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Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Layton and Osage-Layton Play

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Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Layton and Osage-Layton Play

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

by

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

PART II.—The Layton and Osage-Layton Play: Regional Geology

by

Jock A. Campbell

PART III.—The Layton and Osage-Layton Play: Reservoir Studies

by

Jock A. Campbell
with contributions from Dennis L. Shannon

PART IV.—Reservoir Simulation of an Osage-Layton Reservoir, East Lake Blackwell Field, Payne County, Oklahoma

by

R. M. Knapp and X. H. Yang

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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

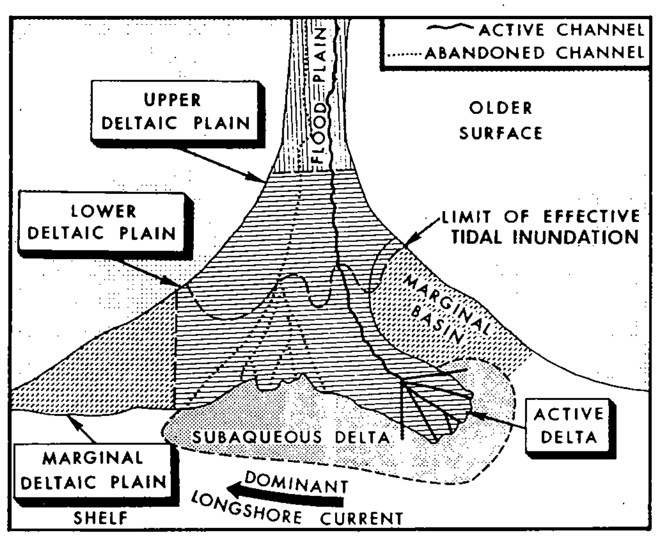
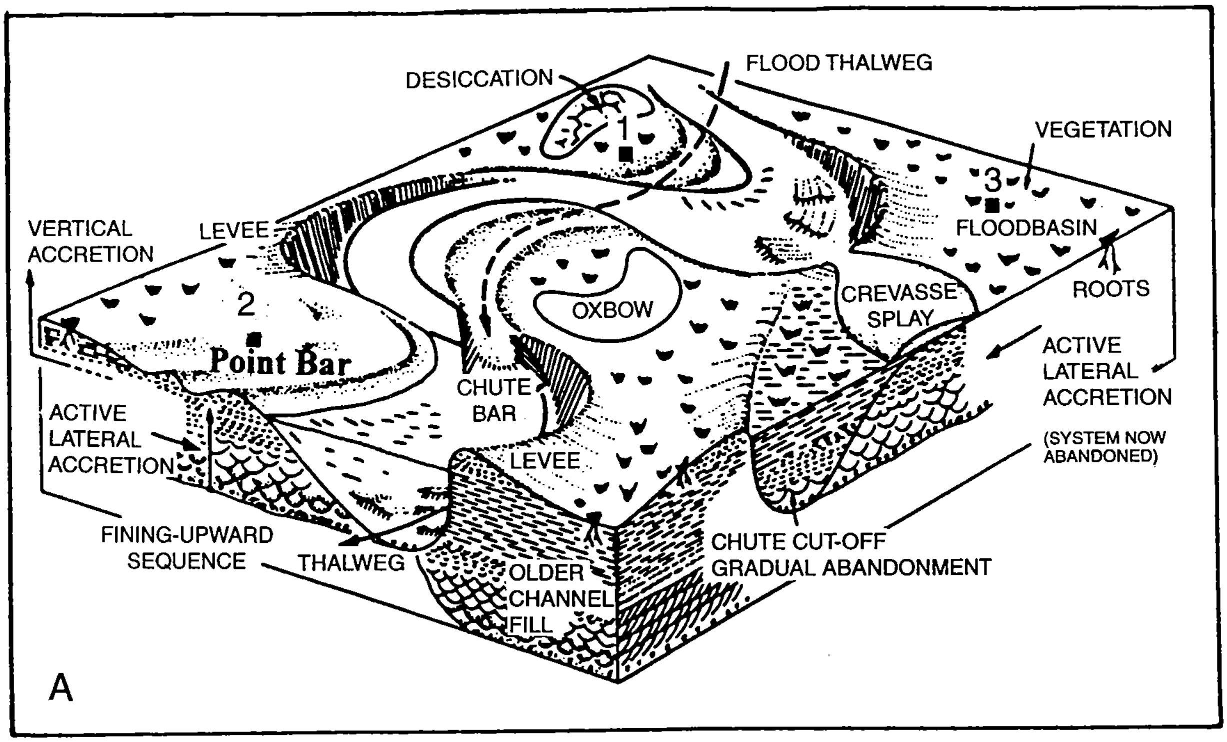


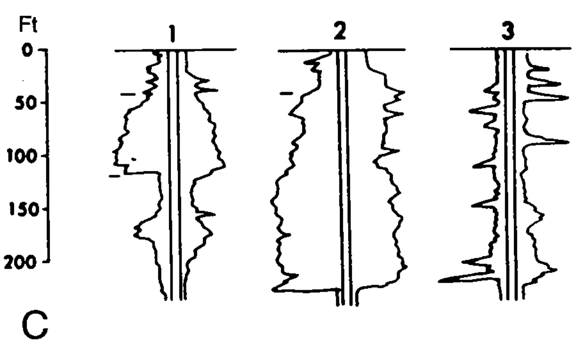
Figure 1. Components of a delta system. From Coleman and Prior (1982).

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





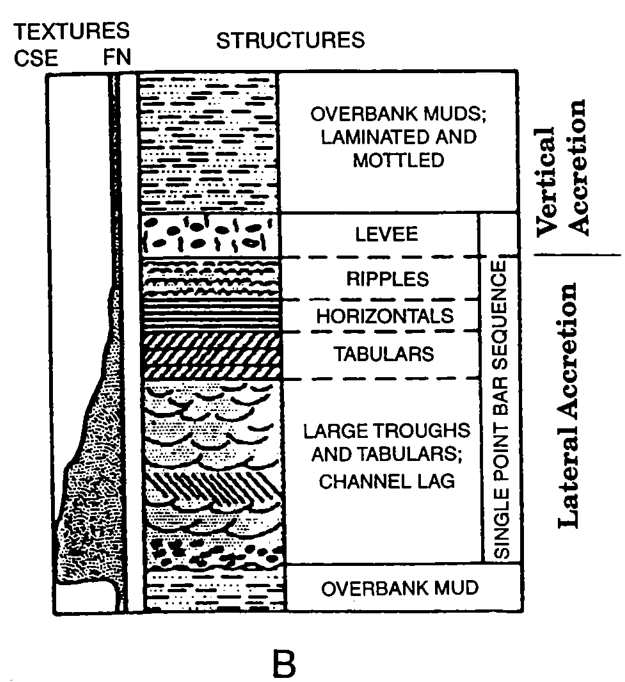


Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified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

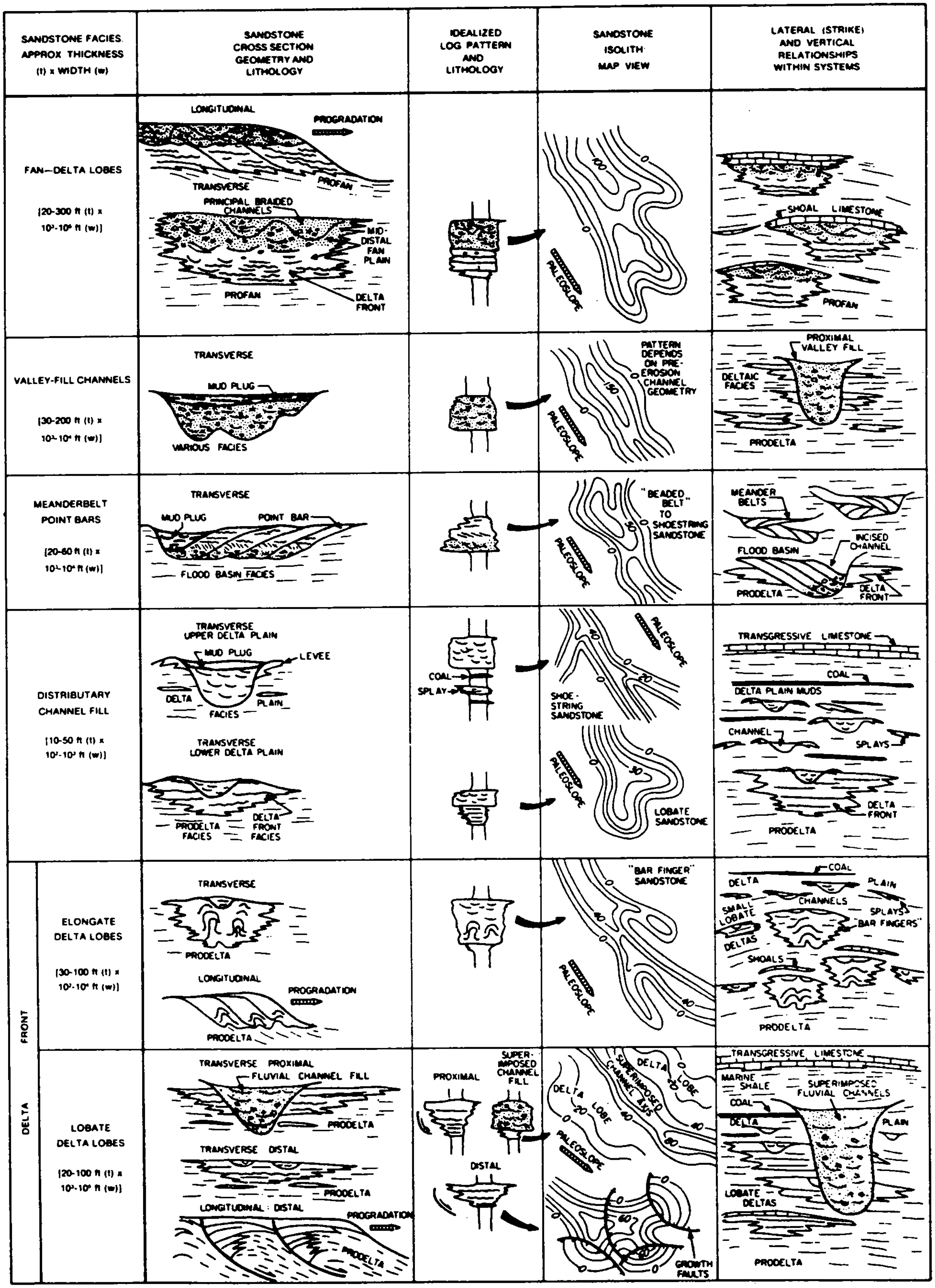


Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

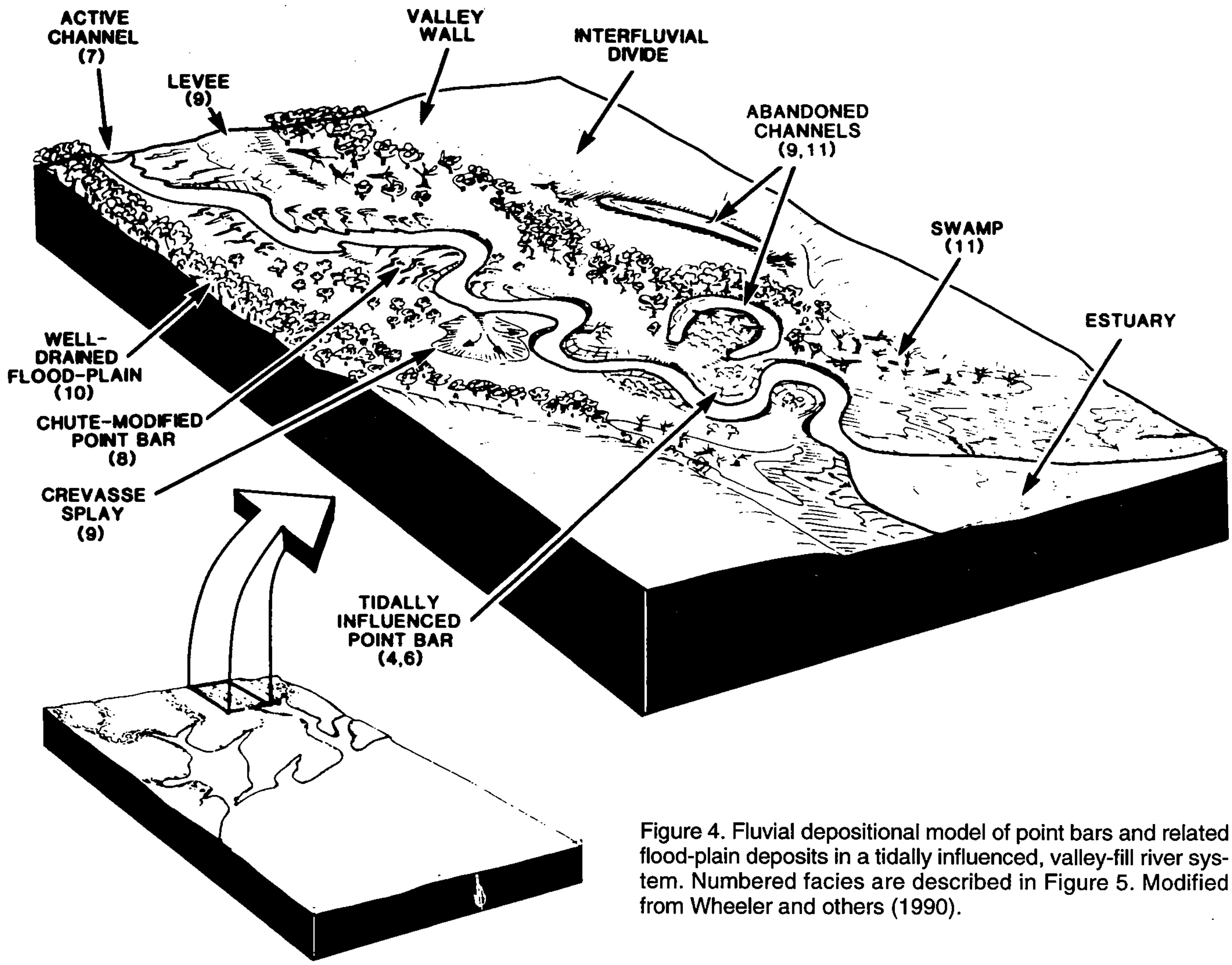


Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

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

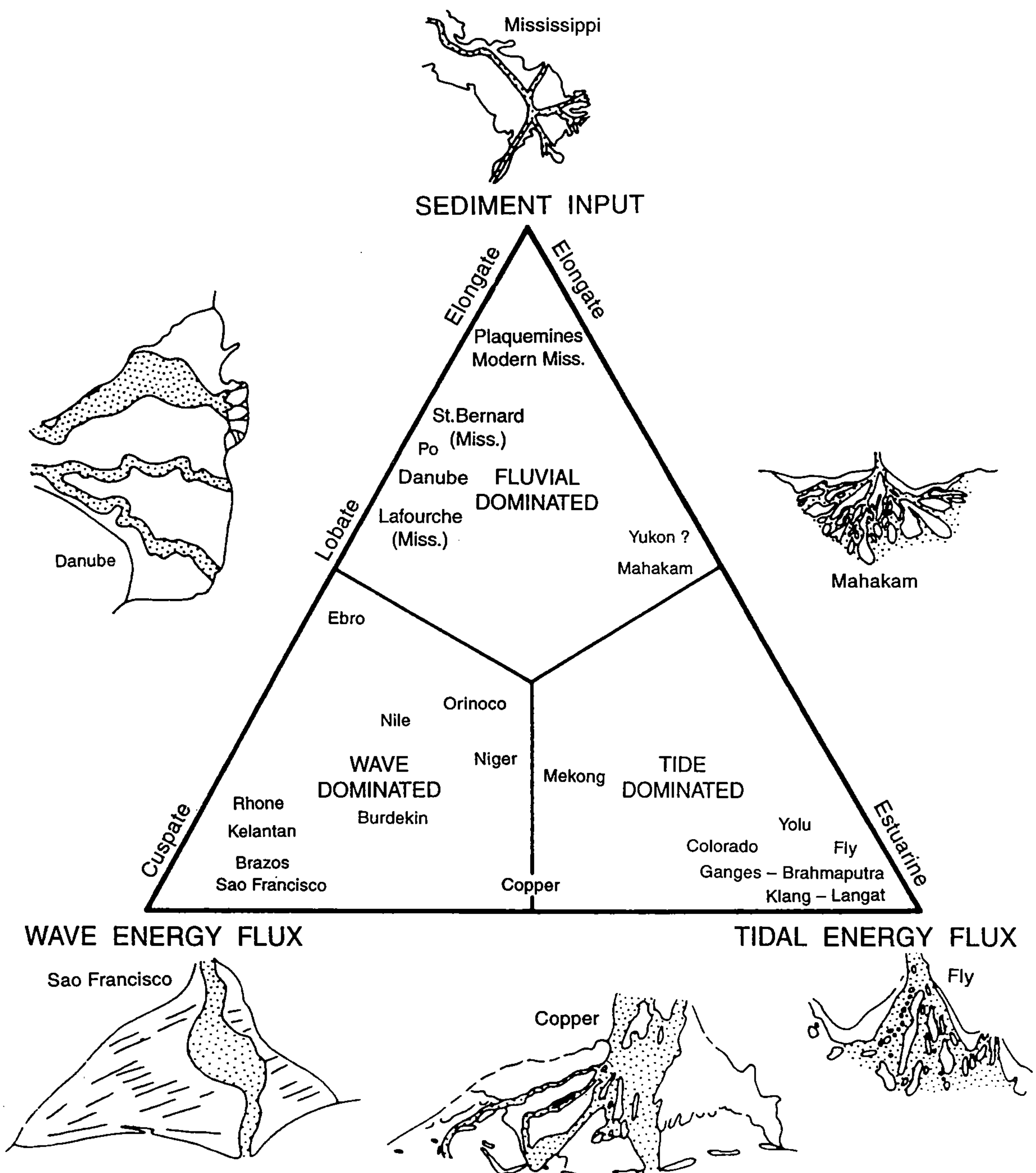


Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

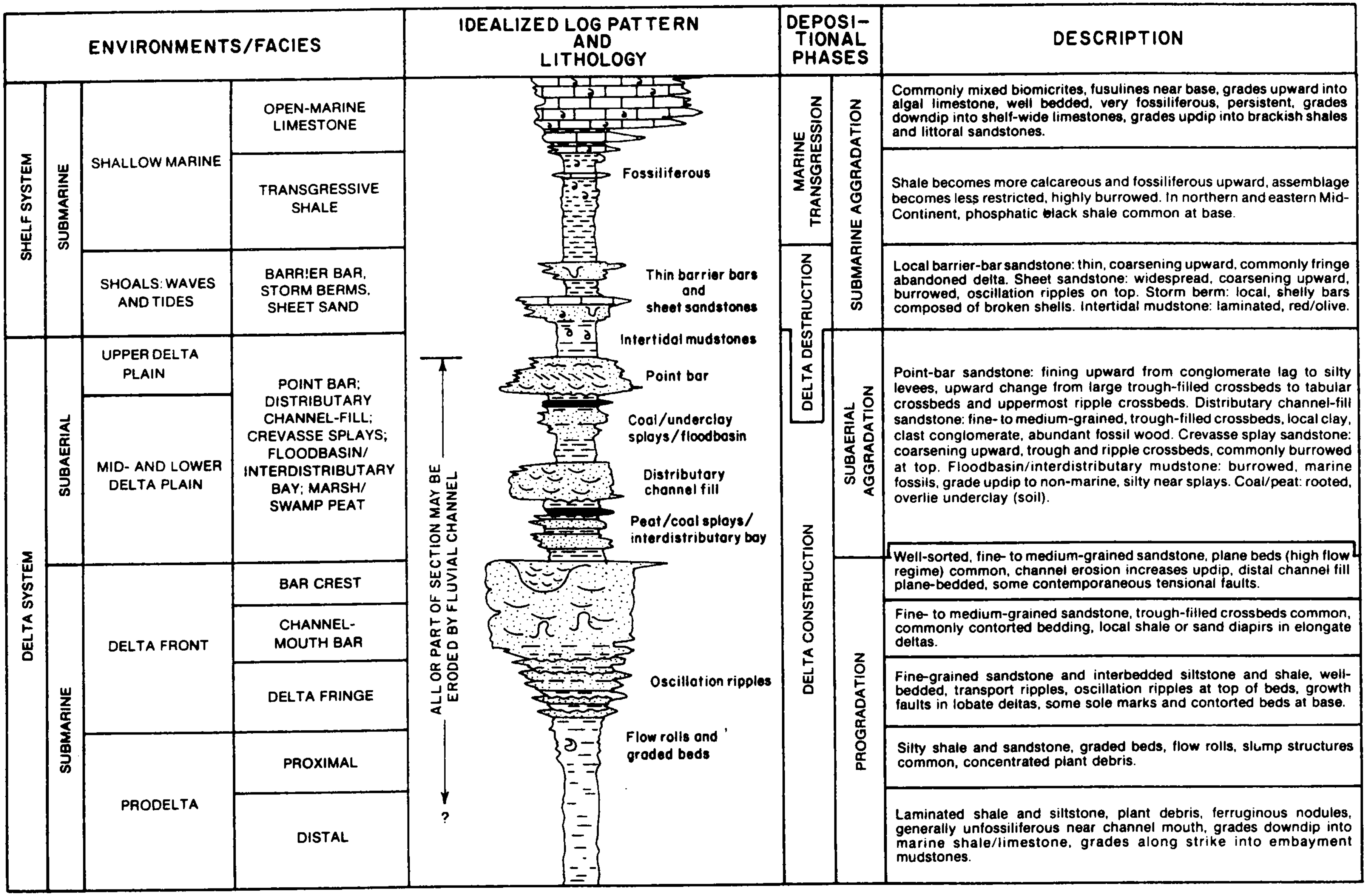


Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

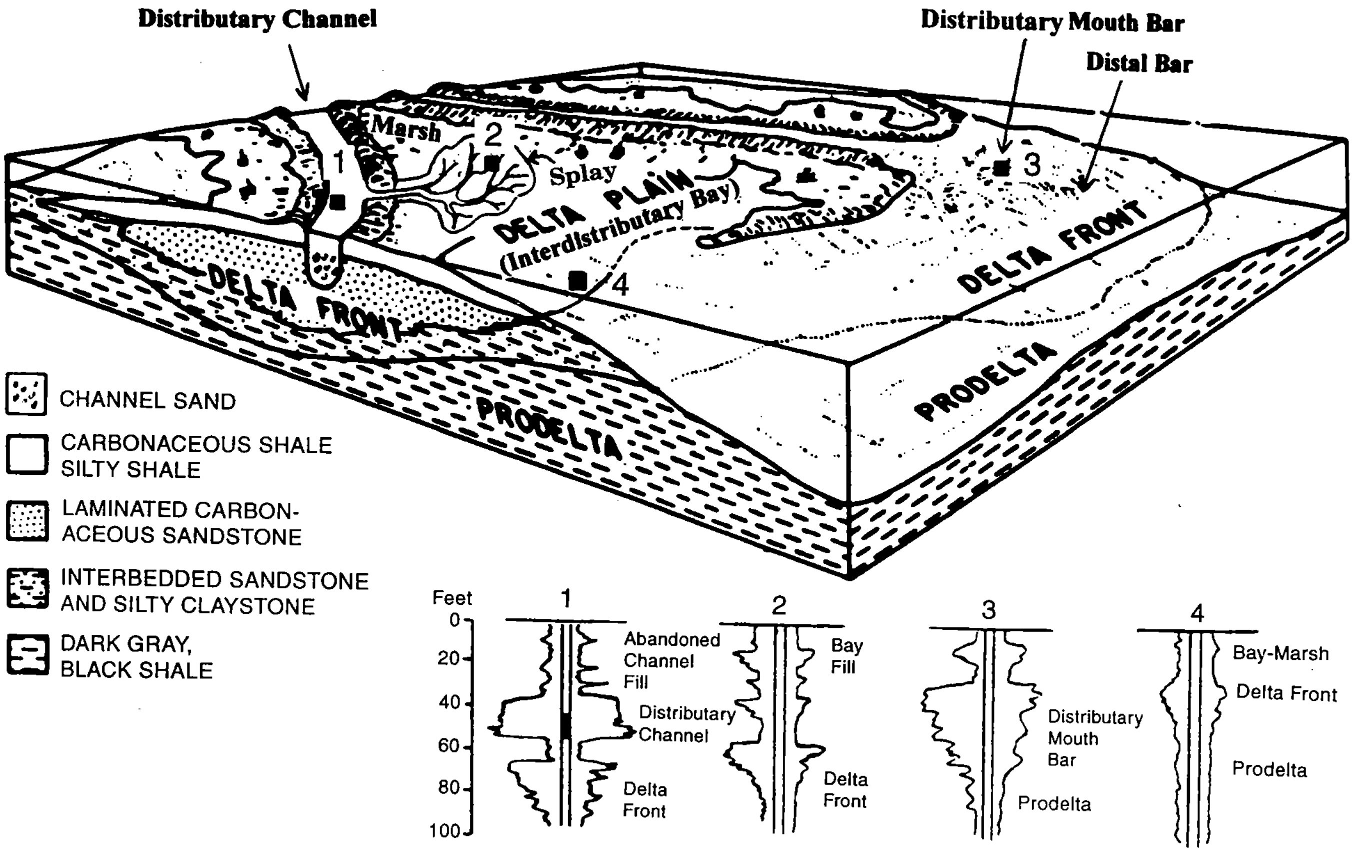


Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

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-

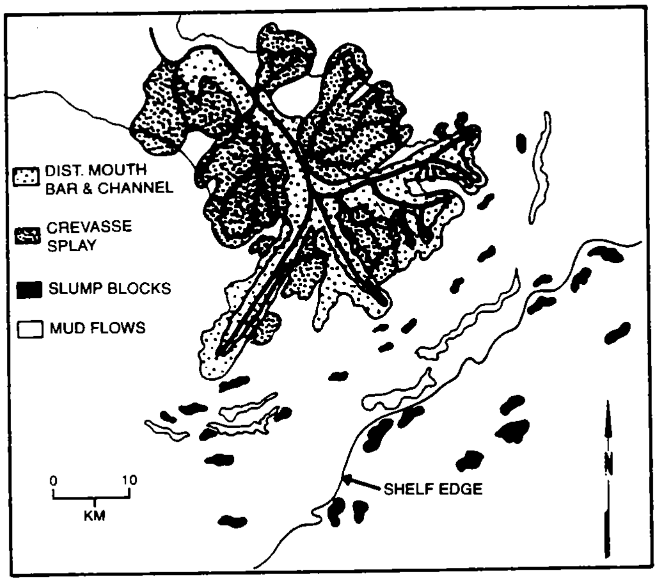


Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

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

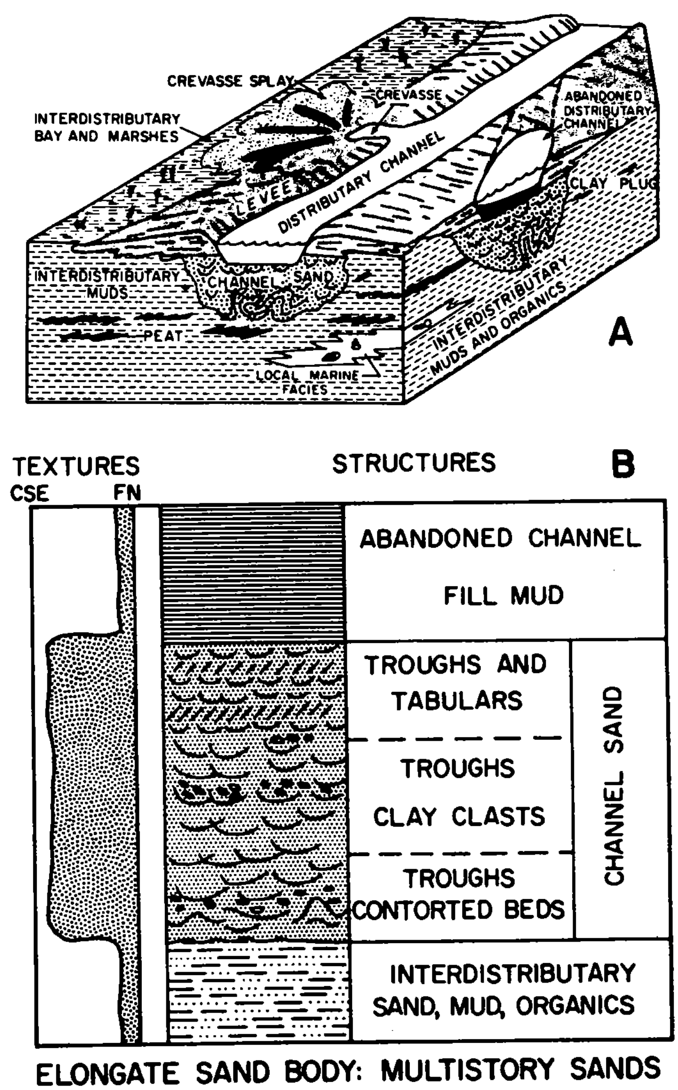


Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

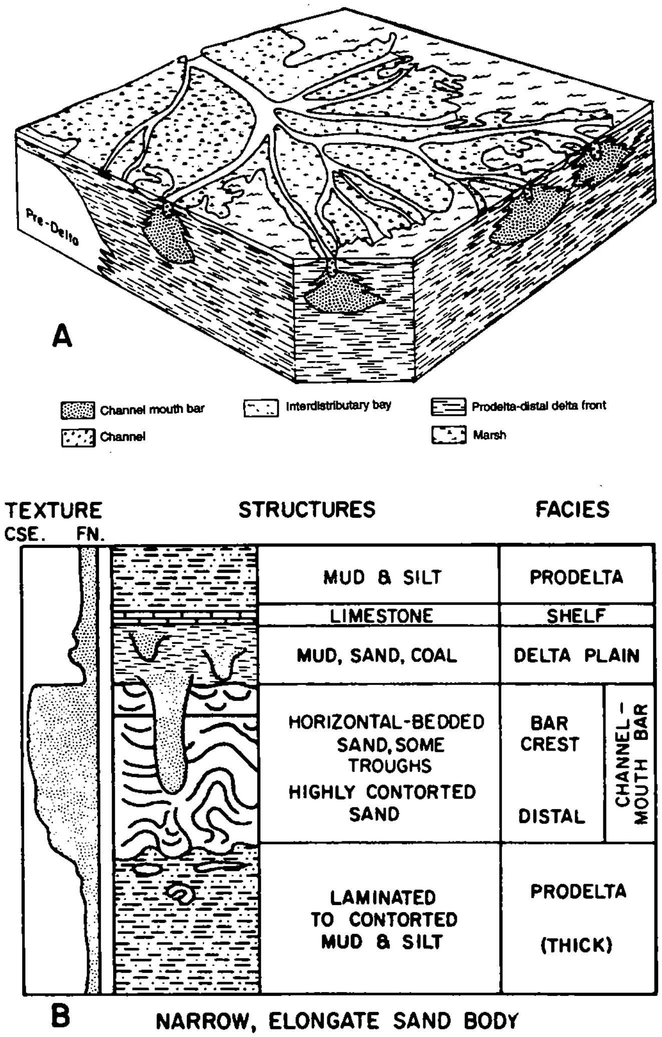


Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

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 Layton and Osage-Layton Play: Regional Geology

Jock A. Campbell
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INTRODUCTION

Numerous sandstones of Pennsylvanian age are present at the surface and occur at shallow to intermediate depths in the Cherokee platform in northeastern Oklahoma, also commonly called the Chautauqua shelf or platform, especially in adjacent Kansas. The Layton and Osage-Layton sands are among a number of sandstone intervals that have been known as "Layton" in oil-field usage, as will be explained in the section on stratigraphy. This report is concerned with these formations in northeastern Oklahoma (Fig. 12).[1]

The "Layton" sands have produced mostly oil, and locally gas, from as shallow as ~900 ft in northeastern Osage County to ~6,500 ft in southwestern Logan County (West Edmond field). Oil and gas in "Layton" reservoirs are trapped stratigraphically because sandstone bodies in a shale framework are distributed irregularly. Anticlinal structures locally have enhanced these stratigraphic traps. An example in which the Layton sand has produced oil and gas is the Cushing field, which is a part of a large anticlinal complex in northwestern Creek County (Ts. 16–19 N., R. 7 E.). The field was discovered in March 1912 and produced only from the Layton sand and the deeper "Wheeler sand" (Fort Scott Limestone [Jordan, 1957b]) until the Bartlesville reservoir was discovered in December 1913 (Beal, 1917). In areas that produced only from the Layton reservoir, some wells produced >500 BOPD (Beal, 1917, pl. VI), presumably the initial production. During the 21 months that oil was produced only from the Layton and Wheeler reservoirs, production per well varied from a few barrels to almost 150 bbl per day. More than 900 wells were drilled, and >83 million bbl of oil were marketed from the two reservoirs before Bartlesville production contributed to the total (Beal, 1917, fig. 1).

[1]In this report, including the illustrations, "Layton" (in quotes) designates the name as applied broadly (and incorrectly) to numerous sandstone intervals. Layton sand (no quotes) refers to the Layton sand as originally designated, commonly called the True Layton sand. Use of the term "Layton" in industry or public records may be a misapplication of the name as originally intended. Quote marks around other stratigraphic names in this report identify those that are undesirable because of similar multiple application, or because of previous established use of the name.

The "Layton" sands have produced oil and gas for at least 84 years, but the cumulative production total is lost to history. Although "Layton" sands widely are regarded as secondary objectives today, production from them has been significant, and considerable potential probably remains, as will be shown in Part III of this volume. The historical record of oil production from Layton and Osage-Layton sands is incomplete. However, from 1979 through 1994, "Layton" and Osage-Layton production was reported from 193 fields and also was reported locally from leases unassigned to fields (Pl. 1). Wells that were reported as having production from Layton and Osage-Layton sands and from the Cottage Grove Sandstone (the formal equivalent of Osage-Layton sand) are presented in support of the fields map (Pls. 2, 3). Table 1 summarizes oil production, mostly by "stripper" wells, from "Layton" and Osage-Layton reservoirs in recent years.

The source of oil and gas in these reservoirs has not been demonstrated in any published study. There may be multiple sources; however, Ece (1987,1989) showed that the Excello Shale (Desmoinesian) is rich in organic matter and thermally mature in the Midcontinent region. Although the Excello Shale is older, and therefore has been buried more deeply, I speculate that oil and gas have been generated locally from marine shales of Missourian age that are associated with "Layton" reservoir sandstones. In the case of large structural traps, hydrocarbons may have migrated vertically along faults and fracture systems from deeper source rocks.

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 (OGS), the Geo Information Systems (GeoSystems) research unit at the University of Oklahoma, and the OU School of Petroleum and Geological Engineering. The continuing effort of Rhonda Lindsey, project manager, Bartlesville Project Office of the U.S. Department of Energy, is greatly appreciated. Special recognition is given to Charles J. Mankin, director of the OGS, and Mary K. Banken, director of GeoSystems, who originated concepts for this program and provided overall leadership. Both the

OGS and GeoSystems also provided funding for this cooperative project.

The investigators are most fortunate in having had the cooperation of Pan Western Energy Corporation, Tulsa, for the purposes of this investigation. We extend our abundant gratitude to Sid Anderson, president; Buddie E. Livingston II, vice president for operations; and Brenda Hampton-Higgins for having provided data supplemental to that in the public records for geologic description and reservoir modeling.

Much of the technical support, including geologic and computer map preparation, core preparation, technical typing and editing, and computer graphics was completed by David Brown, GeoSystems technical project coordinator; Scott March, GeoSystems geotech; Carlyle Hinshaw, GeoSystems petroleum geologist; Betty Bellis, OGS technical typist; Victoria French, student research assistant, OU School of Geology and Geophysics; and Melanie Jackson, GeoSystems technical support. Core examination was made possible by Walter Esry and Larry Austin of the OGS Core and Sample Library. Cartographic drafting, visual-aid preparation, and computer-assisted drafting (CAD) were completed by Wayne Furr, OGS manager of cartography; Jim Anderson and Charlotte Lloyd, cartographic drafting technicians; and Gary Leach and Greg Taylor, contract drafting technicians. Technical review and editing were completed by Charles J. Mankin, OGS director; Kenneth S. Johnson, OGS associate director; Robert A. Northcutt, OGS consulting geologist; Richard D. Andrews, GeoSystems petroleum geologist; Christie Cooper, OGS editor; and Tracy Peeters, OGS editorial assistant. Publication printing was made possible by Paul Smith and Richard Murray (OGS). Special recognition also is given to Michelle Summers, OGS technical project coordinator, for program organization and registration.

The author is most appreciative of the technical reviews by Richard D. Andrews, Robert A. Northcutt, Charles J. Mankin, and Kenneth S. Johnson. Conversa-

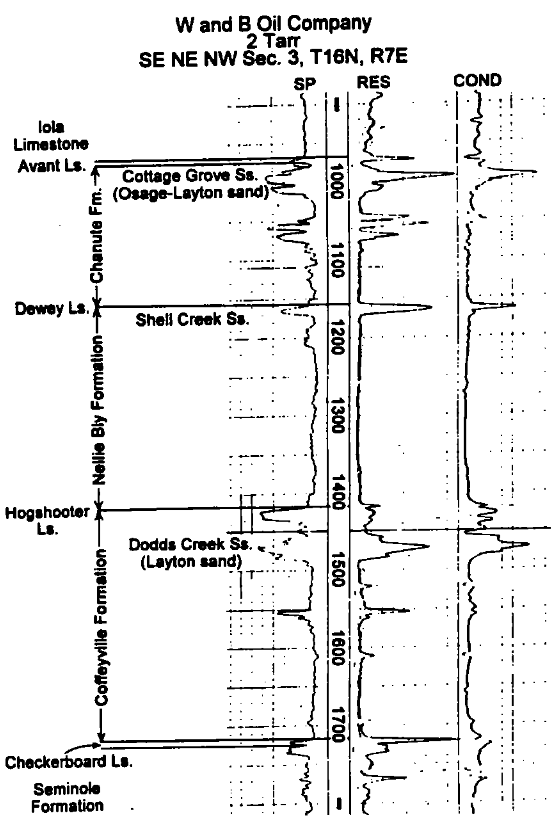
TABLE 1. – Crude Oil Production from "Layton"[a] and Osage-Layton Reservoirs, 1979–94

Reservoir	Leases reporting	Cumulative oil	Average bbl/lease	Other leases[b]
"Layton"	582	11,022,902	18,940	965
Osage-Layton	21	444,119	21,150	26
	603	11,467,021	(20,045)	991

SOURCE: Natural Resources Information Systems (NRIS) oil and gas production data base, available from the Oklahoma Geological Survey, Norman.

[a]For explanation of use of term "Layton," see Footnote 1, p. 13.

[b]Production from two or more reservoirs is combined and reported by lease.



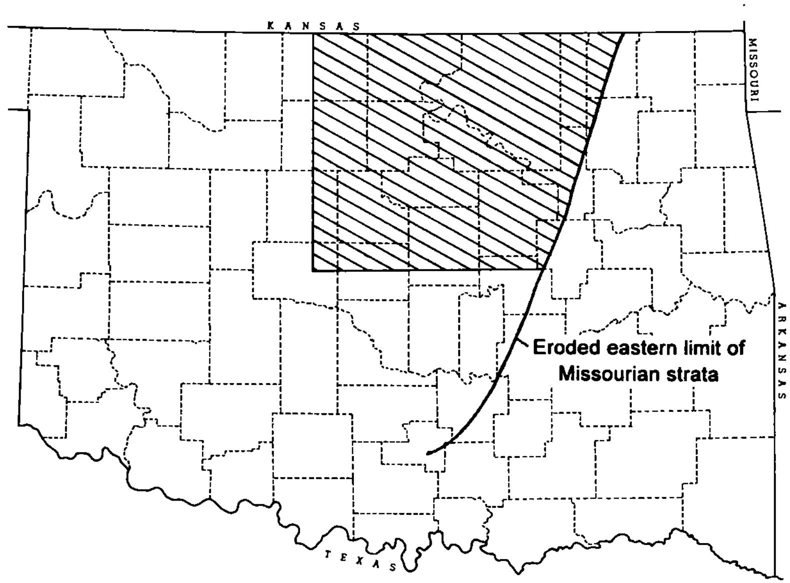


Figure 12. The Layton and Osage-Layton play is located in northeastern Oklahoma and adjacent Kansas, primarily on the Cherokee platform. The play area is generally within the hachured area. Eastern limit of Missourian strata after Johnson and others (1988). The inset log shows spontaneous-potential (SP), resistivity, and conductivity log profiles for the stratigraphic interval of this study, SE¼NE¼NW¼ sec. 3, T. 16 N., R. 7 E., west-central Creek County, Oklahoma (from Tulsa Geological Society, 1985).

tions with Rick Andrews, Dennis Shannon, Bob Northcutt, Greg Riepl, and LeRoy Hemish were most helpful; however, the author alone is responsible for the interpretations and conclusions reached herein.

STRATIGRAPHY

Regional Stratigraphic Relations of Lower Missourian Strata in Northern Oklahoma

The stratigraphic interval that includes the Layton and Osage-Layton sands reaches thicknesses approaching 1,000 ft in eastern Oklahoma. Four regionally extensive limestones separate the major formational units, which consist mainly of shale and sandstone (Fig. 13). Each of these formations tends to have two significant sandstone intervals in the subsurface, but more or fewer occur locally. All of the sandstone intervals are laterally discontinuous in the subsurface, but the Dodds Creek Sandstone Member (Layton or True Layton sand) and Cottage Grove Sandstone (Osage-Layton sand) are the most persistent in the Cherokee platform. To the west, the subject stratigraphic interval thins to ~300 ft (Miller, 1970). The Dewey Limestone no longer is present, and the Cottage Grove Sandstone is the only persistent sandstone interval between the Checkerboard and Iola Limestones (Gibbons, 1962; Miller, 1970).

In the deep Anadarko basin to the south, the Marchand sand occupies a similar stratigraphic position and has been called "Layton" by some workers (Fig. 13). Although some of the earliest subsurface investigations interpreted parts of the Marchand to be of deltaic origin, more recent work indicates that hydrocarbon-producing reservoirs in the Marchand sand consist mainly of deposits that originated as deep marine fans (Shelton and Wilson, 1978; Kessler and others, 1976; Seale, 1981). One recent study interpreted a shallow-marine to tidal-dominated depositional environment for some of the reservoir sandstones (Baker, 1979).

The Wade and Medrano sands also occur in the deep part of the basin, but they are younger than the Marchand sand (Fig. 13). The most thorough study of those intervals in the hydrocarbon-producing areas indicated that they are probably of marine, and, locally, also of tidal-dominated deltaic origin (Lange, 1984). Although fluvial-dominated parts of such deltas may exist, or may have succumbed to erosion, there is no evidence of hydrocarbon production from such facies.

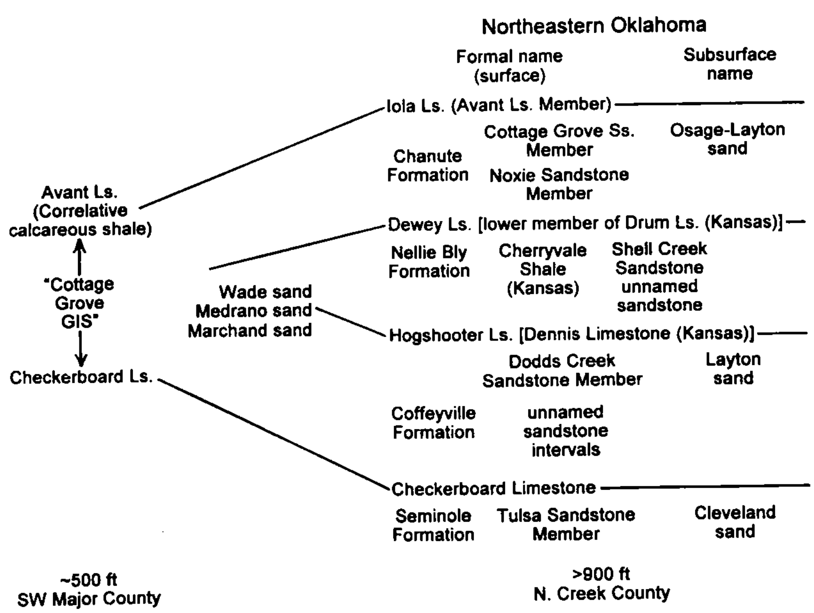


Figure 13. Generalized lower Missourian stratigraphic relations in northern Oklahoma and adjacent Kansas. GIS = genetic increment of strata. Wade, Medrano, and Marchand sands occur in the southeastern Anadarko basin. Compiled from Zeller (1968) and Miller (1970).

The Layton and Osage-Layton Sands

The Layton and Osage-Layton sands are informal names that have become part of the subsurface geologic nomenclature in northeastern Oklahoma. Layton is a drillers' name that dates to the early part of this century. The name Osage-Layton originated from an attempt to correct a *recognized* misidentification of a younger sandstone interval as Layton. The Layton and Osage-Layton sands occur in the Missourian Series of the Pennsylvanian System (Fig. 14). Although subsurface stratigraphy of the region is much better understood since wireline-logging devices came into common use, the Layton sand and Osage-Layton sand "formations" never have been defined by the geological community, and application of those names continues to vary locally according to individual discretion or purpose. Because of the lack of subsurface control for most of the first four decades of petroleum exploration and development, and because of carelessness, locally the name "Layton" has been applied to sandstones that occur in at least six stratigraphic positions in the Missourian Series (Fig. 14).

Several prominent limestones occur in the Missourian Series, so theoretically it is possible to recognize and correlate the correct position of the intervening sandstone and shale sequences (Fig. 14). However, most of the limestones do not persist throughout the entire area of investigation; other, less-persistent limestones occur locally, and the sandstone and shale intervals vary in character and thickness, as the regional stratigraphic sections show (Pls. 4, 5). Only the Checkerboard Limestone persists throughout the study area. Therefore, it is used as the basis for mapping regional structure (Fig. 15), and it is the subsurface datum for regional stratigraphic sections (Pls. 4, 5). Jordan (1957a) pointed out that the names of the four limestone intervals also have been applied locally to more than one discrete geologic formation. To quote

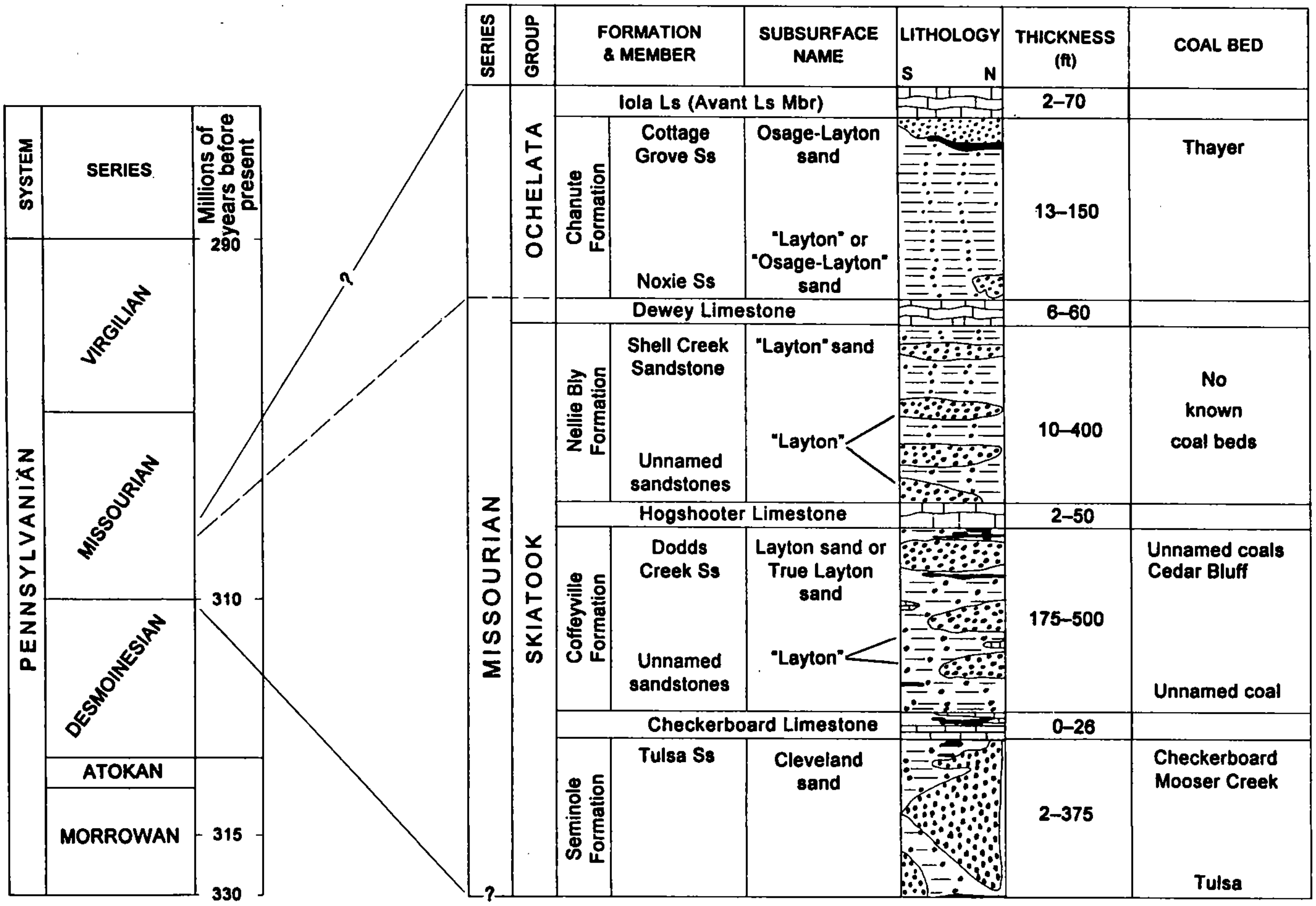


Figure 14. Stratigraphic column for the Missourian Series, with emphasis on the intervals associated with the Layton and Osage-Layton sands, in northeastern Oklahoma. Modified from Tulsa Geological Society (1984–89), Fay (1987), and Hemish (1988). Lithologic column based on surface mapping.

Jordan (1957a, p. 82), "...when different horizons are given the same name, the problem of correcting the miscorrelation is indeed difficult."

The Layton Sand

In spite of the foregoing problems of practice and nomenclature, the originally intended application of the name Layton sand is understood, if not widely applied, correctly (see Footnote 1 on page 13). Thus, the name True Layton commonly is applied to the Layton sand as originally intended. The Layton sand was named for the Layton lease in the Cleveland oil field, in sec. 2, T. 20 N., R. 8 E., eastern Pawnee County. The name was first used in print in 1913 (Jordan, 1957b, p. 120). The Cleveland field was discovered in 1904 (Greig, 1959) and underwent renewed development commencing in 1911 (Bosworth, 1920, p. 120), so it seems probable that the name was in use well before 1913. The Layton sand now is well understood to occur high in the shale, sandstone, and carbonate sequence above the Checkerboard Limestone and below the Hogshooter Limestone. These strata belong to the Coffeyville Formation, or what some authors call the Coffeyville Subgroup. Lukert (1949) and Jordan (1957b) equate the Layton sand to the Dodds Creek Sandstone Member of the Coffeyville Formation.

The Coffeyville Formation first was recognized in southeastern Kansas near the town of Coffeyville (Schrader and Haworth, 1905, p. 448), which is 2.3 mi north of sec. 18, T. 29 N., R. 16 E., Nowata County, Oklahoma (Pl. 6). It was correlated in Oklahoma on the surface by Oakes (1940,1952) and Oakes and Motts (1963), and in the subsurface by Lukert (1949), Ries (1954), Greig (1959), Jordan (1959), and Clare (1963), among others.

The Coffeyville Formation is defined as overlying the Checkerboard Limestone and underlying the Hogshooter Limestone. It commonly consists mostly of shale; however, there are two, and locally at least three, important sandstone intervals in the formation. The upper, the Dodds Creek Sandstone Member, is the best developed and the most extensive. It commonly is called the Layton sand or the True Layton sand in the subsurface. The lower two sandstone intervals remain unnamed on the surface, but commonly are tagged "Layton" in the subsurface. South of Okemah in central

Okfuskee County, the lower part of the Francis Formation is a continuation of the Coffeyville Formation and can be traced to Pontotoc County (Ries, 1954). However, both the Hogshooter and Checkerboard Limestones grade into shale of the Francis Formation (Ries, 1954, p. 56) so that the Coffeyville Formation no longer is mappable on the surface or in the subsurface. To the northwest in the subsurface, the Checkerboard Limestone is correlated easily, but the Hogshooter becomes difficult to recognize beyond T. 19 N., R. 1 E., in northwestern Payne County (Pl. 5).

The name "Layton" sand has been applied indiscriminately to any thick sandstone body in the subsurface that lies between the Checkerboard Limestone and the Iola Limestone (Fig. 14), especially if it bears hydrocarbons. Furthermore, the terms "upper Layton," "lower Layton," and "first Layton," "second Layton," etc., may refer to parts of a major sandstone interval, or they may refer to apparently separate, if not necessarily distinct, sandstone beds, or to porous zones within any interval. As the result of this random usage, the name "Layton" and its kindred no longer designate a specific part of the stratigraphic column. Thus, many workers have applied the name True Layton to the interval as originally intended. It would be *technically* desirable to revise the subsurface nomenclature in an effort to eliminate at least part of the confusion; however, assigning a unique name to the True Layton sand would not correct historical records or literature. Furthermore, it is impossible to be certain that all workers made use of a revised nomenclature. This report recognizes the necessity of using common and established names, while also cautioning the reader of the confusion involved with that established nomenclature.

The Osage-Layton Sand

The term Osage-Layton was introduced into oil-field terminology when it was realized that the Layton sand had been miscorrelated to a younger sandstone interval in Osage County (Jordan, 1957b). Lukert (1949) demonstrated that the Osage-Layton sand is equivalent to the Cottage Grove Sandstone in the subsurface and tied it to Oakes' (1940) surface work in Washington County. This not only corrected the most significant problem in the misapplication of the term "Layton," but also made the term Osage-Layton unnecessary. Awareness of this significant work is too limited, even in the geological community; for example, Busch (1953) continued to use the name "Layton," rather than Cottage Grove Sandstone or Osage-Layton sand.

The Cottage Grove Sandstone is the upper sandstone interval in the Chanute Formation of Oklahoma, called the Chanute Shale in Kansas (Keroher, 1966; Oakes, 1940,1959). It is defined as being underlain by the Dewey Limestone and overlain by the Iola Limestone, commonly known by its upper member, the Avant Limestone, in northeastern Oklahoma (Oakes, 1959). The formation consists largely of shale; however, there are two important and locally thick sandstone intervals—the Noxie Sandstone in the lower part and the Cottage Grove Sandstone in the upper part of the formation. Oakes (1940) established reference localities for the formations in northwestern Nowata County (Pl. 7). In the subsurface, the Cottage Grove and Noxie Sandstones commonly cannot be separated and are known collectively as "Osage-Layton" sand. In oil-field practice, Cottage Grove Sandstone (the correct name for the subject interval) rarely has been applied east of Woods County, or north of Canadian County (Pl. 3). The geological literature is considerably better, with most authors having correctly identified the interval as Cottage Grove Sandstone. However, fewer than half of the authors (Nolte, 1951; Graves, 1954; Stringer, 1957; Querry, 1958; Greig, 1959; Jordan, 1959; Gibbons, 1960; Kurash, 1964; and Calvin, 1965) also identified the interval as Osage-Layton to avoid misunderstanding. Only Lalla (1975a,b) and Mish (1985) completed studies specific to the Osage-Layton sand in the Cherokee platform.

In the absence of knowledge of the correct identity of the Cottage Grove Sandstone, the name Osage-Layton, while a poor choice, at least provides for a separate identity for an important stratigraphic interval. A review of the NRIS data base (Natural Resources Information Systems oil and gas production file, available from the Oklahoma Geological Survey) resulted in the identification of Osage-Layton oil production from 33 leases in 16 fields and two unassigned areas (Pl. 1). Other Osage-Layton production remains inseparable from all other reservoirs that have been called "Layton." The Osage-Layton sand has been identified in 427 wells, concentrated in eight counties (Kay, Osage, Garfield, Noble, Pawnee, Logan, Payne, and Creek). The well-file map (Pl. 2) identifies only those wells from which oil production has been reported.

Several other local names have been applied to the Cottage Grove Sandstone in the Cherokee platform area. Lukert (1949) pointed out that it is the same interval as the Mussellem sand, which originally was identified in the Cushing field (Jordan, 1957b). It also is known locally as the Peoples sand or, according to Lukert (1949), the "Layton of Ponca City." Although the Peoples (below) and Mussellem (above) sands are separated locally by the Dewey Limestone (Bass and others, 1939; Kirk and others, 1941), the lack of continuity of the Dewey and the discontinuous nature of the sandstone intervals results in their being uncorrelatable except locally in the subsurface.

An investigation into the oil- and gas-production and well files of the NRIS data base found that the name Mussellem (surprisingly) occurs exclusively in association with Cottage Grove Sandstone reservoirs. These reservoirs are located almost entirely in T. 22 N., Rs. 16 and 17 W., Major and Woodward Counties. "Mussellman," an apparent misspelling of "Mussellem," also occurs in the well record. The name Peoples and others cited above occur rarely or not at all in the data base. Although Cottage Grove Sandstone is the most accurate name for the subject interval (Keroher, 1966),

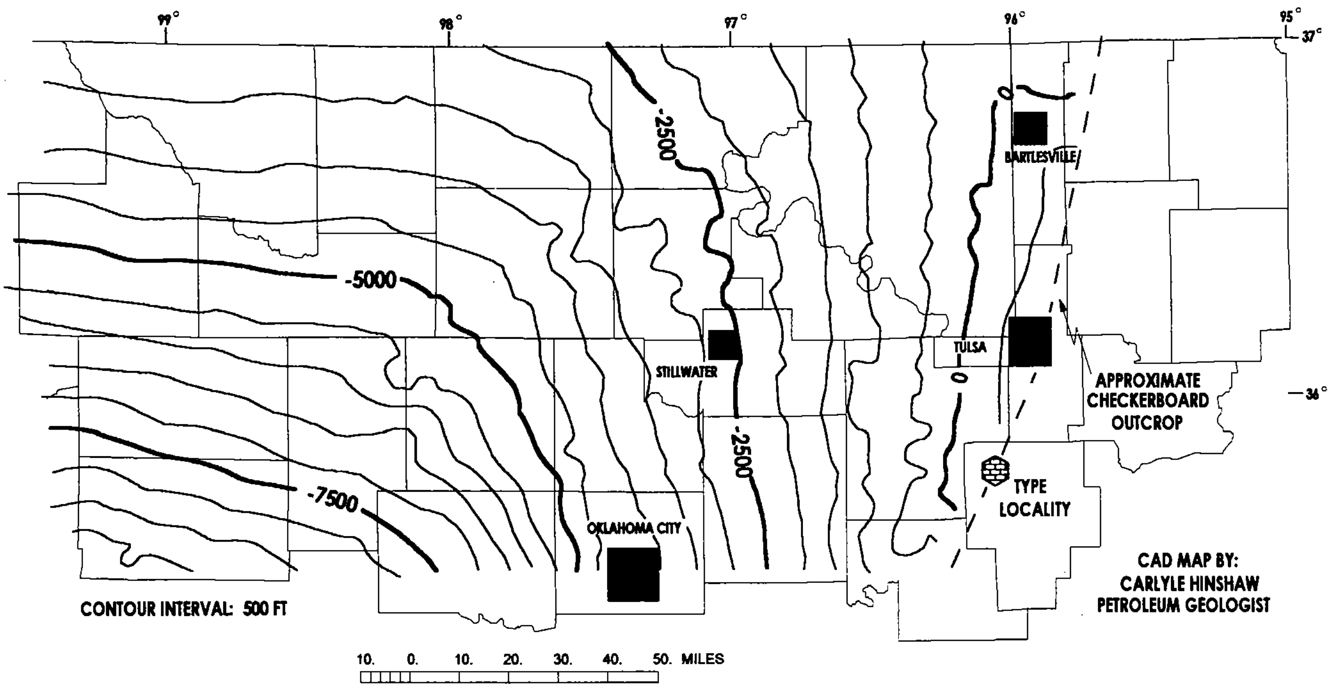


Figure 15. Regional geologic structure on top of the Checkerboard Limestone (lower Missourian). Sea-level datum; contour interval is 500 ft. Compiled from more than 2,300 wells in the NRIS data base, with wells in five sections per township selected initially (secs. 5, 8, 15, 26, and 29). Edited CAD map by Carlyle Hinshaw.

Osage-Layton sand will be used in this report to identify it in the Cherokee platform area, because it is a part of the historical record (Pls. 1, 2), it is accepted by many workers in the area, and it is far superior to the term "Layton."

Nellie Bly Formation

A third interval of sandstone-bearing strata is important to this report, because of its stratigraphic position and because sandstone intervals within it commonly are confused with the Layton sand. Sandstone intervals in the Nellie Bly Formation are less widespread than those in the Coffeyville and Chanute Formations, but are locally significant. D. W. Ohern originally designated the Nellie Bly Formation in an unpublished work in 1914; he cited the type locality as Nellie Bly Creek in southwestern Washington County (Pl. 8). A brief description was published by Gould (1925), and the formation subsequently was described more completely by Oakes (1940). It lies between the Coffeyville and Chanute Formations; therefore it is underlain by the Hogshooter Limestone and overlain by the Dewey Limestone—or, it lies below the unconformity at the base of the Chanute Formation where the Dewey has been removed by erosion (Oakes, 1940). Although the Nellie Bly Formation includes some of the less extensive sandstones within the major geologic units described in this report, there are two persistent sandstone intervals in the subsurface, particularly in parts of Creek, Okfuskee, Okmulgee, and Tulsa Counties. In Osage and Pawnee Counties, one sandstone interval tends to persist in the same stratigraphic position as the upper sandstone interval to the south and southeast. Because of its persistence on the surface and in the subsurface, the upper sandstone interval is correlated with the Shell Creek Sandstone Member of Oakes (1952, fig. 8) and Bennison (1972, p. 59).

Sandstone in the upper part of the Nellie Bly Formation has been identified as "Layton" in Creek County and probably elsewhere. According to Bennison (1972), the Shell Creek Sandstone also is known locally as the "Osage Layton" sand, which adds further confusion to the nomenclature problem. Kirk and others (1941, p. 276) placed the "Peoples sand" in the uppermost part of the Nellie Bly Formation in parts of Osage County. The name "Bruner sand" has been applied to a sandstone-bearing interval below the Dewey Limestone in northern Creek County (Tulsa Geological Society, 1987); however, because the name "Bruner" has been applied to sandstones in several stratigraphic positions, the term should not be used (Jordan, 1957b).

The Nellie Bly Formation may consist mainly of marine shale in much of the Cherokee platform, especially beyond the areas described above. It corresponds to the Cherryvale Shale in Kansas. In the absence of recognizable limestone markers that define its lower and upper boundaries, the marine shales commonly merge imperceptibly with those of the Coffeyville and/or Chanute Formations, and it becomes difficult and locally impossible to recognize the Nellie Bly Formation. However, several studies have identified and correlated the unit in the subsurface. These include Ries (1954), Kirk (1957), Greig (1959), Jordan (1959), Clare (1963), and Cutolo-Lozano (1969).

Stratigraphy of the Nellie Bly Formation is more complex at the surface, indicating that it is probably more complex than is immediately apparent in the subsurface, especially near the outcrop. Six sandstone intervals have been mapped at the surface in Okfuskee County (Ries, 1954), and there are four at the surface in Tulsa County (Bennison and others, 1972, map 1). Oakes (1952, fig. 8) illustrated two sandstone intervals in southeastern Osage County, the upper of which continues into southwestern Washington County. Farther north, the last vestige of sandstone in the Nellie Bly Formation at the surface grades into sandy and silty shale in T. 24 N., R. 13 E. This is probably the same sandy interval that is present below the Dewey Limestone in the type log for northern Washington County (Tulsa Geological Society, 1989).

The origin of the name Shell Creek Sandstone is unclear, but the name apparently has been applied consistently to the same persistent sandstone interval. Oakes (1952) used the name in his figure 8 for a prominent sandstone below the Dewey Limestone, but did not discuss the sandstone in the text. Bennison mapped the Nellie Bly Formation in Tulsa County (Bennison and others, 1972) and assigned the name Shell Creek Sandstone to the same prominent sandstone interval. He also established the type section in Shell Creek just north of the Arkansas River (Bennison, 1972, p. 59), evidently in SW¼ sec. 30 and W½ sec. 31, T. 20 N., R. 11 E., and SE¼ sec. 25, T. 20 N., R. 10 E., Osage County (Pl. 8). Farther south, Ries (1954) also identified the uppermost sandstone in the Nellie Bly Formation to be the thickest and most continuous, but did not apply a name to it. In this volume, the use of the name Shell Creek Sandstone in the subsurface therefore is consistent with surface mapping and continuity of the interval as previously established.

DEPOSITIONAL ENVIRONMENTS OF THE LAYTON AND OSAGE-LAYTON PLAY

The interpretation of depositional environments in this study is based on the limited published literature and on review of hundreds of wireline logs (spontaneous-potential [SP] and gamma-ray profiles). Tens of thousands of wells penetrate the subject intervals; some cores exist, but they are mainly from a few local areas and were not proposed to be a part of this study. There are scant core studies in the published record.

The interpretation of sandstone depositional environments from well logs dates at least to the late 1960s (Krueger, 1968). Concepts of typical wireline-log response to sedimentary sequences that represent specific depositional environments have developed through continuing study (Walker, 1984; Serra, 1985). Early studies were based on SP-log profiles, but concepts matured with wider availability of gamma-ray logs. Many practitioners continue to use the SP-log profile in the absence of gamma-ray logs. The most dependable interpretations result from studies of well-developed depositional systems where wireline logs can be related directly to the geologic interpretation of cores (Coleman and Prior, 1982).

The modern and ancient Mississippi River delta systems are very well developed fluvial-dominated systems and have been studied more extensively than any other delta system in the world. Knowledge gained from studies of these systems does not necessarily apply to ancient depositional systems, especially if the ancient systems cannot be shown to be similarly river- and sediment-dominated. Deltaic systems tend to be highly variable at virtually any scale because they are characterized by many depositional environments (see Part I, this volume); Chaplin (in press) reviewed the difficulties and hazards of interpreting deltaic systems in the subsurface, especially where such interpretations are based on wireline logs from widely spaced wells and minimal core data. Rider (1990) pointed out false logic in the methodology that assumes a relationship between gamma-ray log shapes and depositional environments. He believed that the interpretation of depositional environments from log profiles has been oversimplified and that "a universal application of gamma-ray log shape to [sand] grain size trend and depositional facies is wrong" (Rider, 1990, p. 27).

Missourian Depositional Systems on the Cherokee Platform

Studies of regional distribution of relatively thick intervals of sedimentary rocks that include abundant sandstone, and local studies of specific intervals have resulted in the interpretation of several important deltaic systems in the Pennsylvanian of Oklahoma (Northcutt and Johnson, in press). The general paleogeographic relations during Missourian time are shown in Figure 16. Many of the deltaic systems include locally identified fluvial-dominated deltaic facies, but few, if any, have been studied in sufficient detail to separate and map their constituent facies, except very locally. Among those depositional systems that are poorly understood in detail in the subsurface, and largely on the surface as well, are the three formations that include sandstone intervals commonly known as "Layton" in the subsurface.

The interpretation of deltaic environments in the Coffeyville, Nellie Bly, and Chanute Formations is based on very little documentation. Although the Oklahoma Geological Survey mapped the outcrop 30 to 50 years ago, and earlier (Oakes, 1940,1952,1959; Ries, 1954; Oakes and Motts, 1963), the interpretation of depositional environments beyond marine and nonmarine, based on macroscopic fossil assemblages, was in its infancy. Recent interpretations are based on a few field observations, rare studies of cored intervals, and, typically, study of several wireline well logs per township.

The area that is now the Midcontinent region largely was occupied by a shallow sea with local deep areas

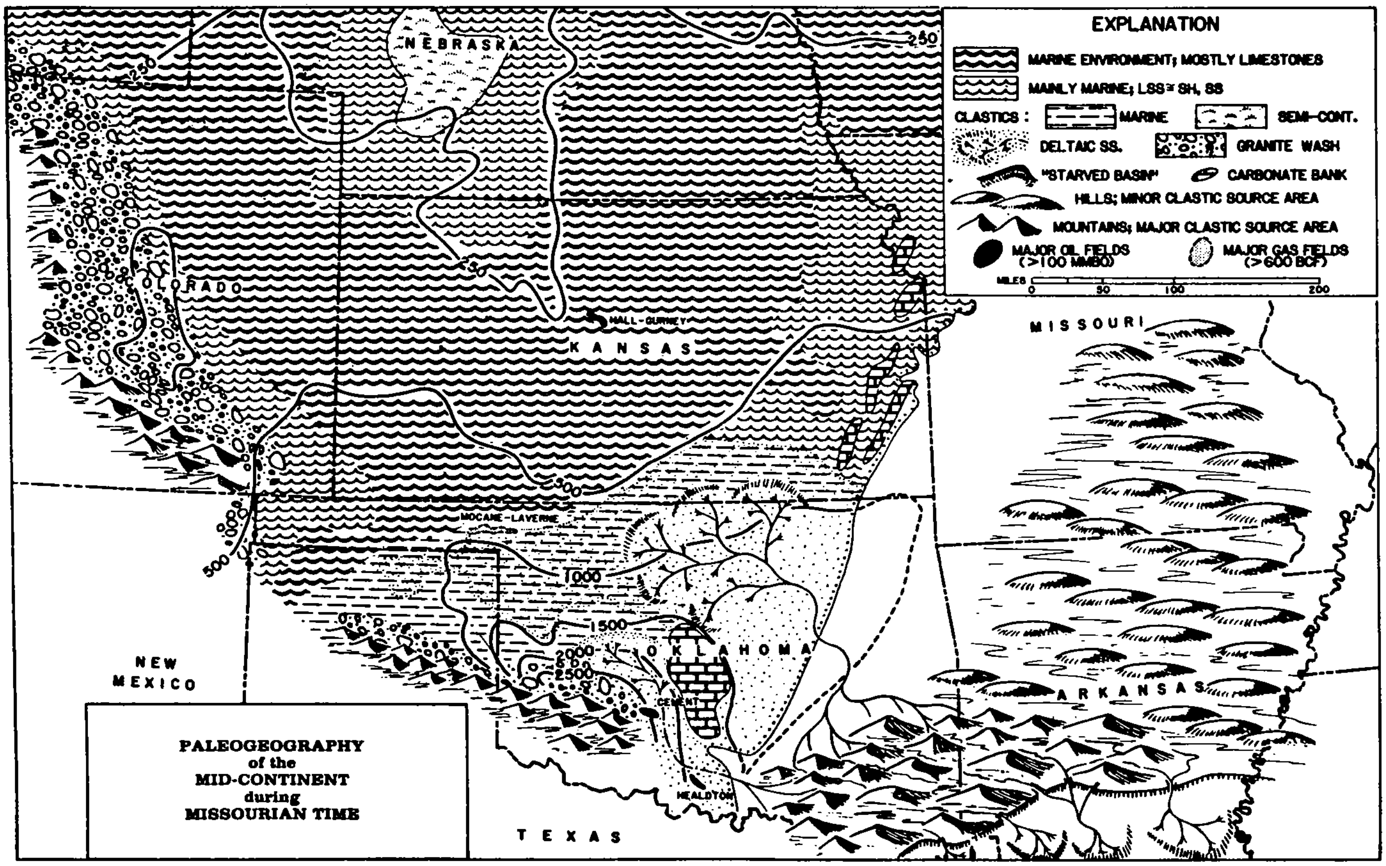


Figure 16. Generalized paleogeography of the southern Midcontinent region during Missourian time and thickness (in feet) of Missourian strata (from Rascoe and Adler, 1983).

throughout Pennsylvanian time. In Oklahoma, the Wichita, Arbuckle, Ozark, and Ouachita uplifts rose along faults from that sea as islands and larger land masses (Cook and Bally, 1975; Johnson and others, 1988). As there was not a large continental land area to provide sediment to the sites of deposition, these uplifts probably were the sources of siliclastic sediments. It is widely agreed that the main sediment source for the Cherokee platform in Missourian time was the Ouachita uplift (Rascoe and Adler, 1983). With the filling of the Arkoma basin by middle Desmoinesian time (Sutherland, 1988), terrigenous clastics derived from the Ouachita uplift prograded onto the Cherokee platform (Krumme, 1981). The Ozark uplift also was emergent, if not mountainous, and also probably contributed sediment. The Mid-Pennsylvanian orogeny that formed the Ouachita Mountains had ceased in early Desmoinesian time (Rascoe and Adler, 1983; Johnson and others, 1988), thus stream gradients became lower, as did sediment supply, by Missourian time. Although sediment was being delivered to a shallow marine shelf, it is difficult to believe this to be a paleogeographic setting in which fluvial-dominated deltaic deposits were being formed on a large scale. Visher and Rennison (1978, p. 20) remarked on the paucity of evidence for strong erosional channeling and suggested that wave energy operated periodically to winnow the sandstone on a shallow delta platform. The area may have been of such low relief and the fluvial currents so weak that tides significantly changed the shoreline daily. Sandstones, described from drill cuttings by most authors, are almost universally fine to very fine grained and are commonly silty. Coarser grain sizes are reported rarely, and those are more common nearer the source in the eastern part of the study area. Micas are a common constituent of the sandstones, and some authors reported feldspar as a minor constituent; both types of minerals suggest a granitic source, presumably the Ozark uplift. At least part of the source area must be crystalline rock rather than older sandstones, so that the grain size would appear to be partly limited not by availability, but by the capability of the sediment transportation system. Therefore the very fine to fine-grain size supports the concept of a low-energy sediment dispersal system, consistent with low relief and sluggish fluvial currents. Although studies of cored intervals from Layton and Osage-Layton sands are uncommon, Mish (1985, fig. 40) reported glauconite in two intervals within the Layton sand from the Grace Petroleum Corporation No. 12 Bair (sec. 23, T. 17 N., R. 7 E., western Creek County). The mineral glauconite commonly is considered to be a strong indicator of a low-energy marine environment; therefore, its presence contradicts a previous interpretation of the area as deltaic (Visher and others, 1975, p. 394). Both illite (typically a marine clay) and kaolinite (typically a clay derived from a continental source) were reported from four sandstone intervals. Although the identification of clay minerals can be very helpful in determination of depositional environments, it must also be realized that more careful study of the clays may be desirable. Tiny fragments of weathered mica (probably of a terrestrial source) have the same X-ray pattern as illite; furthermore, feldspar may be converted to kaolinite in the reservoir sandstone after deposition.

Coal is a common diagnostic sedimentary rock of deltaic deposits. Coals in the Missourian of Oklahoma are few and thin; they have not been observed thicker than 1.5 ft (Hemish, 1988). Coal beds identified in two of three measured sections in Tulsa and Osage Counties (Visher and others, 1975; Visher and Rennison, 1978) were no more than 2 in. thick. The coals analyzed contain high percentages by weight of sulfur. The Cedar Bluff coal occurs below the Dodds Creek Sandstone Member; chemical analysis of that coal is 5.6–5.9% sulfur (Hemish, 1990). That is the highest sulfur content of coals from 10 coal beds in a four-county area, and 1% higher than any other coal analyzed (Hemish, 1990, appendix 3). Stach and others (1975, p. 27) reported that marine-influenced coals are commonly rich in sulfur. In their study of 238 samples from two Appalachian coals, Williams and Keith (1979) found that the average sulfur content of coals overlain by marine strata was >1% higher than those overlain by continental rocks. All of the coals studied contained <4% sulfur. The Thayer coal is overlain by the Cottage Grove Sandstone Member (Fig. 14), but no analyses have been undertaken because it is clearly subcommercial in Oklahoma.

It would be desirable to examine the occurrence of Missourian coals in more detail; however, this preliminary evidence from the Cedar Bluff coal indicates that it was in a paleogeographic position that was influenced or modified by marine conditions. Recurring changes of sea level have been well documented in the Pennsylvanian of the Midcontinent region as repeated sedimentary sequences known as cyclothems. Watney (1980,1985) specifically addressed the Missourian Series. Six major cycles of marine transgression and regression, most of which included cycles of lesser magnitude, have been described in the Missourian of northeastern Oklahoma and adjacent Kansas by Bennison (1985). The existence of at least 10 marine transgressions has been established between the Checkerboard and Iola Limestones (Bennison, 1985, p. 223).

Sediment supply for Missourian depositional systems was much diminished compared to those of the Desmoinesian. Missourian delta systems are less extensive, thinner, and contain thinner sandstone sequences than the Desmoinesian Bluejacket-Bartlesville (Visher and others, 1971), Taft–Red Fork (Al-Shaieb and others, 1989), and Chelsea-Skinner and Lagonda-Prue (R. D. Andrews, in preparation [Fluvial-dominated deltaic (FDD) oil reservoirs in Oklahoma: the Prue and Skinner plays]). The paleogeographic setting was a delta plain of very low relief and limited sediment supply. As such, marine and tidal sediment dispersal mechanisms are likely to have been as important as fluvial. The most likely delta model is that of a delta plain with local fluvial channels, modified by episodic marine invasions. The Missourian deltas probably resemble the tide-dominated types of Galloway and Hobday (1983) (Fig. 6).

One must also recognize that the sediment-dispersal system is "beheaded" at the outcrop in eastern Oklahoma (Pls. 6–8). So little detailed work has been done where the strata are exposed that there is little documentation of the sedimentary environments, and therefore of the paleogeographic relations. A timely opportunity exists to study the sedimentology of the Missourian, especially the Coffeyville and Chanute Formations, and much of the rest of Pennsylvanian strata where they crop out in northeastern Oklahoma.

The Layton Sand

The Layton sand, in its originally intended application, is that sandstone that occurs below the Hogshooter Limestone (Jordan, 1957b). It therefore occupies the stratigraphic position of the Dodds Creek Sandstone Member of the Coffeyville Formation. The Oklahoma Geological Survey recommends that use of the name Layton be limited to sandstone in that stratigraphic position (Fig. 17).

The Layton sand is most commonly described as a fine- to very fine grained sandstone with the common association of micas (mainly muscovite) and clay minerals. It also is commonly silty, and commonly is described as having calcareous cement, although it is locally poorly consolidated and noncalcareous. Some authors described the sandstone as medium- and coarse-grained, but few described a core or drill cuttings through a complete sandstone interval. Mish (1985) described cuttings from a complete sandstone-bearing interval in northeastern Payne County (Table 2). Visher and others (1975, p. 390) described 4–5 ft of medium- to fine-grained sandstone in a measured section in southeastern Osage County. All other sandstones they described are fine grained. Blumenthal (1956) described the Layton sand as medium to coarse grained, subangular, and loosely cemented, but he did not cite the well, location, or interval described.

Many authors described Layton sandstones as having a clay, or clayey matrix, but only one report described those clays. Mish (1985) used X-ray diffraction to study clays extracted from four intervals of a core of the Grace Petroleum Corporation Bair No. 12, sec. 23, T. 7 N., R. 7 E. Both illite (typically a marine clay) and kaolinite (typically a terrestrially derived clay) occur in all four samples, as explained above. Not only does this suggest a mixed marine and deltaic depositional environment, but it emphasizes the fact that either or both

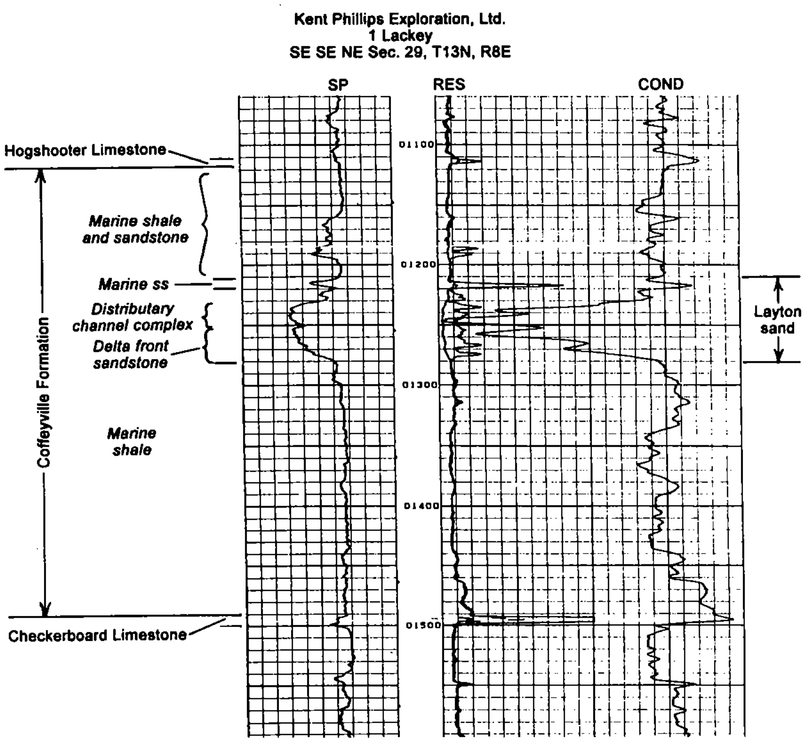


Figure 17. Wireline log illustrating the Coffeyville Formation, including the Layton sand and its possible depositional environments, in the SE¼SE¼ NE¼ sec. 29, T. 13 N., R. 8 E., northwestern Okfuskee County, Oklahoma. Log patterns for spontaneous potential (SP), resistivity, and conductivity are shown.

major clay species may occur in Layton sandstones. It is important to identify clays present in reservoir rocks before introducing any fluids into the reservoir, because water that is incompatible with the clays can cause them either to swell or migrate, and thereby potentially clog pore throats in the reservoir rock.

The previous investigation of the Layton depositional system was a master's thesis by Ekebafe (1973), which was published in large part by Visher and others (1975). In that study, the Layton sand was interpreted as deltaic, including fluvial distributaries, in an area of >6,200 mi^2 (~175 square townships) in northeastern Oklahoma. Although the subsurface study was supported by eight outcrop sections (Visher and others, 1975, p. 386), only three of those sections were published with lithologic description, and environments of deposition were based primarily on wireline logs. SP-log profiles were described, but no typical profiles were illustrated in either the published or unpublished work. Presumably, the criteria were comparable to those of the log profiles in Figure 18. Considerable doubt has been cast on that methodology, as discussed previously; for example, sharp contacts at the base of a "clean" sandstone and "blocky" profiles, commonly interpreted as channel-fill sandstones (Fig. 18A,B), may occur in marine environments. Thinner sandstone intervals (Fig. 18C) also may have a marine origin. However, no other technique is available for such a regional synthesis, although all available cores would be interpreted in a more ideal study.

The present study extends and, in part, reinterprets the work of Visher and others (1975) (Pl. 6). For the purposes of this study, it will be assumed that a delta system is defined loosely in areas of locally abundant sandstone, where "typical" log profiles like those shown in Figure 18 occur regularly. Because of ambiguities involved with the methodology, Plate 6 is compiled from stratigraphic sections in regional studies (Pl. 9) and from interpretation of individual wireline logs, and is probably an over-interpretation of the geographic extent of true deltaic environments. Areas that are predominantly shale, and in which sandstone tends to occur as thin units (10–20 ft thick) separated by shale, are reinterpreted as delta fringe and open marine, rather than bay and crevasse. The reinterpretation affects mainly northeastern Lincoln, southern Creek, and adjacent Okfuskee Counties and is supported by studies at the outcrop.

The Coffeyville Formation is ~80% marine shale in eastern Okfuskee County, where it was mapped by Ries (1954). Sandstone occurs in the lower half of the formation, and the uppermost and more prominent of two sandstone units was identified as "Layton" by Ries (1954, p. 90). It varies from 10 to 30 ft thick. However, wells nearest the outcrop penetrate only shale, demonstrating the discontinuity of sandstone intervals within the marine shale. Only marine fossils, locally in abundance, were recovered from shales and sandstones in the Coffeyville, so there is no compelling reason to identify any part of the formation as deltaic in this area. Farther north, surface studies in Creek, Tulsa, and Washington Counties (Oakes, 1959, 1952,1940, respectively) did not remark on the biota. However, there is no reason to believe that "interfingering lenses of sandstone and extremely sandy shale" that characterize the Coffeyville where it crops out in Creek County (Oakes, 1959, p. 19) are anything but marine. In Tulsa County, Coffeyville sandstones become more distinct and continuous units. The uppermost and most continuous sandstone occupies the stratigraphic position of, and probably is, the Dodds Creek Sandstone Member, or Layton sand, but is not the one identified as "Layton" by Oakes (1952, p. 58). Three measured sections of Layton sand in Tulsa and southeastern Osage Counties were interpreted as deltaic by Visher and others (1975).

The uppermost sandstone in the Coffeyville Formation in Washington County is not discussed in detail (Oakes, 1940, p. 38) but is correlated with the Dodds Creek Sandstone Member, and the Layton sand of the subsurface. It is continuous with the sandstone in the same stratigraphic position in Tulsa County (Oakes,

TABLE 2. – Description of the Layton Sand from Drill Cuttings of the Magnum Energy Inc., Nancy No. 1, SE¼SW¼SE¼ sec. 7, T. 19 N., R. 5 E.
(After Mish, 1985)

Depth (ft)	Lithology of the True Layton sandstone interval
2,510–2,520	Sandstone: gray, very fine grained, very carbonaceous, micaceous; dirty, clayey appearance, dense black and green clasts (grains?), quartz overgrowths, calcite cement, pyritic.
2,520–2,526	Limestone: white to tan, soft, chalky.
2,526–2,677	Interbedded sandstone and shale:
	Sandstone: gray, very fine grained, carbonaceous, micaceous; dirty, clayey appearance, quartz overgrowths, calcite cement, pyritic, with dense black and green clasts.
	Shale: gray to dark gray, silty, fissile, pyritic, "greasy" appearance, fossiliferous.
2,677–2,690	Sandy limestone: tan, carbonaceous, dolomitic, silty to very fine grained sand, micaceous, with dense green and black grains.
2,690–2,703	Sandstone: light gray to gray, silty to very fine grained, very micaceous, very carbonaceous, with dirty, clayey appearance.
2,703–2,711	Limestone: pinkish-white, compact, partly crystalline, mottled.
2,711–2,735	Sandstone: silty to very fine grained, light gray to gray, very micaceous, very carbonaceous, with dirty, clayey appearance.
2,735–2,774	Interbedded siltstone and shale:
	Siltstone: light brown to gray, quartz overgrowths, compact, slightly carbonaceous, slightly micaceous, with dense black and green fragments.
	Shale: gray to dark gray, silty, fissile, pyritic, "greasy" appearance, fossiliferous.
2,774–2,778	Sandy limestone: very pale orange, silty to very fine grained sand, crystalline, with dense black and red grains.
2,778–2,793	Interbedded siltstone and shale:
	Siltstone: light gray, very micaceous, carbonaceous, soft, very friable, with calcite cement and dense black, green, and orange grains.
	Shale: gray to dark gray, silty, fissile, pyritic, "greasy" appearance, fossiliferous.
	Underlain by limestone.

1952, fig. 6). This sandstone unit, as mapped by Oakes (1940), can be interpreted to represent a prograding delta complex and is so interpreted in the subsurface on Plate 6.

In the western part of the study area, the relatively common sandstones of a probable lower deltaic plain give way to less continuous, marine delta-front or delta-fringe sandstones. The Nemaha uplift was apparently a barrier to the westward development of the Layton delta. However, marine processes distributed sandstone discontinuously farther west (Pl. 6).

The Shell Creek Sandstone

The Shell Creek Sandstone Member is the uppermost and most persistent sandstone in the Nellie Bly Formation (Fig. 19). It is continuous at the outcrop (Oakes, 1952,1959; Ries, 1954) but commonly discontinuous in the subsurface. The Shell Creek Sandstone of Plate 8 is not correlated from well to well, but includes any sandstone in the stratigraphic position of the Shell Creek Sandstone. It occurs in the place of, or immediately below, the Dewey Limestone (Oakes, 1952,1959), or it is the stratigraphically highest sandstone interval with as much as 90 ft of shale between it and the Dewey Limestone (Ries, 1954).

Detailed information about the Shell Creek Sandstone is even more elusive than that for the Layton and Osage-Layton sands. The prominent, stratigraphically highest sandstone interval in the Nellie Bly Formation at the surface in Okfuskee County (herein correlated with the Shell Creek Sandstone) was described by Ries (1954, p. 67) as being 20–50 ft thick, "massive," and "sparsely fossiliferous." These criteria are hardly diagnostic, but a flood plain, or lower delta plain, environment appears to occur in southern Creek, Okfuskee, and adjacent Lincoln Counties (Pl. 8). SP-log profiles suggest an adjacent area of delta-front sandstones. Oakes (1940, p. 49) described the Shell Creek Sand-

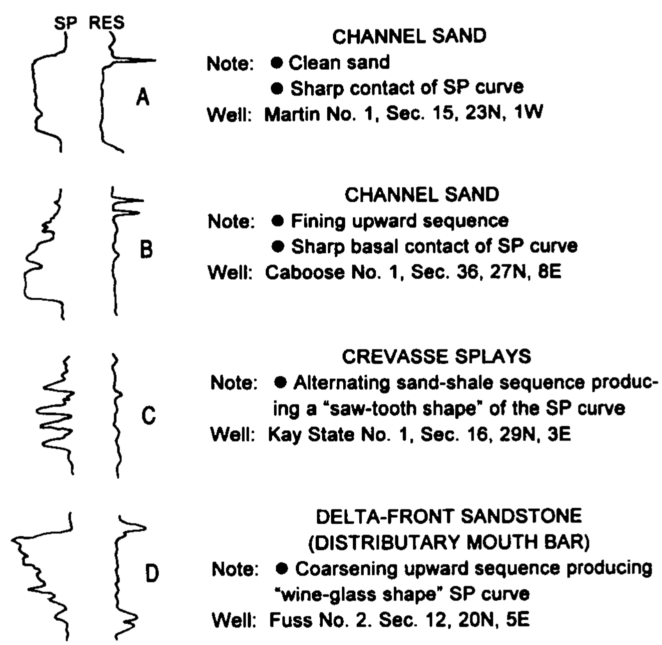


Figure 18. Typical spontaneous-potential (SP) and resistivity log profiles used in the interpretation of depositional environments of the Osage-Layton sand in northeastern Oklahoma (from Lalla, 1975a,b).

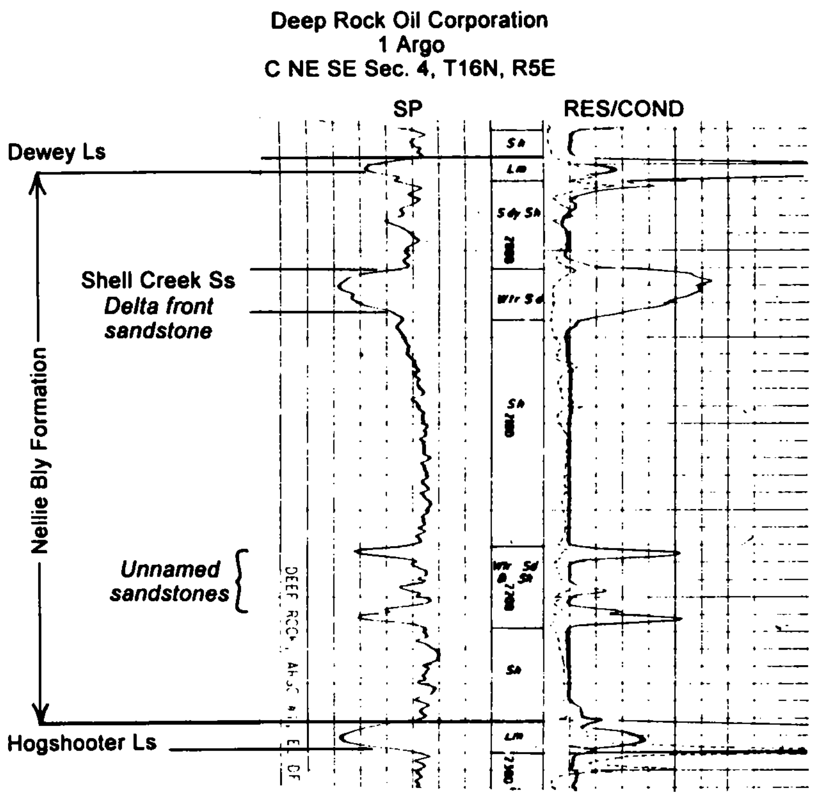


Figure 19. Wireline log illustrating the Nellie Bly Formation, including the Shell Creek Sandstone Member (locally called "Layton") and its apparent depositional environment in the C NE¼SE¼ sec. 4, T. 16, N., R. 5 E., north-central Lincoln County, Oklahoma. Log profiles for spontaneous potential (SP), resistivity, and conductivity are shown (from Tulsa Geological Society, 1987).

stone as being 10 ft thick, poorly consolidated, and fine to medium grained at one locality in Washington County. Bennison (1972) did not describe the lithology, but remarked briefly on depositional environments. He described (p. 58) "strong deltaic-type foreset sandstone beds" in western Tulsa County; this is the basis for extending the deltaic environment on Plate 8 to that point. Bennison (1972, p. 59) also reported "prominent current ripple beds with various orientation[s] toward the top and its excellent sorting toward the top suggests shoreward winnowing" (herein interpreted as marine delta-front sandstone) along Shell Creek in southeastern Osage County. This, and SP-log profiles in the subsurface, are the basis for mapping the Shell Creek Sandstone in eastern Osage and Pawnee Counties as a marine sandstone. The lack of continuity of the interval in the subsurface in this area can be assumed to result, at least in part, from local nondeposition of sandstone facies; however, it is also probably in part the result of pre-Chanute erosion cited by Oakes (1952, p. 78).

In Osage County, sandstones of *apparent* deltaic origin were remarked on by Ross (1922, p. 172 and 183). However, the deposits occur lower in the section (Oakes, 1952, p. 65) and therefore evidently are not related to the subject interval. According to Oakes (1952, p. 65), "The area provides opportunity for much more detailed study."

The Osage-Layton Sand

It is not known when the error of correlation that resulted in the introduction of the name Osage-Layton sand occurred, or when it was discovered. However, it was a matter of record by the mid-1950s (Jordan, 1957b). The oldest current production identified as being from the Osage-Layton sand is from wells completed in 1959 in the Ponca City field in sec. 19, T. 25 N., R. 2 E., Kay County.

It is now well understood that the Osage-Layton sand is identified correctly as the Cottage Grove Sandstone, a member of the Chanute Formation. The term Osage-Layton sand is used in this report because of its historical and current use in the oil industry, and because of its presence in the public records. In common industry usage, Osage-Layton designates the "eastern" facies of the Cottage Grove Sandstone, which is largely of flood-plain and deltaic origin. The name Cottage Grove most commonly is used in association with the "western" facies, which is of marine origin. A typical occurrence of the Osage-Layton sand in the Cherokee platform is illustrated in Figure 20.

The Osage-Layton sand is commonly described as a fine- to very fine grained sandstone. It is commonly silty and micaceous, indicating low-energy environments of deposition. However, the sandstone locally may be medium grained and well sorted, as reported by Lalla (1975b, p. 71) from outcrops in Tulsa County. Chaplin and Kareem (in press) described a sandstone-dominated interval of the Osage-Layton sand from a core hole in northeastern Kay County (Table 3). Although a detailed study of depositional environments has not been completed, the 123-ft interval probably represents a transition from upper- to lower-delta plain (James R. Chaplin, personal communication, 1995). Mish (1985) described a 206-ft-thick, sandstone-rich interval of Osage-Layton sand from drill cuttings from the Magnum Energy Inc., Nancy No. 1 well, SE¼ SW¼SE¼ sec. 7, T. 19 N., R. 5 E., northeastern Payne County. That interval includes fine- and very fine grained, micaceous to slightly micaceous sandstones. The sandstones described have a clayey matrix and are locally silty and carbonaceous. The less micaceous sandstones tend to have calcite cement and presumably are better sorted than the former.

The Cottage Grove Sandstone/Osage-Layton sand is commonly thicker and exhibits a much greater area of distribution than the Layton sand (Pl. 7). Unlike the Dodds Creek Sandstone/Layton sand, marine facies are abundant west of the Nemaha uplift and Nemaha

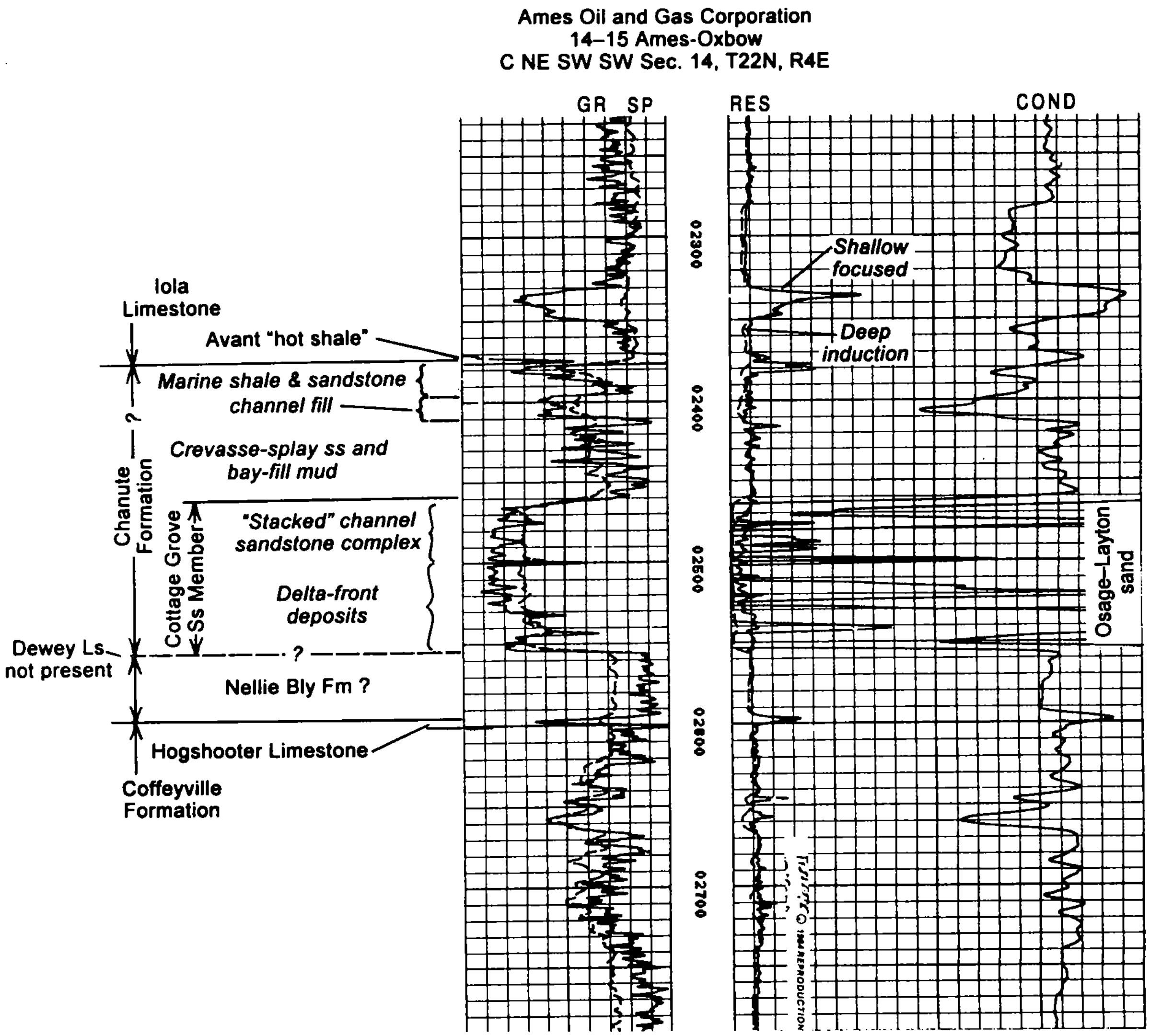


Figure 20. Wireline log illustrating the Chanute Formation, including the Osage-Layton sand and its possible depositional environments in the C NE¼SW¼SW¼ sec. 14, T. 22 N., R. 4 E., in eastern Pawnee County, Oklahoma. Log profiles for spontaneous potential (SP), gamma-ray (GR), resistivity, and conductivity are shown.

fault zone (Gibbons, 1962; Towns, 1978; Fruit and Elmore, 1988). The limit of significant sandstone deposition in Woods and Woodward Counties (Pl. 7) is modified from Capps (1959).

A lowering of sea level prior to deposition of the Chanute Formation resulted in removal of all or part of the Dewey Limestone, and, locally, part of the Nellie Bly Formation in parts of Creek, Tulsa, and Washington Counties (Oakes, 1952). Erosion is believed to be as deep as the Hogshooter Limestone locally (Oakes, 1940, p. 65). The Noxie Sandstone (lower part of the Chanute Formation) is known to occupy erosional channels, but the same has not been demonstrated for the Cottage Grove Sandstone (Oakes, 1940). Horne (1965) attributed the broad distribution of the Cottage Grove Sandstone to the lowstand of sea level, which resulted in a much larger source area for terrigenous sediment.

The Cottage Grove Sandstone, or Osage-Layton sand, commonly occurs as a thick, megascopically massive sandstone unit, both in outcrop and on the subsurface. It is easily recognized in the subsurface where it occurs as such, as in the interval 2,460–2,530 ft in Figure 20. Lalla (1975a,b) mapped the Osage-Layton depositional system in northeastern Oklahoma east of the Indian Meridian and north of T. 13 N. to the Kansas state line. Environments of deposition were interpreted almost entirely from wireline-log profiles (Fig. 18). The investigation of a cored interval was limited to a few core chips without reported depths; three outcrop investigations lacked measured or described sections, and locations were not reported in enough detail for one to repeat observations of the same outcrops. SP-log profiles, such as those illustrated in Figure 18, are present in the study area but occur among a plethora of less "diagnostic" profiles.

Furthermore, sandstone-dominated intervals are as likely to exhibit coarsening-upward profiles (similar to

TABLE 3. – Description of the Osage-Layton Sand from the Conoco No. 33-5 Test Borehole, sec. 33, T. 28 N., R. 3 E., Kay County, Oklahoma*

Sandstone, light olive gray, very fine grained, noncalcareous except from 2,480 to 2,508 ft; intervals with carbonized plant fragments, soft-sediment deformation features, and small-scale trough and planar crossbeds; some massive, structureless intervals; rare coaly shale spars, shale rip-up clasts, and conglomeratic horizons; some rare intervals interstratified with dark gray, noncalcareous, fissile, silty shale.

*Generalized description of the 123-ft interval of recovered core from 2,390.1 ft through 2,530.1 ft. The interval is >95% sandstone (Chaplin and Kareem, in press).

Fig. 18A) as they are likely to exhibit fining-upward profiles (Fig. 18B). If regional depositional environments can be interpreted in the Osage-Layton sand by this method, I do not believe it can be done with a few well logs per township (actual density of control was not reported by Lalla). I found that ambiguities in the method are too common to extend the interpretation, with confidence, beyond Lalla's (1975a,b) area of study. For example, the SP-log profile in Figure 18A cannot be assumed to represent uniquely a channel-fill sandstone, especially where "blocky" sandstone units are separated by shales in which the SP-log or gamma-ray-log profile tracks a straight "shale line." Thick sandstone intervals, as represented by such "blocky" log profiles, can be found locally as far west as Major County (Gibbons, 1962; Miller, 1970). In addition, this general SP-log or gamma-ray-log profile (Fig. 18A) has been shown to occur not only in association with *identified* fluvial channels, but also with delta-front sands (Saitta-B. and Visher, 1968), barrier bars (Fons, 1969, p. 16; Berg, 1976, p. 5c), tidal-sand ridges and barrier bars (Taylor, 1977, fig. 1), tidal-channel fill (Garcia, 1981, fig. 4), and river-mouth tidal ridges (Coleman and Prior, 1982, p. 166).

In the present study, it was necessary to approximate the limits of the Osage-Layton delta with more general criteria. Figure 18B is a log profile common to flood-plain environments; in this study such evidence of a flood plain is included in the interpreted delta. Thus, the limit of the Osage-Layton "delta" is defined generally and possibly is over-interpreted (Plate 7 is compiled from stratigraphic sections in regional studies [Pl. 10] and from interpretation of individual wireline logs). If the Osage-Layton depositional system could be studied in greater detail, a greater variety of depositional environments would be found. In addition to fluvial channels and bayfill muds, silts, and crevasse-splay sandstones, there likely are wave- or tidal-dominated and estuarine facies, such as those described by Bhattacharya and Walker (1991). Existing outcrop studies are of limited use in shedding light on depositional environments. Ries (1954) found the Chanute Formation in Okfuskee County to be almost devoid of fossils; no fauna were found, but *Calamites* (a large, tree-like jointed fern) was found rarely in sandstones. These criteria permit the interpretation of a deltaic environment for sandstones of the Chanute Formation that crop out in Okfuskee County, and are compatible with wireline-log interpretation to the west (Pl. 7).

The Cottage Grove and Noxie Sandstones are separate intervals within the Chanute Formation at the surface (Oakes, 1940), but the Noxie Sandstone does not occur at the surface south of northern Tulsa County (Oakes, 1952). The two sandstone bodies are not necessarily separated by shale in the subsurface, and it is therefore not always possible to map them separately in the subsurface. The same relationship between the two intervals was noted by Calvin (1965), whose study area was mainly in southeastern Kansas. Therefore, the Osage-Layton sand of the subsurface almost certainly includes both sandstone intervals locally, particularly in the Oklahoma counties bordering Kansas. The Osage-Layton sand commonly occurs as a massive sandstone interval (Fig. 20), which is commonly ≥40 ft thick and locally reaches ≥100 ft thick. The thickest individual sandstone bodies occur mostly in the northern part of the study area, i.e., Osage, Kay, Pawnee, Noble, and adjacent Payne Counties. Continuous intervals of sandstone are commonly thinner to the south; however, the thickness of combined sandstone intervals are comparable, locally reaching 100–160 ft of net thickness in both northern and southern areas (Lalla, 1975b, fig. 5). This is in contrast to the Layton sand, in which the most continuous area of net thick sandstone approximates the position of the Arkansas River from Tulsa County to eastern Noble County (Visher and others, 1975, fig. 14). In general, the net sandstone thickness of both the Layton and Osage-Layton intervals varies from 20 to 60 ft over much of a 175-square-township area of northeastern Oklahoma. However, in the thickest areas of sandstone deposition, sandstones in the Osage-Layton interval locally reach 160 ft, whereas the thickest net sandstone in the Layton interval exceeds 100 ft (Fig. 21).

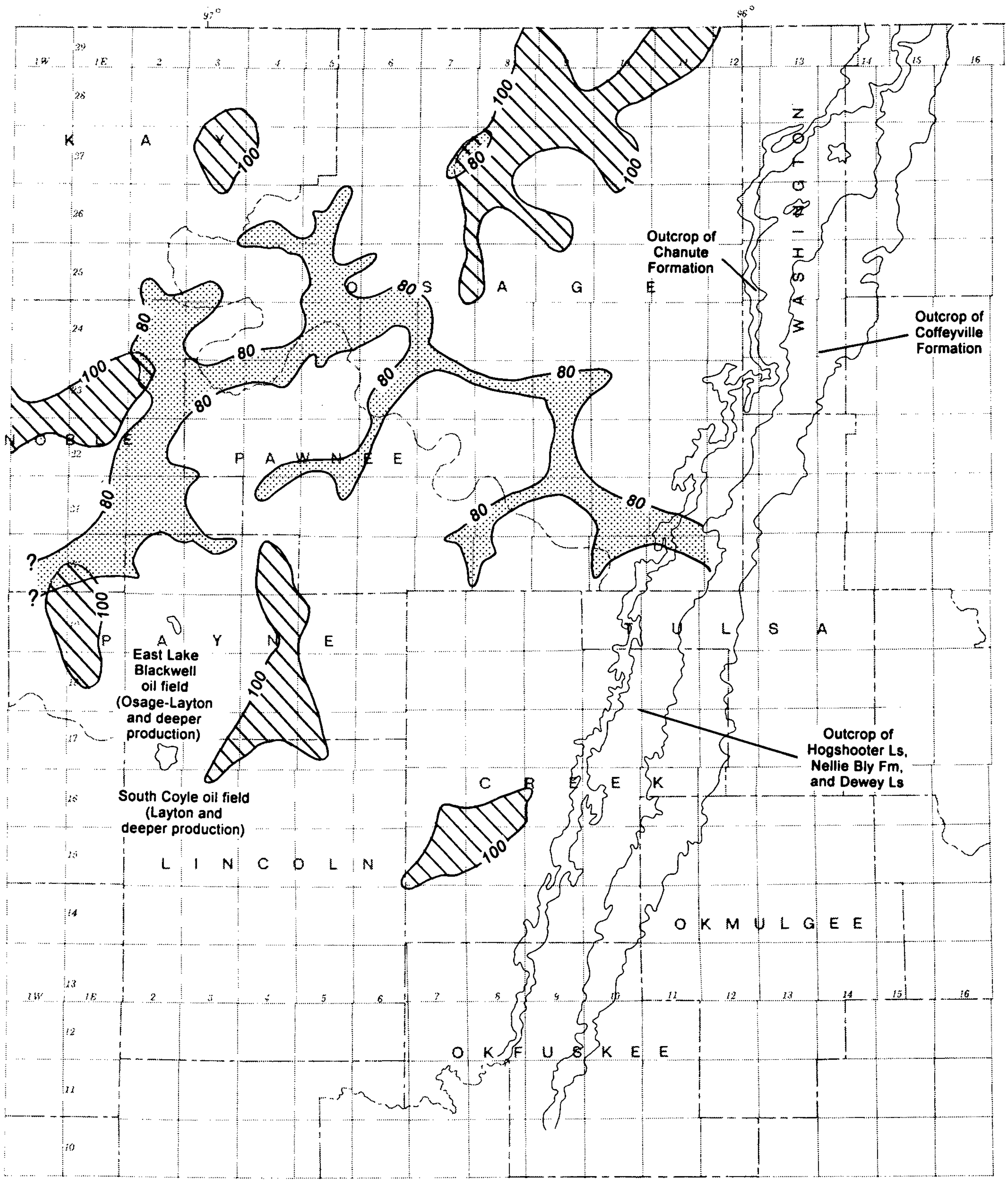


Figure 21. Maximum net thickness of Layton and Osage-Layton sandstones in the delta area. Layton sand (stippled); minimum thickness shown is 80 ft (after Ekebafe, 1973). Osage-Layton sand (hachured); minimum thickness shown is 100 ft (after Lalla, 1975a). Outcrop areas from Miser (1954).

PART III

The Layton and Osage-Layton Play: Reservoir Studies

INTRODUCTION

The purpose of the reservoir studies is to determine the nature and extent of reservoirs, and the mechanics of hydrocarbon entrapment in a fluvial-dominated(?) deltaic reservoir system in the Layton and Osage-Layton play. The case histories presented in this part may provide insights for exploration and development of other reservoirs in the play. It also is hoped that the case histories and the reservoir simulation study (Part IV, this volume) will shed light on the potential for infill drilling and/or water flooding of the reservoirs.

It was necessary to overcome several logistical problems in order to identify reservoirs in the Layton and Osage-Layton play for study. First, only logged drill holes that penetrate the entire Layton or Osage-Layton stratigraphic unit could be used to describe and explain the geology of the producing intervals. Because, however, the reservoirs are relatively shallow and can be exploited at relatively low cost, many operators have logged only the discovery well, or, more commonly, an older logged well may lead to the development of a shallow reservoir, in which case the confirmation well has been logged. Many development wells may not be logged and, in some cases, may be drilled only a few feet into the top of the stratigraphic unit or to the known (apparent) reservoir interval within it. These practices make it difficult to find logs of wells drilled through the complete sandstone interval.

Second, a history of production is essential for reservoir study purposes. A history may be difficult to obtain because it is common for oil produced from multiple wells and reservoirs on one lease to be collected in the same tank battery, so that oil produced from any specific well or reservoir cannot be measured unless individual wells are metered. Locally, of course, production from more than one reservoir may be produced through a single well bore. Thus, the investigator commonly finds himself thwarted between a circumstance in which production cannot be isolated to a specific stratigraphic unit (deeper production occurs on the lease), versus one in which few wells are drilled and logged deep enough to penetrate the entire stratigraphic interval. These were the most common difficulties encountered in the search for a candidate reservoir to study. Finally, it also is easier to verify production history and to obtain additional information about the wells and reservoirs if there is a limited number of operators (one or two).

OSAGE-LAYTON SAND RESERVOIR STUDY, EAST LAKE BLACKWELL OIL FIELD AREA

(T. 19 N., R. 1 E., Payne County, Oklahoma)

by Jock A. Campbell

Discovery and Development

The Osage-Layton sand reservoir in the East Lake Blackwell area is located in the northern three-fourths of sec. 14, T. 19 N., R. 1 E., northwestern Payne County (Figs. 22, 23). Most production from the Osage-Layton sand lies west of the established field boundary (Fig. 22). It was discovered in 1987 by Stillwater Oil and Gas, Inc.; Las Colinas Oil Corporation continued development beginning in early 1991 with the drilling of the No. 1 Oltmanns well, NE¼NE¼ sec. 14, T. 19 N., R. 1 E. The discovery well was the Coastal Oil and Gas Company No. 1-14 Arnold, NE¼NW¼ sec. 14, T. 19 N., R. 1 E. The well originally was drilled to 5,000 ft on September 9, 1987, to test the "Wilcox" sand. Subsequently, the well underwent three operator changes prior to completion in the Osage-Layton sand on September 26, 1987. It has been rumored that crude oil was circulated to the surface while drilling through the Osage-Layton sand, following a drill-pipe connection. Because the sandstones commonly have low permeabilities, one cannot expect to find such an excellent show in every well drilled through hydrocarbon-bearing Layton or Osage-Layton sands. Development beyond the discovery well began in May 1990 with completion of the No. 1 Ham well (SW¼NE¼ sec. 14, T. 19 N., R. 1 E) and continued through July 1993 with completion of the No. 1-A Pike (SE¼NE¼ sec. 14, T. 19 N., R. 1 E.). There is no spacing order for the area by the Oil and Gas Division of the Oklahoma Corporation Commission. However, the effective spacing for most wells producing from Osage-Layton sand is 40 acres per well. The exceptions are the Nos. 1 and 1-A Pike, spaced at 20 acres per well. Development drilling probably is not complete.

As of the end of 1994, there were 10 producing wells, two dry and abandoned wells, and one well that was subeconomic because it produced mostly salt water (Table 4). Total production from 10 wells was nearly 300,000 barrels as of December 31, 1994 (Fig. 24). Three wells on three leases (No. 1 Ham, No. 1 Harrington, and No. 1 Pike) originally were completed with production of associated gas. Subsequently, gas also has been

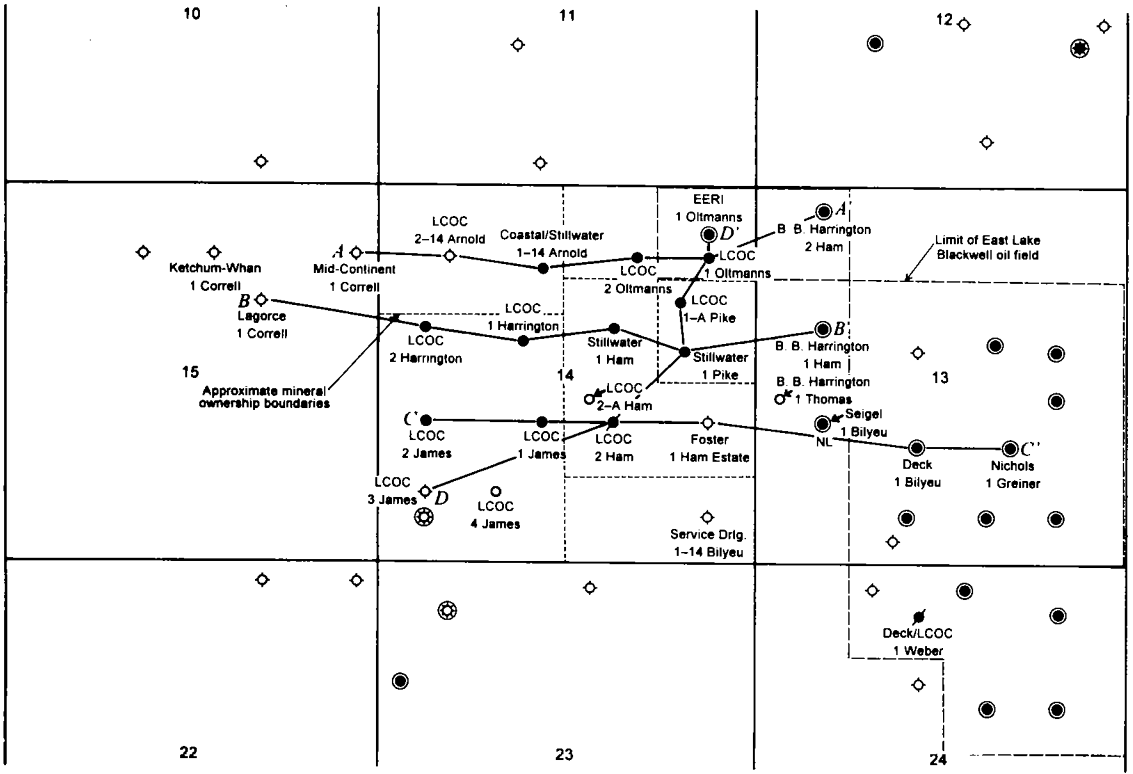
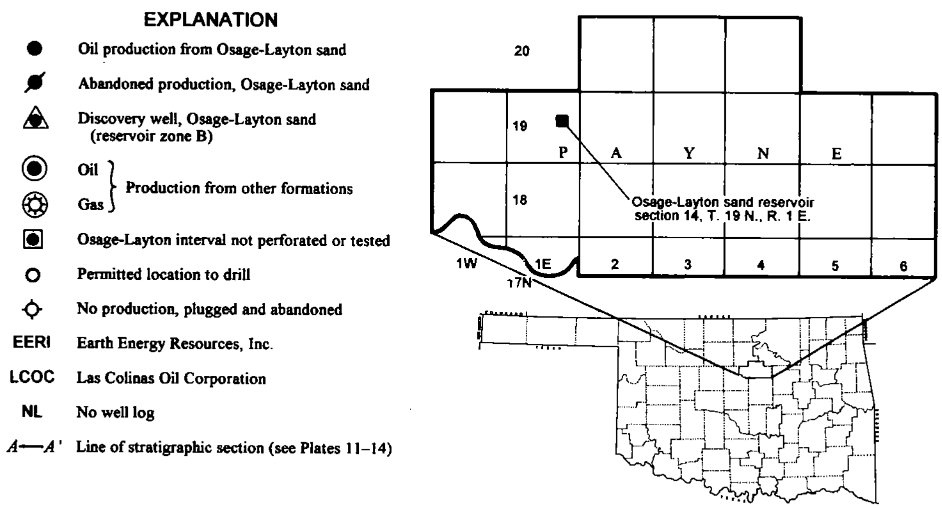


Figure 22. Information map of the East Lake Blackwell oil field area, sec. 14, T. 19 N., R. 1 E., northwestern Payne County, Oklahoma.



produced from the Oltmanns lease. Total marketed gas from October 1991 to December 31, 1994, was 38,300 MCF. Of the original well completions for which initial production data were reported, 7 of the 10 wells produced water. Of these, six produced more water than oil, but one well (No. 2 Harrington) was recompleted for equal amounts of oil and water. Only three wells were completed with little or no accompanying production of water (Table 5), and those are structurally the highest wells in the field.

The most common completion practice is to drill into the Osage-Layton sand with water-based drilling mud while watching drill-cuttings carefully for oil shows. A mud-logging unit on the site is extremely valuable in monitoring any shows that may be encountered. Gamma-ray, spontaneous-potential (SP), and resistivity logging are useful in identifying and correlating sandstone reservoirs, especially if they are thin. However, resistivity anomalies associated with hydrocarbon-bearing zones typically are very subtle, so the importance of hydrocarbon shows is redoubled. Neutron-density logs identify and quantify the best porosity within the reservoir sandstone intervals. Once production pipe is set and the desired zone(s) are perforated, some wells are treated with 250 gallons of 7.5% hydrochloric acid as a mud-cleanout agent (Table 5). It also is apparent that locally it is desirable to perforate only a zone at the top of the reservoir interval to keep water production as low as possible. Ideally, the discovery well, or the confirmation well, would be cored at the first show of oil in a sandstone. The core might be followed by a drill-stem test of the hydrocarbon-bearing interval.

Las Colinas Oil Corporation of Dallas continues to operate the two wells on the Pike lease. Eight other wells on five leases are operated by Pan Western Energy Corporation of Tulsa, Oklahoma.

Stratigraphy and Depositional Environments

The Osage-Layton sand in the subsurface is stratigraphically equivalent to the Cottage Grove Sandstone Member of the Chanute Formation (Jordan, 1957b). Although these names were used originally in Kansas, they are applied correctly in northeastern Oklahoma (see Part II, this volume). The unfortunate use of the term "Layton" to refer to any sandstone interval between the Checkerboard Limestone and the Avant Limestone continues to cause confusion. In fact, well records in the study area submitted to the Oklahoma Corporation Commission (1002-A forms) in the study area refer to the reservoir sandstone interval as both "Layton" *and* Osage-Layton.

The Osage-Layton sand is present throughout the study area, although its character varies significantly from well to well. This is exhibited on structural-stratigraphic cross sections A–A′, B–B′, C–C′, and D–D′ (Pls. 11–14). The internal stratigraphic relations and depositional environments of the Osage-Layton sand in the study area are complex and locally ambiguous. In the absence of well cores in the local area, the depositional environments as interpreted from wireline logs are somewhat speculative.

A geologist using wireline logs feels more certain interpreting a deltaic depositional environment if the sequence of depositional events shows typical deltaic-system characteristics, including the presence of delta-front deposits at the base of the sequence, which commonly overlie a marine shale. Although several wells may exhibit a gamma-ray or SP log response that can be interpreted as delta-front, these identifications are more presumptuous than they are clearly defined examples. Although the local absence of delta-front deposits is not necessarily significant (they may be eroded or redistributed locally prior to deposition of overlying distributary-channel-fill deposits), it is worrisome when these deposits are poorly developed or generally absent. On the other hand, the sequence of fluvial-deltaic(?) deposits in the study area is <200 ft thick in every well except one, the No. 1 Correll at the west end of structural-stratigraphic cross section B–B′ (Pl. 12). Therefore, this is not a strong depositional system by any definition of a delta, and one therefore cannot expect to find examples of "classic" styles or easily interpreted depositional environments. However, the presence of sandstone bodies that can be interpreted as distributary-channel-fill deposits suggests a fluvial-deltaic system. The more thinly bedded sandstones and shales in many of the wells can be defended most easily as interdistributary-channel-fill and bay-fill deposits that are common in a deltaic environment. These deposits consist of bay-fill mudstone or shale and crevasse-splay (or "overbank") sandstones, and possible crevasse-channel sandstones. Although the mudstones and/or shales are evidently rich in organic matter, no coal layers were identifiable on wireline logs. The common variation of strata within the short distance between wells is, in itself, indicative of a nonmarine environment. The deposits probably represent a lower deltaic plain, i.e., one subject to frequent tidal, or even occasional marine, flooding. The evidence for this is the paucity of coal deposits and the apparent marine sandstone that occurs at the top of the Osage-Layton sand in the area (Pl. 11).

Reservoir units, as well as nonhydrocarbon-bearing sandstones, are interpreted to be distributary-channel-fill and crevasse-splay deposits (see Part I, this volume). The difference between minor channels and crevasse

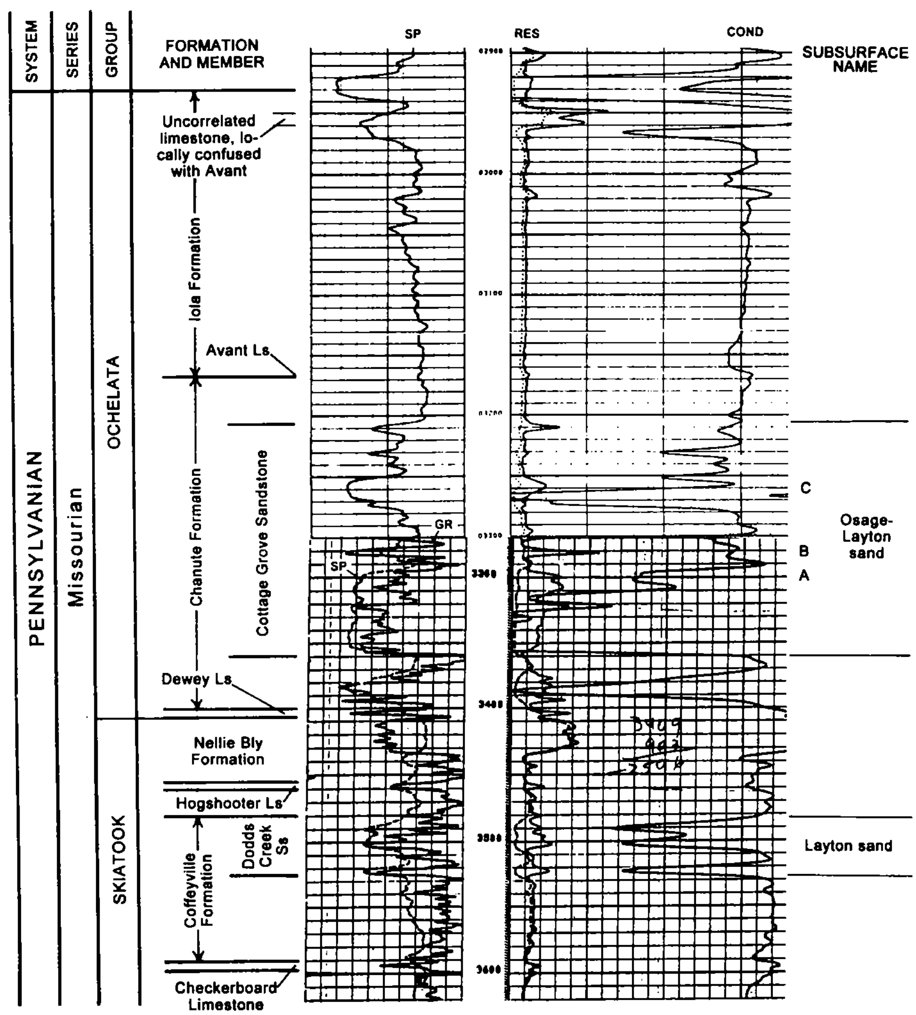


Figure 23. Representative log of the Osage-Layton sand and associated strata, East Lake Blackwell oil field area.

TABLE 4. – Chronological Order of Well Completions in the Osage-Layton Sand, East Lake Blackwell Oil Field Area, Payne County, Oklahoma

Well and Lease	Zone A	Zone B	Zone C	Zone D
Arnold No. 1-14	*	9-12-87		
Ham No. 1	5-28-90			
Pike No. 1	1-08-91			
Arnold No. 1-14	1-24-91			
Oltmanns No. 1	3-28-91			
Ham No. 2	4-08-91 Subeconomic.		ca. 4-08-91 Plugged & abandoned.	
Oltmanns No. 2	5-13-91			
Harrington No. 1	6-17-91			
James No. 1	8-14-91		*	
Harrington No. 2	9-24-91*			*
Arnold No. 2-14	Structurally low; D&A 10-22-91.			
Harrington No. 2				2-25-92
Harrington No. 2	3-18-92			
James No. 2	5-01-92			
James No. 1	Squeezed (6-12-92)		6-16-92	
James No. 3	Structurally low; D&A 11-11-92.			
Pike No. 1-A	7-?-93			

NOTE: Compiled from operator records, Oklahoma Corporation Commission data (1002-A forms), and completion-card information. Oil-producing zones are in approximate stratigraphic order, from lowest to highest, with A being the lowest.

*Well subsequently recompleted in zone indicated.

splays is not specifically determined from wireline-log study alone; however, these features ideally have distinctly different gamma-ray (or SP) log signatures (Fig. 3), and channel-fills are generally thicker than splays. Any given channel or splay is likely to have limited geographic distribution so that it is discontinuous in wireline-log sections. A channel correlated along a line of section may not be continuous if it is truncated by a younger channel between wells, or if the line of section does not coincide with its meandering path. In addition, internal geometry and composition of channel-fill deposits may prevent fluid communication, so that separate compartments may occur in the reservoir. Similarly, separate or overlapping crevasse-splay and/or minor channel-fill deposits may produce separate compartments in a reservoir that *appears* to correlate in wireline-log section. Figure 25 illustrates the concept in map view; it is based on field and shallow-subsurface study of Westphalian A (Early Pennsylvanian) deposits in the Durham coal field, England (Fielding, 1984). Although the length of the splay complex parallel to the crevasse-splay channel in Figure 25 is ~12 km (7 mi), the scale is deleted because of the great range of sizes possible. The stratigraphic cross sections (Pls. 11–14) are annotated with depositional environments as interpreted from the study of wireline logs.

Mish (1985) examined lithologies of the Osage-Layton sand using cuttings from the Magnum Energy Inc., No. 1 Nancy, located in sec. 7, T. 19 N., R. 5 E., ~20 mi east of the study area. Sandstones in the Osage-Layton interval range from transluscent to white and light gray in color and are micaceous to slightly micaceous. Those sandstones also are commonly calcareous, suggesting proximity to a marine environment. Grain sizes are fine to very fine; the thinner sandstone intervals in particular are silty and locally carbonaceous. The presence of silt and mica indicates poor sorting, common in deltaic sandstones. In general, their presence reflects a transport medium that lacks *persistent* energy, a trait typical of nonmarine environments. Carbonaceous material also suggests a deltaic environment and is consistent with the variable energy in a fluvial-related depositional environment that has resulted in poorly sorted sandstones. In contrast, the equivalent Cottage Grove Sandstone (in common usage; explained on p. 17) also is fine to very fine grained, but is well to very well sorted. This is consistent with deposition in a marine environment (Waller, 1993). A clayey matrix is common to all six of the intervals containing sandstone that were examined by Mish (1985). The clay was not examined in detail to determine the clay-mineral species present, nor am I aware of any published report in which the clay mineralogy of the Osage-Layton sand has been examined in detail. However, Mish (1985, p. 91–94) found clays of apparent continental *and* marine origin in a more detailed analysis of a core of the Layton sand (Part II, this volume).

Local Structure and Entrapment of Hydrocarbons

Oil, and locally gas, occur in combination traps in four discontinuous sandstone intervals (Figs. 26, 27). In general, traps are formed by facies changes from sandstone to shale in an eastward, updip direction. Local geologic structure contributes to the entrapment as a subtle, westerly plunging anticlinal nose (Fig. 28).

Local geologic structure is mapped on the horizon represented by the top of the Osage-Layton sand (Fig. 28). A sandstone commonly is not an ideal sedimentary body for structural mapping, because it is subject to variations in deposition that may cause local

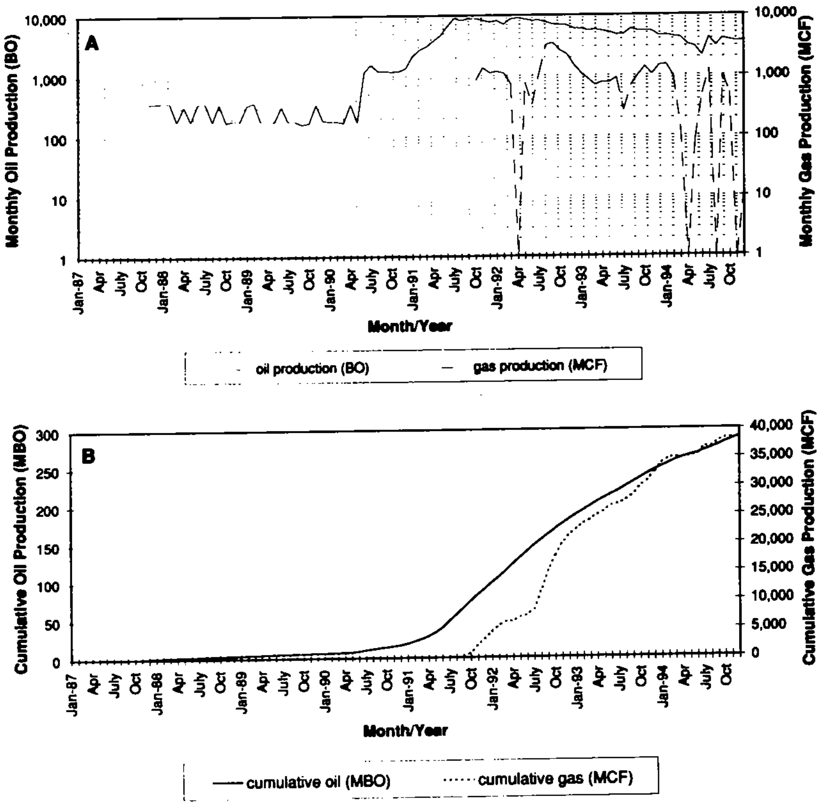


Figure 24. Oil production from Osage-Layton sand reservoirs, East Lake Blackwell oil field area: (A) monthly production; (B) cumulative production.

changes in the stratigraphic position of the top of the unit. The top of the Avant Limestone is probably a more dependable surface for structural mapping in this area, but it is separated from the Osage-Layton sand by 40–80 ft of shale. The top of the Osage-Layton sand has the advantage of being the lowest continuous and recognizable horizon above the producing reservoirs in the local area. This structural surface helps to explain local entrapment of hydrocarbons; however, because of local differences in sedimentation and compaction patterns, any given stratum within the Osage-Layton sand does not necessarily correspond in detail to that structural surface. Because structure is subtle, a sea-level datum was selected for the geologic cross sections (Pls. 11–14) so that local structural relations between wells along those lines of section can be viewed easily by the reader.

The discontinuous nature of sandstone bodies in the Layton and Osage-Layton sands commonly results in stratigraphic traps where local geometry of sandstone bodies is in a favorable position relative to regional dip, such that oil and gas are trapped. In this particular location, the westerly plunging anticlinal nose (Fig. 28) seems to be a significant factor in localizing the hydrocarbon accumulation, even though there is only about 20 ft of structural relief in the area of production from Osage-Layton reservoirs (Fig. 28).

Regional geologic structure has a westerly dip in the area (Fig. 29) and is likely to have contributed to local hydrocarbon entrapment in the subject reservoirs. Zones C and D have mappable northerly and easterly limits (Figs. 26, 27) and probably formed local traps in response to regional dip alone. The sandstones that form zones A and B are not likely to have great lateral continuity, but their northeasterly limits are unknown due to the limited number of penetrations (Figs. 26–28); therefore, it is speculative whether entrapment would have occurred at this particular location as the result of regional dip alone. At the very least, local structure apparently has caused localization of hydrocarbon entrapment in four intervals, so that fewer wells are required to penetrate multiple reservoirs. Therefore, local structure has had a positive effect on the economics of exploitation of this accumulation.

Hydrocarbon production clearly clusters along the prominent, if subtle, anticlinal nose (Fig. 28). The three structurally highest wells are the only ones that produced no water initially (Table 5; Fig. 28). In addition, a map of cumulative oil production exhibits a similarity to local structure (Fig. 30). In the absence of this local structure, the four reservoirs would be unlikely to be confined to a small area, and the more extensive reservoirs would have less than the existing hydrocarbon column. Certainly fewer reservoirs would be penetrated by each well; thus, more favorable economic circumstances have been created by the subtle anticlinal nose.

Oil and Gas Production Zones

Four hydrocarbon-producing intervals have been identified in the Osage-Layton sand in the East Lake Blackwell oil field area. Zone A is the most widespread of the four reservoirs. It also is the lowest stratigraphically; the others are herein designated B, C, and D, respectively, in stratigraphic order. The four zones are laterally discontinuous; thus, no single well produces from every zone, nor does any single well penetrate every zone (Figs. 26, 27). In addition, some other sandstone bodies do not, or *evidently* do not, bear hydrocarbons. A gross reservoir-quality sandstone map (Fig. 31) gives a clearer picture of the reservoir potential of the entire Osage-Layton sand in the area.

Suppressed log-resistivity response is a common characteristic of Layton and Osage-Layton reservoirs. It is probable that suppressed resistivity of hydrocarbon-bearing intervals is the result of clay contained in shaly or "dirty" sandstones. Clay minerals in shale typically contain variable amounts of water trapped in the mineral structure. Such water adds to the conductivity of the interval and thus suppresses the response of resis-

TABLE 5. – Initial Production Data for Osage-Layton Sand Reservoirs in the East Lake Blackwell Oil Field Area, Payne County, Oklahoma

Well and Lease	Date of completion	Completed zone	Initial production (pumping)[a] Oil	Gas	Water	Oil:Water ratio	Completion practice Acid	Fracture
Arnold No. 1-14	9-12-87	B	22	0	7	3.14:1	500 gal 15%	none reported
Ham No. 1	5-28-90	A	40	10	44	0.91:1	none reported	none reported
Pike No. 1	1-08-91	A	33	20	0	—	none reported	no
Arnold No. 1-14	1-24-91[b]	A	25	0	8	3.13:1	none reported	none reported
Oltmanns No. 1	3-28-91	A	32	0	trace	—	yes[c]	yes[c]
Ham No. 2	4-08-91	A[d] & C[d]	3	0	140	0.02:1	none reported	none reported
Oltmanns No. 2	5-13-91	A	50	0	80	0.63:1	no	no
Harrington No. 1	6-17-91	A	56	20	75	0.75:1	250 gal 7.5%	no
James No. 1	8-14-91	A	7	0	102	0:17:1	250 gal[c]	no
Harrington No. 2	9-24-91	A	13	0	151	0.09:1	250 gal 7.5%	no
Arnold No. 2-14	10-22-91 (D&A)	n.a.				n.a.		
Harrington No. 2	2-25-92[e]	D	60	0	60	1.00:1	250 gal 7.5%	no
Harrington No. 2	3-18-92[e]	A	no data available					
James No. 2	5-01-92	A	17	0	70	0.24:1	none reported	none reported
James No. 1	6-16-92[e]	C	17	0	100	0.17:1	none reported	none reported
Weber No. 1	10-30-92	n.a.	5	0	170	0.03:1	500 gal[c]	no
James No. 3	11-11-92 (D&A)	n.a.				n.a.		
Pike No. 1-A	7-?-93	A	50	0	0	—	none reported	none reported

NOTE: Compiled from operator records, Oklahoma Corporation Commission data (1002-A forms), and completion-card information. Oil-producing zones are in approximate stratigraphic order, from lowest to highest, with A being the lowest.

[a]Oil and water reported in barrels daily; associated gas reported in thousands of cubic feet daily.
[b]Additional perforations. [c]Details unavailable. [d]Production abandoned. [e]Recompletion.

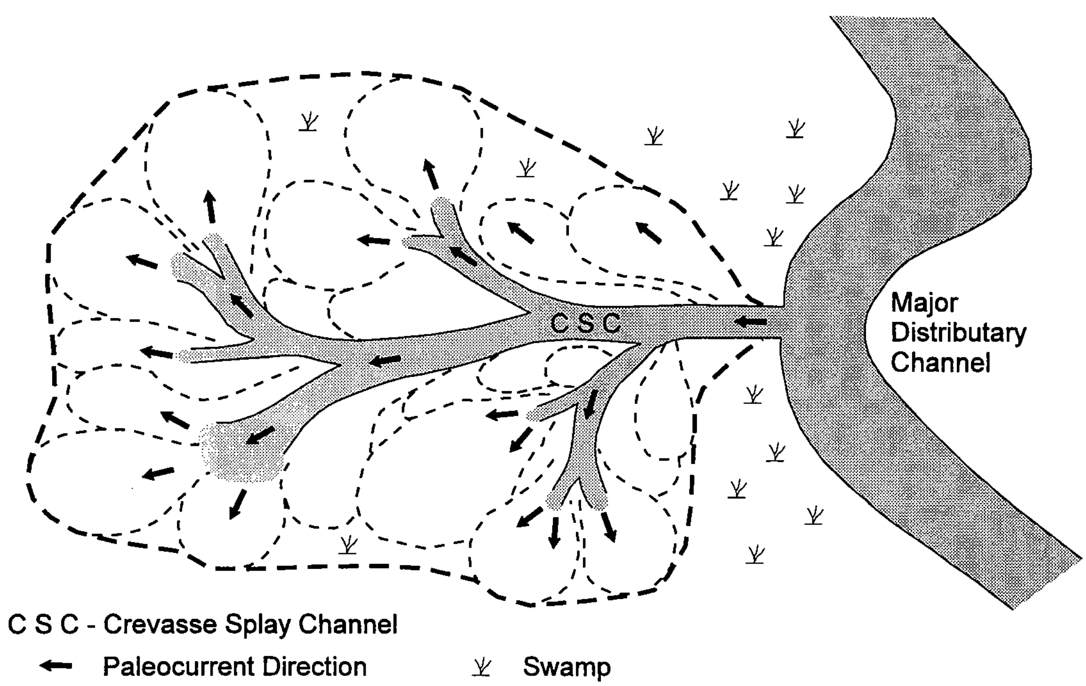


Figure 25. Crevasse-splay sandstone complex that forms a crevasse subdelta. Modified from Fielding (1984).

tivity to hydrocarbons that may be present. A review of the formation (deep) resistivity profile of several wells aids understanding of the presence and location of hydrocarbons.

In the No. 1-14 Arnold, background resistivity, as observed below the producing intervals (from about 3,320 to 3,360 ft; Pl. 11), is about 1–1.5 ohm-meters. In zone B, the total resistivity is only 4–5 ohm-meters; it is even less in zone A, ~2 ohm-meters. Zone B was completed in all 6 ft of a 6-ft interval, whereas zone A was completed in the upper 12 ft of a 14-ft interval (Pl. 11). The two zones were completed for comparable amounts of oil and water, even though zone A exhibits about half the resistivity but is about twice as thick as zone B.

The No. 1 and No. 2 Oltmanns wells (Pl. 11) exhibit comparable formation resistivities in zone A, ~2.5 ohm-meters. However, the No. 1 Oltmanns initially produced only a trace of water, and the No. 2 well produced substantially more water than oil (Table 5). Both wells are perforated in the entire zone A interval (Pl. 11). The No. 1 Pike (Pl. 12) and No. 1-A Pike (Pl. 14) have resistivities of 2–4 and 3–5 ohm-meters associated with zone A, respectively. Both wells had water-free initial production; thus, it is apparent that these intervals represent the highest formation resistivities that one can expect to find in this Osage-Layton sand reservoir, and probably in many others.

There is a little more than 2 ohms of deep resistivity associated with zone A in the No. 1 Ham and No. 1 Harrington; both wells produced substantial amounts of water initially (Table 5). In wells with still lower oil-to-water ratios (i.e., No. 2 Ham), deep resisitivity exhibits little or no response to the hydrocarbons present. In conclusion, it is apparent that deep resistivity is a guide to the hydrocarbon-producing potential of these intervals, but certainly it does not provide for universal understanding. One cannot overemphasize the value of careful study of drill cuttings coincident with drilling for visual evaluation of oil saturation. Given the ambiguity of well logs for thin beds and suppressed resistivities in the presence of hydrocarbons, drill cuttings may be the best single guide to both discovery and reservoir development.

Three production zones exhibit oil-water contacts (Figs. 26, 27), two of which are mappable in well bores. These will be discussed with individual reservoir intervals.

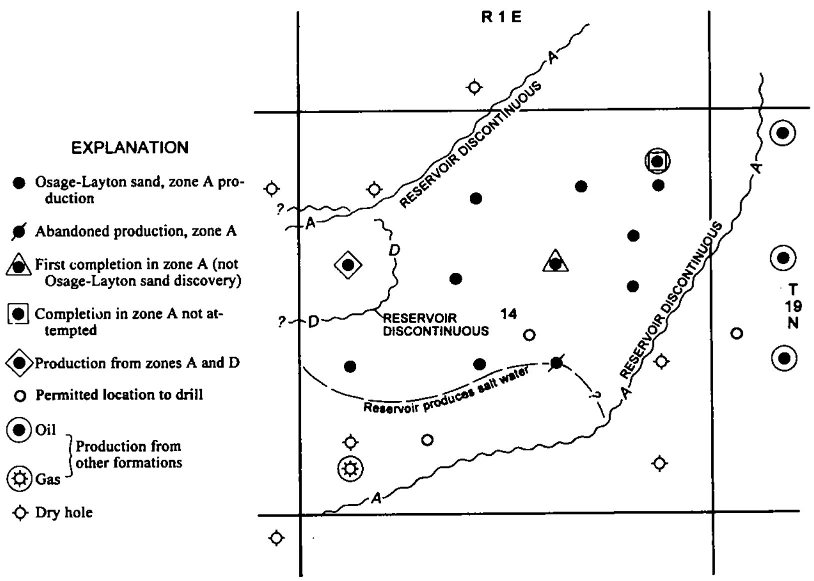


Figure 26. Distribution of production zones A and D of the Osage-Layton sand in the East Lake Blackwell oil field area, sec. 14, T. 19 N., R. 1 E.

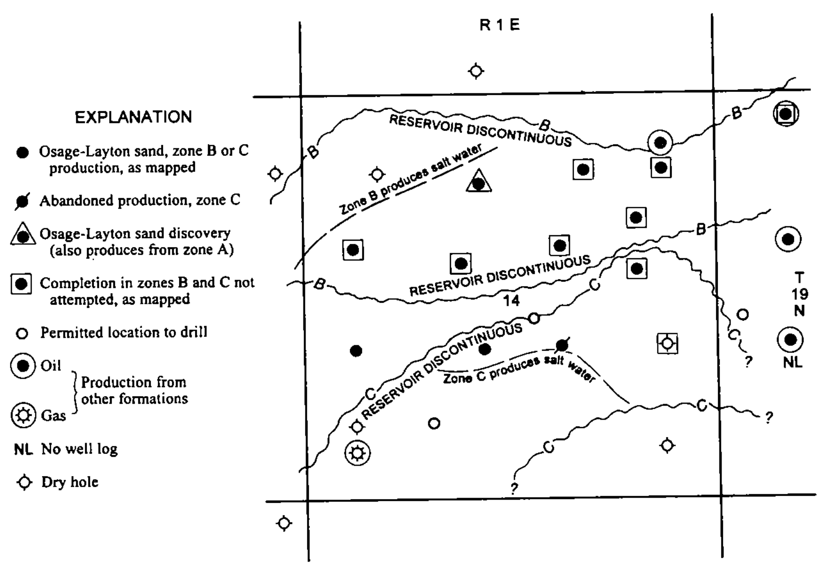


Figure 27. Distribution of production zones B and C of the Osage-Layton sand in the East Lake Blackwell oil field area, sec. 14, T. 19 N., R. 1 E.

Production Zone A

Production zone A is the most widespread and stratigraphically lowest (deepest) of the four reservoir intervals identified to date. The complexity of reservoir geology is evident from the fact that zone A initially was not completed in the discovery well, No. 1-14 Arnold. That well was completed in the next-highest sandstone, herein designated zone B. Zone A was not perforated in the Arnold well until after the completion of the No. 1 Ham and No. 1 Pike, about 19 months after initiation of development drilling (Table 4). Productivity from the Arnold well increased significantly following the completion in zone A (Fig. 32), although the greater resistivity anomaly is associated with zone B (Pl. 11).

Zone A subsequently has been completed in eight additional wells, through July 1993, for a total of 11 producers (Table 4; Fig. 26). These include the most productive wells, with the lowest coproduction of water in the field (Table 5). Zone A is the most laterally continuous zone and is penetrated by 14 wells (Fig. 26). The structurally lowest wells, on the south side of the field (Fig. 33; Pl. 13), produce high proportions of water, and at least one of them is subeconomic—the No. 2 Ham (Tables 4, 5).

Production histories of the other leases that produce from zone A are presented in the order in which the

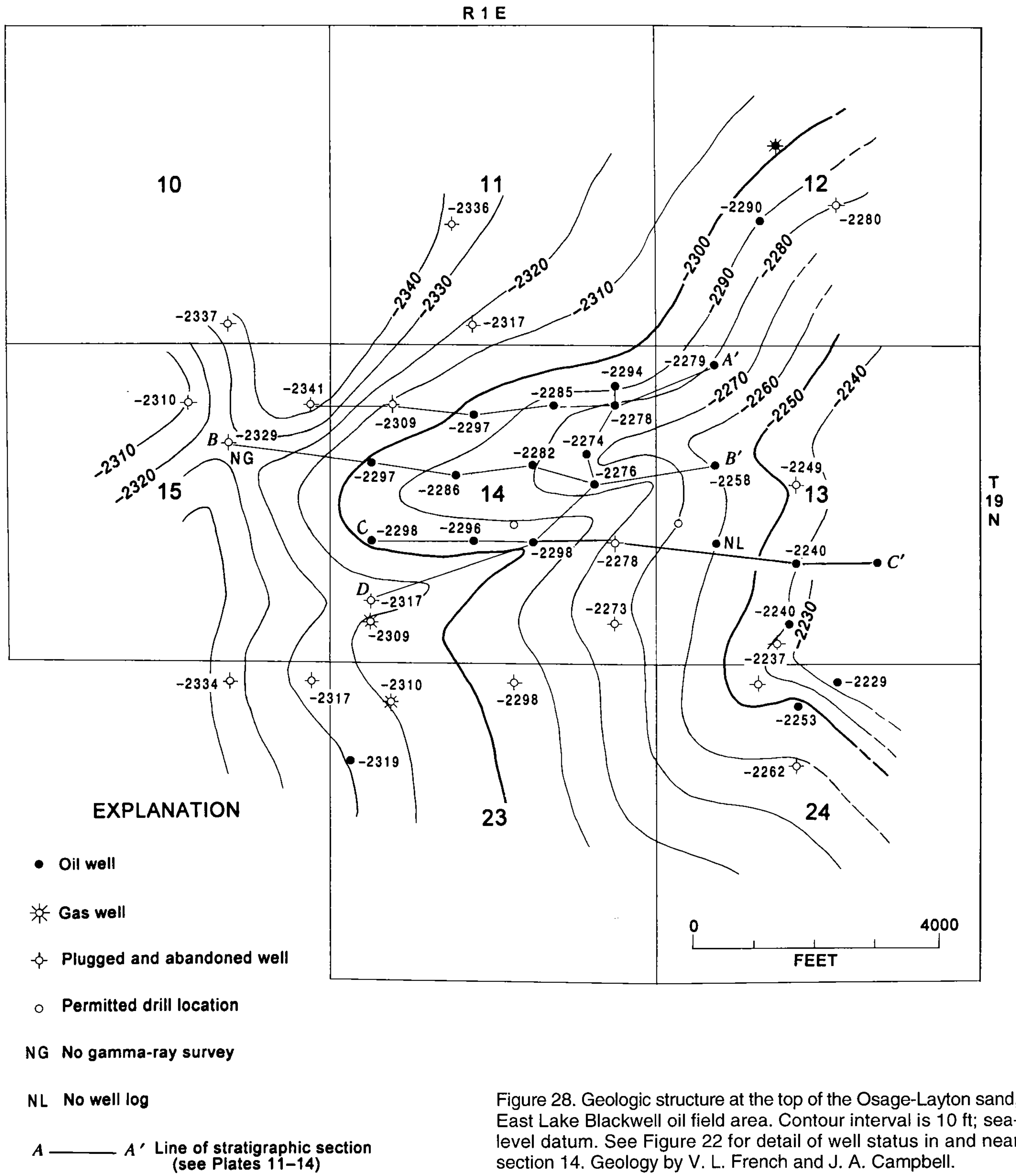


Figure 28. Geologic structure at the top of the Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 10 ft; sea-level datum. See Figure 22 for detail of well status in and near section 14. Geology by V. L. French and J. A. Campbell.

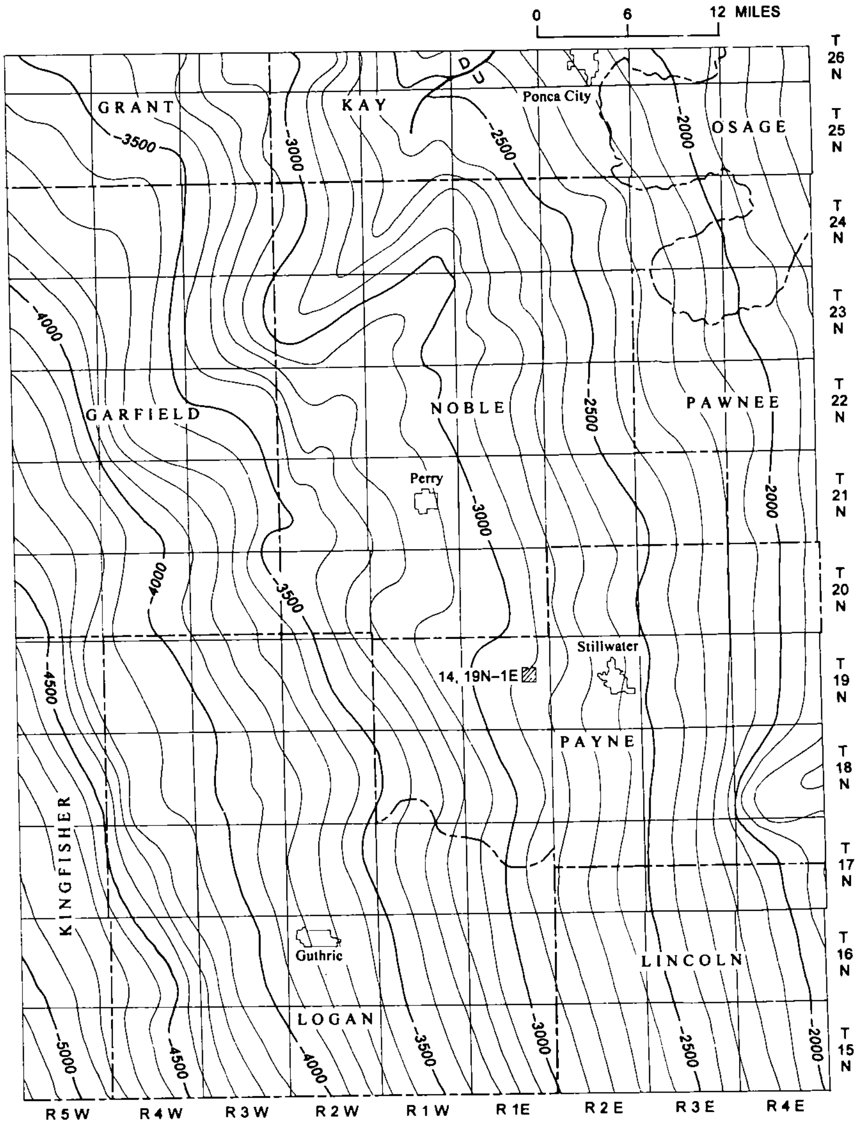


Figure 29. Regional geologic structure on top of the Checkerboard Limestone (Missourian) in part of north-central Oklahoma. Area of Osage-Layton sand reservoir study is hachured (sec. 14, T. 19 N., R. 1 E.). Contour interval is 100 ft; sea-level datum. Modified from Fambrough (1962,1963).

first well was completed on the subject lease: Ham (Fig. 34), Pike (Fig. 35), Oltmanns (Fig. 36), Harrington (Fig. 37), and James (Fig. 38). There is but a single datum point for laboratory analysis of reservoir quality and fluid saturations in zone A. It is from the lowermost foot of the lower perforated interval in the No. 1-14 Arnold (Table 6). Although the Earth Energy Resources No. 1 Oltmanns is not completed in zone A, the reservoir is continuous to that well (Pl. 14) and is presumed to be potentially productive there.

Geologic structure at the top of production zone A (Fig. 33) is similar to that of the top of the Osage-Layton sand (Fig. 28) with two significant differences: Figure 33 exhibits apparent closure of at least 4 ft near the No. 1-A Pike; and structural relief is greater by ~5 ft. Because of the limited distribution of zone A, an arbitrary structural low must be selected as a reference from which to estimate local structural relief. The lowest producible well, No. 2 Ham, is taken as that convenient reference. Measured from that arbitrary low, there is ~40 ft of structural relief at the top of zone A (Fig. 33), as compared to 33 ft at the top of the sandstone interval within sec. 14 (Fig. 28). The decrease of structural relief upward indicates that warping of strata occurred after deposition of the zone A, but had waned by the end of deposition of the Osage-Layton sand interval.

Natural-gas production apparently is not associated with geologic structure. The structurally highest No. 1 Pike well produced gas initially, but other structurally high wells did not (No. 1-A Pike, and Nos. 1 and 2 Oltmanns) (Fig. 33; Table 5). Gas was marketed from the Oltmanns lease after six months of oil production (Fig. 36); however, not enough gas was available to market from the Pike lease until 38 months after completion of the No. 1 well, or about 30 months following the marketing of gas from the Oltmanns lease (Fig. 35). Pike lease gas is used to operate production facilities.

Production zone A is interpreted to be a continuous reservoir, composed of at least two facies. It consists primarily of crevasse-splay sandstones, which are intersected by a younger channel-fill facies, as shown on Plate 14. It is consistently between 18 and 22 ft thick, except in the No. 2 Harrington, where it is only ~12 ft thick, and in the No. 3 James, where it is ~25 ft thick (Pls. 11–14). The detail visible on the gamma-ray logs indicates that the zone commonly consists of two or three thin (≤8 ft thick) sandstones, separated by organic-rich shales or mudstones. The sandstones are interpreted to be crevasse splays, although some may have been deposited as crevasse-channel sands.

The intervening organic-rich rocks probably originated as bay-fill muds. The composite character of zone A is consistent over most of its area of distribution. The gamma-ray profile is remarkably similar from the No. 1-14 Arnold to the No. 1 Oltmanns in the north (Pl. 11), and the No. 1-A Pike on the east side, and to the No. 3 James in the southwest corner of the area (Pl. 14). The channel-fill-sandstone facies of the reservoir occurs under the Nos. 1 and 2 James and the No. 2 Ham (Pl. 13). Because the gamma-ray log signature of the No. 3 James is so similar to those of the No. 1-A Pike and No. 1 Oltmanns (Pl. 14) and other wells in the northern part of the field, I interpret the channel-fill complex to be younger than the crevasse splays, which represents downcutting through the latter facies.

The contrast in facies between composite crevasse-splay and channel-fill sandstones indicates a two-part reservoir that may behave as separate compartments. There is insufficient information at present to determine whether or not the two facies of the reservoir are in communication. One might safely assume *pressure* communication; however, there may be barriers to

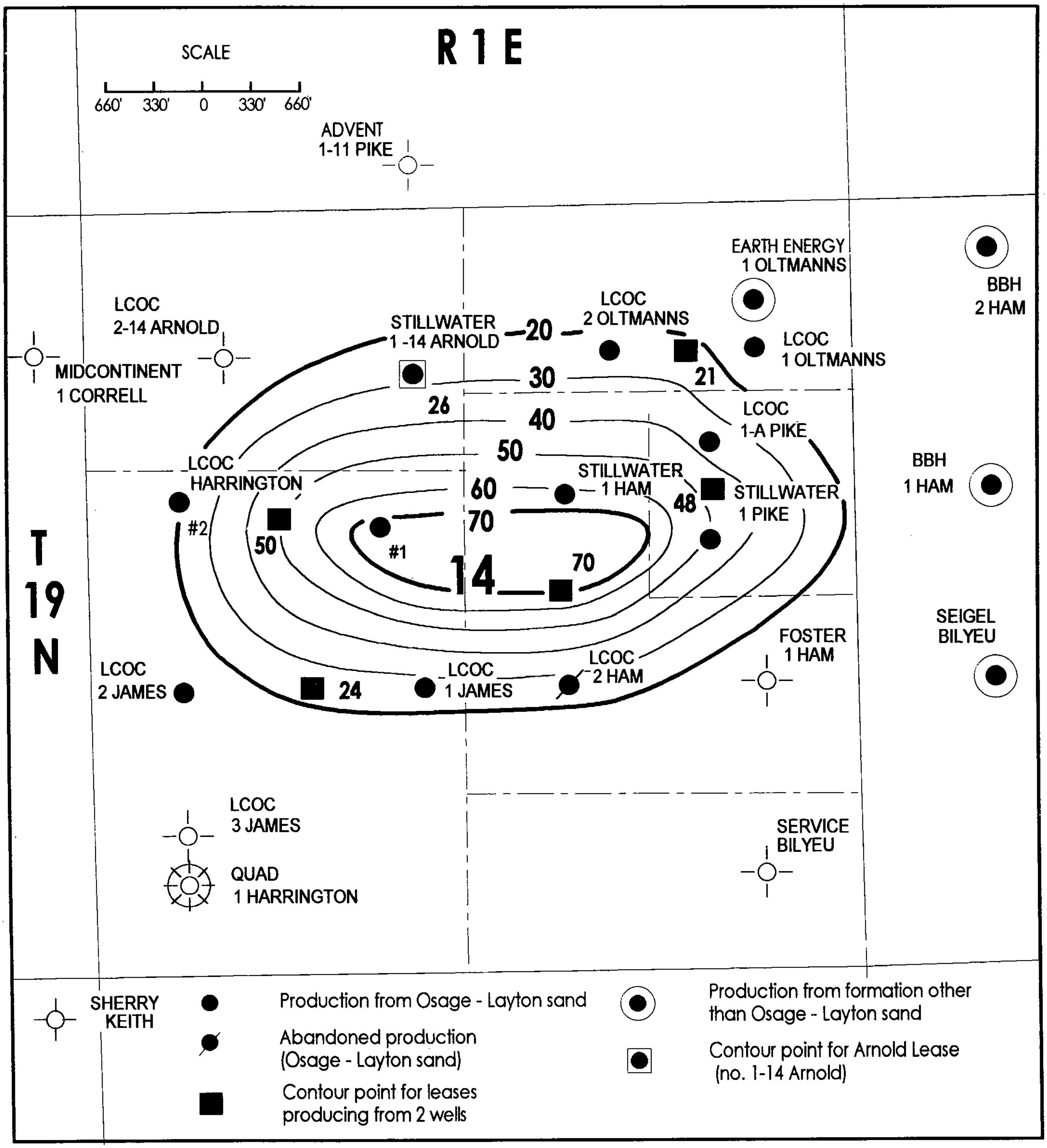


Figure 30. Cumulative oil production, Osage-Layton sand zones A, B, C, and D, East Lake Blackwell oil field area. Cumulative production by lease as of December 31, 1994; NRIS data base. Contour interval is 10 MBO. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

fluid communication across the interface between the two apparent depositional facies. Net-reservoir-sandstone isopachs represent the ideal case of a single reservoir (Fig. 39). Another map interprets the depositional model in more detail (Fig. 40). However, these oversimplify the actual geology, because zone A consists of as many as three thin sandstone intervals. Net sandstone for both maps is ≥10% porosity, based on density-neutron-log response. The log-interval thicknesses vary no more than a foot from calculated porosities in all wells. The highest observed porosity was 23% (effective porosity), in the No. 1-A Pike.

The northeastern limit of zone A has not been defined, except that it is not present in the Advent No. 1-11

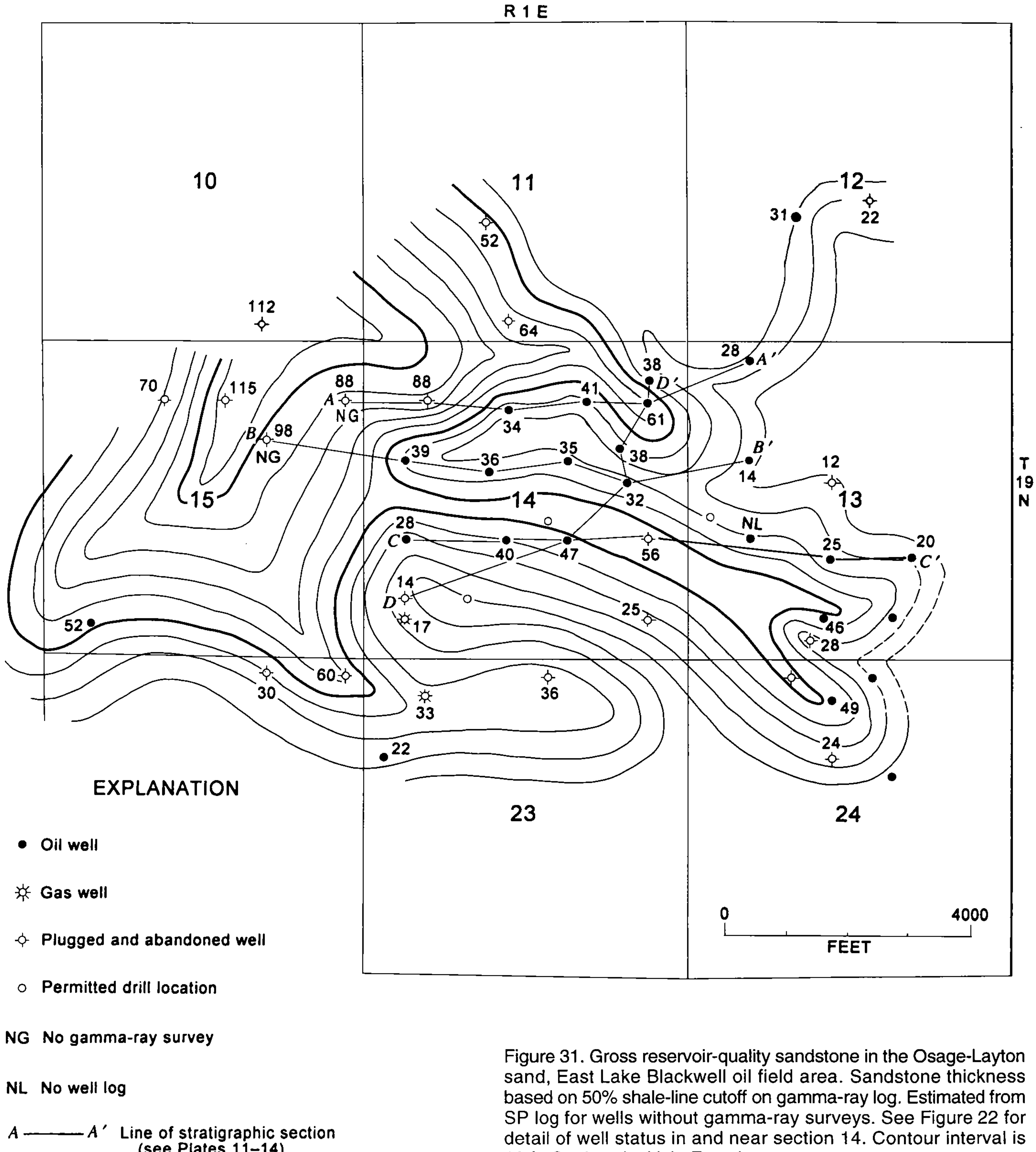


Figure 31. Gross reservoir-quality sandstone in the Osage-Layton sand, East Lake Blackwell oil field area. Sandstone thickness based on 50% shale-line cutoff on gamma-ray log. Estimated from SP log for wells without gamma-ray surveys. See Figure 22 for detail of well status in and near section 14. Contour interval is 10 ft. Geology by V. L. French.

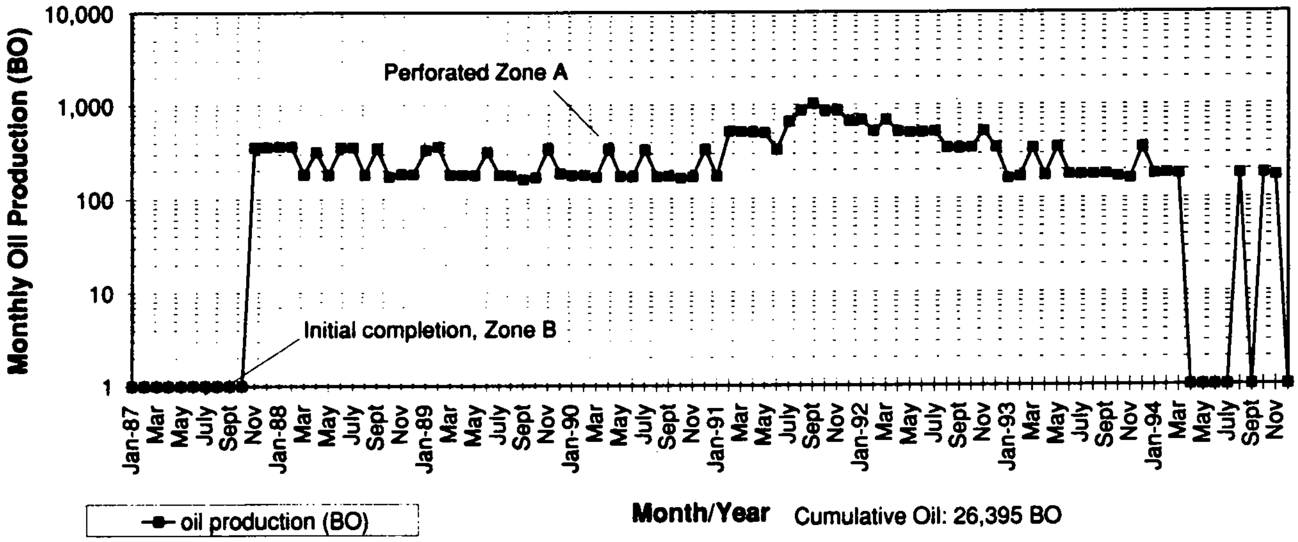


Figure 32. Oil-production plot for the No. 1-14 Arnold, East Lake Blackwell oil field area (monthly data).

Pike in sec. 11, or in the two B. B. Harrington Ham lease wells in the NW¼ of sec. 13 (Figs. 39, 40). Local geologic structure apparently declines with relative steepness on the north side of sec. 14, so that further development on the north side involves the risk of penetrating the reservoir (if present) near or below the oil-water contact. However, to the east, the reservoir, if it is present, will remain structurally high (Fig. 33).

Oil-Water Contact in Production Zone A.—An oil-water contact is present in zone A, as interpreted from formation resistivities (Figs. 39, 41). It mimics the form of the west–southwest-plunging anticline defined by local structure (Figs. 28, 33). The anticlinal form of the oil-water contact seems enigmatic at first, but a closer look may improve our understanding. As discussed previously, local geologic structure is of very low relief, but conspicuous; the maximum structural relief as measured in well bores that have produced from the Osage-Layton sand is 24 ft (Fig. 28) and 40 ft (Fig. 33). The maximum relief on the oil-water contact is only about 10 ft (Fig. 41), or approximately one-third of the structural relief (Table 4). Subtle indeed!

Another way to compare the relief on the oil-water contact with structural relief is to look at the inclination of the line (structural or oil-water contact) that approximates the plunge of the structure in a west–southwest direction. The relief between wells can be expressed in feet per mile (Table 7). Again, the inclination of the oil-water contact is about one-third that of geologic structure. This condition is shown in a schematic north–south cross section (Fig. 42), in which the oil-water contact has not adjusted to gravitational forces that normally separate oil and water on a horizontal plane. The simplest explanation for the unusual oil-water contact is that local structure formed subsequent to, or late in the process of, oil migration into the stratigraphic trap. Because the reservoir rocks have low permeability, and probably high capillary pressures, the oil-water contact did not reach equilibrium (a horizontal plane) following warping of the strata in the subtle anticlinal flexure. Very high subsurface fluid pressures are required to move oil through the miniscule interstices between grains in a fine-grained, silty sandstone; furthermore, lithostatic pressure in the region has been reduced, due to erosion of as much as 2,500 ft of Permian and Mesozoic strata since late Cretaceous time (Johnson, 1989). This has caused a reduction of reservoir pressure, which also has been unfavorable to the equilibration of the oil-water contact. The above discussion does not necessarily assume that the oil-water contact in this reservoir has ever been horizontal.

Another explanation for the unusual oil-water contact is that the oil-water contact is partly the result of a natural water drive, modified by local geologic structure. Meteoric water enters the Chanute Formation at the outcrop to the east in Washington, Tulsa, and Creek Counties. A pressure head is created, as the Osage-Layton sand lies at ~2,400 ft below sea level in the local area, or ~3,100 ft below where the formation crops out in Tulsa County. The presence of such a hydrogeologic state in the Osage-Layton sand would impart the westerly tilted, homoclinal form of the regional geologic structure (Fig. 29) to the oil-water contact: One can visualize easily the oil-water contact (Fig. 41) as being the result of local warping of that regional form into a gentle fold. Thus, the present form of the oil-water contact may be the result of a westerly tilt of the regional hydrologic surface, modified by the anticlinal nose, and the lack of having achieved gravitational equilibrium, as explained above.

Notably, it has been reported that the four structurally highest wells (Fig. 33) flowed oil briefly (hours or days) from zone A following perforation and prior to installation of pumping units. The flows were substantially lower than the initial pumped rates reported. This may be evidence of either a fluid expansion in the reservoir or a weak hydrodynamic condition. However, continuing water production and preservation of reservoir pressure indicate the latter (Part IV, this volume).

An analysis of produced water from the Harrington lease (Table 8) provided by Pan Western Oil Corporation shows that total salinity is 168,000 ppm (parts per million)—not a particularly high value for oil-field brine. For example, Levorsen (1967, p. 166) reported nearly 195,000 ppm for water associated with a Prue

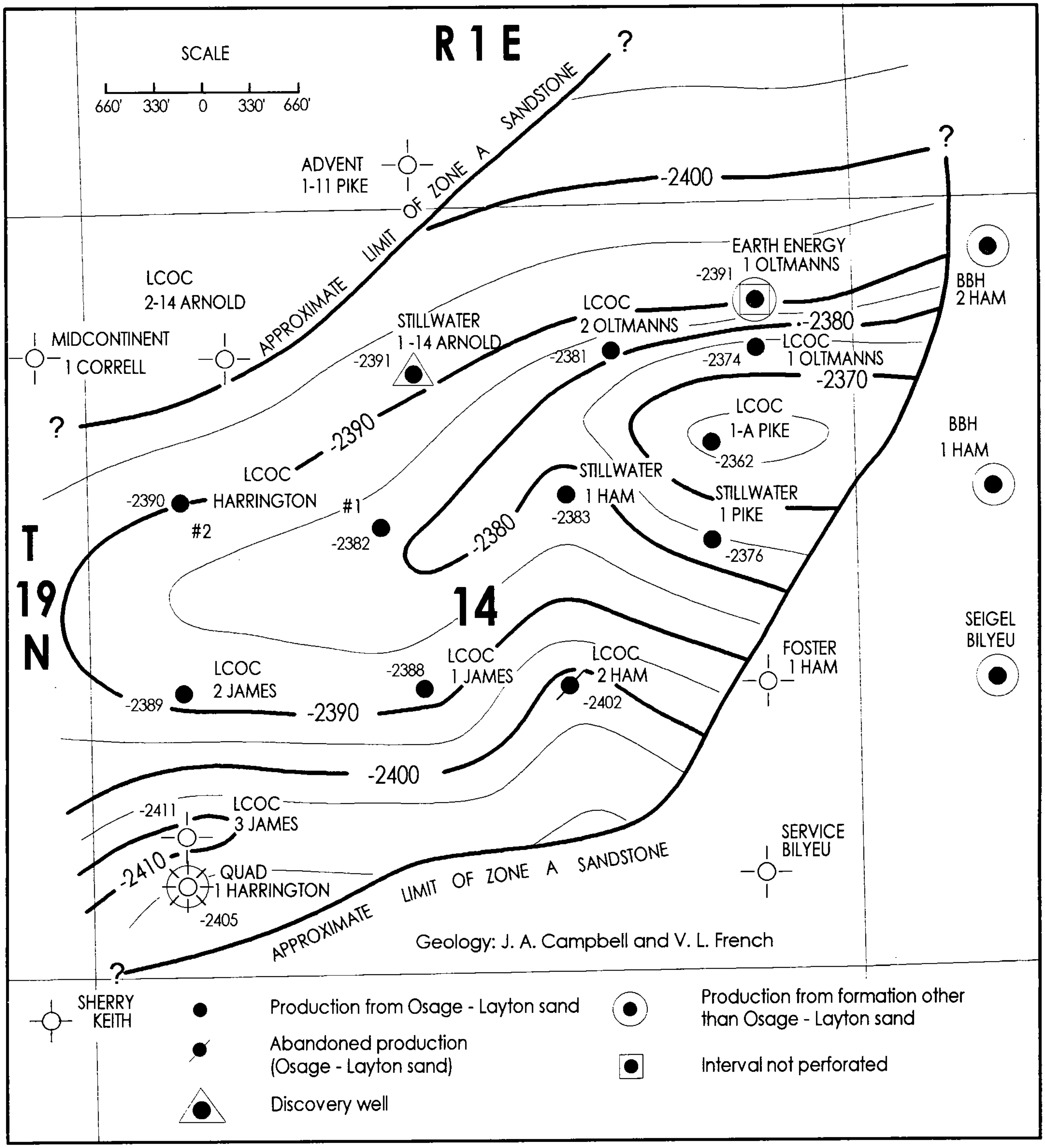


Figure 33. Geologic structure at the top of production zone A, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 5 ft; sea-level datum. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

sand reservoir in east-central Lincoln County. The fact that the reservoir does not produce fresh water does not imply that there cannot be a hydrodynamic condition in the reservoir. There probably is no natural outlet for water contained in the formation, so it cannot be "flushed" by fresh water entering at the outcrop. There is no doubt that hydraulic pressure can be transmitted to the local reservoir from the outcrops; that relationship has developed over geologic time. However, the permeability through that tortuous path from the outcrop is probably extremely low. Water from this reservoir, although less saline than that from the Prue sand, has not necessarily been diluted by fresh water. Any effort less than a regional study of formation water is not likely to improve our understanding of this matter.

Production Zone B

The discovery well, Stillwater Oil and Gas, Inc., No. 1-14 Arnold, is the only well that has produced from zone B. It was completed in that zone in September 1987 at a pumped rate of 22 BO (barrels of oil) and 7 barrels of water per day. It continued to produce

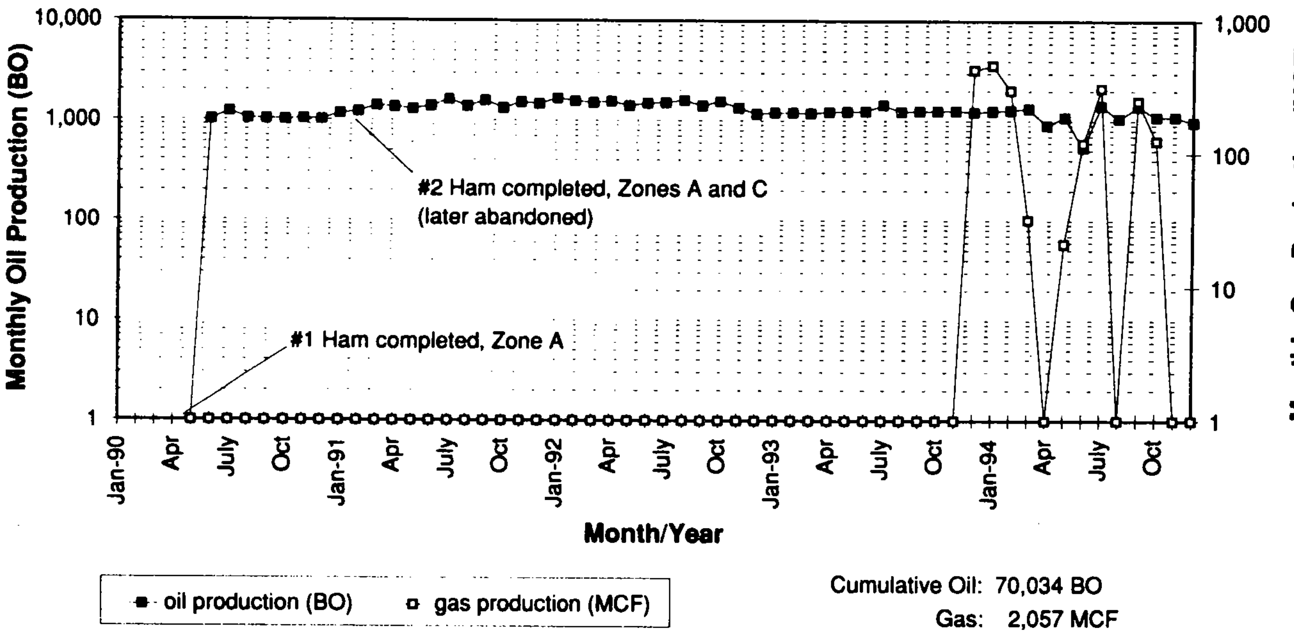


Figure 34. Oil- and gas-production plot for the Nos. 1 and 2 Ham, East Lake Blackwell oil field area (monthly data).

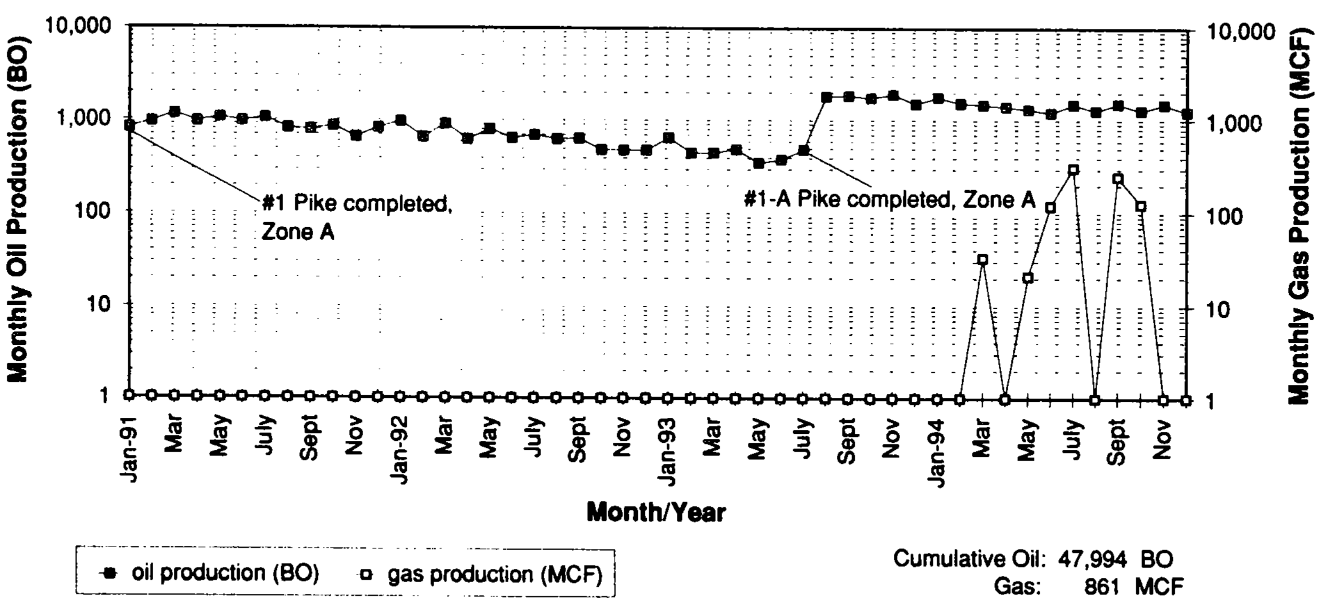


Figure 35. Oil- and gas-production plot for the Nos. 1 and 1-A Pike, East Lake Blackwell oil field area (monthly data).

solely from zone B through most of January 1991. Total production for that time interval is ~9,400 BO, or ~36% of the total produced by the well through the end of 1994 (Fig. 32). Zone A was perforated in January 1991, and both zones continue to produce from the No. 1-14 Arnold.

Anecdotal information is that an excellent show of oil was the tipoff to the discovery: A good show of crude oil reportedly was circulated to the surface following a drill-pipe connection while drilling through the Osage-Layton sand. A subsequent drill-stem test of the interval 3,300–3,360 ft recovered 150 ft of salt water (Pl. 11); if those depths are correct with respect to the wireline logs, the test interval included most of zone A but not zone B. However, as mentioned previously, there is a greater resistivity anomaly associated with zone B. The sandstone body that forms zone B is continuous to seven other wells, not including the dry hole. Five of them produce from zone A, one from zones A and D, and one that has not been completed in the Osage-Layton sand (Figs. 26, 27). None of them has been perforated in zone B. All seven are structurally higher than

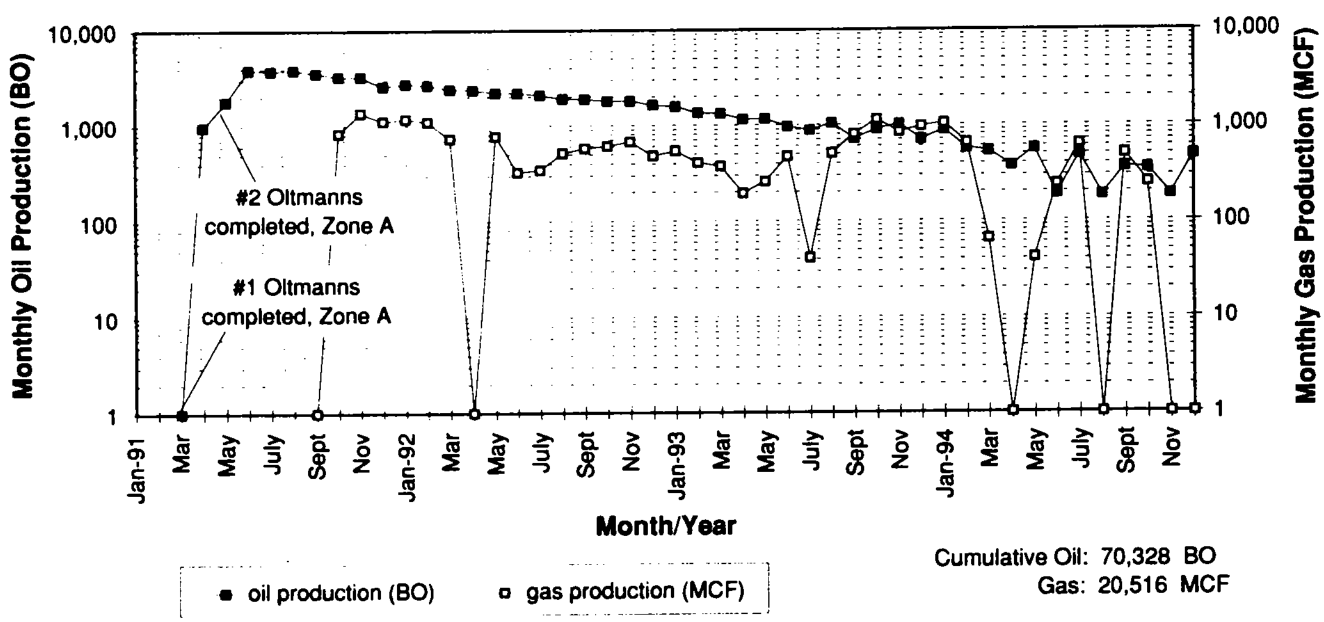


Figure 36. Oil- and gas-production plot for the Nos. 1 and 2 Oltmanns, East Lake Blackwell oil field area (monthly data).

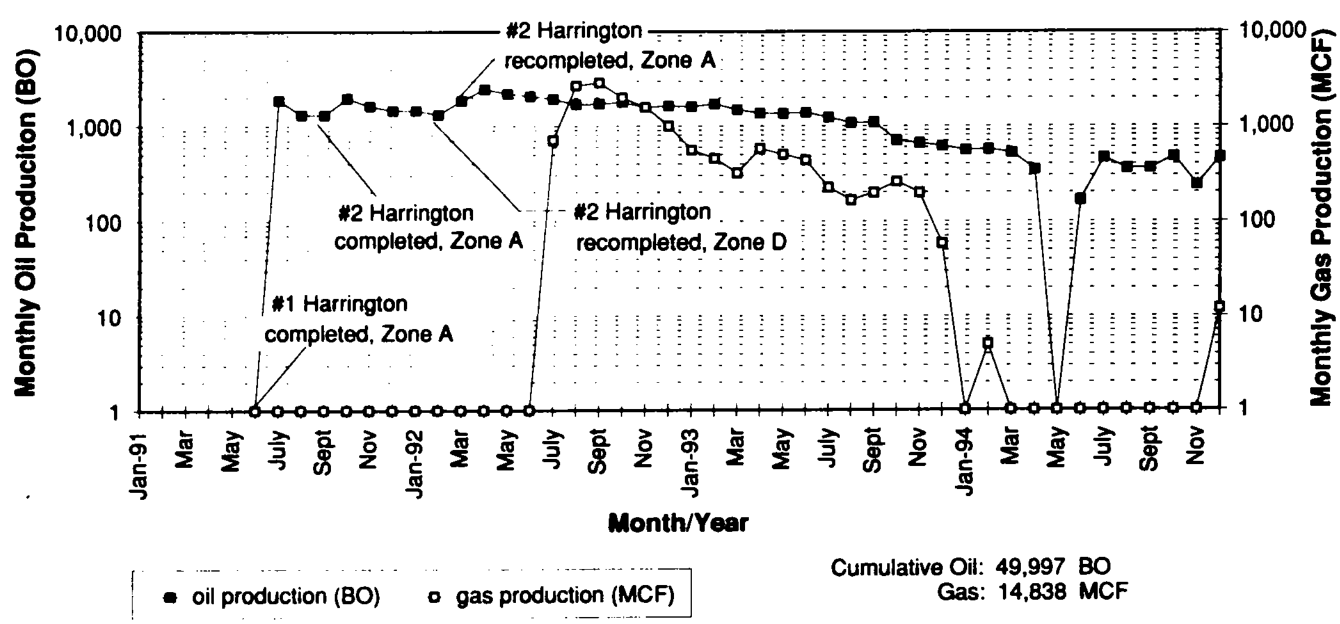


Figure 37. Oil- and gas-production decline for the Nos. 1 and 2 Harrington, East Lake Blackwell oil field area (monthly data).

TABLE 6. – Analyses of Sidewall Cores[a] of the Osage-Layton Sand, East Lake Blackwell Area

Depth (ft)	Porosity (%)	Permeability (md)	Saturation Oil (%)	Saturation Water (%)
3,218.1	19.6	43	0	81.6
3,221.9	16.5	13	0	74.5
3,280.0[b]	15.4	15	26.0	50.6
3,281.9[b]	16.1	19	19.9	42.2
3,307.0[c]	18.7	31	7.0	60.6
3,322.1	18.4	24	10.3	60.1
3,376.0	19.2	28	0	84.9
3,384.0[d]	—	—	—	—
3,385.9	22.3	53	0	76.1
3,387.9	19.8	34	0	81.8

[a]Stillwater Oil and Gas, Inc., No. 1-14 Arnold, SE¼NE¼NW¼ sec. 14, T. 19 N., R. 1 E., Payne County, Oklahoma.
[b]Production zone B, perforated 3,276–3,282 ft.
[c]Production zone A, perforated 3,296–3,308 ft.
[d]Core too broken for analysis.

the No. 1-14 Arnold (Fig. 43). The formation resistivity anomaly associated with zone B is relatively high, except in the No. 2-14 Arnold, which penetrated the zone below the oil column (Pls. 11, 12, 14). There is no doubt that there are unexploited hydrocarbons in this zone. There are two data points that provide reservoir-quality and fluid-saturation information for zone B. Both are in the lower part of the zone in the No. 1-14 Arnold (Table 6).

The net-sandstone isopach (Fig. 44) is taken directly from neutron- and density-porosity logs, with minimum porosity of 10%. Maximum observed porosity in zone B is 19% effective porosity; it occurs locally in the No. 1-A Pike and No. 2 Harrington wells (Pls. 12, 13). The interval has a remarkably continuous thickness of 4–6 ft, although it is ~8 ft thick in the No. 1 Harrington. That continuity and the persistent gamma-ray log signature (Pls. 11, 12, 14) provide convincing support to the interpretation that the unit was deposited as a minor channel sand, although parts of it may be a crevasse-splay sand. The geographic limits of zone B are poorly understood on the north and east sides of production (Figs. 43, 44). The absence of zone B in the Earth Energy Resources No. 1 Oltmanns (Fig. 44; Pl. 14) indicates a limited northerly distribution of the reservoir. Zone B cannot be mapped farther east than the northwest corner of sec. 13, but there is a barrier to eastward oil migration, because geologic structure is higher to the east (Figs. 28, 43).

An oil-water contact apparently is present in zone B, but its position is known only to occur between the No. 1-14 and No. 2-14 Arnold wells (Pl. 11). It is estimated here to occur about half the vertical distance between those wells and is shown parallel to structural contours (Figs. 27, 44).

Production Zone C

The geographic distribution of zone C is limited to the southern part of the subject area (Fig. 27). The sandstone bodies that form zone C range in thickness from about 20–40 ft; they probably are a composite of distributary-channel-fill deposits. The interpretation recognizes two major channels with production, to date, limited to the upper part of the upper channel, C_2 (Pls. 13, 14). Actual geologic conditions may be more complex than this interpretation; however, the lower of the two channels (C_1) has apparently been incised by the upper (C_2), which appears to have a more limited geographic distribution.

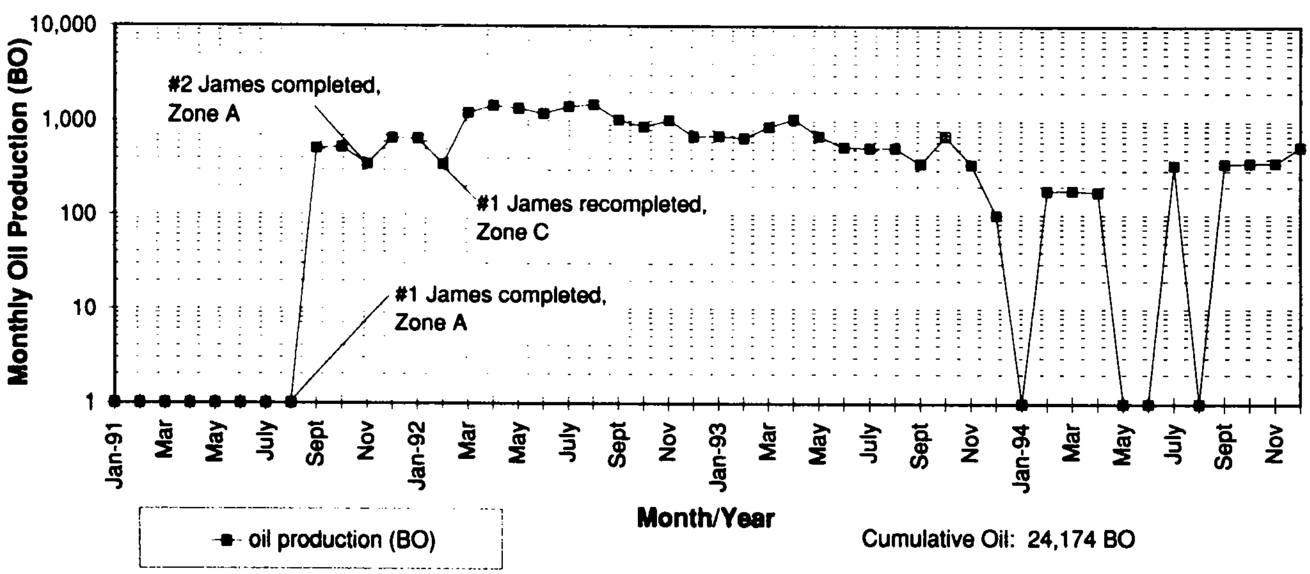


Figure 38. Oil-production plot for the Nos. 1 and 2 James, East Lake Blackwell oil field area (monthly data).

Wells completed in zone C to date are structurally low (Figs. 28, 45) and plagued with water-production problems (Table 5). Production from the No. 2 Ham has been abandoned, and only the No. 1 James has continued to produce from the interval (Fig. 45). However, the sandstone body probably is continuous to at least two structurally higher wells. It is herein correlated to the No. 1 Pike in cross section B–B′ (Pl. 12), where there is an increase in resistivity associated with the upper part of the zone. Whereas that anomaly may

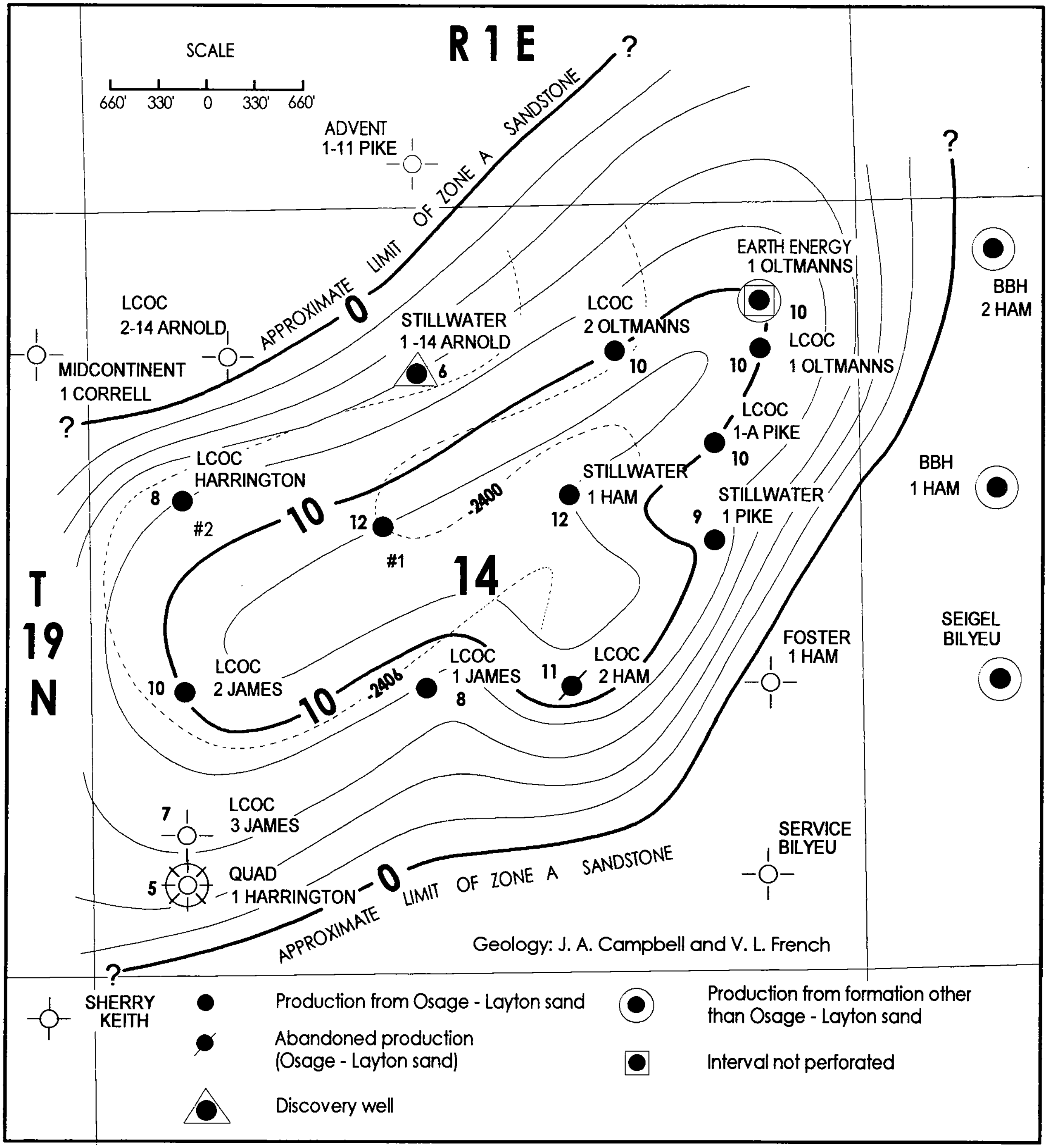


Figure 39. Net reservoir-sandstone isopach, production zone A, Osage-Layton sand, East Lake Blackwell oil field area. Case 1: Reservoir represented as a single, continuous sandstone body. Minimum log porosity: 10%. Contour interval is 2 ft. Dashed line is oil-water contact (see Fig. 41). BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

be partly related to the overlying shale, it is a more convincing anomaly than that in the No. 2 Ham, which produced from zone C for an unknown length of time. The upper sandstone of zone C also occurs in the Foster No. 1 Ham Estate, a well drilled in 1963 to test the "Wilcox" sand and subsequently plugged and abandoned. There also is an enticing increase in formation resistivity associated with the upper part of zone C there (Pl. 13). Both the No. 1 Pike and No. 1 Ham Estate are structurally higher than the No. 1 James and No. 2 Ham (Fig. 45) and represent future hydrocarbon-production potential from the zone. The eastward conti-

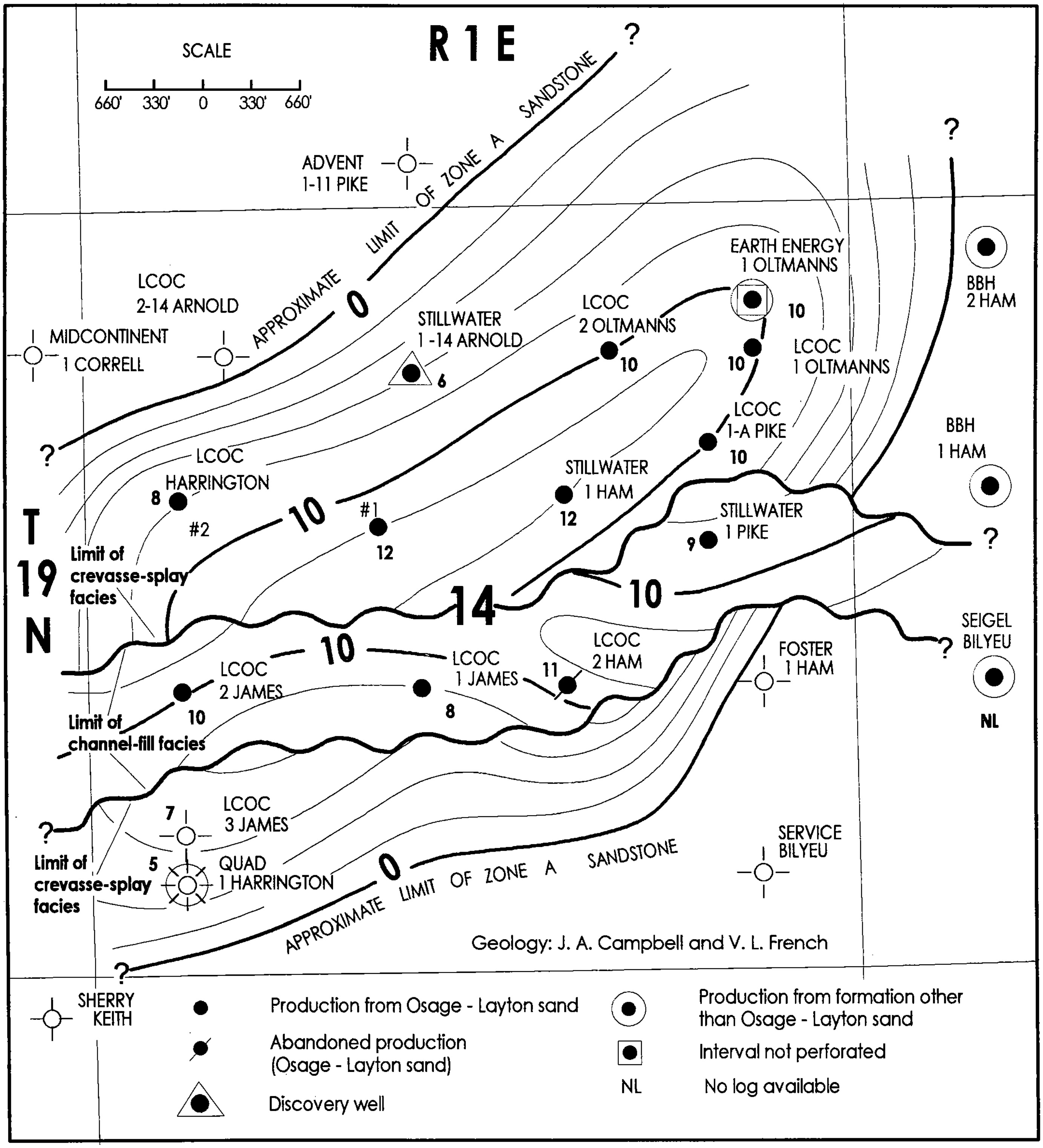


Figure 40. Reservoir-sandstone isopach, production zone A, Osage-Layton sand, East Lake Blackwell oil field area. Case 2: Zone A separated into crevasse-splay complex and channel-fill depositional facies. Contour interval is 2 ft. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

nuity of zone C is speculative, especially because the Seigel No. 1 Bilyeu log has not been released to the State (Pl. 13). A channel-fill(?) sandstone body occurs in a stratigraphic position similar to that of zone C in the Deck Oil Company No. 1 Bilyeu, but a correlation with zone C is not made in the present study because the distance is >0.5 mi to the No. 1 Ham Estate well (Fig. 22; Pl. 13). However, a formation-resistivity anomaly is present in the prominent sandstone between 3,222 ft and 3,240 ft in the Deck well, indicating the Deck well's association with a hydrocarbon trap. The Deck well also is structurally higher than the Ham Es-

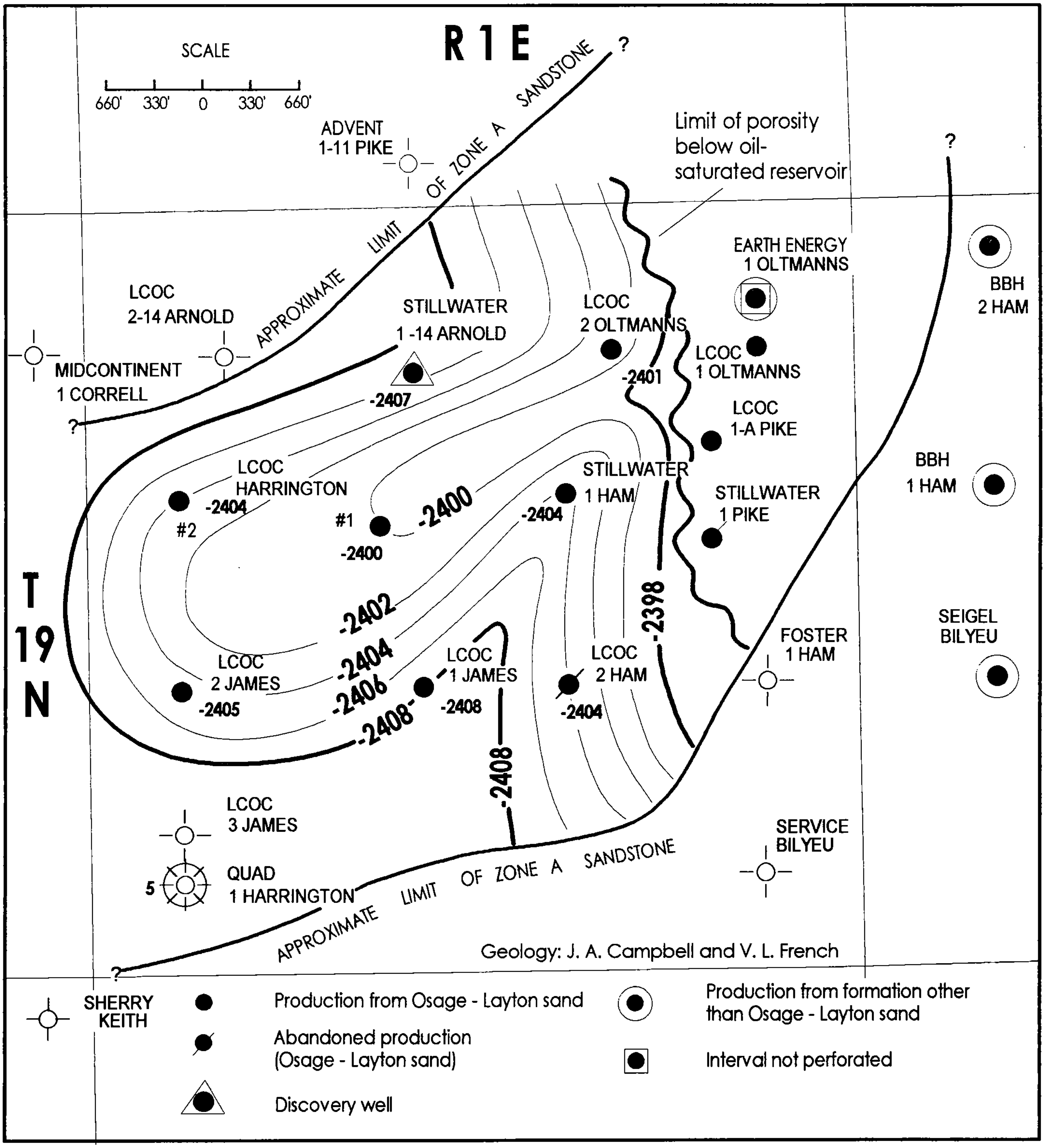


Figure 41. Oil-water contact in lower sandstone, production zone A, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 2 ft; sea-level datum. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

tate well (Fig. 28). To the east of the Deck well, in the Nichols Exploration No. 1 Greiner, the character of the Osage-Layton sand changes to predominantly fine-grained sediments, with thinner sandstone bodies. This indicates a trapping mechanism similar to that of zone A, discussed previously (Pls. 11, 12).

The net sandstone isopach (Fig. 46) incorporates the total sandstone in zone C that is ≥10% porosity, based on density-neutron log response. The best porosity is 20%, observed in the No. 1 James well. The map does not attempt to depict channel-form sandstone bodies, because the reservoir is a composite of channels and because of a lack of well control to the south. Oil production from zone C is shown on Figures 34 and 38, but cannot be separated from that of zone A on the Ham and James leases.

TABLE 7. – Comparison of Relief on the Oil-Water Contact with Structural Relief, Osage-Layton Sand Zone A, East Lake Blackwell Oil Field Area

	Oil-water contact (ft)	Top Osage-Layton sand (ft)	Top production zone A (ft)
Greatest (structural) relief*	14	24	39
Inclination approximately parallel to structural plunge (west–southwest)*	11 12.1 ft/mi	24 32.4 ft/mi	27 31.6 ft/mi

*As measured in production well bores. Refer to Figures 28, 33, and 41.

Oil-Water Contact in Zone C.—An oil-water contact also is evident in the four wells that define production zone C. Relief is only 12 ft on that horizon (Fig. 47). Although the form of the oil-water contact does not reflect that of geologic structure (Fig. 45), the relative positions of high and low wells are similar on the two maps, with the exception of the No. 1 Ham Estate, which is relatively high structurally but has a low oil-water contact. Geologic structure and the oil-water contact indicate that the trap is caused by a barrier to migration to the northeast, although that barrier could occur farther north and east than shown here (Figs. 45, 47).

Production Zone D

The sandstone body that forms zone D is interpreted to have originated as a crevasse-splay sand. It is ~12 ft thick in the No. 2 Harrington, which is the only well that penetrates the interval (Fig. 48; Pl. 12). The No. 2 Harrington originally was completed in zone A, from which it produced a high proportion of water (Table 5). It subsequently was recompleted in zones A and D (Tables 4, 5). The initial oil-production rate from zone D was the highest of any well in any of the four reservoirs (Table 5; Fig. 49). Because both wells on the Harrington lease also produce from zone A, it is not possible to determine the quantity of oil produced from zone D. Oil and gas production from the Harrington lease is presented in Figure 37.

Thickness of the reservoir in the No. 2 Harrington (Fig. 48) is based on density-neutron log response, and includes only that sandstone having porosity ≥10%. The highest reservoir quality in zone D is 18.5% effective porosity. Because of the evident, if precisely unknown, areal limit of zone D, and the apparent decline of structure to the northwest (Figs. 33, 43, 48), further development of the zone appears to be risky at best.

Other Production and Potential Production from the Osage-Layton Sand

Many other sandstone bodies occur in the Osage-Layton sand in the study area (Pls. 11–14). Formation resistivity profiles suggest that hydrocarbons may be

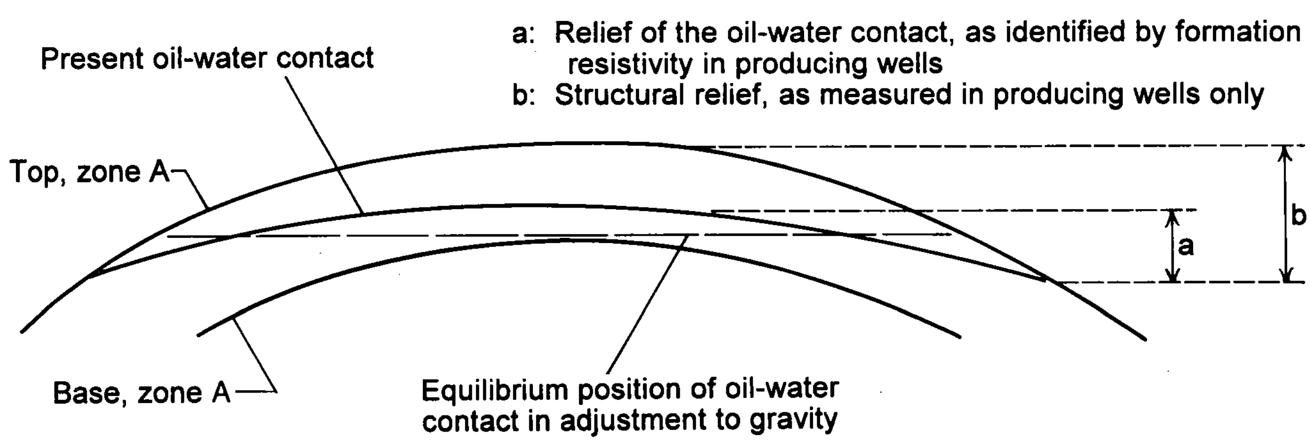


Figure 42. Schematic north–south cross section of oil reservoir, showing incomplete adjustment of oil-water contact to gravity in an anticlinal structure. Refer to Figures 38 and 41. Present position of oil column probably results from low permeability in sandstone bodies that have a complex internal structure.

TABLE 8. – Analysis of Produced Water from the Osage-Layton Sand, East Lake Blackwell Oil Field Area*

Iron	27
Calcium	15,500
Magnesium	2,690
Sodium	74,000
Barium	0
Sulfate	520
Carbonate	0
Bicarbonate	26
Chloride	14,900
Total dissolved solids	168,000
pH	5.4
Alkalinity as $CaCO_3$	21
Specific gravity @ 60°/60°	1.1580

*Composite of produced water from the James Harrington lease, NE¼SW¼ sec. 14, T. 19 N., R. 1 E. Sample dated May 3, 1994. Values in milligrams/liter (parts per million).

present locally. However, the lack of having knowledge of possible oil shows gained during drilling of the wells means that any statements made on the basis of well logs alone, especially for thinner sandstone intervals, would be speculative. Therefore, this study does not attempt to deal with the possibility of additional hydrocarbon-bearing intervals.

Nearly a mile to the southeast of the study area, Las Colinas Oil Corporation also has produced oil from the Osage-Layton sand. The No. 1 Weber well (Fig. 22; Table 4) was a workover of a former Red Fork and Tonkawa producer, originally drilled by Deck Oil Company in 1981. Unlike other reservoirs in the area, the reservoir in the Osage-Layton sand occurs in the uppermost part of the unit. The reservoir zone apparently is unrelated to those in the study area and will not be discussed further in this report.

About 0.6 mi west–northwest of the No. 2 Harrington, the Ketchum-Whan Drilling Company No. 1 Correll (SW¼NW¼NE¼ sec. 15, T. 19 N., R. 1 E.) (Fig. 22) was drilled to 4,920 ft to test the "Wilcox" sand and was plugged and abandoned in 1953. However, a show of hydrocarbons evidently resulted in a drill-stem test of the Osage-Layton sand. The tested interval was reported as 3,350–3,376 ft (completion card) and 3,356–3,376 ft (written on log). There also is a weak, but potentially significant, resistivity anomaly associated with that interval. The top of the porous sandstone occurs at 3,348 ft. At least two questions are in order with regard to the test: First, was the uppermost part of the sandstone interval that corresponds to the resistivity anomaly tested? Second, was the tested interval too long for the best hydrocarbon recovery? Local geologic structure (Fig. 28) indicates that the Ketchum-Whan well encountered a separate hydrocarbon accumulation; the apparent structural position also indicates that further investigation is warranted.

Other promising and evidently unexploited resistivity anomalies occur in the B. B. Harrington No. 2 Ham (Fig. 44; Pl. 13), the Foster No. 1 Ham Estate (Fig. 46; Pl. 13), and the Deck Oil Company No. 1 Bilyeu (Pl. 13). They were discussed in the parts of this report that dealt with production zones B and C.

Conclusions

1. Four separate sandstone intervals produce hydrocarbons from the Osage-Layton sand in the East Lake Blackwell oil field area.

2. The Osage-Layton pools in the East Lake Blackwell oil field area are combination traps.

3. All zones locally produce substantial volumes of water, especially in structurally low wells.

4. Hydrocarbons occur in sandstones belonging to several depositional facies. These may occur in any stratigraphic position within the formation. Therefore, both exploratory and development wells must be drilled through the entire sandstone sequence and logged. Wireline logs are essential to determine the position of reservoirs and their relationship from well to well.

5. Although there is no nearby core to confirm this interpretation, reservoir facies consist of distributary-channel-fill and crevasse-splay sandstones. Locally, the latter also may include crevasse-channel deposits. None of the reservoir rocks in the Osage-Layton sand in the East Lake Blackwell oil field area are the thick, more-or-less uniform, distributary (or shallow-marine) sandstones that many believe to be typical of Osage-Layton sand reservoirs.

6. Formation-resistivity anomalies associated with hydrocarbon-bearing sandstones are subtle, typically only one to several ohm-meters greater than background resistivity. Formation resistivity is a very helpful, but commonly not the only, criterion for the identification of pay zones.

7. Layton and Osage-Layton sand reservoirs range from moderately underpressured to moderately overpressured with respect to the depth at which they occur. In either case, it is desirable to drill with low water-loss fluid and watch drill cuttings carefully for oil shows, in order that all potential oil reservoirs are detected. A mud-logging unit at the well site can be invaluable in identifying and maintaining a record of depths, types, and relative strengths of oil and gas shows. Because these reservoirs occur typically in stratigraphic traps that are difficult to predict geographically, the above is true not only for Layton and Osage-Layton exploratory tests but for all wells drilled to test or develop deeper formations.

8. Reservoir rocks in the Layton and Osage-Layton sands typically are composed of fine- to very fine

grained sandstones. Poor sorting is a common corollary to the fine grain sizes in nonmarine environments. These are major factors in lowering permeability of the sandstones and therefore oil recovery. Porosities in Osage-Layton sandstones typically approach and locally exceed 20%; but permeabilities average ~30 md

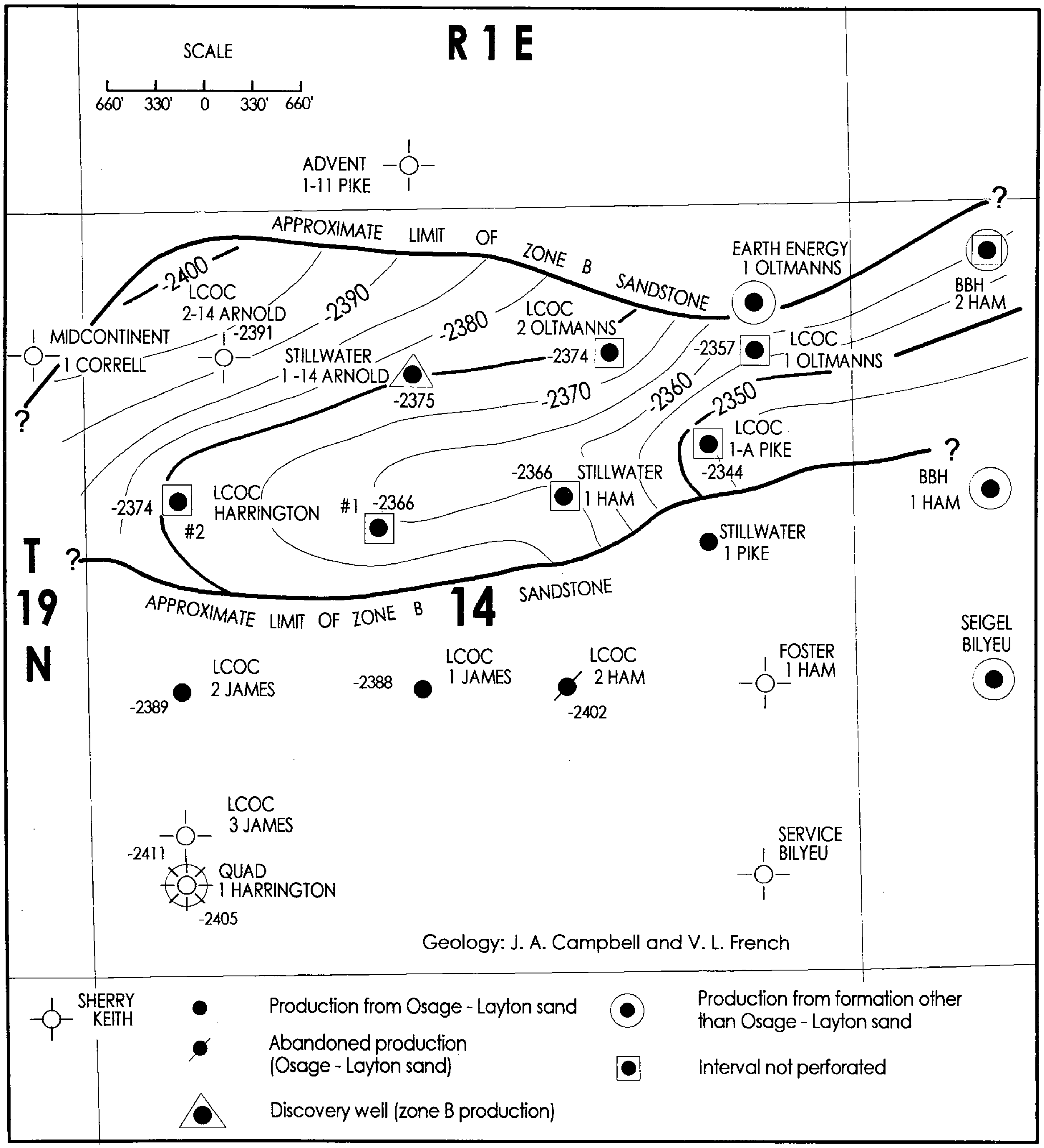


Figure 43. Geologic structure at the top of production zone B, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 5 ft; sea-level datum. BBH = B. B. Harrington; LC OC = Las Colinas Oil Corporation.

(Table 6). Therefore, optimum oil recovery from a single well bore may be significantly less than the present 20- or 40-acre spacing per well.

9. It may be advantageous to initiate pressure maintenance with produced gas or water early in the productive history of some reservoirs.

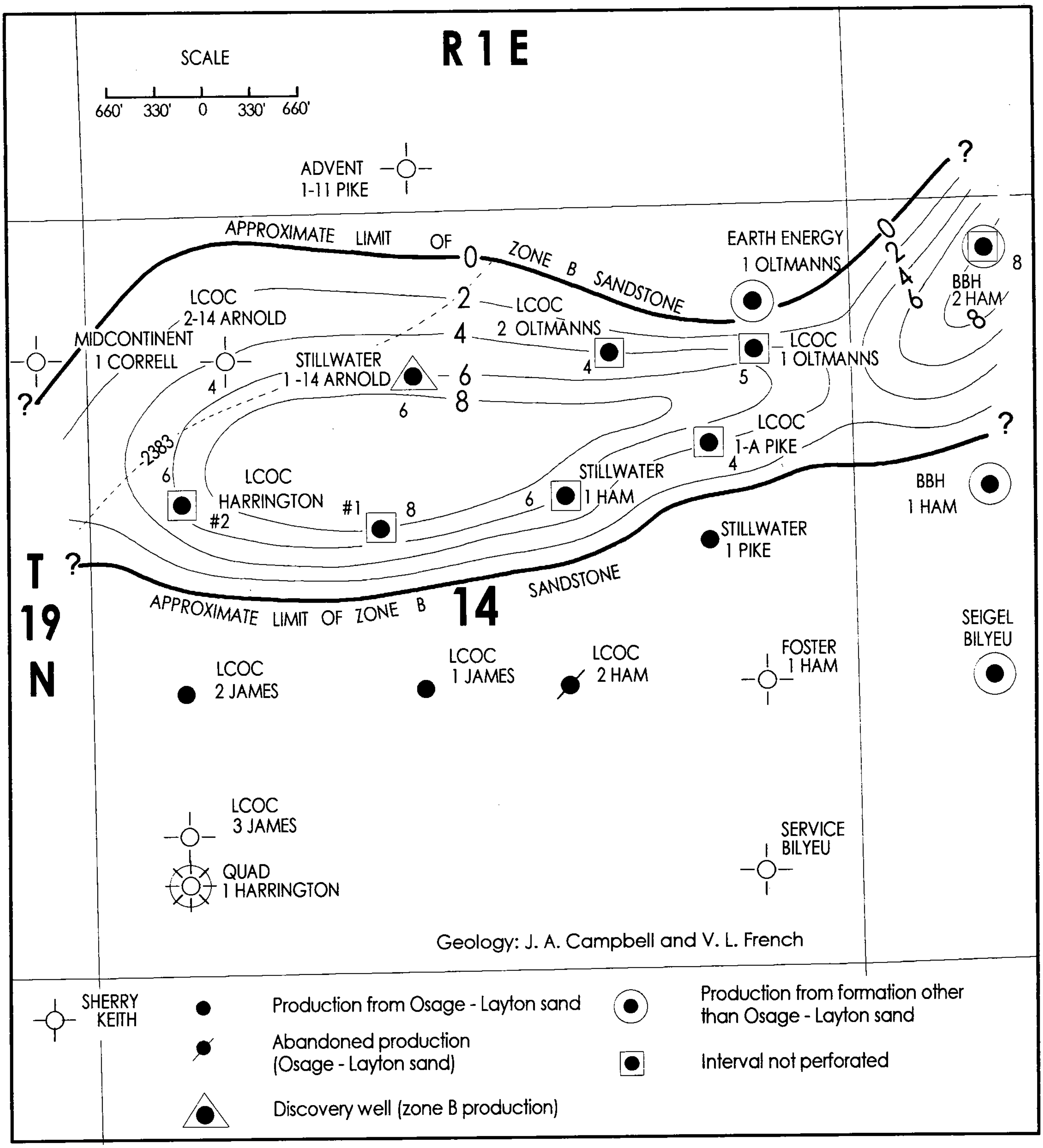


Figure 44. Reservoir-sandstone isopach, production zone B, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 2 ft; sea-level datum. Dashed line is oil-water contact; explanation in text. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

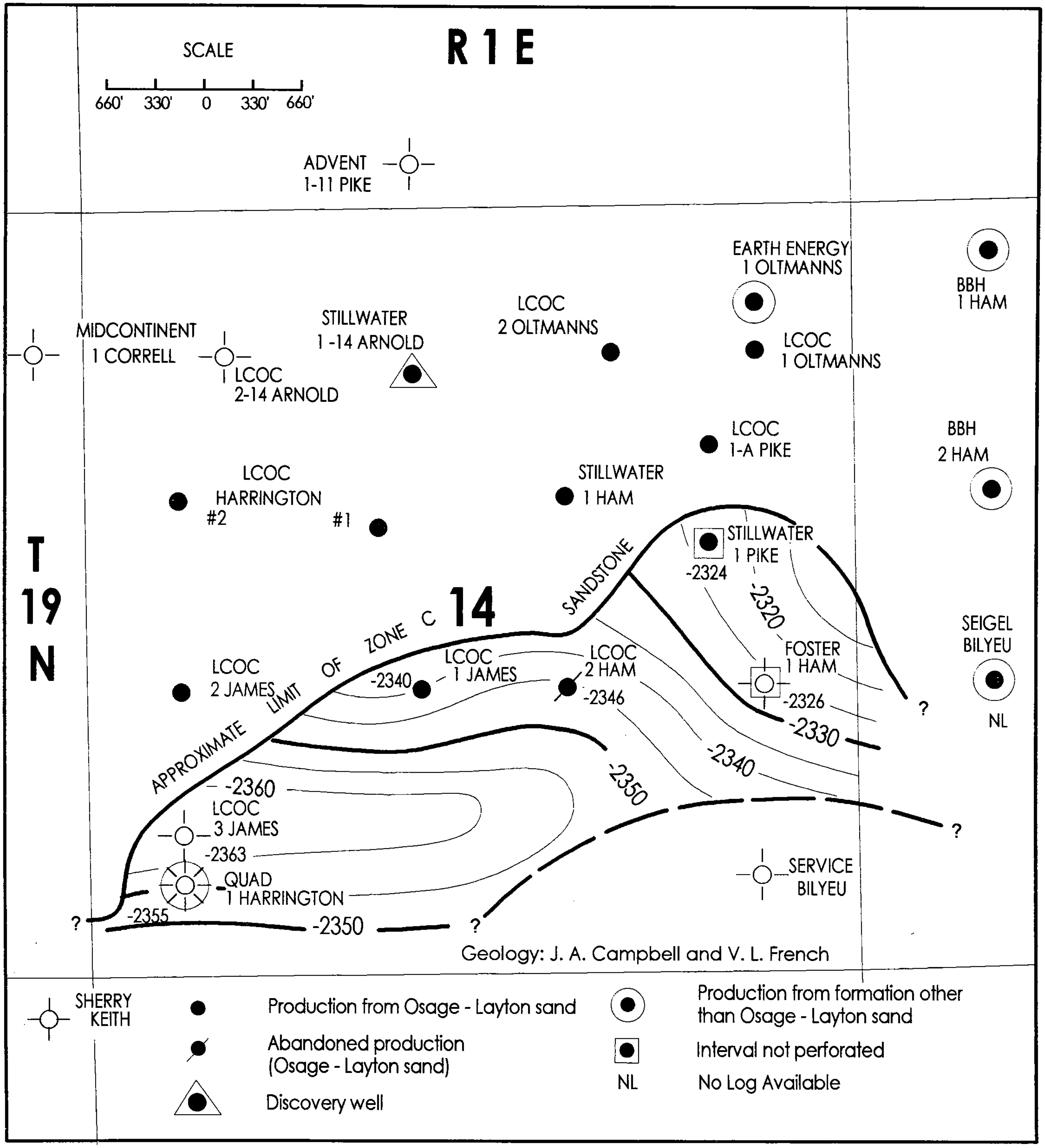


Figure 45. Geologic structure at the top of production zone C, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 5 ft; sea-level datum. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

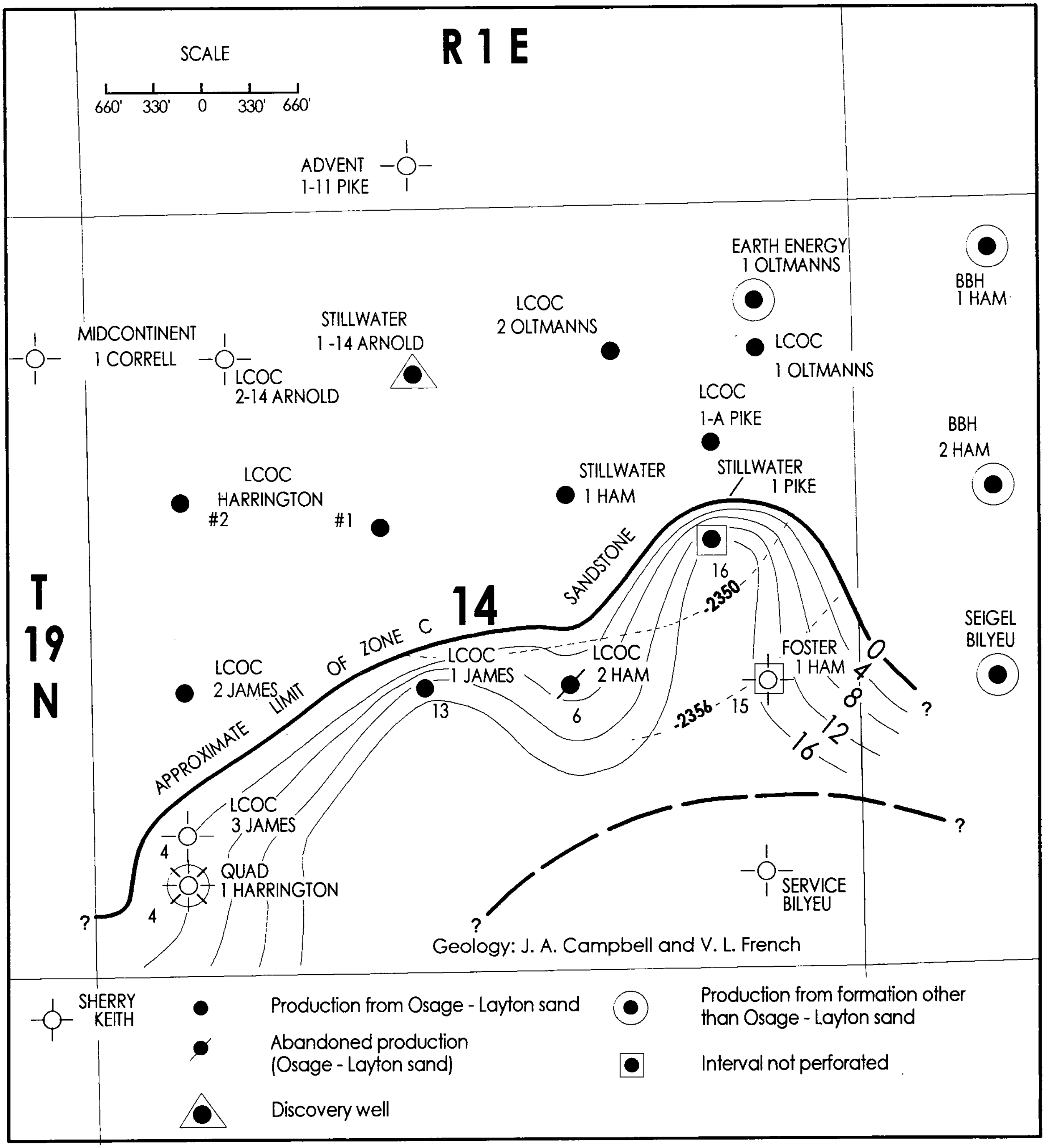


Figure 46. Reservoir-sandstone isopach, production zone C, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 4 ft. Dashed line is oil-water contact (see Fig. 47). BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

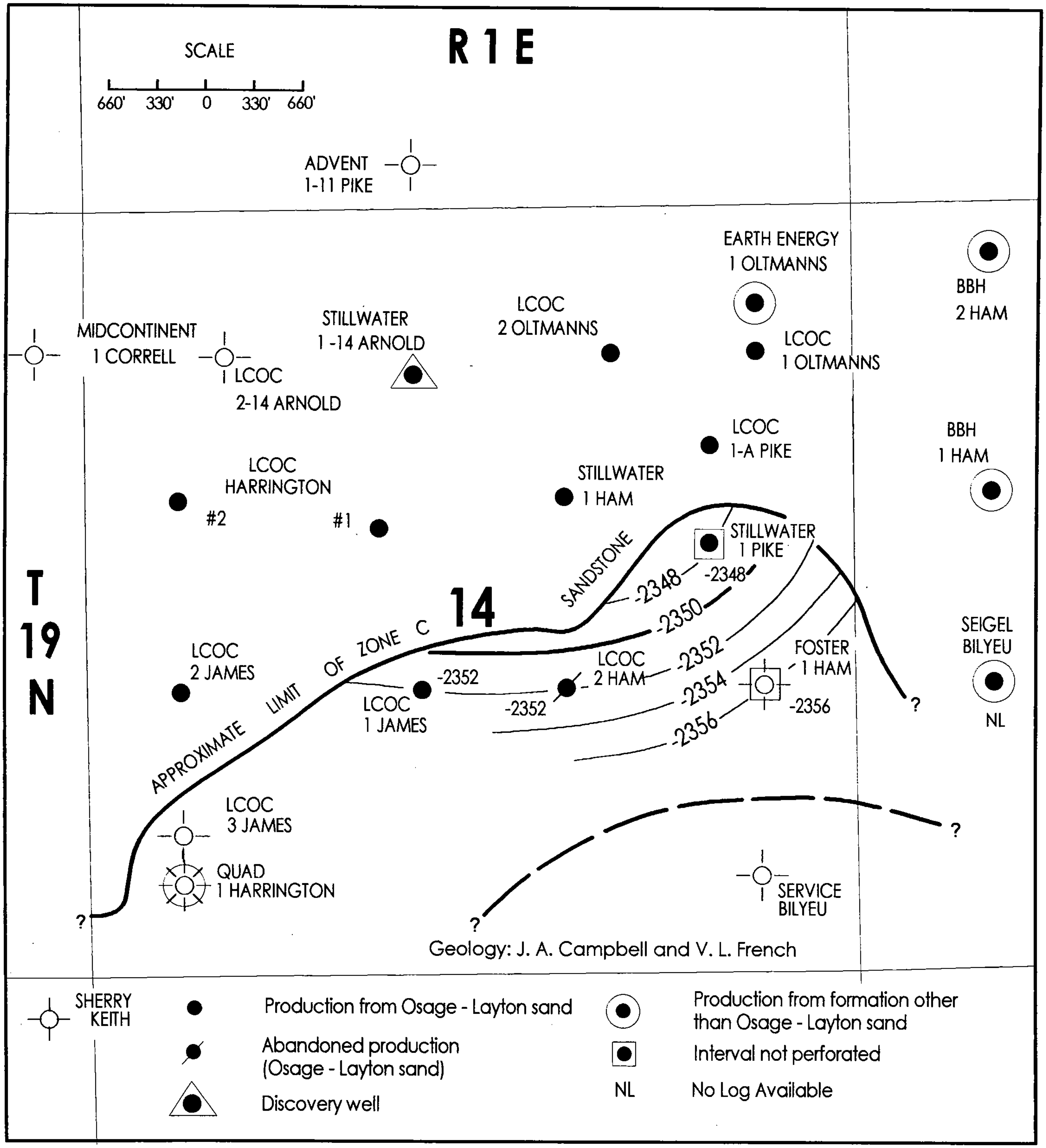


Figure 47. Oil-water contact in production zone C, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 2 ft; sea-level datum. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

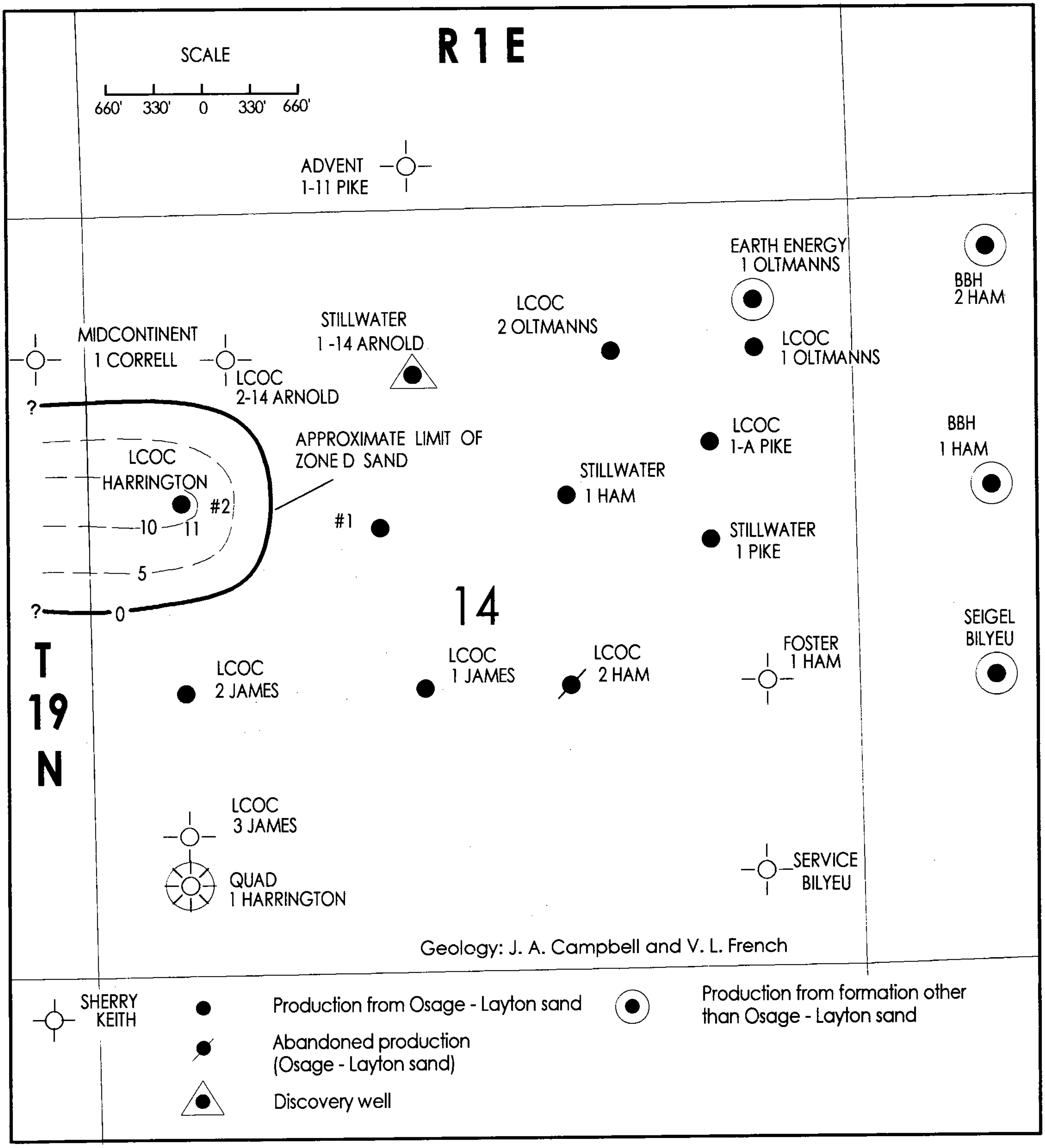


Figure 48. Reservoir sandstone isopach, production zone D, Osage-Layton sand, East Lake Blackwell oil field area. Contour interval is 5 ft. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

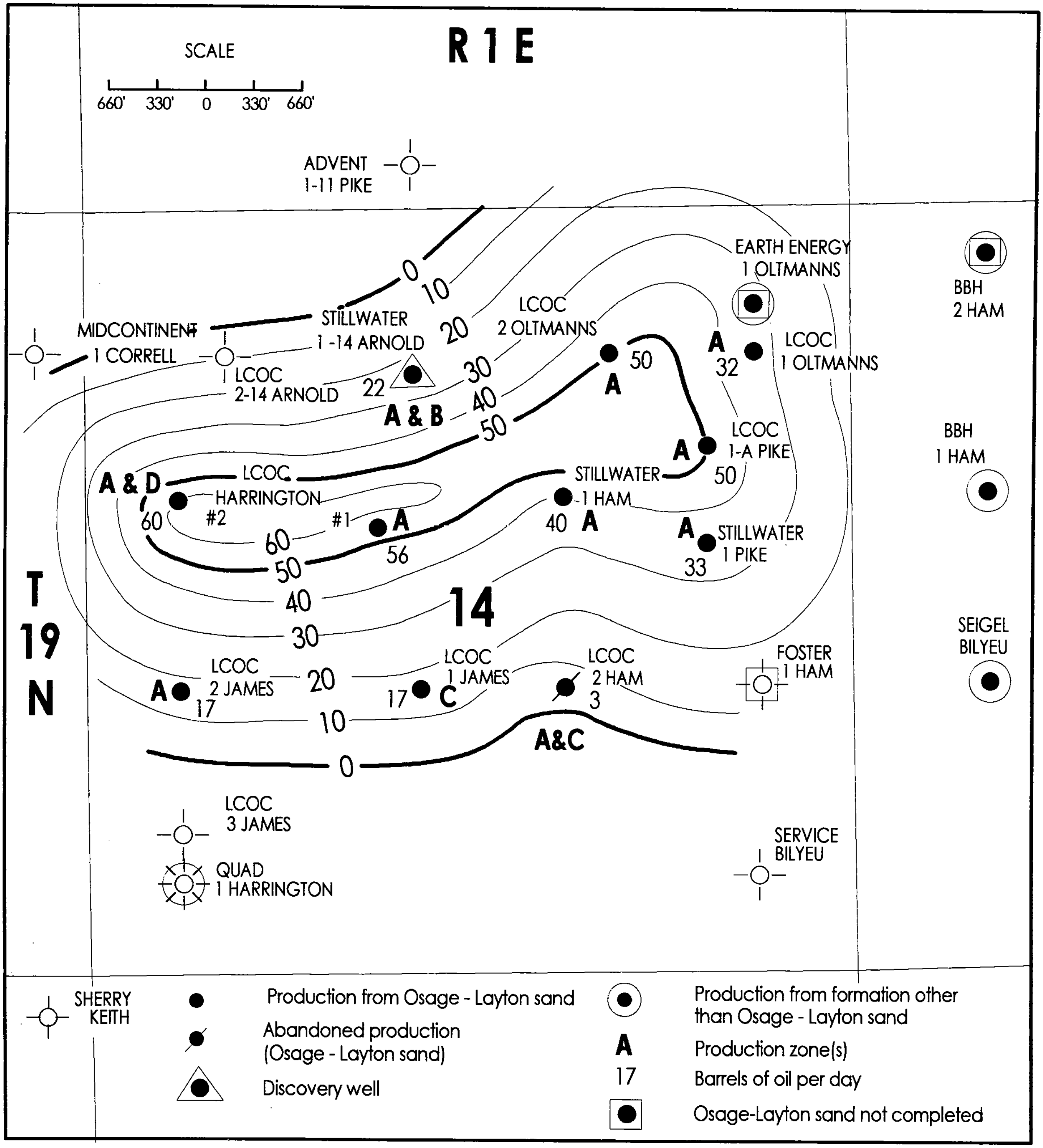


Figure 49. Initial oil production of wells producing from Osage-Layton sand (all zones), East Lake Blackwell oil field area. Contour interval is 10 BOPD. Data compiled from Oklahoma Corporation Commission well-completion reports (1002-A forms) and operator-provided information. BBH = B. B. Harrington; LCOC = Las Colinas Oil Corporation.

LAYTON SAND RESERVOIR STUDY, SOUTH COYLE OIL FIELD AREA

(T. 17 N., R. 1 E., Logan and Payne Counties, Oklahoma)

by Dennis L. Shannon

The South Coyle oil field is located in T. 17 N., R. 1 E., in Logan and Payne Counties, Oklahoma (Fig. 50). Although the field has been called both South Coyle and West Central School in the well listings, "South Coyle" is used in this study because this name was designated by the Oklahoma Nomenclature Committee of the Mid-Continent Oil and Gas Association for Layton sand oil producers in secs. 22, 27, and 34. This name is applied here in *all* Layton oil producers in T. 17 N., R. 1 E., for simplicity, and because all discoveries appear to be geologically related. The Layton sand is defined stratigraphically as sandstones in the interval between the Hogshooter Limestone and the Checkerboard Limestone. Figure 51 is a representative log showing typical log patterns in the field area and the generally accepted stratigraphic nomenclature.

Layton production in the field area originally was established on April 16, 1947, with the discovery of oil in the Layton sand in the Gulf Oil Corporation No. 1 Bliss well, SE¼ NW¼NE¼ sec. 26, T. 17 N., R. 1 E., from perforations at 3,634–3,658 ft (Fig. 52). This well was completed for an initial potential pumping of 11 BOPD + 125 bbl of water per day with an oil gravity of 47.6° API. This first producing well was abandoned at an unknown date after producing only 2,042 BO. The next Layton completion did not occur until 34 years later, when the Funk Exploration, Inc., No. 1 Woods well in SW¼NE¼SW¼ sec. 28, produced from perforations at 3,704–3,730 ft (Fig. 52). The Layton was completed in that well in June 1981 and had an IPF of 26 BO + 25 BW + 150 MCFGPD. Field development continued in November 1983 and continued through August 1988 (Table 9; Fig. 52). By June 1995 the Layton reservoir in the South Coyle field had a total of 14 wells, with a cumulative production of almost 190,000 BO. The cumulative production for the best single well was 35,756 BO. Table 9 and Figure 53 summarize oil production from the Layton reservoir. Some of the completions have been natural, but

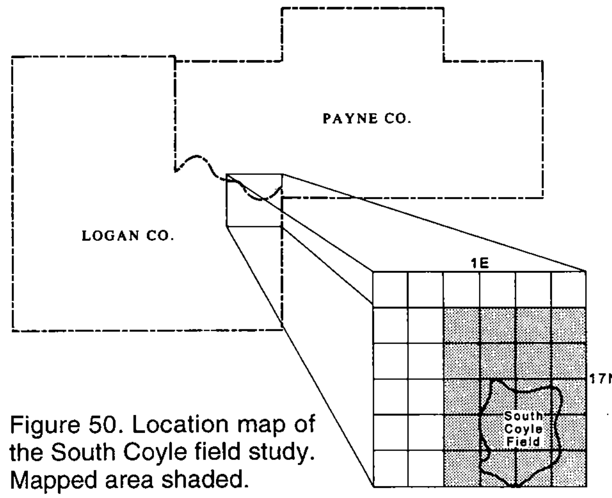


Figure 50. Location map of the South Coyle field study. Mapped area shaded.

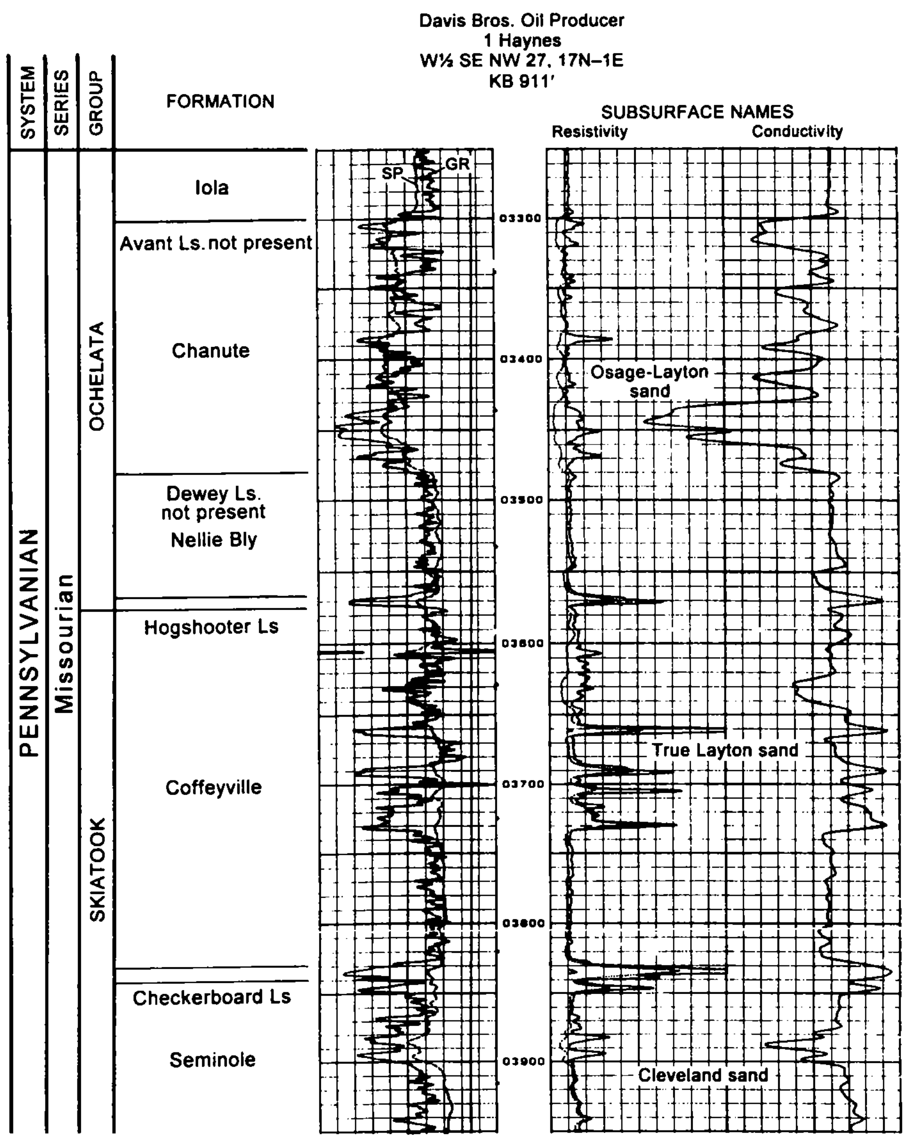


Figure 51. Log representative of the Layton sand and associated strata in the South Coyle field area, W½SE¼NW¼ sec. 27, T. 17 N., R. 1 E., Logan and Payne Counties, Oklahoma, showing log patterns of gamma-ray (GR), spontaneous-potential (SP), resistivity, and conductivity measurements. See well number 11, cross section A–A′ (Fig. 54, in envelope) for expanded log of this well.

TABLE 9. – Oil Production Statistics for the Layton Reservoir, South Coyle Field

Year	Number of oil wells	Annual oil production (bbl)	Average monthly oil production (bbl)	Average daily oil production (BOPD)	Cumulative oil production (bbl)
1947	1	?	?	?	2,042
...*	—	—	—	—	—
1981	1	1,580	263	9	3,622
1982	1	2,960	247	8	6,582
1983	2	2,230	159	5	8,812
1984	5	16,919	463	14	25,734
1985	6	15,163	323	11	40,894
1986	5	12,119	242	8	53,013
1987	8	31,773	474	16	84,786
1988	9	30,296	300	10	115,082
1989	9	20,148	187	6	135,230
1990	9	13,586	126	3	148,816
1991	9	10,586	108	3	159,402
1992	8	9,025	109	3	168,427
1993	6	7,724	107	4	176,151
1994	6	9,243	128	4	185,394
1995 (1st ½)	6	4,507	125	4	189,901

*Annual production data unavailable following 1947 discovery. The cumulative of 2,042 barrels is at an unknown point in time.

others may have been given a light acid treatment prior to production.

The Layton reservoir consists of stratigraphically controlled accumulations of oil in an interval of thin, shaly sands. The field outline is currently defined only by producers and not by dry holes. The nature of the reservoir makes this field difficult to categorize, quantify, or map, and is both a curse and a blessing, as will be discussed.

Stratigraphy

Oil production occurs in an indistinctly defined shaly sand interval approximately 40–80 ft below the top of the Hogshooter Limestone. The producing sandstones in the Layton interval typically are very shaly, as can be seen in cross sections A–A′ and B–B′ (Figs. 54 and 55, in envelope). Resistivities are low, ranging from ~1 to 5 ohm-meters, due in large part to the shaliness of the sandstones. Individual sandstone correlations are tenuous at best, but the productive sandstone/shale sequence can be defined roughly by the wider separation of the resistivity curves that indicate invasion by drilling fluids. However, because of the very shaly nature of the interval there is not a distinct top or base, but only transitional zones.

Directly below the sandstone/shale reservoir sequence is a limestone/shale sequence recognized on density-neutron logs (Figs. 54, 55). This interval is easily correlated over the mapped area, but individual members can vary. Below this interval is almost 100 ft of shale (presumably marine) above the Checkerboard Limestone (Figs. 51, 54, 55). With limestone immediately below and above the sandstone/shale reservoir sequence, the environment of deposition is probably a near-shore facies, transitional between low-energy marine and delta front.

Cross section A–A′ (north–south through the center of the field) demonstrates the shaly nature of the reservoir interval sandstones (Fig. 54). The gamma-ray profile cannot be used to determine accurately gross sandstone interval or net sandstone due to the "hot" nature of the strata throughout the reservoir interval, as can be seen on Figure 54. A comparison of geologic structure (Fig. 56) to structural position of the completed intervals (Fig. 57) illustrates that the occurrence of fluid phases (oil, gas, and water) is not governed by structural position.

The lowest perforations in the Funk Exploration, Inc., No. 1 Woods (SW¼NE¼SW¼ sec. 28) found oil, gas, and water, as did the highest subsea perforations in the J.O.C. Operating No. 1-A in the E½SE¼NW¼ of sec. 12 (Fig. 57). From observations of these data and the structure map on top of the Hogshooter Limestone (Fig. 56), it readily can be concluded that this is a complex of stratigraphic traps. The map of initial potential and cumulative production (Fig. 52) and the structural position (Fig. 57) show the variability of production, as well as oil gravities that range from 40° to 47.6° API. Some completions are water-free, but most include some water. Gas is produced locally, but gas from some wells was reported in quantities too small to measure. The oil gravities appear to group into three ranges: one at ~40°, another at 42°, and another at ~47° API. It is apparent from the variation in the production that the Layton reservoir in the South Coyle field is best described as numerous accumulations in several small, discontinuous, stratigraphically trapping sandstone lenses, rather than as a continuous reservoir.

Structure

The top of the Hogshooter Limestone, persistent in the area and easily recognized, was used as the datum for structural mapping; the top of the Layton oil zone is indistinct and is not suitable for structural mapping. The South Coyle field occurs on a structural terrace, seen as a slight flattening of a homoclinal dip to the

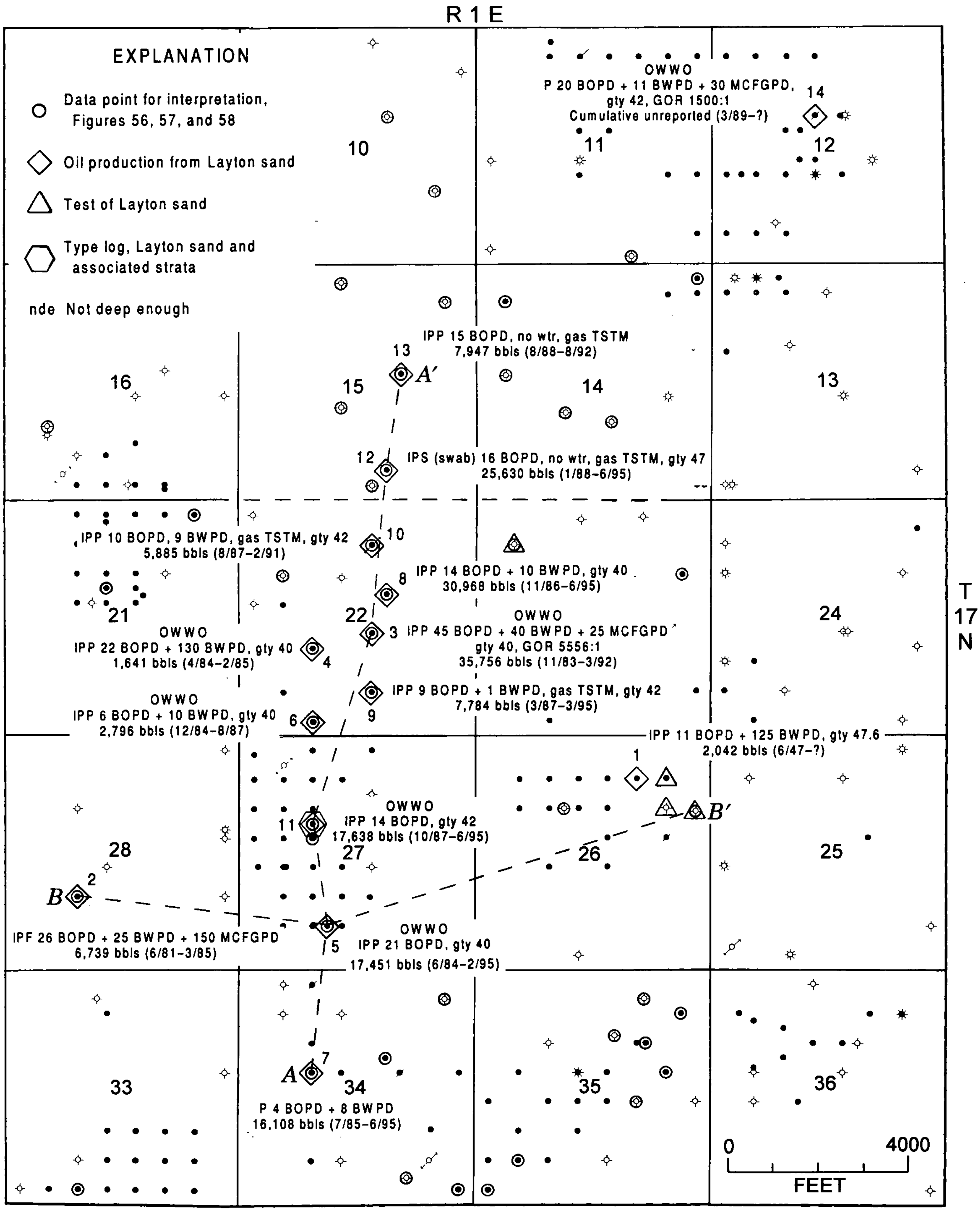


Figure 52. South Coyle oil field, with emphasis on wells producing from Layton sand. Numbers adjacent to wells show chronological order of completion in Layton sand reservoirs.

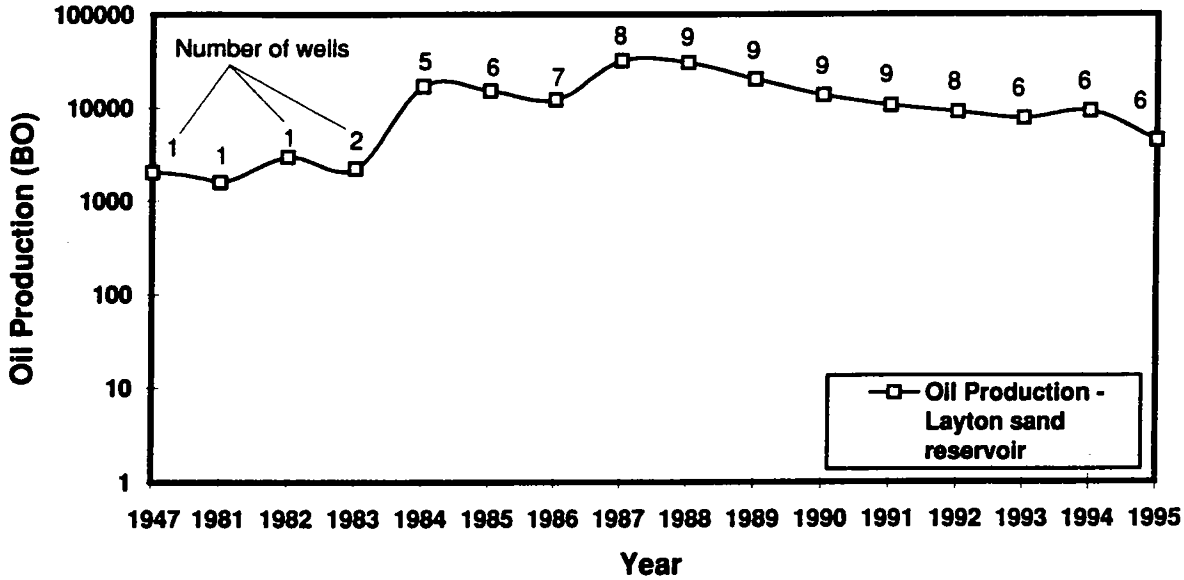


Figure 53. Cumulative oil production plot for the Layton sand, South Coyle oil field.

west at 75–150 ft/mi (Fig. 56). Structural position seems to have played no part in the Layton accumulations.

Isopach Mapping

Unlike oil reservoirs in many of the other fields presented in the FDD series of oil plays, the Layton oil reservoir in South Coyle field does not consist of robust channel sandstones that have obvious limits and axial trends. Because it is a poorly defined sandstone/shale sequence with no known limits in the immediate area, an isopach was not made for a specific sandstone interval. Individual sandstone lenses are difficult or impossible to correlate between wells. The entire sandstone/shale reservoir sequence is difficult to delineate because of indistinct vertical limits. Therefore, the isopach was constructed between the two best marker units surrounding the reservoir sequence, namely, the Hogshooter Limestone above and the Checkerboard Limestone below (Fig. 58). It was anticipated that this map might show a thickening where the Layton sand is better developed; that is, where sandstones might have compacted less than stratigraphically equivalent shales. Had this been observed, such a map would have been demonstrated as a tool useful for exploration. It would have been better to make the vertical interval smaller, but no other markers were sufficiently consistent over the mapped area to minimize the interval isopach and thus accentuate the differences of sandstone and shale thickness within the Layton sequence. Analysis of the isopach map (Fig. 58) shows overall thickening to the north and northwest, but with little variation through the center of the field. Note that the best production extends in nearly a straight line from well number 12 in the SW¼SE¼ of sec. 15 to well number 7 in the SW¼SE¼NW¼ of sec. 34 (Fig. 52). This area has almost no change in the isopach interval, as was the case on the structure map (Fig. 56).

Reservoir Characteristics

The shaly nature of sandstones in the Layton interval makes the calculation of porosity problematical. The density curve is probably the best indication of porosity, but quantifying it would require numerous empirical log calculations with a result that still would be an educated guess (Figs. 54, 55). For the few wells that have micrologs, there are good indications of permeability. There is no core analysis available for the reservoir in this area.

Formation Evaluation

Reservoir evaluation is difficult for the Layton sand. This is a bonus, in a sense, as it provides operators an opportunity to find reserves in the Layton sand interval. Reservoirs that were easy to evaluate have already been found because of the dense drilling that is common on the Cherokee platform. Low resistivities, shaliness, and indistinct porosities have caused the Layton sand to be bypassed or ignored over a considerable area. The most informative wireline logs seem to be the density curve and the microlog. Detailed sample description is a definite advantage, especially if done during drilling of the well.

Note that the density curve on the density-neutron logs on the porosity version of cross sections A–A′ and B–B′ (Figs. 54, 55) shows good response; the density and neutron curves do approach each other. In summary, the clues that indicate possible future production seem to be: (1) significant response of the density curve toward higher porosity; (2) development of mud cake or microlog response, if available; (3) invasion profile on resistivity logs; and (4) oil shows in the drill cuttings, if available. It is hoped that this study will provide a model of low-permeability Layton sandstones that will make operators more aware of the potential of the Layton sand, at least as a secondary objective.

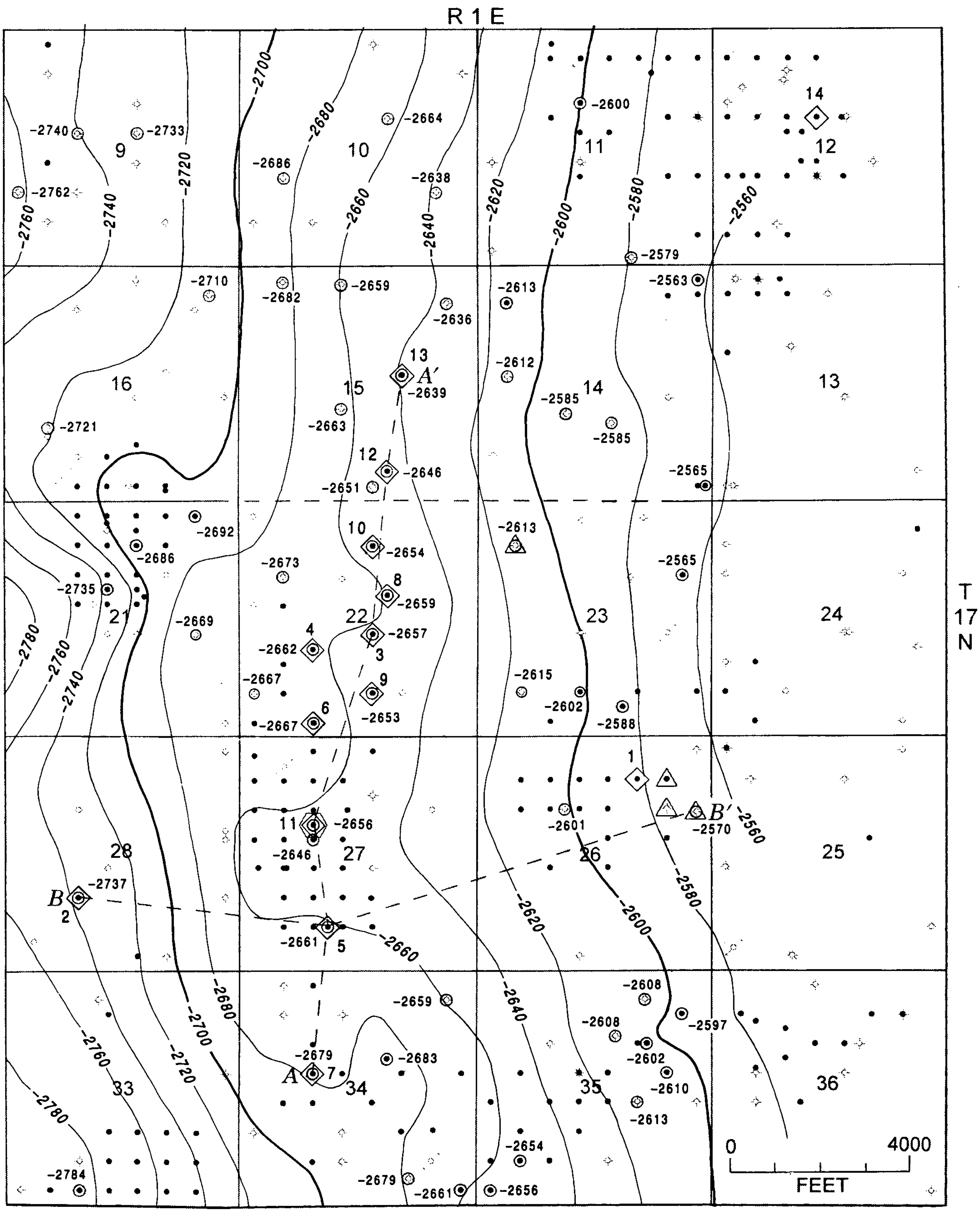


Figure 56. Geologic structure on top of the Hogshooter Limestone. Contour interval is 20 ft. Each well is identified by a number indicating its chronological order of completion.

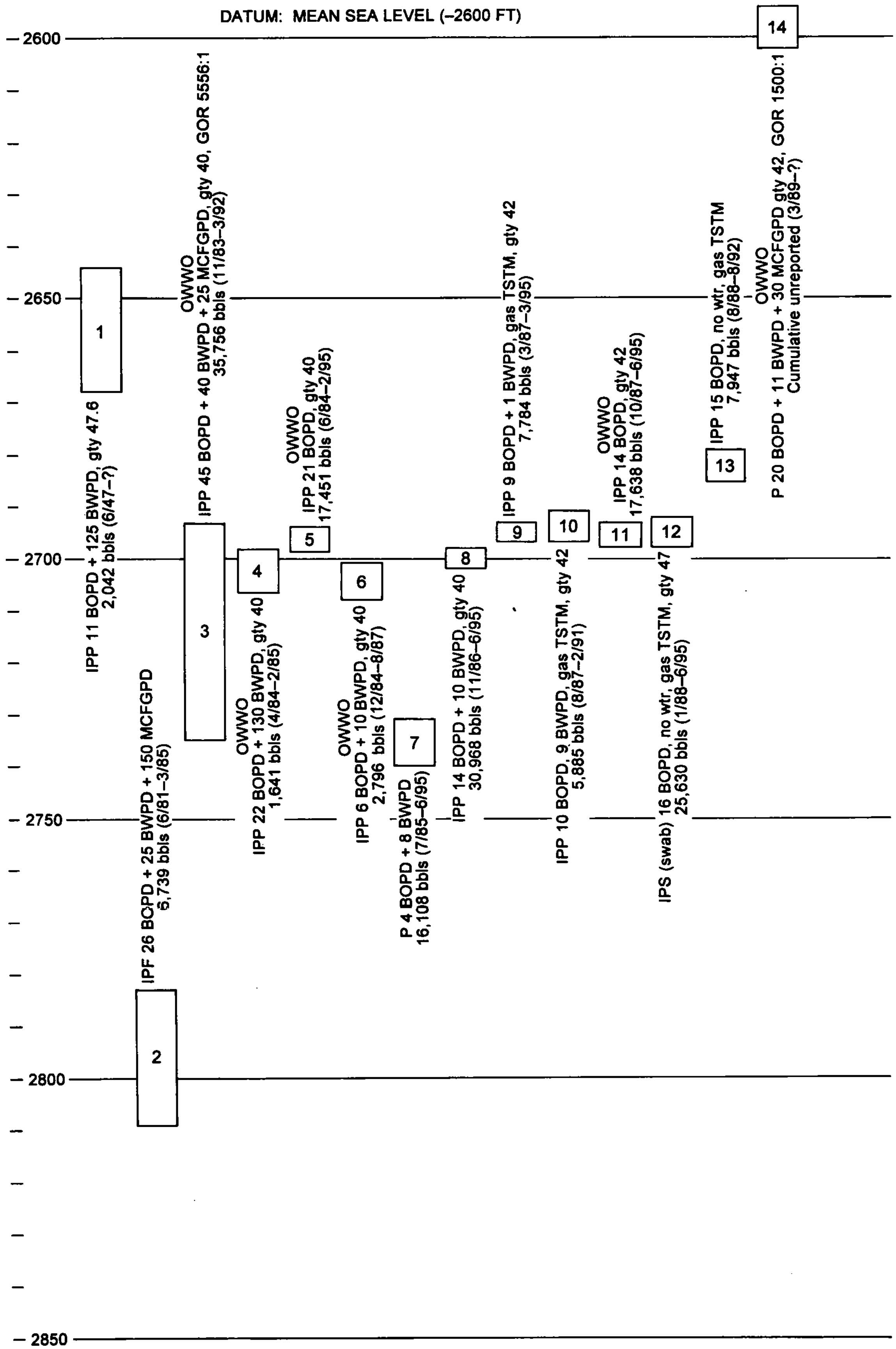


Figure 57. Structural position of wells producing from Layton sand, South Coyle oil field. Each rectangle represents the position of Layton sand perforations relative to mean sea level. Each well is identified by a number indicating its chronological order of completion.

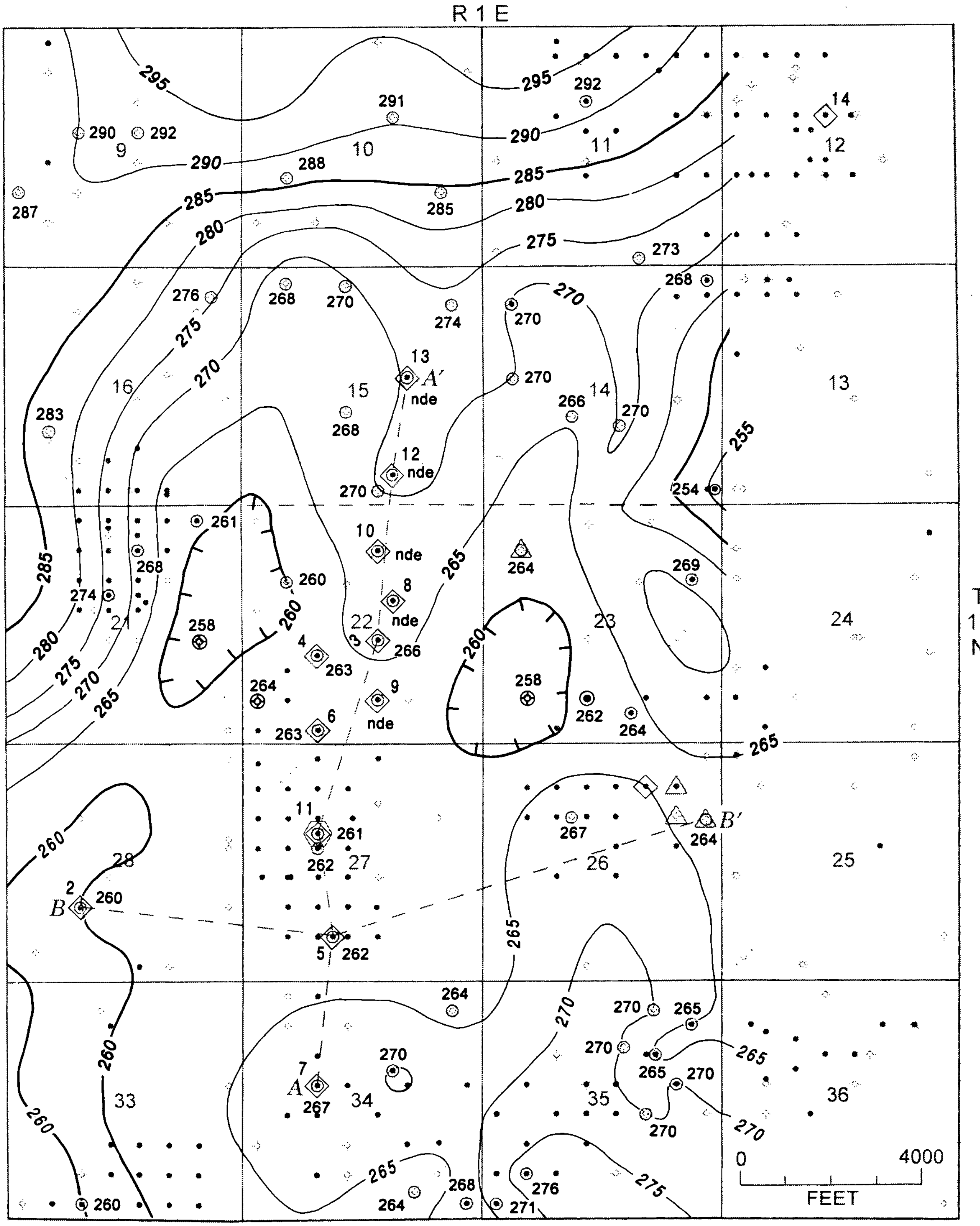


Figure 58. Isopach of the interval from the top of the Hogshooter Limestone to the top of the Checkerboard Limestone. Contour interval is 5 ft. Each well is identified by a number indicating its chronological order of completion.

Older wells also locally may provide leads to development of Layton reservoirs as a primary objective.

Oil and Gas Production and Well Completion

Cumulative oil production through June 1995 for all Layton producers in the township is ~190,000 bbl (Table 9; Fig. 53). The best well has a cumulative production of 35,756 bbl over a 10-year period; the poorest well has produced only 1,641 bbl. The average for 14 field wells is slightly more than 13,500 bbl/well. Eleven wells in the central area of the field in secs. 15, 22, 27, and 34 have a cumulative production of 169,604 bbl. The average production of these 11 wells is >15,400 bbl/well. Many of the Layton sand wells have been completed without treatment, whereas others have been given a light acid treatment before production. Casinghead gas has been reported from only one well and is minor, with a cumulative production of 17,324 MCF over a 3.5-year period (J.O.C. No. 1 Haynes W½SE¼NW¼ sec. 27).

In this stratigraphic accumulation, the reservoir does not have established limits and additional production is likely to be found. This reservoir is difficult and economically risky as a primary exploration objective; however, it provides for understanding of the keys to production. The Layton sand will continue to be a secondary, and locally a primary, zone of interest over a large geographic area.

PART IV

Reservoir Simulation of an Osage-Layton Reservoir, East Lake Blackwell Field, Payne County, Oklahoma

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INTRODUCTION

The East Lake Blackwell field consists of 360 proven productive acres in sec. 14, T. 19 N., R. 1 E., northwestern Payne County, Oklahoma. The Osage-Layton sand in this reservoir is at depths of 3,330 ft, or –2,390 ft subsea (below mean sea level). The Osage-Layton sand consists of at least four separate sandstone bodies with a combined average net thickness of 39 ft. Zone A (see Part III, this volume), the lowest and largest of the sandstone bodies, has an average net thickness of 11 ft and an areal extent of 360 acres. Zone B has an average net thickness of 6 ft and an areal extent of 190 acres. Zone C has an average net thickness of 14 ft and an areal extent of 160 acres. Zone D has an average net thickness of 8 ft and an areal extent of 40 acres. The channel sandstones that make up the reservoirs are sealed to the northeast and south. To the west are aquifers that provide a water influx to drive oil. In zone C, the aquifer is attached to the south, and the west is sealed. Eleven wells in zone A, one well in zone B, two wells in zone C, and one well in zone D have been completed. Two additional wells that penetrated one or more zones were dry holes. A complete discussion of the reservoir of the East Lake Blackwell field, including petrography and depositional environments, can be found in Part III of this volume.

The simulation area in this study included 11 production wells on six leases, two dry holes, and two wells that penetrated in the Osage-Layton sands but have not been completed in them. By the end of September 1995, the 11 production wells had produced nearly 320,000 BO since discovery in 1987.

The initial phase of development in the East Lake Blackwell field began when zone B was discovered and began producing from the No. 1-14 Arnold in November 1987. In 1987, this well averaged 12 BOPD; water production was not reported. From 1990 through 1993, eight additional wells were drilled and completed in zones A, C, and D. The main production has been from zone A, which was perforated in all 11 producing wells. The oil production rates in this field declined from 300 BOPD in 1992 to 90 BOPD in September 1995, and water cut reached >90% in February 1996. Water breakthrough has occurred in eight wells, and at least one well, the No. 2 Ham, is not economic. At least one well, the No. 1 Oltmanns, has not produced water. The average initial pressure was 1,450 PSIA, and the oil is believed to have been undersaturated initially with respect to gas. Based on current reservoir pressure and production data, the main sources of reservoir energy in this field are natural water drives. However, the areal extent of the aquifers is uncertain. The major objective of this study was to use the available field data to develop a reservoir simulation model for the small East Lake Blackwell field. The model could then be used to evaluate past field performance and design and test potential strategies to improve oil recovery.

DATA AVAILABILITY

Data used for reservoir characterization and simulation included depths to the top of sandstone, sand thickness, porosity, permeability, lithology, initial water saturation, and depths to the oil-water contacts (OWC) for each zone. Values of these parameters were obtained from well logs or from core analyses.

Campbell (Part III, this volume) interpreted the depths to the top of each zone and net-pay thickness of the reservoir. Porosity, absolute permeability, and initial water saturation data were evaluated directly from a core analysis report of the No. 1-14 Arnold well (Table 6). The initial reservoir pressure was determined from the drill stem test (DST) in the No. 1-14 Arnold well (Pl. 11). The initial gas-oil ratio (GOR) was obtained from the initial production test for the No. 1 Ham, No. 1 Pike, and No. 1 Harrington wells (Table 5). The Oklahoma Geological Survey provided oil and gas production records, and operators provided core and fluid analysis reports. Data that are useful for reservoir studies but were not available for this study included (1) reservoir pressure data during production, (2) history of water production, and (3) capillary pressure and relative permeability data.

ANALYSES OF ROCK DATA

The No. 1-14 Arnold was the only well cored. From it, average values of permeability, porosity, and water

TABLE 10. – Reservoir Properties, Osage-Layton Reservoir, East Lake Blackwell Field, Payne County, Oklahoma

Estimated properties	Zone A	Zone B	Zone C	Zone D
Porosity	12–22%	15.5%	17%	18%
Permeability	10–50 md	35 md	40 md	35 md
Average Gross Pay	70 ft	50 ft	60 ft	20 ft
Average Net Pay	11 ft	6 ft	14 ft	8 ft
Initial Water Saturation	46%	46%	46%	46%
Initial Bottom-Hole Pressure	1,450 PSIA	1,440 PSIA	1,430 PSIA	1,430 PSIA
Initial Gas-Oil Ratio	400 SCF/STB	400 SCF/STB	400 SCF/STB	400 SCF/STB
Initial Formation-Volume Factor	1.22 RB/STB	1.22 RB/STB	1.22 RB/STB	1.22 RB/STB
Reservoir Temperature	110°F	110°F	110°F	110°F
Oil Gravity	43.0° API	43.0° API	43.0° API	43.0° API
Specific Gas Gravity	0.95	0.95	0.95	0.95
Initial Oil in Place	1.6 MMSTB	0.51 MMSTB	0.39 MMSTB	0.10 MMSTB

saturation were used to help create the reservoir simulation model. Average property values for the Osage-Layton reservoirs are shown in Table 10. Almost all wells had resistivity and density/neutron porosity logs. This data set made it possible to:

1) Develop a log permeability versus porosity (ϕ) crossplot and correlation from the core analysis of the No. 1-14 Arnold (Fig. 59);

2) Develop a ϕ_{core}/ϕ_{log} crossplot and correlation from corresponding log-derived and core-derived porosity values from the No. 1-14 Arnold (Fig. 60); and

3) Determine permeability values at uncored wells by interpreting ϕ_{log} values from neutron/density logs, and by using Figure 60 to obtain ϕ_{core} and Figure 59 to obtain permeability.

Porosities and permeabilities in zone A, the most widespread and main production zone, were evaluated by applying the above method throughout the zone. However, uniform porosities and permeabilities were used in the model for zones B, C, and D because of the limited number of well bores that penetrated the zones. One well was completed in zone B, two wells were completed in zone C, and one well was completed in zone D.

Initial water saturation values, determined from core analysis of the No. 1-14 Arnold well, were 50.6% and 42.2% in zone B (Table 6). The average 46.0% of initial water saturation was used in this study for all four zones. By assuming that the initially water-saturated reservoir was driven to irreducible water saturation by oil at the time oil migrated into the trap, and that the oil-bearing rock was subsequently driven to residual oil saturation by water, the

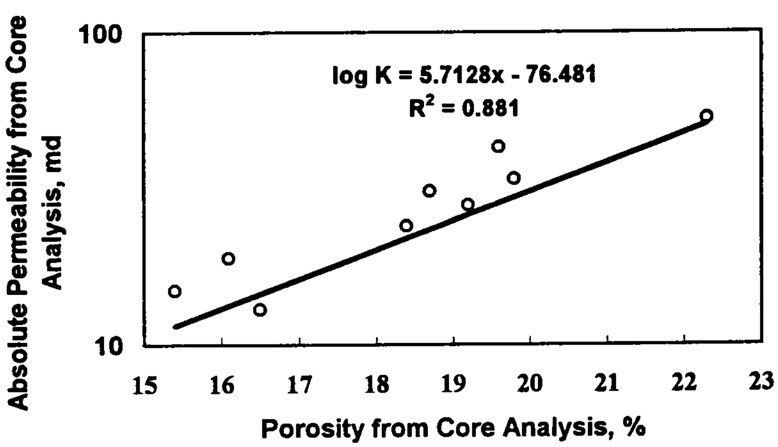

Figure 59. Crossplot of absolute permeability and porosity based on core analysis from the No. 1-14 Arnold well, East Lake Blackwell field, Payne County, Oklahoma.

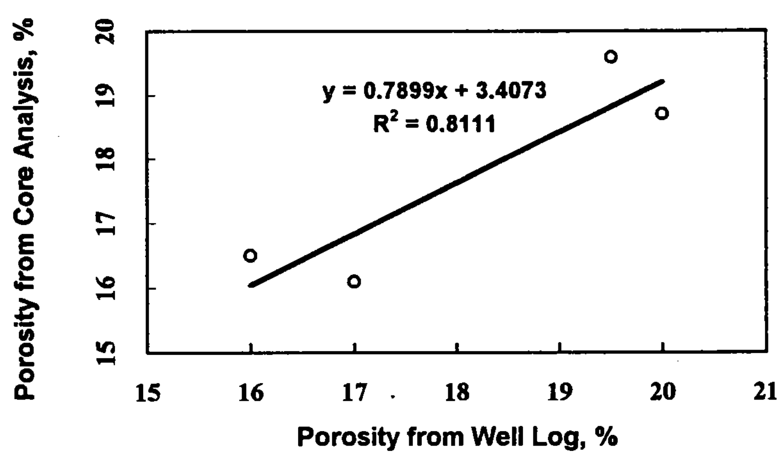

Figure 60. Crossplot of porosity based on core analysis and well log from the No. 1-14 Arnold well, East Lake Blackwell field, Payne County, Oklahoma.

TABLE 11. – Osage-Layton Reservoir Wells in the East Lake Blackwell Field, Payne County, Oklahoma

		Production Dates		Cumulative Production		Zone A	Zone B	Zone C	Zone D
						Penetrated Intervals			
Well Name	Well Location	Initial	Final	(Oil, lease) (STB)	(Gas, lease) (MCF)	Top — Bottom Subsea Depth, ft	Top — Bottom Subsea Depth, ft	Top — Bottom Subsea Depth, ft	Top — Bottom Subsea Depth, ft
Arnold # 1-14	14-19N-1E	11/1/87	Sep-95	27267	not reported	2391 — 2397	2375 — 2381		
Ham # 1	14-19N-1E	5/28/90	Sep-95			2383 — 2395	2366 — 2372		
Ham # 2	14-19N-1E	4/8/91	Dec-92	75936	2540	2402 — 2413		2346 — 2352	
Pike # 1	14-19N-1E	1/8/91	Sep-95			2376 — 2385		2324 — 2340	
Pike # 1-A	14-19N-1E	Jul-93	Sep-95	59310	2227	2362 — 2372	2344 — 2348		
Oltmanns # 1	14-19N-1E	3/28/91	Sep-95			2374 — 2384	2357 — 2362		
Oltmanns # 2	14-19N-1E	5/13/91	Sep-95	71758	20048	2381 — 2391	2374 — 2378		
Harrington # 1	14-19N-1E	6/17/91	Sep-95			2382 — 2394	2366 — 2374		
Harrington # 2	14-19N-1E	9/24/91	Sep-95	58983	15554	2390 — 2398	2374 — 2380		2316 — 2334
James # 1	14-19N-1E	8/14/91	Sep-95			2388 — 2402		2340 — 2353	
James # 2	14-19N-1E	5/1/92	Sep-95	26682	not reported	2389 — 2399			
Arnold # 2-14	14-19N-1E	Dry Hole				2410 — 2474	2391 — 2402		
James # 3	14-19N-1E	Dry Hole				2409 — 2435		2364 — 2386	
Ham-Estate # 1	14-19N-1E	Not perforated in any zone						2325 — 2366	
Oltmanns # 1 (Earth Energy Resources)	14-19N-1E	Not perforated in any zone				2391 — 2425			
New # 1(Simulated)	14-19N-1E	Infill Well				Completed in A			
New # 2(Simulated)	14-19N-1E	Infill Well					Completed in B		
New # 3(Simulated)	14-19N-1E	Infill Well						Completed in C	
New # 4(Simulated)	14-19N-1E	Infill Well							Completed in D

residual oil saturation of 19% was determined from the last three points of the core analysis in No. 1-14 Arnold (Table 6). The three original OWCs interpreted from geophysical logs (Part III, this volume) were –2,404 ft subsea in zone A, –2,389 ft subsea in zone B, and –2,352 ft subsea in zone C. The geophysical log interpretations were confirmed by core analyses of the No. 1-14 Arnold in zone A.

Capillary pressure data, calculated using the method of Smith (1991), were used in this simulation study to determine reservoir transition zone distributions. Relative permeabilities as saturation functions were calculated using Honarpour and others' (1986) method and were used for all four zones.

The average reservoir temperature reported on well logs was 110°F, and the final shut-in pressure of 1,450 PSIA from a DST in the No. 1-14 Arnold was chosen as the initial average reservoir pressure at the depth –2,427 ft subsea (DST chart for No. 1-14 Arnold).

FLUID PROPERTIES

The oil gravity ranged from 40.5° to 45.5° API and averaged 43.0° API. Surface samples of gas from the East Lake Blackwell field were analyzed by Southwest Laboratory of Oklahoma (Natural Gas Analysis Summary, 1993, unpublished report nos. 18566, 18567, and 19382). Measured specific gravities of gas ranged from 0.847 to 1.032 and averaged 0.95 (air = 1.0). Pan Western Energy Corporation (James Harrington lease water analysis, May 5, 1994, unpublished report) provided an analysis of produced water (Table 8). The specific gravity of water was 1.158, and the salinity of water was 168,000 ppm. The initial GOR varied from 250 to 600 SCF/STB and averaged 400 SCF/STB. The original saturation (bubble-point) pressure of the oil estimated using Al-Marhoun's correlation (McCain, 1990) was 1,000 PSIA. An estimated average initial oil formation-volume factor of 1.22 RB/STB and an estimated initial oil viscos-ity at reservoir conditions of 1.86 cp were used in this simulation study. Average reservoir properties are listed in Table 10. The fluid properties are consistent with the low shrinkage assumption made in the simulation.

FIELD DEVELOPMENT OVERVIEW

Wells that were completed in the Osage-Layton reservoir and used in the simulation study are listed in Table 11. Depths were interpreted from logs. A total of 15 wells were drilled and completed in the East Lake Blackwell field. Eleven of the wells were perforated in zone A. The No. 1-14 Arnold was perforated in both zones A and B. The No. 2 Harrington was perforated in zones A and D. The No. 1 James, No. 3 James, and No. 2 Ham were perforated in both zones A and C. The No. 2 Ham was subeconomic and abandoned because its extremely high water cut (Part III, this volume). The No. 3 James and No. 2-14 Arnold were dry holes. The No. 1 Ham Estate and Earth Energy Resources No. 1 Oltmanns were not completed in any of the four Osage-Layton zones. The oil production history of the Osage-Layton sand study area within the East Lake Blackwell field during the 8-year period 1987–95 is given by Campbell in Part III of this volume and shown in Figure 61. Oil production began in November 1987 and peaked from May 1991 through April 1992 at ~300 BOPD from 10 wells. A gradual production decline occurred over the next four years and oil production in September 1995 was 85 BOPD. The current average values of shut-in bottom-hole pressure are ~1,180 PSIA, and the total average field water cut is >90%. The primary performance in the East Lake Blackwell field suggests that these reservoirs have robust associated aquifers with bottom and edge water drive mechanisms.

ESTIMATION OF RESERVES AND OIL RECOVERY FACTOR

The total original oil in place in this field was estimated to be 2.6 MMSTB based on an initial water saturation of 46%. Zone A has 1,600,000 bbl or 61% of the OOIP, zone B has 510,000 bbl or 20% of OOIP, zone C has 400,000 bbl or 15% of OOIP, and zone D has 95,000 bbl or 4% of OOIP, respectively. The maximum theoretical recovery, based on an estimated residual oil saturation of 19%, could be as much as 1.7 MMSTB, or 65% of OOIP. The unrecoverable immobile oil is estimated to be 0.92 MMSTB. Primary recovery from the wells in the simulated area through September 1995 was 319,936 STB, or 12.3% of OOIP (Fig. 61). Consequently, ~52% (1.35 MMSTB) of OOIP in the East Lake Blackwell field is unproduced mobile oil and is a target for well recompletion and an infill drilling program.

HISTORY MATCHING

To be confident that the reservoir model adequately represented the behavior of the study reservoirs, the model was validated by obtaining history matches of

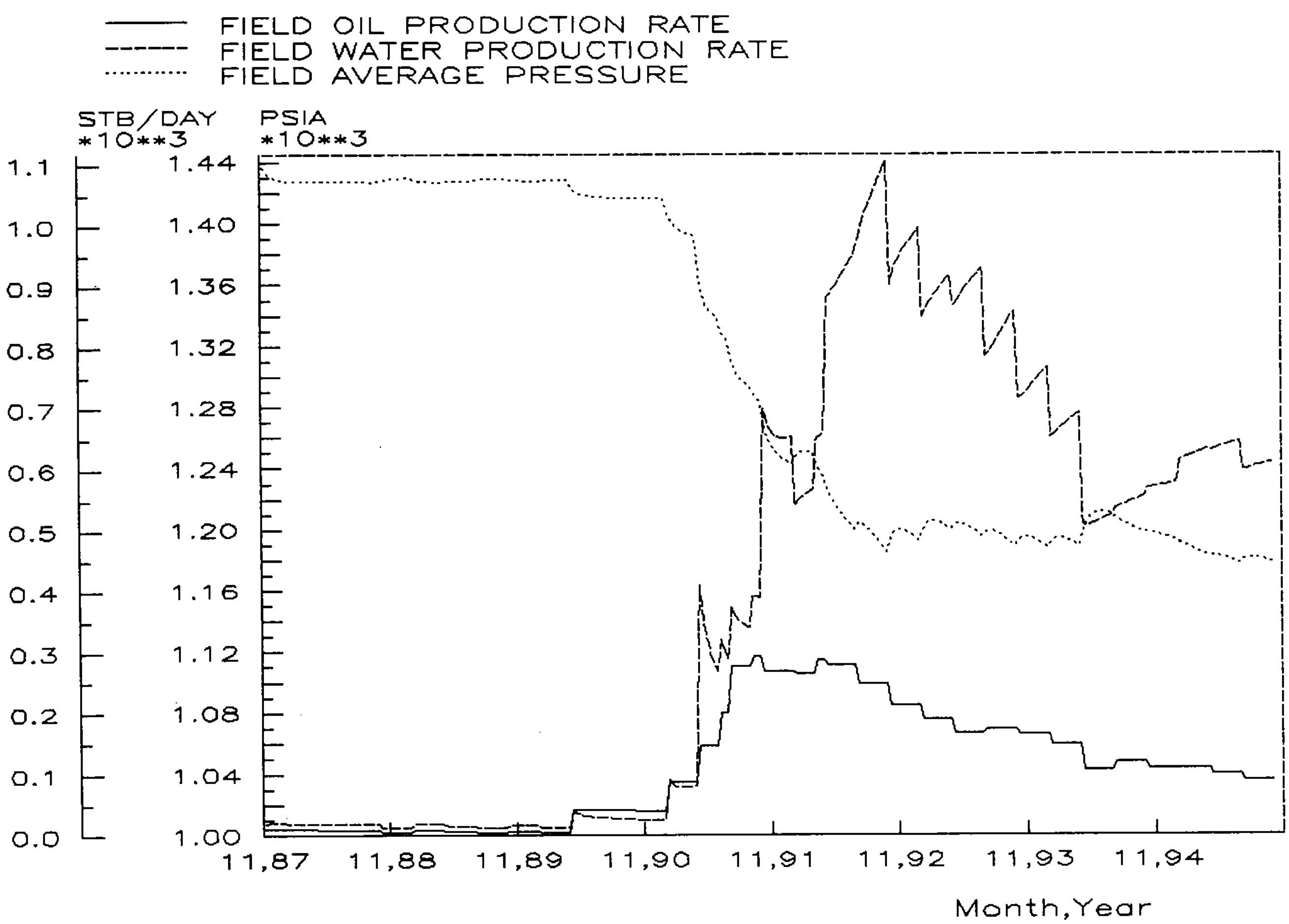

Figure 61. Oil and water production rates and field pressure for the Osage-Layton reservoir in the East Lake Blackwell field, Payne County, from November 1987 through September 1995.

TABLE 12. – Oil Recovery Comparisons for Different Development Cases, Osage-Layton Reservoir, East Lake Blackwell Field, Payne County, Oklahoma

Formation	Primary (9/30/1995)			Base (12/31/2005)			Recompletion (12/31/2005)			Infill Wells (12/31/2005)		
	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (Barrels)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (Barrels)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (Barrels)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (Barrels)
Zone A	227,000	14	850,000	310,000	19	1,800,000	500,000	31	1,500,000	570,000	36	1,800,000
Zone B	75,000	15	28,000	82,000	16	44,000	260,000	50	160,000	280,000	55	160,000
Zone C	6,000	1.5	240,000	7,000	1.8	470,000	165,000	42	690,000	186,000	48	580,000
Zone D	12,000	12	42,000	22,000	22	90,000	15,000	15	56,000	30,000	30	70,000
Total	320,000	12	1,200,000	421,000	16	2,400,000	940,000	36	2,400,000	1,066,000	41	2,600,000

the actual production performance for the 11 production wells in the study area. Oil production was chosen as the specified history production variable because it was considered to be the most reliable data available. Because current measured pressure and water production data were available for the reservoir, the goal in simulating production history was to match the wells' specified oil production rates and estimated water production rates and pressure values on September 30, 1995. This was accomplished for all wells. The gas production rates for some wells also were available and honored in the history match.

The process of history matching consisted of adjusting uncertain parameters to simulate the production and pressure behavior of an actual reservoir. Through the history match, significant adjustments made to estimated model parameters included: (1) Zone A permeability and porosity were increased approximately 20% and 10%, respectively; (2) the relative permeability to water was adjusted to fit late history; (3) initial oil-water contacts were raised 0.5–1.0 ft for each zone; (4) the volumes of aquifers in zones A, B, C, and D were assumed to be 60, 40, 50 and 30 million bbl, respectively, to fit the high water cuts and current reservoir pressure. That all aquifers had a single face connection with each oil zone was assumed based on the geological maps and history match requirements. In this study, the Fetkovich aquifer model was used to estimate water influx as it predicts the performance of irregularly shaped volumetric aquifers realistically (Fetkovich, 1971).

Good matches of current water cuts and pressure performance for most of the wells were obtained. The No. 1-14 Arnold is the only well where the simulated water production rate is much lower than the current reported data. Primary oil and water productions for the past 8 years are shown in Figure 61.

EVALUATION OF FUTURE DEVELOPMENT OPPORTUNITIES

The analysis of current oil reserves in the East Lake Blackwell field showed that 52% of the estimated OOIP, 1.35 MMSTB oil, is mobile. Several strategies for reservoir management were investigated to maximize recovery at this field. These included well recompletions and infill wells. The following three options were independently investigated and compared: (1) base-case option, (2) well recompletion, and (3) infill well drilling.

Base-Case Option

The base-case simulation assumes that there are no changes in the field development and that the well operating conditions (BHPs) of September 1995 were kept unchanged. After 10 more years of production, the additional recovery of oil is expected to be ~4.0% of OOIP, or 0.1 MMSTB, with additional water production of 1.2 MMSTB (Table 12).

Well Recompletion

For this case, two wells, the No. 1-14 Arnold and No. 2 Ham, were converted into water injection wells. Produced water from other wells was injected into these wells. Water injection rates were maintained constant at 300 BWPD with BHP limits of 1,800 PSIA. Four wells, the Nos. 1 and 2 James, No. 2 Harrington, and No. 2 Oltmanns, were closed in all zones. The No. 1 Foster Ham Estate and No. 1 Pike were perforated in zone C. Four wells—the No. 1-A Pike, No. 1 Oltmanns, No. 1 Harrington, and No. 1 Ham—were completed in zone B. Production rates for these wells were specified to be 15–70 BOPD with minimum BHP limits for all wells specified as 500 PSIA. The oil rate limits and water injection rate limits were designed for the best water drive sweep efficiency. After 10 years of simulated production for this case, the recovery of oil above that of the primary case is expected to be ~24% of OOIP (0.62 MMSTB) with additional water production of 1.2 MMSTB (Table 12).

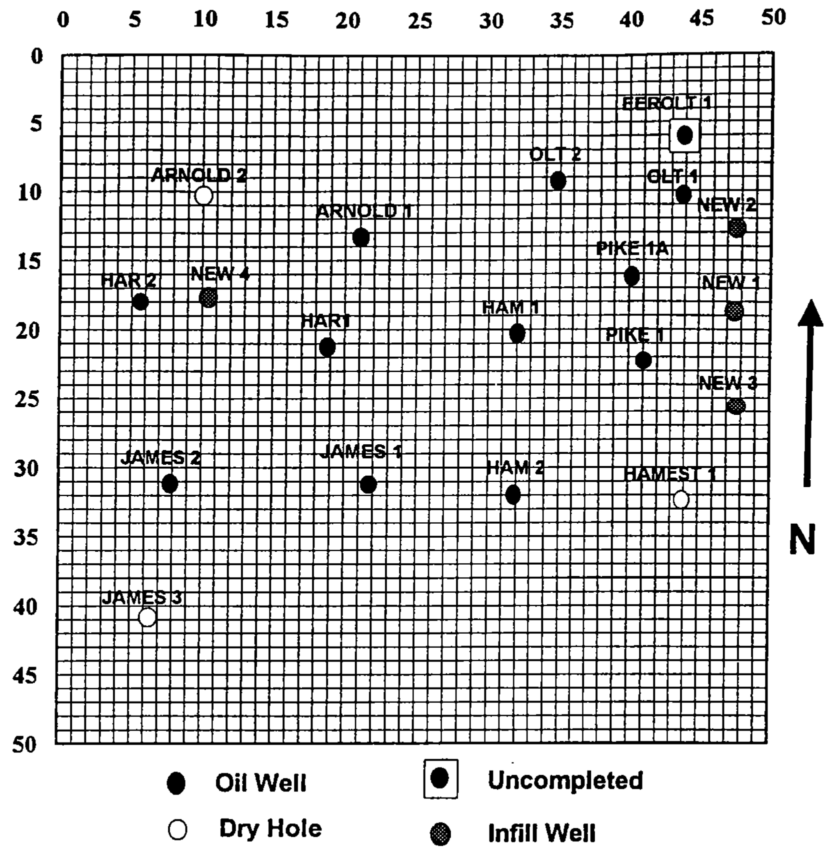

Figure 62. Well locations in 50 × 50 grid system, the East Lake Blackwell field, Payne County, Oklahoma. EEROLT = Earth Energy Resources Oltmanns; HAMEST = Ham Estate; HAR = Harrington; OLT = Oltmanns.

Infill Well Drilling

In addition to the recompletion case changes, four infill production wells, No. 1 New through No. 4 New, were drilled and completed in zones A, B, C, and D, respectively. These new well locations are (48, 19), (48, 13), (48, 26) and (11, 19) in 50 × 50 grid system (Fig. 62) and were selected to be at extreme edges of the four reservoirs to maximize sweep. Production rates were set to be 60–70 BOPD and BHP limits for the infill wells were specified as 500 PSIA. After 10 years of simulated production for this case, the recovery of oil above that of the primary case is expected to be ~29% of OOIP, or 0.75 MMSTB and with additional water production of 1.4 MMSTB (Table 12).

SUMMARY

The estimated original oil in place in the East Lake Blackwell field was 2.6 MMBO. About 12% of that amount has been recovered after 8 years of primary production. The estimated volume of unproduced mobile oil in this field, ~1.4 million bbl or 52% of OOIP, provided a strong motivation for considering future oil recovery opportunities.

Among the alternatives considered for development of the East Lake Blackwell field, base case, well recompletions, and infill wells with recompletions were simulated. The results of the model simulations show that infill wells with recompletions would result in the highest additional oil recovery: 29% of OOIP or 750,000 BO, or ~230% of primary recovery. After the infill well drilling program, the total recovery for both primary and secondary production could be as much as 1,066,000 BO, or >40% of the OOIP.

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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.

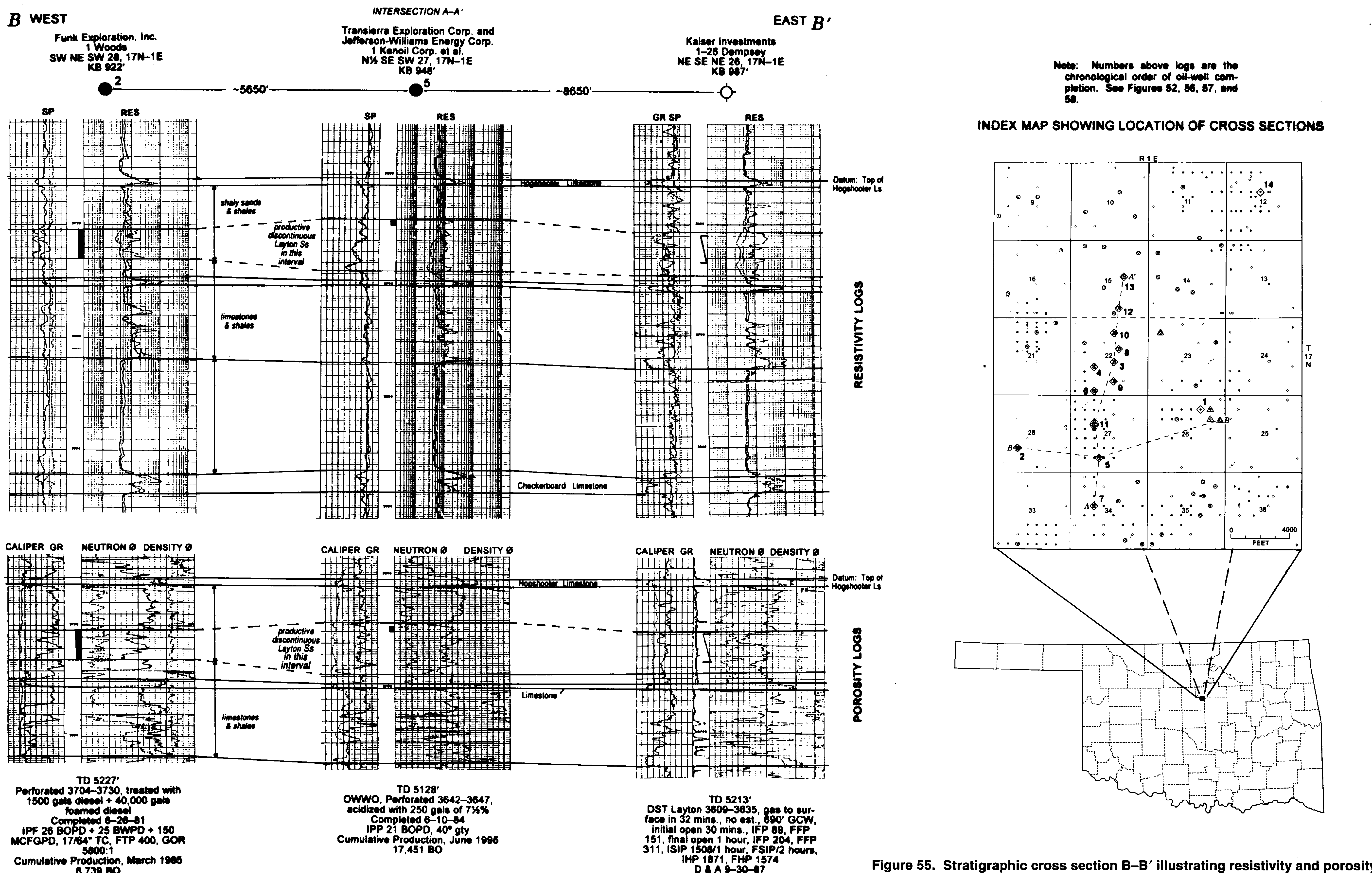

Figure 55. Stratigraphic cross section B–B′ illustrating resistivity and porosity, South Coyle Layton sand reservoir, T. 17 N., R. 1 E., Logan County, Oklahoma.

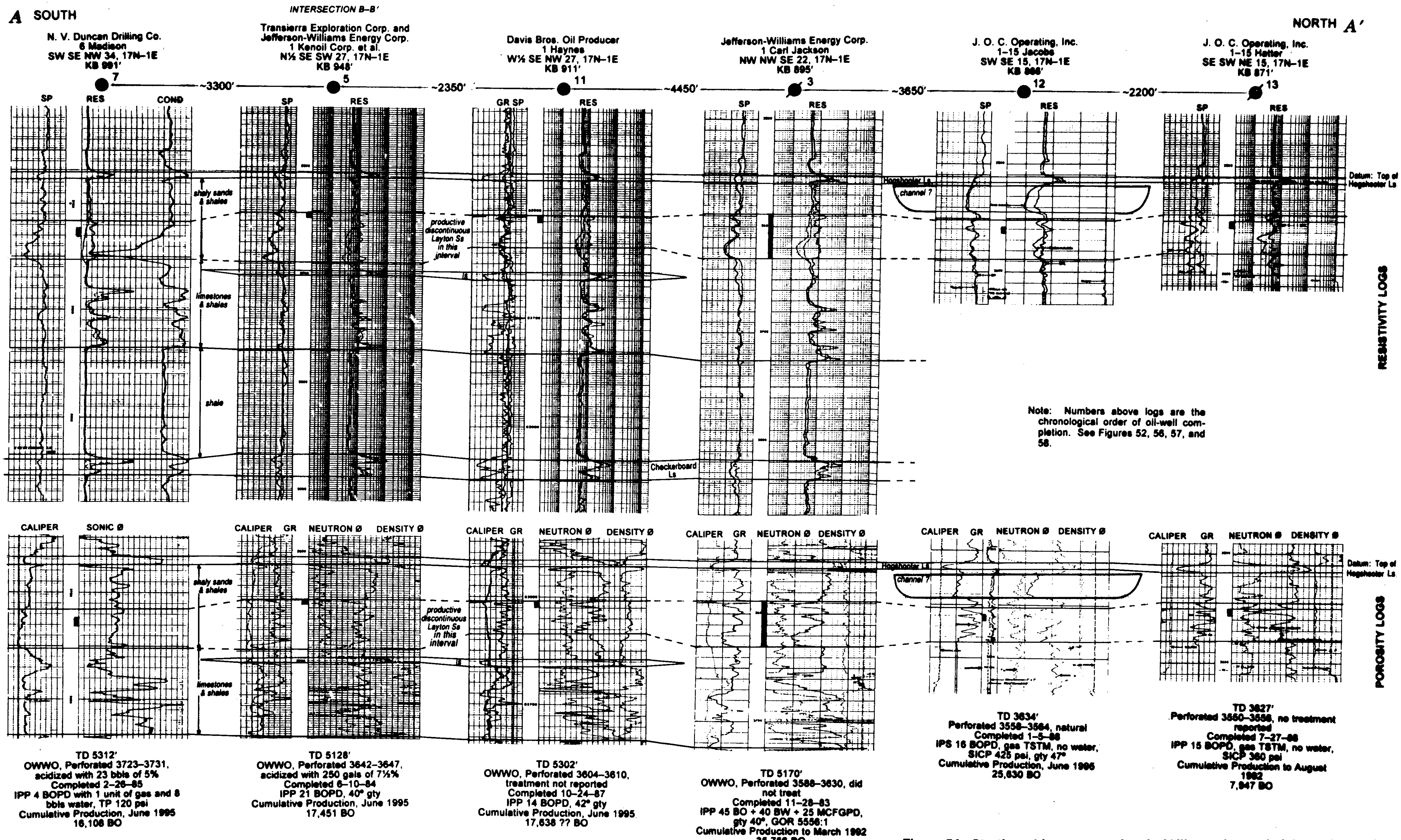

Figure 54. Stratigraphic cross section A–A′ illustrating resistivity and porosity, South Coyle Layton sand reservoir, T. 17 N., R. 1 E., Logan and Payne Counties, Oklahoma. See Figure 55 for index map showing location of cross sections.