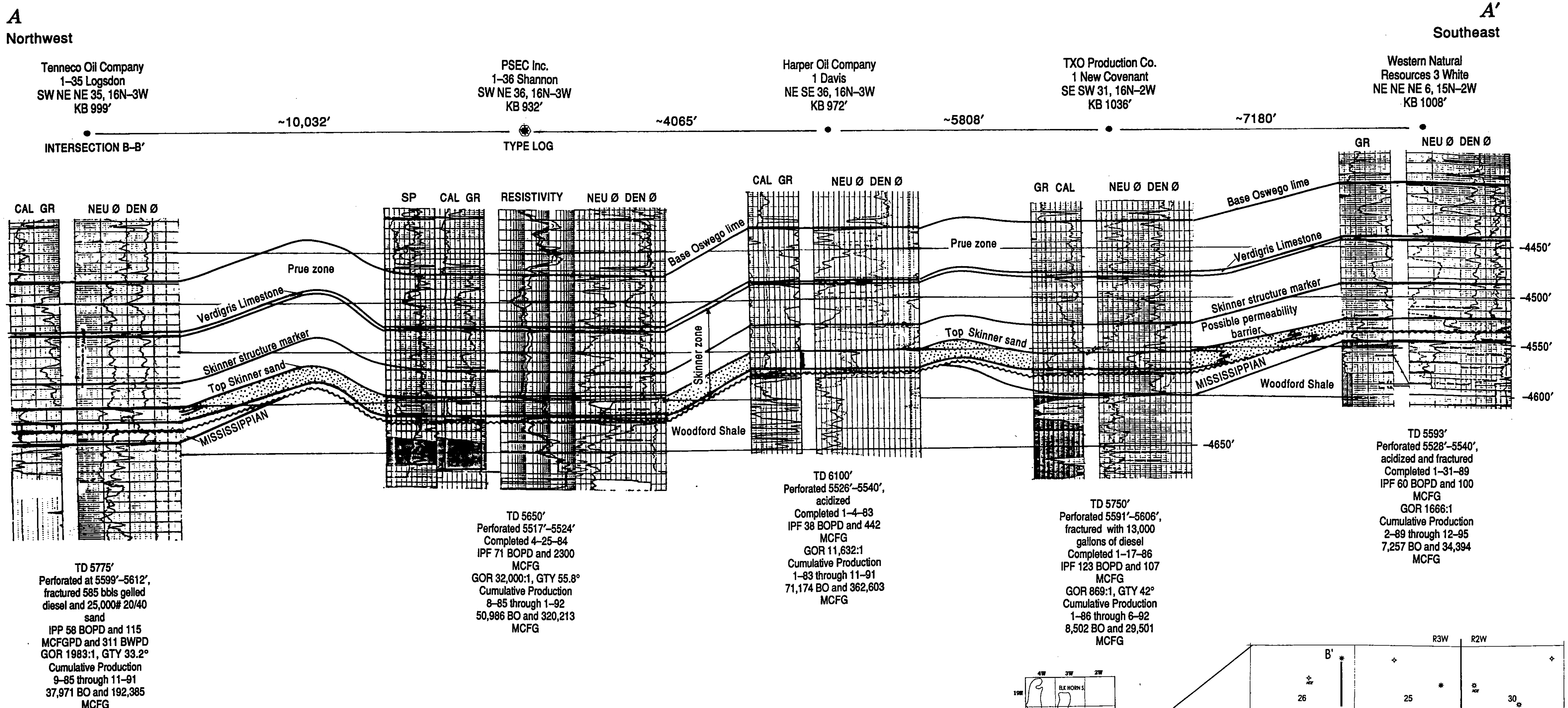


Figure 55. Structural and stratigraphic cross section B–B′, Guthrie SW Skinner sand area, southern Logan County, Oklahoma. (Datum: Sea Level, no horizontal scale)



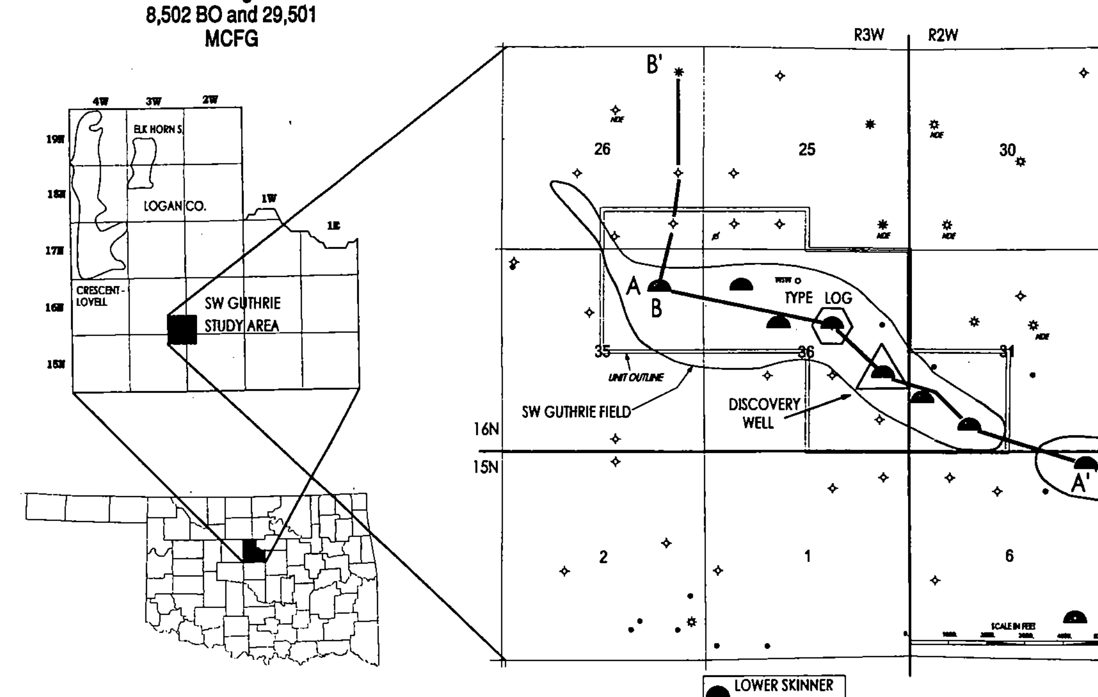
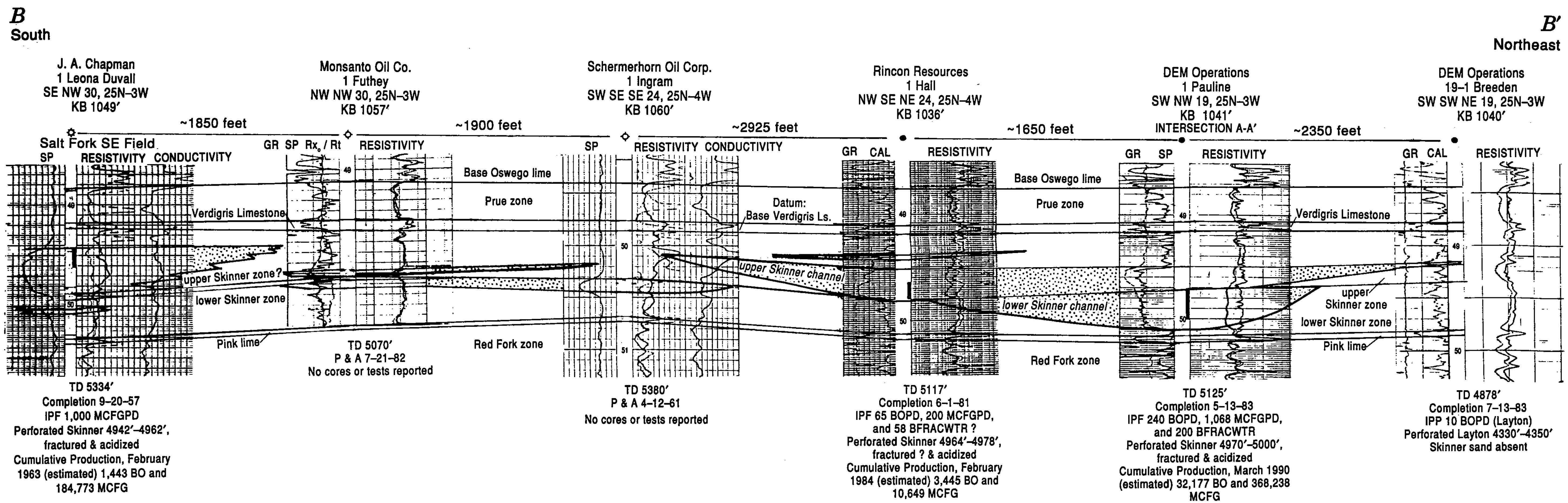


Figure 54. Structural and stratigraphic cross section A–A′, approximately parallel to strike, Guthrie SW Skinner sand area, southern Logan County, Oklahoma. (Datum: Sea Level, no horizontal scale)



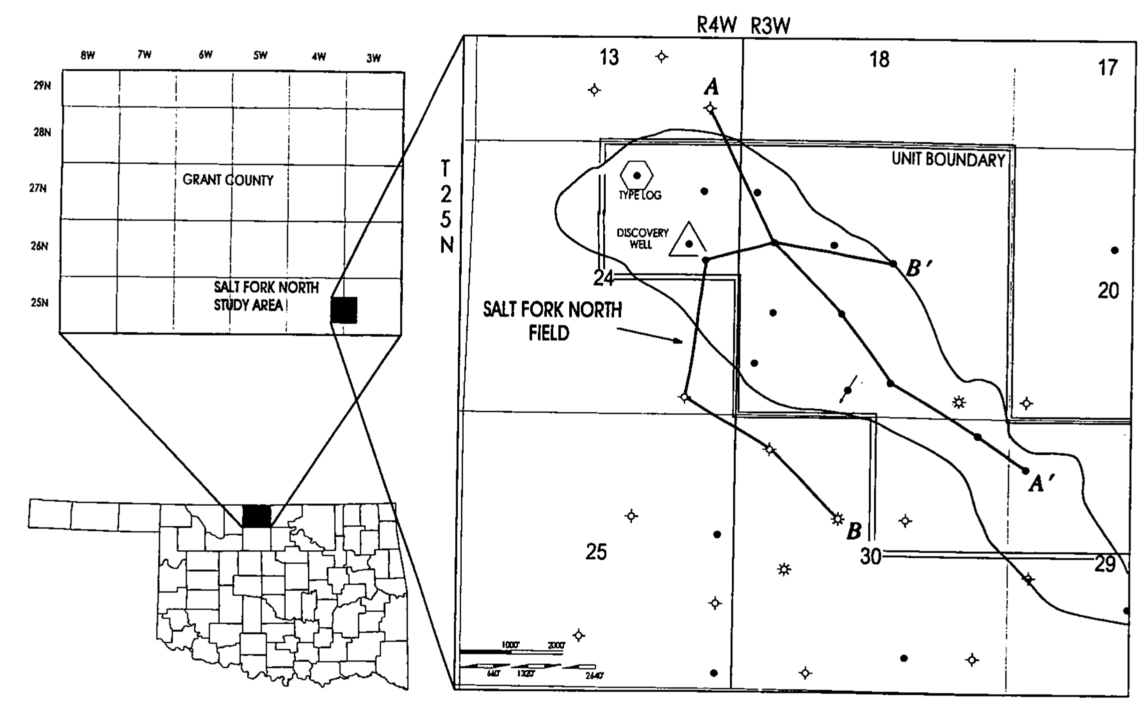
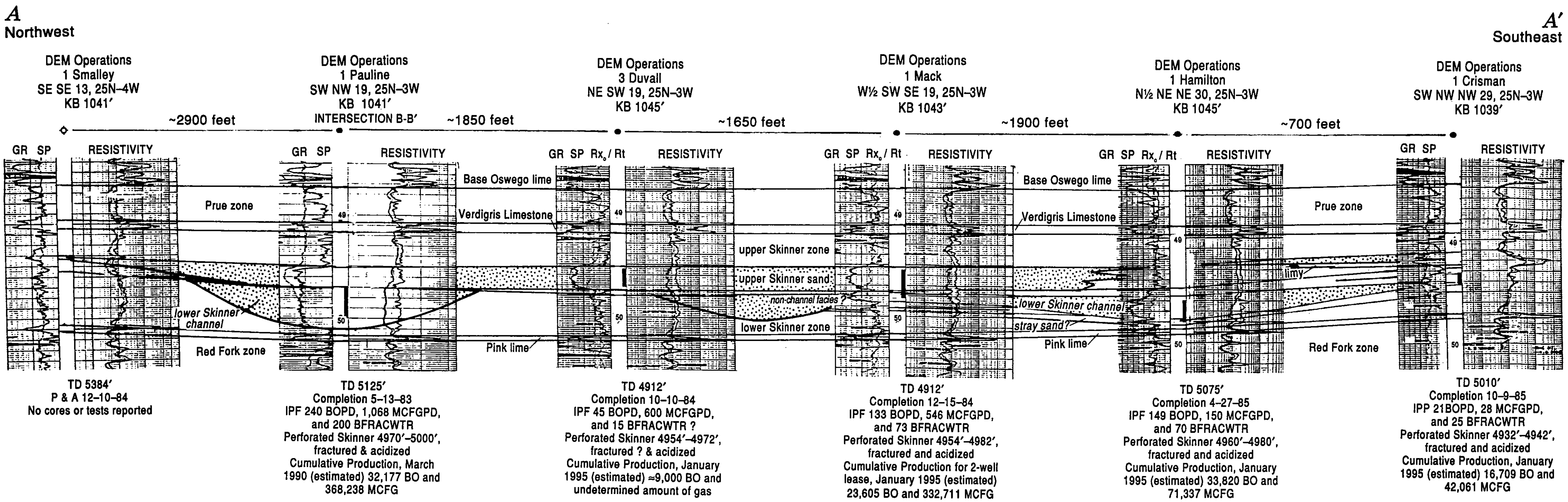


Figure 38. Stratigraphic cross section B–B′, Salt Fork North and Salt Fork SE field areas, southeastern Grant County, Oklahoma. (Vertical scale: 1 in. ≈ 100 ft, no horizontal scale)



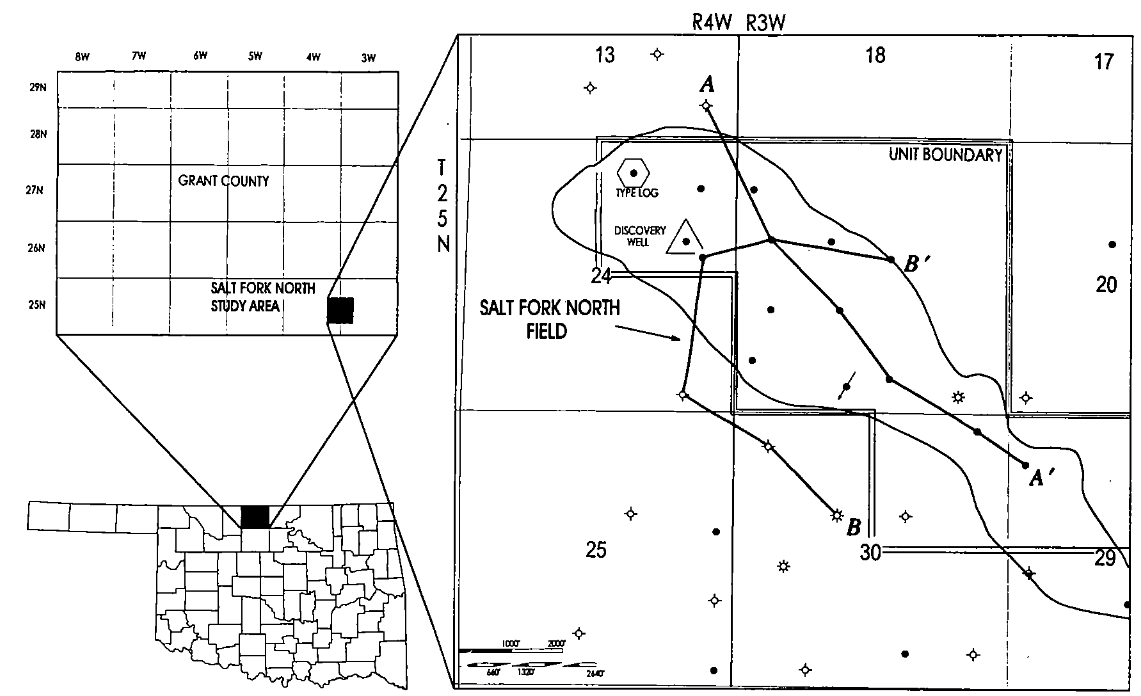


Figure 37. Stratigraphic cross section A–A′, Salt Fork North field, southeastern Grant County, Oklahoma. (Datum: Base Verdigris Limestone, Vertical scale: 1 in. ≈ 100 ft., no horizontal scale)

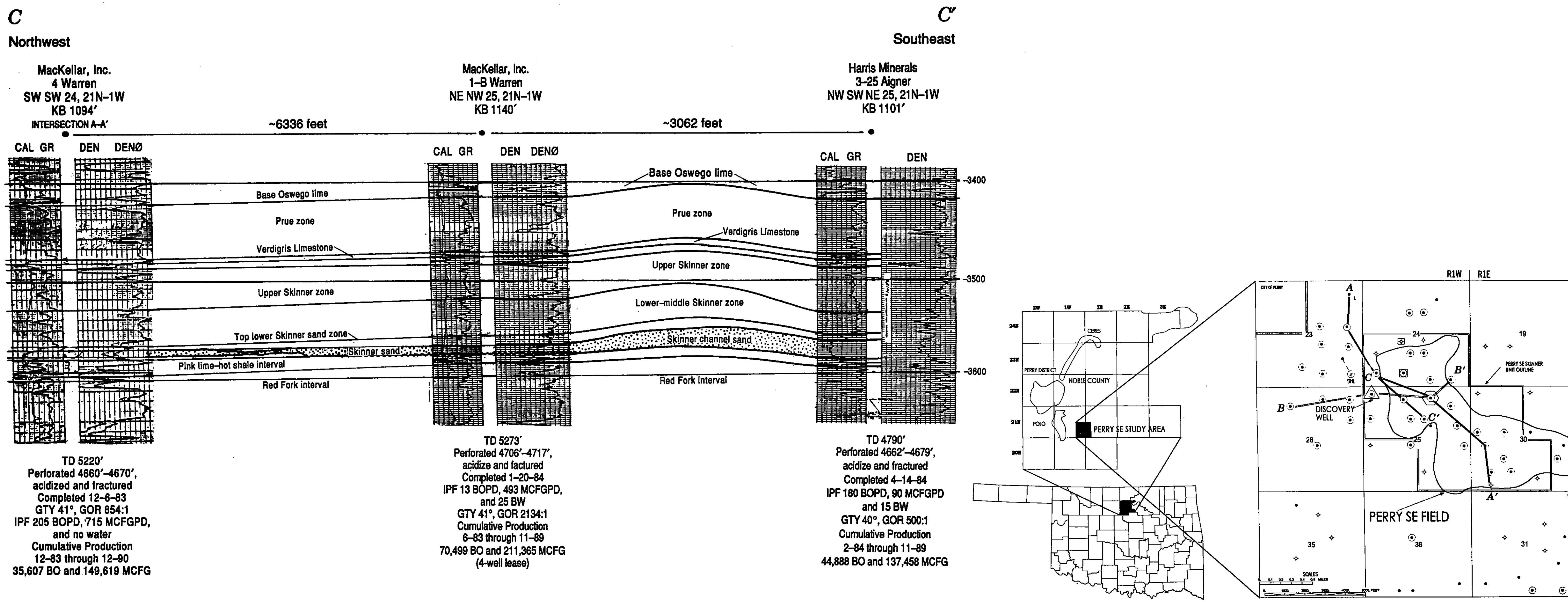


Figure 32. Structural and stratigraphic cross section C–C′, Perry SE Skinner field area, southern Noble County, Oklahoma. (Datum: Sea Level, no horizontal scale)

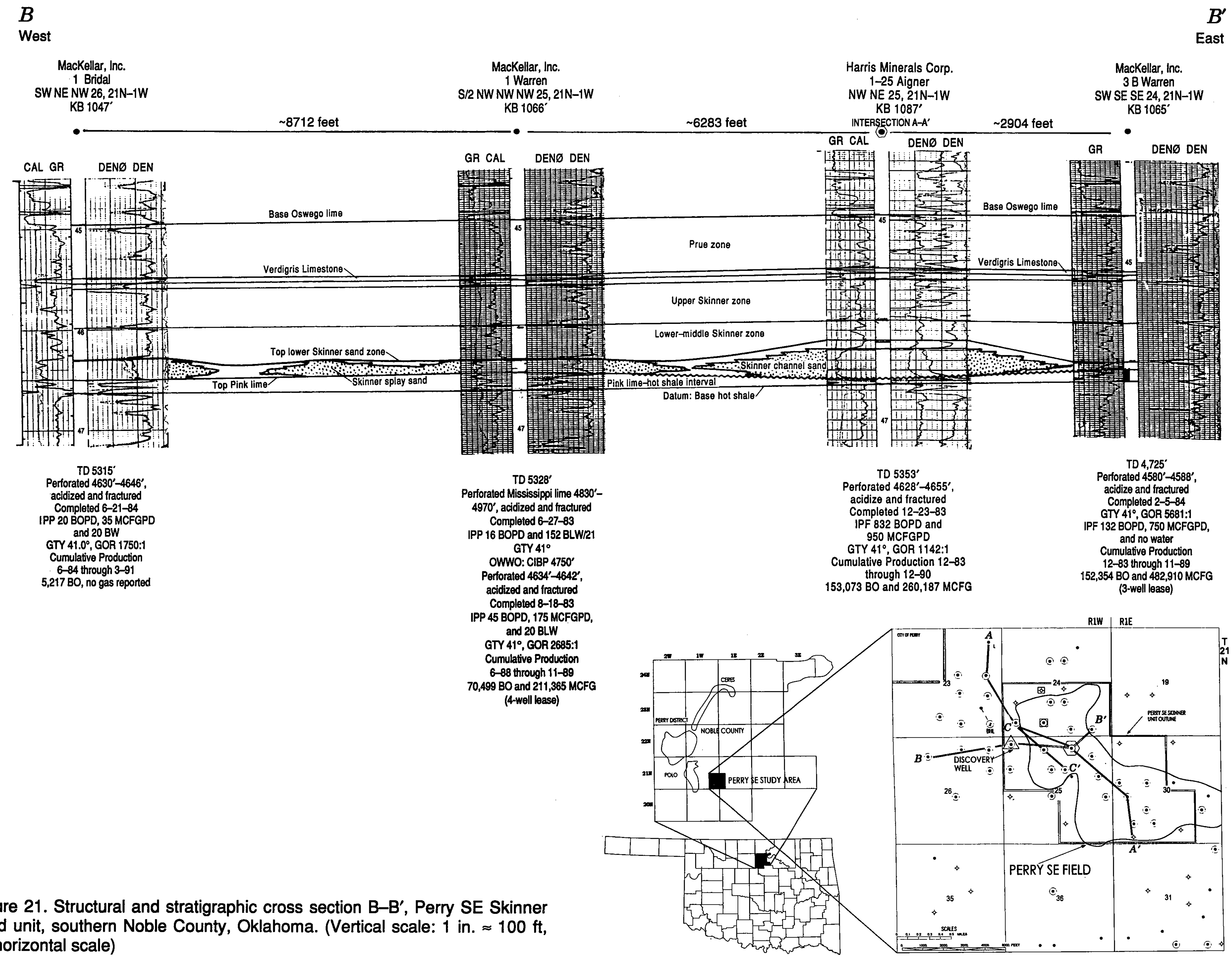


Figure 21. Structural and stratigraphic cross section B–B′, Perry SE Skinner sand unit, southern Noble County, Oklahoma. (Vertical scale: 1 in. ≈ 100 ft, no horizontal scale)

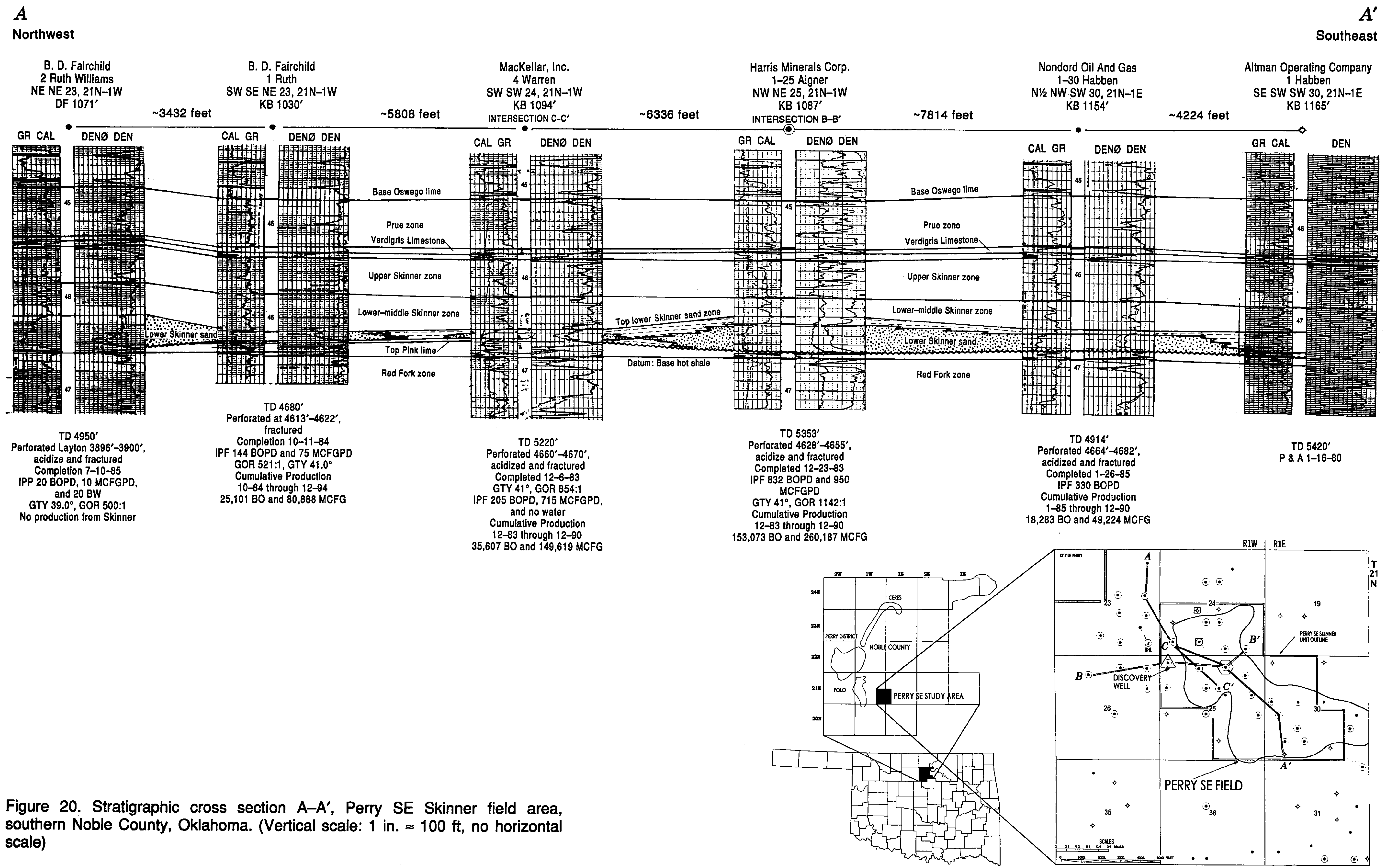


Figure 20. Stratigraphic cross section A–A′, Perry SE Skinner field area, southern Noble County, Oklahoma. (Vertical scale: 1 in. ≈ 100 ft, no horizontal scale)