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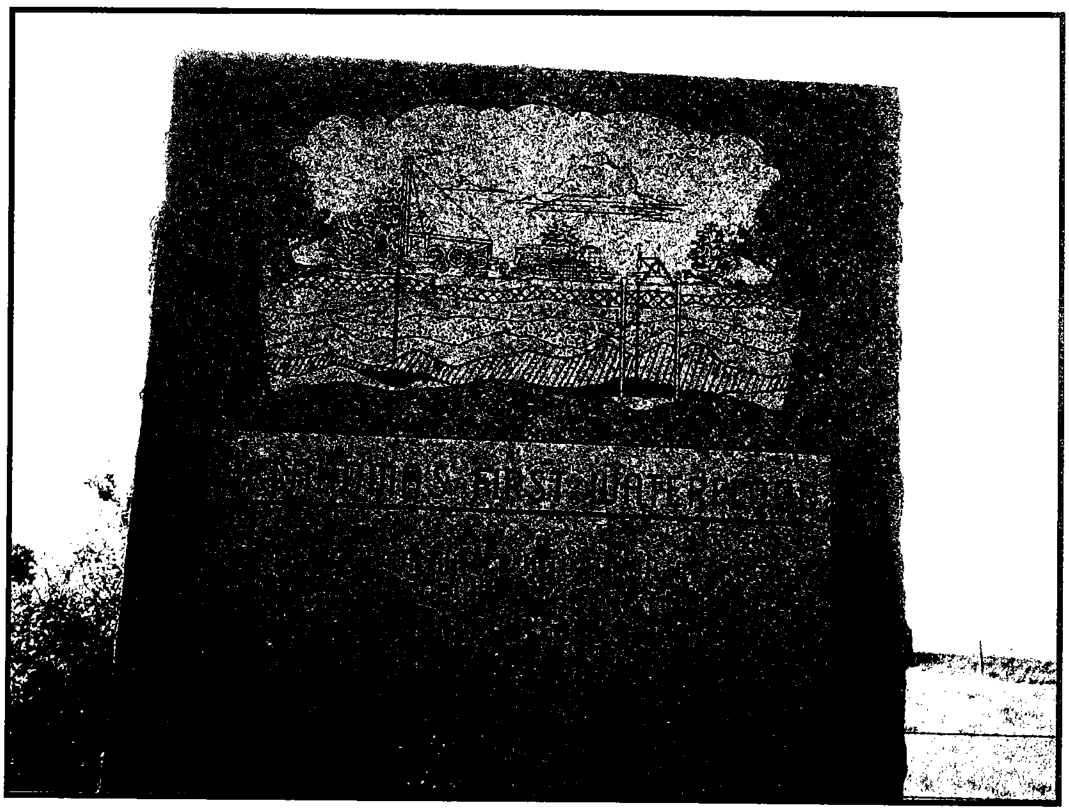
Geological Considerations of Waterflooding: A Workshop



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Geological Considerations of Waterflooding: A Workshop

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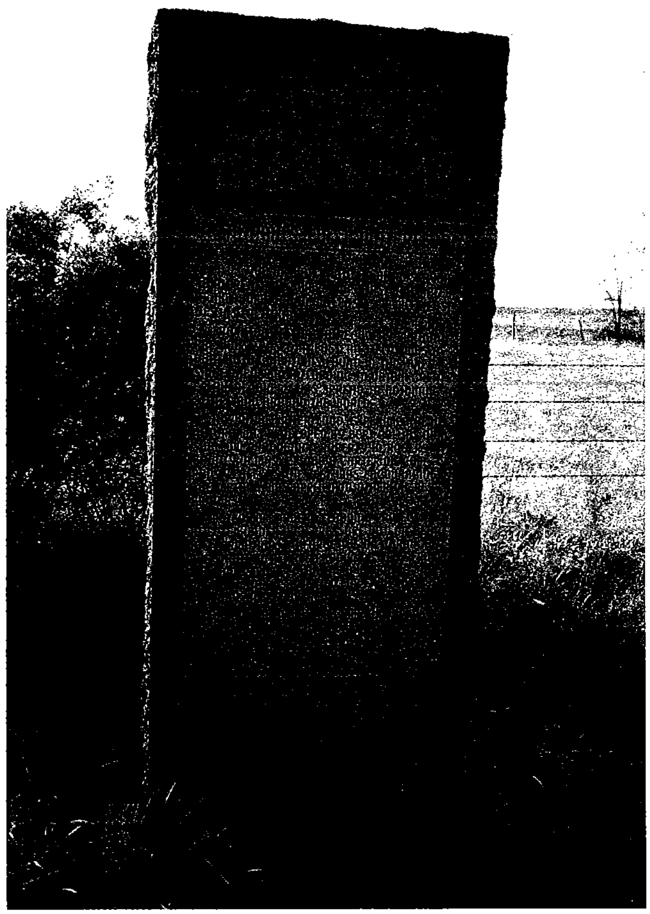

A granite marker commemorates the first waterflood in Oklahoma, attempted in Rogers County in 1931 on an oil lease about 6 mi east of this site. The marker stands at the intersection of U.S. Highway 169 and Winganon Road, south of Nowata and west of Chelsea.

Second Printing
1999

This publication, printed by the Oklahoma Geological Survey, is issued by the Oklahoma Geological Survey as authorized by Title 70, Oklahoma Statutes, 1981, Section 3310, and Title 74, Oklahoma Statutes, 1981, Sections 231–238. 250 copies have been prepared at a cost of $1,633 to the taxpayers of the State of Oklahoma. Copies have been deposited with the Publications Clearinghouse of the Oklahoma Department of Libraries.

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Concepts and Goals of the Workshop

CHAPTER 1

Concepts and Goals of the Workshop

INTRODUCTION

Petroleum geology is composed of two basic components. The first is exploration geology. Exploration geology depends on sound geologic principles, but often these principles are augmented by intuitive experience. Regional "trendology," serendipity, and pure luck probably account for a substantial part of our State's reserves, as do those reserves found from hard, systematic geologic principles. The petroleum industry's risk money allocated for exploration is generally based on the concept that drilling dry holes is unavoidable and acceptable. This rationale differs dramatically from the second component—developmental geology—which includes waterflooding. Developmental geology, and waterflooding in particular, depend on exact calculations, known parameters, and few surprises. Once the waterflood reservoir has been geologically evaluated, the risk money allocated toward its development is based on an economic and successful outcome, which is essential for a company's financial welfare.

The sole purpose of the Oklahoma Geological Survey's waterflood workshop is to familiarize geologists and engineers with those pitfalls that can jeopardize the potential success of a waterflood candidate. The following is a list of the topics that are addressed in this publication:

- Determining reservoir data
- Deciphering production data
- Determining and isopaching net pay
- Defining sand geometry and boundaries
- Implications of structure
- Understanding analogies
- Coring and core results
- Distinguishing natural and induced fractures
- Water-supply evaluation
- Permitting

Another workshop would be needed to deal with engineering concepts such as waterflood design, reservoir models, installation, monitoring, injection and production rates, operations, environmental considerations, and land use.

We hope to persuade the petroleum industry that familiarity with engineering principles by geologists, and geological principles by engineers, is for the ultimate benefit of their companies. The responsibility for the success of a waterflood candidate is not based solely on a geologist's or engineer's evaluation but on the input of their evaluation to the waterflood's economic analysis. If any of these data are wrong, the prodigious up-front capital expense of the waterflood project is in jeopardy, which, for many operators in the Midcontinent, means that the company's financial welfare also is in jeopardy.

HISTORICAL REVIEW

Waterflooding is generally acknowledged to have begun as a result of accidental water injection in the Pithole City area of Pennsylvania in 1865 (American Petroleum Institute, 1960). In 1880, John F. Carll concluded that water introduced into oil sands from shallower sands would be beneficial in increasing oil recovery. Craig (1971) states that many of the early waterfloods occurred accidentally either by casing leaks or by surface water entering the wellbore. The introduction of this water was considered beneficial, because it was thought to help maintain reservoir pressure, thereby increasing oil production.

Probably the earliest attempt at pattern flooding was the practice known as "circle flooding" (American Petroleum Institute, 1960). With this technique, water was injected into a single well, and as the adjacent wells watered out, the watered-out wells were converted to injection to extend the area of water invasion. Forest Oil Corp. modified this technique by converting a line of wells to injection, thus forming a line-drive pattern (Fettke, 1938). Also, in the southern part of the Bradford field of Pennsylvania, the first five-spot pattern was initiated (Frick and Taylor, 1962).

Craig (1971) states that operators were slow to initiate waterflooding operations outside of Pennsylvania. The first waterflood in Oklahoma was initiated in a shallow Bartlesville sand in Nowata County. Within a few years, many of the shallow Bartlesville sands were under flood, and within 10 years, waterflooding was a common practice in most of the State's oil-producing areas.

BRIEF OVERVIEW OF WATERFLOOD PRINCIPLES

A reservoir approaching the end of its primary life may still contain economically recoverable oil. Such factors as drive mechanism, depth, gas saturation, oil saturation, and water saturation obviously will influence the decision to pursue secondary-recovery operations. *Secondary recovery* is defined as production of oil or gas as a result of artificially augmenting the reservoir energy, as by injection of water or other fluid (Jackson, 1997). This publication will cover only pre-reservoir-model issues, which deal mainly with the preliminary geological evaluations of a waterflood candidate and associated problems and pitfalls that might arise.

Many secondary-recovery prospects appear attractive economically because of the amount of primary oil produced; however, their viability really is influenced by the efficiency of the primary depletion. Figure 1 is a chart plotting gas/oil ratios (GORs) versus recovery factor as defined by the ratio of primary oil production to original oil in place. A solution-gas-drive reservoir is probably one of the least efficient primary drive mechanisms, but a reservoir of this drive type could be lucrative for secondary operations because of the higher oil saturations present at depletion, assuming that good development and production practices have been observed.

Conventional waterflood operations involve injecting water into the reservoir to displace mobile oil to the producing wells for recovery. The factors mentioned previously are a few of the major parameters a geologist or engineer must understand and interpret accurately in order to thoroughly evaluate a waterflood candidate. Waterflood types are classified according to the producer-injector pattern established.

Figure 2 (modified from Clark, 1969) is a typical production curve for a solution-gas-drive reservoir during primary- and secondary-production operations. The primary-operations curve starts at time zero, and with field development, the production increases until at some point maximum oil production is reached. Reservoir-pressure depletion occurs, and with it normal production-decline processes occur, until the reservoir is at or near abandonment (step 1). Steps 2, 3, and 4 illustrate major stages for a waterflood project, and these stages are also represented on the decline curve. Figure 3A illustrates a map view of a basic five-spot pattern, and Figure 3B illustrates a cross-sectional view from injector to producer for the reservoir at step 1 in Figure 2. The saturations for this reservoir are typical for a depleted solution-gas-drive reservoir, assuming that the connate-water saturation of 25% is at or near irreducible water-saturation values. The 25% gas saturation assumes that the initial reservoir pressure was at or near the bubble-point pressure and that the reservoir originally had a moderate initial GOR. Of course, the fluids will be dispersed throughout the reservoir, as this is only a schematic representation.

Figure 4A,B illustrates the areal and cross-section views of the five-spot pattern at step 2 on the secondary curve of Figure 2. Water injection has commenced, resulting in displaced oil that has formed an *oil bank*, resaturating the gas pore space and moving oil toward the producer. The water injected forms a bank termed the *water bank*. Ahead of the oil bank, the reservoir is still in the fluid percentage state, which was present prior to injection.

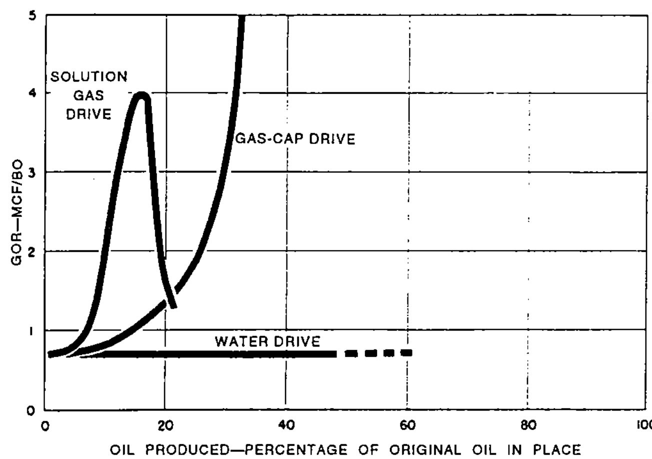


Figure 1. General gas/oil-ratio curves for three primary drive mechanisms. (Modified from Clark, 1969, fig. 70; reprinted by permission of American Petroleum Institute.)

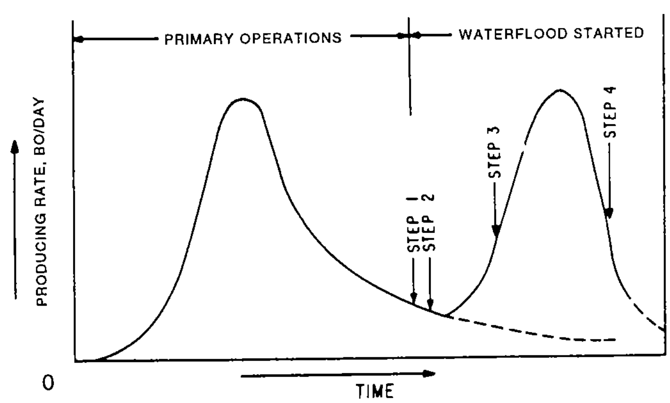


Figure 2. Example of primary- and secondary-production curves for a solution-gas-drive reservoir. (Clark, 1969, fig. 127; reprinted by permission of Society of Petroleum Engineers.)

Figure 5A,B illustrates in areal and cross-section view the five-spot reservoir at *fill-up*, which is essentially that point when the gas pore volume has been filled by either the displacing or the displaced fluids. It is at this point that production from the producer should increase dramatically, as illustrated at step 3 of Figure 2 in response to the oil bank having reached the producer.

Eventually, the water bank will reach the wellbore; this condition is termed *water breakthrough*. Normally, water production increases, and oil production will start to decrease. This stage is illustrated by Figure 6A,B, which represents step 4 on the secondary portion of the production curve of Figure 2. The oil-production rate decreases until it reaches that portion of the production curve represented by the dashed curve (Fig. 2). At this point, the project's lifting and handling costs approximate oil-production income, termed the *productive economic limit*.

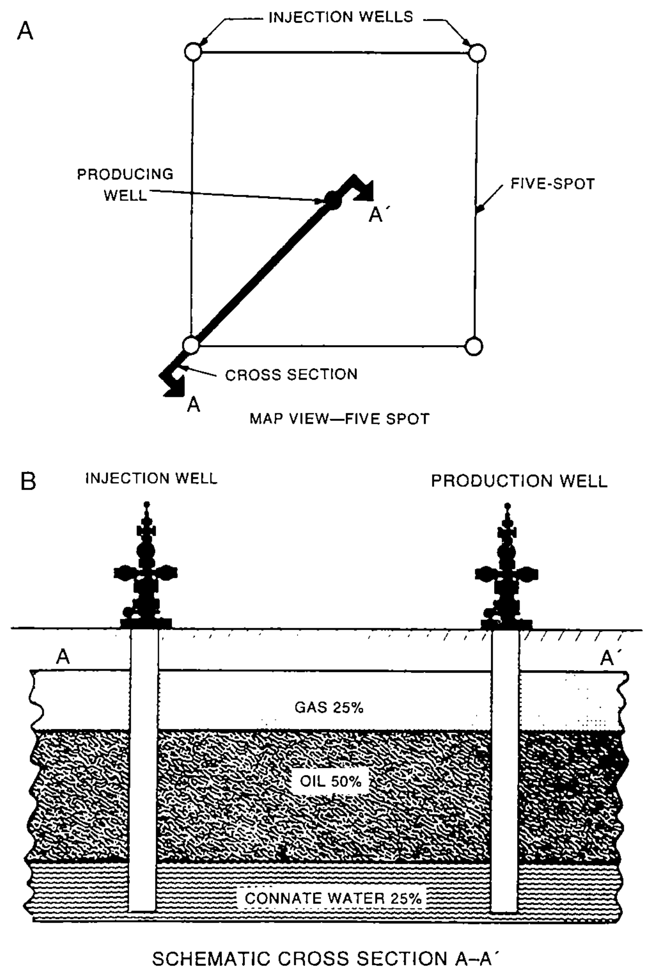


Figure 3. Areal (A) and cross-section (B) views of a five-spot pattern at depletion of reservoir-energy conditions for a solution-gas-drive reservoir. Reservoir condition illustrates step 1 on the production curve of Figure 2. (Clark, 1969, fig. 126; reprinted by permission of Society of Petroleum Engineers.)

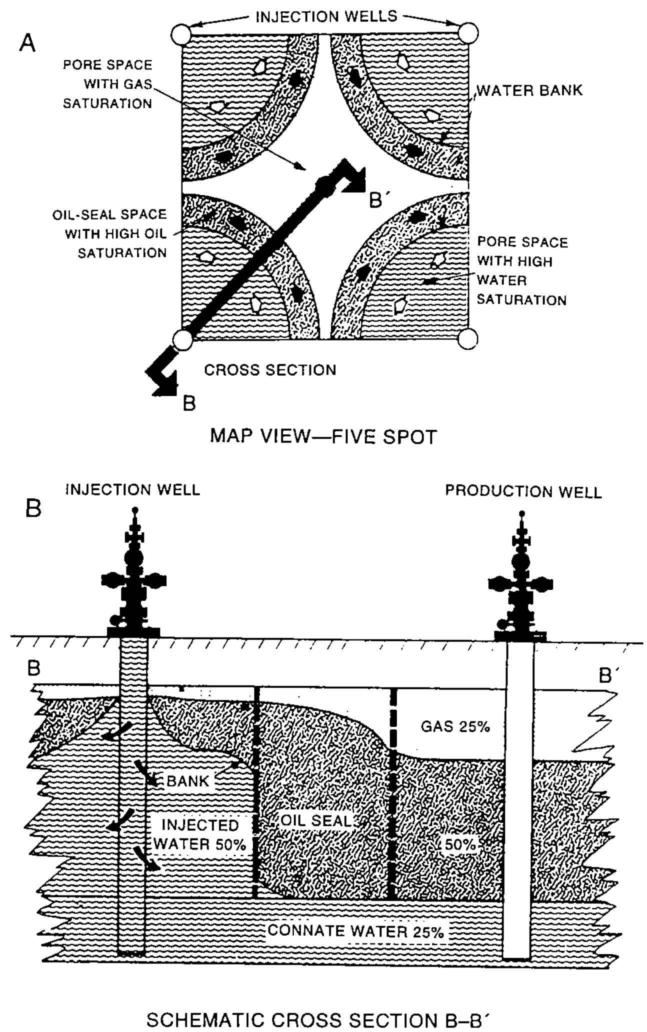


Figure 4. Areal (A) and cross-section (B) views of a five-spot pattern under injection for a solution-gas-drive reservoir. Formation of an oil bank in front of a water bank. Reservoir condition illustrates step 2 on the production curve of Figure 2. (Clark, 1969, fig. 128; reprinted by permission of Society of Petroleum Engineers.)

GOALS OF THE WATERFLOOD WORKSHOP

The current economic climate and the trend toward downsizing force companies to require geologists and engineers to familiarize themselves with subjects other than their own specialties. The Oklahoma Geological Survey recognizes this trend. To date, the Survey's effort has been to broaden geologists' knowledge of various geologic subjects through seminars, workshops, and publications.

The current economic climate has also affected many companies' philosophies and operating procedures. Gone are the days of abundant investor capital or engorged profits from high oil prices. In those days, many internal mistakes were easily absorbed and overlooked. Today, an uneconomic project can jeopardize a company's welfare. Reservoirs discovered and waterflooded in the early days of the petroleum industry were generally those that were of the highest quality and the simplest to produce. Many of the reservoirs under consideration today were not waterflooded in the past because those operators recognized many of the risks involved.

Table 1 is a list of differences between those early reservoirs and those that remain today. Today's reservoirs have many problems that greatly increase the risk of successful secondary ventures. For this reason, this attempt to recognize potential pitfalls is important for operators today. Thus, the goal of this waterflood workshop is to familiarize geologists and engineers with those geological pitfalls that can jeopardize the potential success of a waterflood candidate.

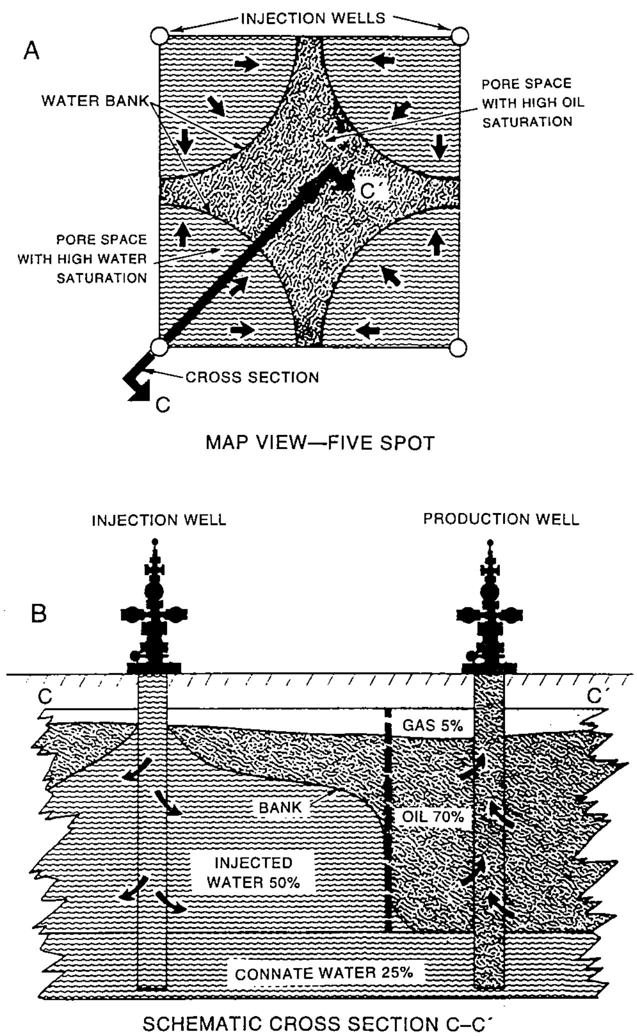


Figure 5. Areal (A) and cross-section (B) views of a five-spot pattern at fill-up for a solution-gas-drive reservoir. Reservoir condition illustrates step 3 on the production curve of Figure 2. (Clark, 1969, fig. 129; reprinted by permission of Society of Petroleum Engineers.)

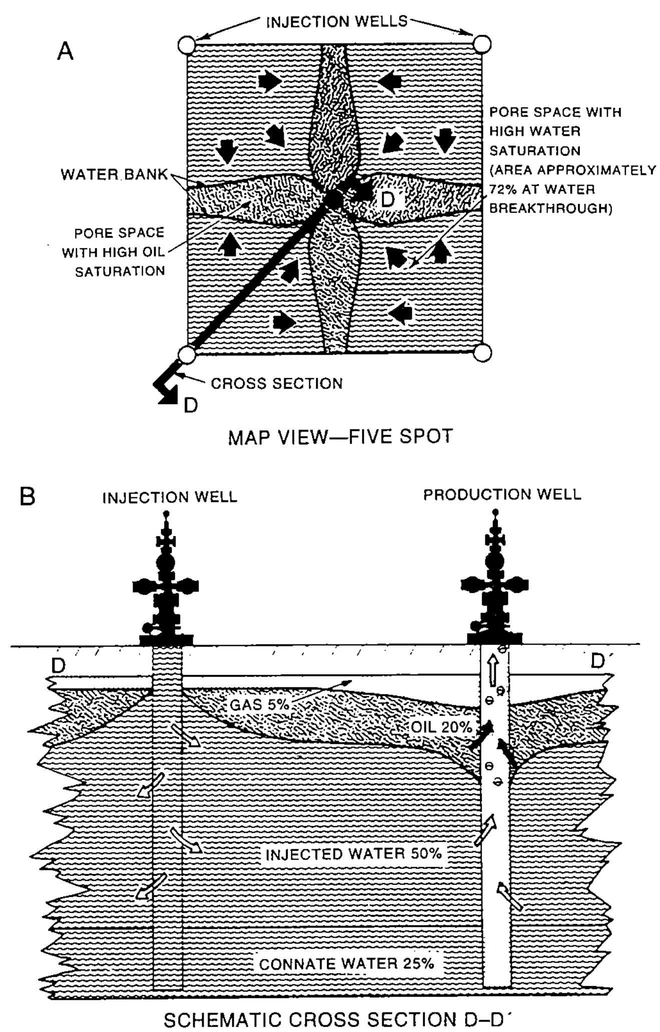


Figure 6. Areal (A) and cross-section (B) views of a five-spot pattern near abandonment. Reservoir condition illustrates step 4 on the production curve of Figure 2. (Clark, 1969, fig. 130; reprinted by permission of Society of Petroleum Engineers.)

One of the most important concepts a company can learn—a pitfall to avoid—is the importance of eliminating knowledge segregation that tends to exist between internal departments. The following true examples of the lack of interaction between the geological and engineering departments actually occurred.

A certain oil company's geological department became interested in a field they thought might be a waterflood candidate (Fig. 7). They apparently proceeded on the assumption that since only 20 million barrels of oil (MMBO), of a total of 100 MMBO in place, had been produced, the remaining 80 MMBO should be sufficient to supply some secondary reserves for the waterflood prospect. The department spent about 1 man-year of time and energy evaluating the project. On completion of the evaluation, the project was turned over to the engineering department for their input (Fig. 8). By using the parameters supplied for this prospect and plugging the data into the formula for current oil saturation, it was determined, within an hour of work, that there was not enough remaining oil to waterflood because of the high shrinkage of the oil. One man-year of effort was thereby wasted.

Waterflood-evaluation failures are not limited to a geological department's inability to evaluate a project correctly, as the following true example illustrates.

An engineering department acquired a waterflood project and proceeded to install a waterflood unit without an in-depth consultation with the geological department. The geology did not seem complicated, as the apparent pay zone had practically the same subsea values throughout the reservoir. After several years of injection with an almost total lack of response, the geological department was given the task of ascertaining why this response was lacking (Fig. 9). After a few days of analysis, it became readily apparent that the struc-

TABLE 1. – Conceptual Differences Between Reservoirs of the Past and Today

Subject	Historical	Present day
Depth	Shallow, commonly in simple drilling environments	Medium to deep; may require advanced drilling techniques
Reservoir size	Large reservoirs with well-defined gas caps and oil columns	Smaller, commonly with higher water saturation, higher GOR
Discovery difficulty	Surface features indicate structure; generally large, obvious subsurface structures	Deeper structures require advanced interpretation techniques; environment of deposition critical to field development
Reservoir quality	Generally larger, cleaner, well-sorted high permeability and porosity; low GOR	Shalier, siltier, lower permeability and porosity; medium to high GOR
Economics	Large reservoirs with large reserves, yielding high profit margins	Smaller reservoirs, yielding lower profit margins

Actual example of the lack of engineering fundamentals employed by the geological department

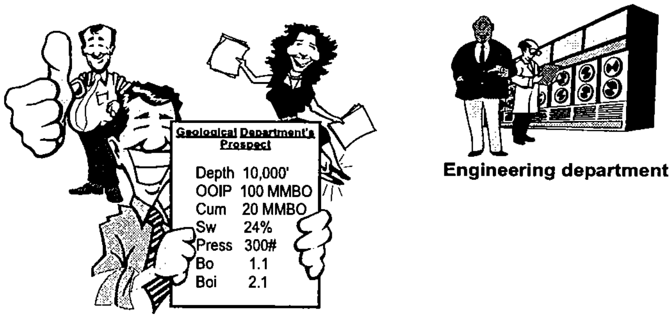


Figure 7. Geological department's 1 man-year of effort.

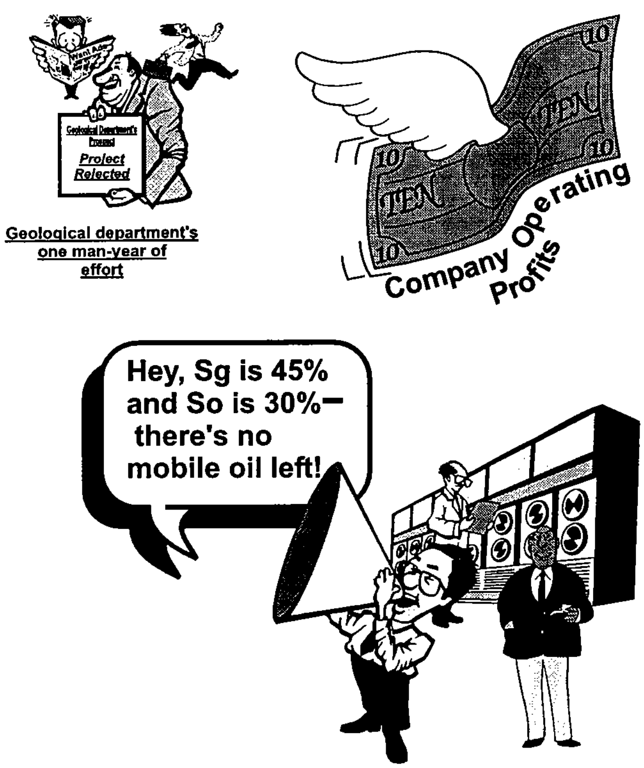


Figure 8. Engineering department's 1-man-hour evaluation killed the prospect from the geological department.

ture, and the corresponding correlation of the pay zones, were considerably more complex, and that the pay zones had been grossly miscorrelated. To enable communication between the injectors and producers, the field would require drastic conversion of the well patterns (Fig. 10). The conversion recommended would require considerable capital expense—enough so that it was questionable whether the changes would be economic.

These two examples illustrate the effect that the lack of cooperation and communication between internal departments can have on a company. The Oklahoma Geological Survey hopes to persuade the petroleum industry that familiarity with engineering principles by geologists and geological principles by engineers is to the industry's benefit. Thus, the mindset that the geological department or the engineering department is solely responsible for the success of a waterflood project can be a costly one. The success of a waterflood candidate is not based on a geologist's or an engineer's evaluation but on the evaluation of the waterflood project's economic analysis (Fig. 11). The goal of this workshop is not to teach waterflooding principles but to point out pitfalls that can arise when evaluating the geological aspects of a waterflood candidate. These pitfalls, if undetected, will contribute to wasted capital expense or lost income that could deplete the margin of profit for the project and affect even the economic viability of the company.

PRINCIPLES THAT WILL AND WILL NOT BE ADDRESSED

The growth of a waterflood prospect, from conception to abandonment, can be divided into two primary phases.

The first phase deals with the initial analysis up to the development of the reservoir model for the waterflood candidate. This phase is heavily geologically oriented.

The second phase deals with the development of the reservoir model to the abandonment of the project.

Actual example of the lack of geological fundamentals employed by the engineering department

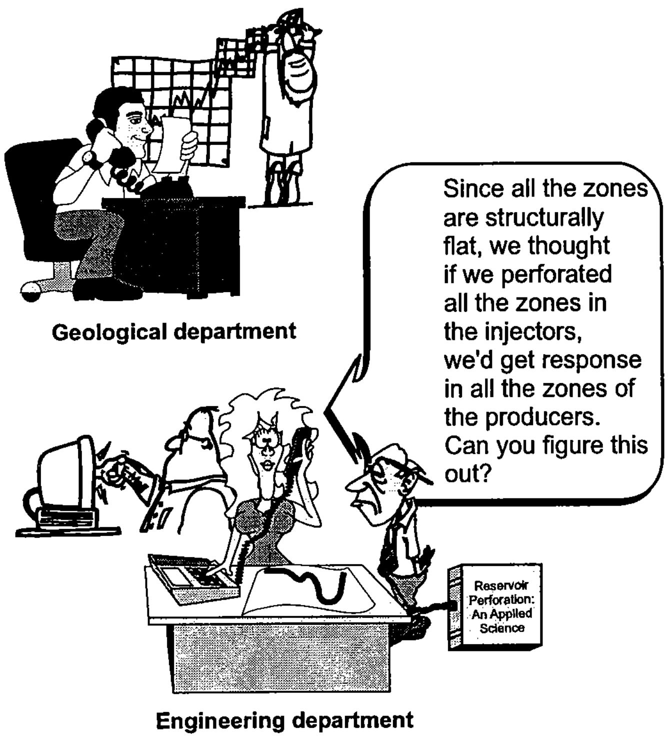


Figure 9. The engineering department could not figure out the reason for the lack of response in the waterflood project they acquired.

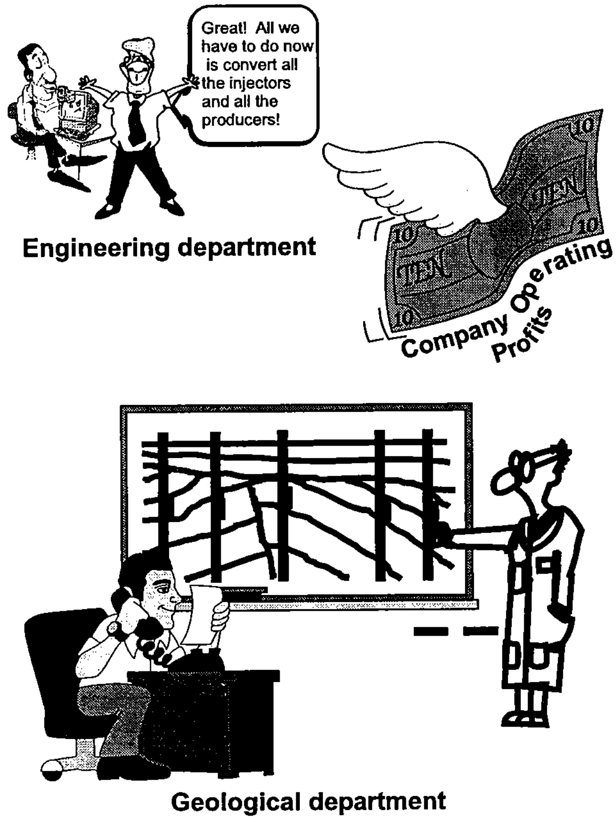


Figure 10. The geological department ascertains the reason for the lack of response in the waterflood project installed by the engineering department.

This phase is heavily engineering oriented.

This workshop presents the pre-reservoir model, which is geologically oriented. Another workshop would be needed to present the post-reservoir model, which would be engineering oriented.

Basic geologic principles, such as electric-log interpretation and normal geological routines and practices normally conducted during the course of business, will not be discussed. It is assumed that the geologist or engineer will be familiar with those basic concepts. This workshop will deal with practical situations that a geologist or engineer may face during the course of the geologic portion of a waterflood-project evaluation that could determine the economic success of the project.

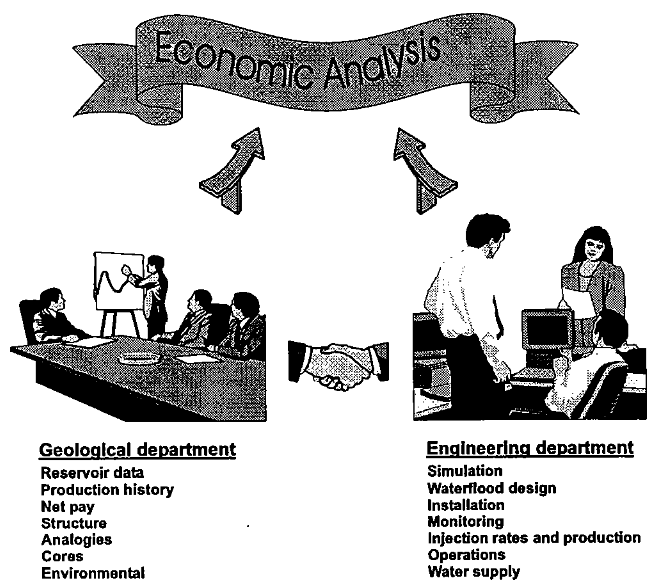


Figure 11. The geological and engineering departments are responsible for their respective contributions to the economic analysis of the waterflood project.

METHOD FOR ADDRESSING PRINCIPLES

The examples used in this workshop are those familiar to the author and those that have been contributed by operators for use in this publication. The practice of confidentiality will be observed for all examples. If readers wish to pursue additional information for any of the examples, they may contact the author, who will seek permission from the contributing operator to release additional data.

Figure 12 is the tabular and graphical representation of various geological and engineering variables from a reservoir that will be used as the reference reservoir for this workshop. This reference reservoir is an actual field in central Oklahoma. Detailed and accurate

Miscellaneous

Pi	2,156 psi
P	265 psi
Depth	4,950 ft
P-grad	0.436 psi/ft
T	117 °F
k	30 md
Oil Grav	40.0 °API
Gas Grav	0.75
NaCl %	0.0%

Material Balance

N	1,263,225 stbo	
G	2,706 mcf	
m	0.00	
Gas Cap %	0.2%	
SGDI	99.14%	217,703 stbo
GCDI	0.48%	1,046 stbo
WDI	0.00%	0 stbo
PVCI	0.39%	851 stbo

PVT Data

Condition	Initial	Current	BP
P (psi)	2,156	265	1,687
Rs (scf/stb)	475	53	475
Bt (cf/stb)	7.02	30.75	7.06
Bo (rb/stb)	1.2502	1.0583	1.2572
μo (cp)	0.9306	2.5215	0.8873
Co (1/psi)	1.194E-05	2.232E-03	1.525E-05
Bg (cf/scf)	0.0056	0.0588	0.0073
μg (cp)	0.0189	0.0116	0.0162
Cg (1/psi)	4.407E-04	3.597E-03	4.967E-04
Bw (rb/stb)	1.0071	1.0098	1.0078
μw (cp)	0.5724	0.5724	0.5724
Cw (1/psi)	3.326E-06	3.242E-06	3.318E-06

Volumetrics

N	1,263,313 stbo	A	252.90 ac
G	2,706 mcf	ø	12.5%
		Sw	25.0%

	Total	Oil	Gas
h (ft)	8.6	8.6	0.0
Vb (ac-ft)	2,175.20	2,171.52	3.68
Vp (ac-ft)	271.90	271.44	0.46
Vphc (ac-ft)	203.93	203.58	0.35

Reserves

	stbo	bpaf	Rf
Np	219,600	101.13	17.4%
Nwf	157,066	72.33	12.4%
Nult	376,666	173.46	29.8%
N	1,263,313	581.76	100.0%

Gp	504,036 mcf
G	2,706 mcf
Wp	0 bw
We	0 bw
Rp	2,295 scf/stb
Nwf/Np	0.72 to 1

Waterflood

Vb flood	1,492.10 ac-ft	Vb flood	68.7%
Inj Rate	1,000 bwpd	Ea	72.0%
V fillup	478,967 bw	Ev	72.0%
t fillup	1.31 yrs	Ed	42.5%
Sor	30.0%	Et	22.0%

Oil Column Conditions

	Initial	Current
Sw	25.0%	25.0%
So	75.0%	52.2%
Sg	0.0%	22.8%

Comments:

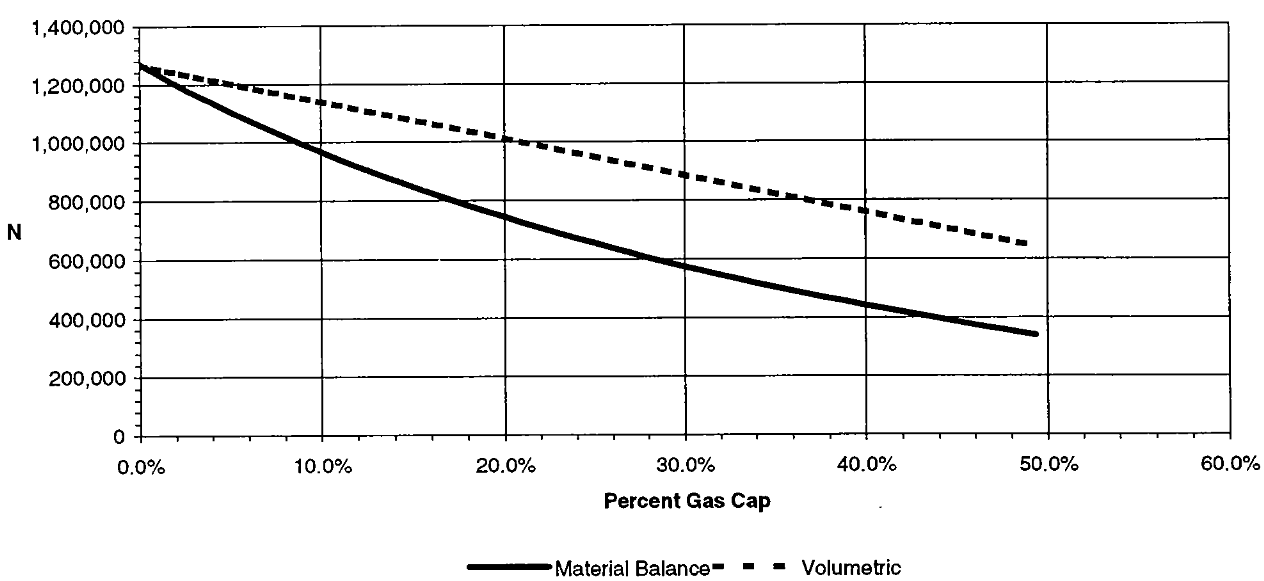


Figure 12. Example of reservoir model used in this publication. The model illustrates various geological and engineering input and output variables for an actual reservoir used as a reference in central Oklahoma. See Appendix 1 for explanation of abbreviations.

TABLE 2. – Geologic and Engineering Formulas Used in This Report

Original oil in place	$\text{OOIP} = \dfrac{7{,}758 \cdot \phi \cdot A \cdot H \cdot (1 - S_w)}{B_{oi}}$
Gas/oil ratio	$\text{GOR} = \dfrac{\text{Initial potential gas, CF}}{\text{Initial potential oil, BO}}$
Cumulative gas/oil ratio	$\text{Cum GOR} = \dfrac{\text{Cumulative gas, CF} - \text{gas reinjected}}{\text{Cumulative oil, BO}}$
Recovery factor	$\text{RF} = \dfrac{\text{Cumulative oil produced}}{\text{Original oil in place}}$
Current oil saturation	$S_o = (1 - N_{pp}/N) \cdot (B_o/B_{oi}) \cdot (1 - S_{wc})$
Average gas/oil ratio	$\text{GOR}_{avg} = \dfrac{\Sigma\ \text{GOR}_{individual} \cdot Q_{individual}}{\Sigma\ Q_{individual}}$
Acre-feet	$\text{Acre-ft} = \text{Reservoir acres} \cdot \text{reservoir average height}$
Effective decline rate	$D_e = \dfrac{qi - qt}{qi}$

Note: See Appendix 1 for explanation of abbreviations.

production and pressure data are known. The volumetric and material-balance original-oil-in-place calculations are almost identical. This reservoir model will be used occasionally in this publication. It illustrates how changes of various reservoir parameters affect the output of the known reservoir's parameters.

Table 2 represents the predominant formulas that are used in this publication. A list of the abbreviations and definitions for these variables is included in Appendix 1.

2

Evaluating Preliminary Reservoir Data

CHAPTER 2

Evaluating Preliminary Reservoir Data

INTRODUCTION

Generally, the first step that a geologist or engineer takes with a new waterflood candidate is the evaluation of reservoir data. This evaluation should occur in two phases.

First, the geologist or engineer undertakes a cursory review of initial production potential, gas/oil ratios (GORs), the amount and type of water production, pressure information, and core information. If this initial review meets the evaluator's criteria for a potential waterflood prospect, a second, more thorough review of data for pressure, volume, and temperature (PVT) for the reservoir should be initiated in cooperation with the engineering department. These data types are critical to the evaluation of the waterflood candidate.

This publication does not deal with such topics as methods of calculating water saturations, acceptable or unacceptable water-production limits, or advanced PVT data such as viscosity. This publication does illustrate potential pitfalls that might arise when the evaluator initiates this first-phase review. If the following criteria are favorable, the waterflood candidate should be examined in further detail.

INITIAL-PRODUCTION EVALUATION—DETERMINING GOR

One of the most important initial evaluations of a waterflood candidate is determining whether the candidate is an oil or a gas reservoir. This is done by examining initial-production records for each of the wells in the reservoir. The *initial production* (IP) for a well is defined as the volume or quantity of oil or gas that a well produces or is capable of producing during the first 24 hours after completion (Jackson, 1997). The IP of a well describes the fluid characteristics of the reservoir affected by the wellbore. Water potentials are usually reported along with the oil and/or gas potentials and are an important aspect of the evaluation. The IP can be expressed as the *gas/oil ratio*, or GOR. This ratio is defined as the quantity of gas produced with oil from an oil well, usually expressed as the number of cubic feet of gas per barrel of oil (Jackson, 1997). M. B. Standing (1977) describes a multi-component system (dissolved gas in oil) produced through surface equipment, as "gas-oil ratios less than 2,500 cu ft per bbl. The indicated 2,500 cu ft per bbl solution gas-oil ratio represents approximately the maximum amount of gas that can be dissolved in oil at pressures up to about 10,000 psi. The tank oil normally is deeply colored, and the gravity may be as high as 45° API." Standing describes a gas-condensate system as "production of a condensate system through surface traps [that] usually results in gas-oil ratios greater than 5,000 cu ft per bbl and tank oil gravity between 45° and 70° API. (The figure 5,000 cu ft per bbl assumes production of only vapor from the reservoir. The production of both vapor and liquid from a reservoir to give 5,000 cu ft per bbl (or more) does not necessarily indicate a condensate system.) The tank oils usually are white or only slightly colored. A definition of the upper value of the gas-oil ratio of a gas-condensate system is arbitrary; usually a system having a ratio greater than 100,000 cu ft per bbl (0.43 gal per MMCF) is considered a dry gas."

The definitions above can describe a well's (or a field's, on the basis of cumulative production information) oil or gas classification.

In Oklahoma, the Codified Rules of Practice of the Oklahoma Corporation Commission classify a gas well, for allowable purposes, as having a GOR of 15,000/1 or greater. An oil well is classified as having a GOR of less than 15,000/1. If the well has been completed in multiple zones, each zone of the completion is classified separately for allowable purposes. If production from the well is commingled, the classification of the well, for allowable purposes, is determined by the GOR of the commingled production. This definition is for the purpose of classifying a well for production or allowable purposes and really does not address the physical make-up of the fluids in the reservoir. For example, if the well's production is commingled and has a GOR of 16,000/1, it is classified as a gas well even though one producing zone may be a low-GOR oil reservoir and another zone a dry-gas reservoir, giving this ratio for the commingled production.

The ideal waterflood candidate should have low GORs. Personal experience suggests that reservoirs with cumulative GORs of less than 3,000/1 should be sought. Gas reservoirs do not make favorable waterflood candidates because of the lack of sufficient oil to bank. However, in many reservoirs the GORs vary, owing to fractionization of the fluids in response to structural inclination or to drilling date with respect to discovery date. The variability of the GOR for a well within a reservoir can also increase with the number of isolated layers perforated and the commingling of the different fluid saturations from each layer. Detailed stratigraphic correlation should be able to distinguish the types of fluids coming from various zones. Often, however, the GOR for a reservoir may seem to be extraordinarily high or low for unknown reasons. Consider the following two cases of enigmatic GORs.

Case history 1 (Fig. 13) illustrates a reservoir in central Oklahoma whose log characteristics suggest a single uniform channel deposit. The operator's pressure data indicate that all the wells are producing from the same reservoir, with continuous horizontal and vertical permeability. This reservoir is paradoxical, however, with respect to the structural position of the wells with the highest GORs. Well D's pay zone is the lowest structurally in the reservoir, but it has the highest GOR. Well E, the discovery well, is classified as almost a gas well. The initial evaluation of this reservoir, based on the first two GORs, would probably suggest that it is too gassy to waterflood. Another approach to evaluate a reservoir's GOR is to use an average well ratio or a field ratio. The average-well GOR for the reservoir is not the arithmetic average value of the individual well ratios but is obtained by dividing the total gas IP of all wells by the total oil IP of all wells (Frick and Taylor, 1962). The formula for this expression is given in Table 2. The average GORs for the seven wells (Fig. 13, *A–G*), using this method, is 5,209/1. This value is fairly high for an oil reservoir.

A more accurate method of analyzing the GOR for the reservoir, however, is to determine the cumulative GOR. This determination is made by dividing the cumulative produced gas (in cubic feet) by the cumulative produced oil. By using this method, the cumulative GOR is found to be 4,765/1. The comparison of a GOR of 5,200 by using the average-well method, with a GOR of 4,765 by using the field average, is not a large difference. Both methods, however, suggest that the reservoir contained a significant amount of oil, as Figure 14 illustrates, with the response to injection having occurred in this field 14 months after injection commenced. In this example, the IP GORs for the first two wells drilled in the field, especially with consideration

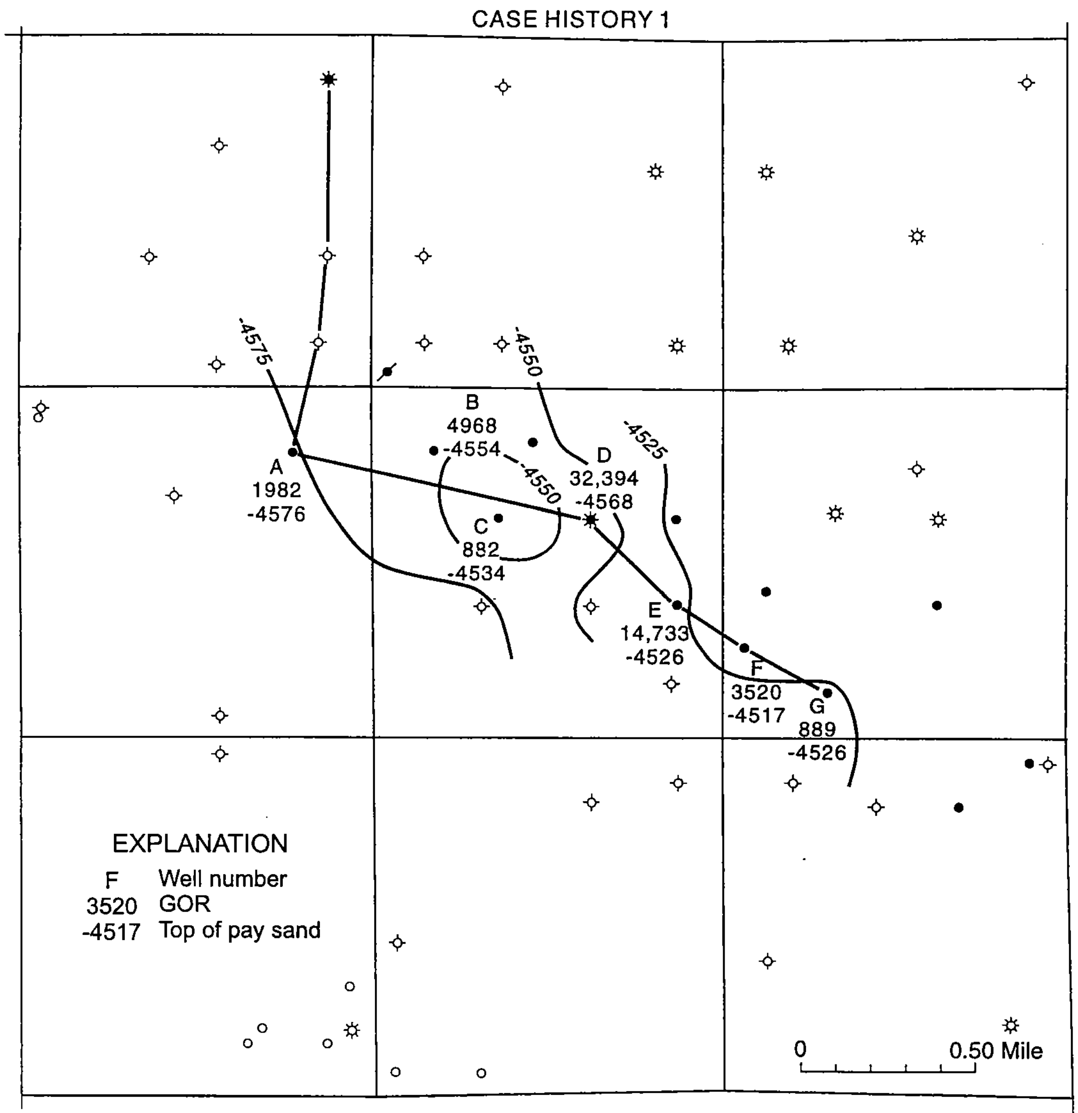


Figure 13. Gas/oil-ratio data for the reservoir of case history 1 (central Oklahoma).

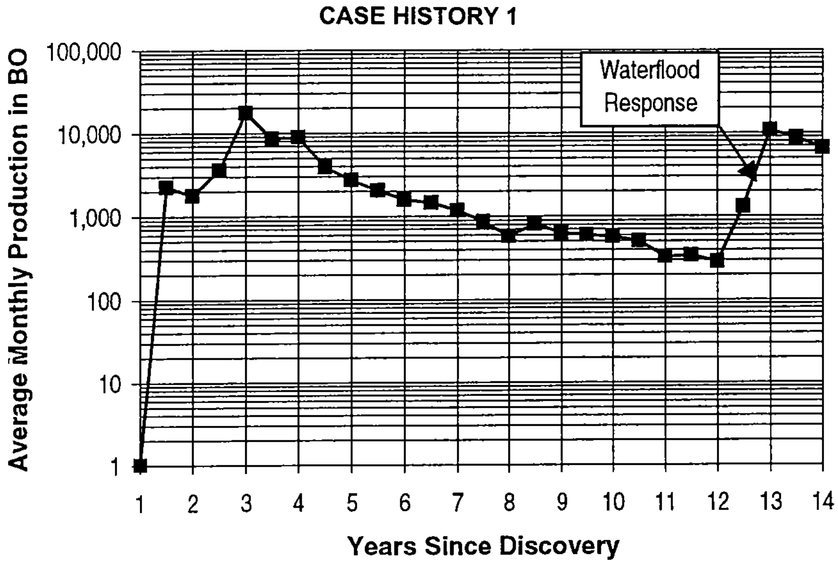


Figure 14. Production curve for the reservoir of case history 1. *MBO* = thousand barrels of oil.

of their structural position, suggest that the reservoir was too gassy to waterflood and that the reservoir was a borderline gas field. However, the average-well GOR and the cumulative GOR indicated the reservoir to be an oil field with solution gas. This is an example of how the IP GORs might not reflect the true ratios of a multicomponent system.

Sometimes a reservoir's GORs, on a per-well basis, might suggest that the reservoir's fluid saturations are in the realm of an oil field. Consider the reservoir illustrated in Figure 15 (case history 2). The IPs of all the wells but one are classified as oil wells. Well J is close to being classified as a gas well, with a GOR of 13,333/1. The remaining wells generally have GORs of less than 3,333/1. The average GOR of all the wells, including the gas wells, is 3,415/1, which is significantly less than the average-well GOR for case history 1 (Fig. 13).

At first glance, this reservoir would seem to be a reasonable candidate for waterflooding, but the cumulative GOR calculation is 7,000/1, which is probably marginally high for a waterflood candidate and more than 50% higher than the cumulative GOR for case history 1. Also, the difference between the average-well GOR of 3,415/1 and the cumulative GOR of 7,000/1 is significant. The cumulative GOR probably is closer to representing the actual ratios of the components than the average well GOR because of effects of completion techniques, depletion, and other unknown variables. Well M (Fig. 15) was converted to an injector, and after approximately 200–250 barrels of water per day (BWPD) was injected, well K responded with an increase of water production to ~70 BWPD with no oil. This breakthrough of water with a lack of oil could be due to the high gas saturation and low oil saturation, suggested by the cumulative GOR for the reservoir. Figure 16 shows the primary production curve for the field.

Case histories 1 and 2 exhibit properties similar to those of many reservoirs under consideration for waterflooding today. Both have portions of the reservoirs that might contain free gas. The IP GORs for case history 1 indicate that the reservoir is too gassy to waterflood, and the IP GORs for case history 2 indicate it to be a likely waterflood candidate. The cumulative GOR for each field, however, indicates that the opposite conclusion should be reached.

The cumulative GOR for a field is a good indicator of its waterflood potential only if it is an oil reservoir. Free gas is associated with the reservoirs in case histories 1 and 2, which might or might not have an effect on the performance of the flood. If a gas cap is not differentiated, the cumulative GOR for the field may be more accurate in determining the presence of free gas than either the individual or the field average IP GOR. In a reservoir with a well-defined gas cap, the cumulative GOR for the field would not be an appropriate indicator. Consider case history 3 (Fig. 17). This shows a portion of a field with a well-defined gas–oil contact. Those wells above the gas–oil contact have a GOR of 30,000/1 or greater. The wells below the contact have a GOR of 5,000/1 or less. Notice how the GORs decrease downdip from the gas–oil contact. This is due to thin stringers of sand that are gas saturated, production from which is commingled with production from sand that is predominantly oil saturated.

Table 3A gives a comparison of the cumulative GOR for the oil column and gas cap at depletion of the reservoir. The cumulative GOR for the oil column is 2,895/1, which is clearly in the realm of an oil reservoir, and the cumulative GOR for the gas cap is 47,288/1, which is clearly a gas-cap reservoir. The cumulative GOR for this portion of the field, however, is 4,559/1. If this were a submitted prospect, and only the field cumulative GOR was included, any effort spent in evaluating this reservoir could be wasted by assuming that the entire reservoir was oil productive. This waterflood project might be abandoned if, for example, the gas cap in the reservoir were seven times as large. The production figures would then be represented by Table 3B. Now, the cumulative GOR for the field is more than 15,000/1, which means that the field is classified as a gas reservoir even though a significant portion of the reservoir is a viable waterflood candidate. A general rule of thumb may be applied here. If a gas–oil contact is established for a field, the field cumulative GOR is not appropriate when evaluating waterflood potential. Only the cumulative GOR for the oil column should be considered. If a field does not have a clearly defined gas–oil contact, then the field cumulative GOR would be appropriate for evaluating the waterflood potential of the reservoir.

The relationship of a well's IP GOR to time is also important to understand. In fact, geologists and engineers cannot arbitrarily define a well's GOR without considering the relationship of time. Prior to production, gas is dissolved in the oil, and this saturation is stable. If free gas is in the reservoir, the oil is considered to be saturated. If free gas is not available in the reservoir, the reservoir is considered to be undersaturated. Figure 18 shows a typical performance curve of the GOR surface ratio and the reservoir ratio for a solution-gas-drive reservoir. At the beginning of production, the producing GOR is roughly equivalent to the solution GOR. The reservoir GOR is at or near zero, because all the gas in the reservoir is dissolved in the oil, leaving little or no free gas in the oil column. The surface GOR represents the actual amount of produced gas divided by the volume of produced oil at initial conditions. As reservoir pressure drops and gas breaks out of solution in the reservoir, both the surface and the reservoir ratios start to increase. The surface or producing GOR increases, because the gas that breaks out of solution in the reservoir flows more easily to the wellbore and is produced along with gas being liberated from oil in the wellbore. This increased amount of produced gas in comparison to the produced oil increases the surface or produced GOR with respect to time. If the geologist or engineer evaluates the well's GOR after the well has started to pressure deplete, only a substantially higher GOR would be observed, not the initial GOR. Some gas remains in the reservoir, which increases the reservoir's GOR over time. As the pressure depletes in the reservoir, the liquids cease to flow, and the surface GOR will reach its maximum value; the gas-production rate will also start to drop, until eventually the surface GOR will drop to its final value. At this point, the reservoir's GOR is at its highest value, because, at depletion, the oil volume has reached its smallest value in comparison to the gas volume.

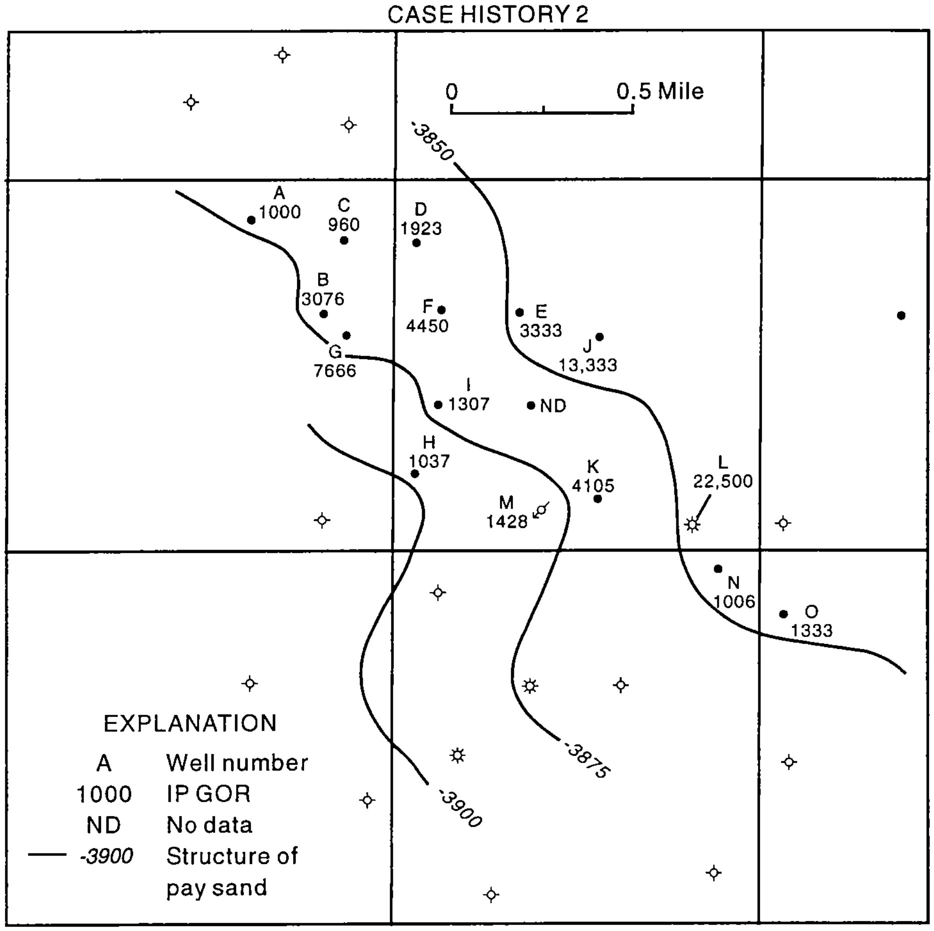


Figure 15. Gas/oil-ratio data for the reservoir of case history 2 (northern Oklahoma).

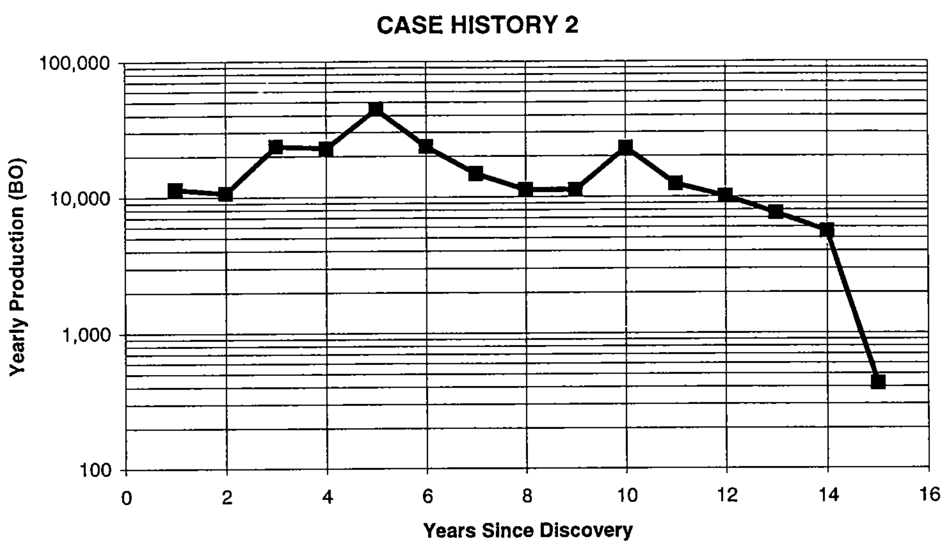


Figure 16. Production curve for the reservoir of case history 2.

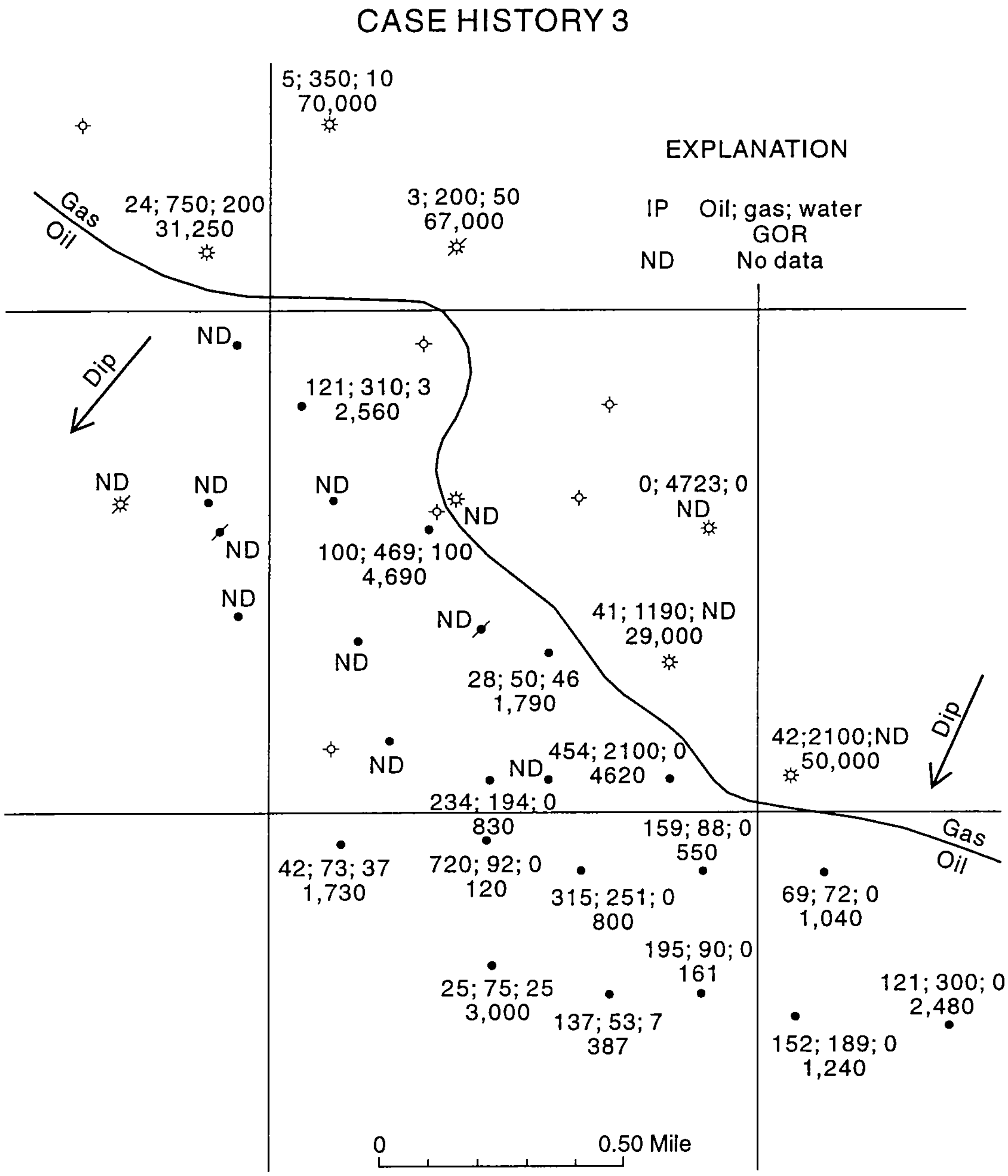


Figure 17. Oil-, gas-, and water-production data and IP GOR for part of the reservoir of case history 3 (central Oklahoma).

The shape of the surface GOR curve (Fig. 18) is useful in determining what the initial GOR for a reservoir should be. This curve should be created for every field under consideration as a waterflood candidate in order to determine the initial GOR. Case history 3 (Fig. 19) is a scatter plot of IP GORs for a field from time zero through 36 months of production after discovery. The solid line, which represents the approximate best-fit curve of the GORs, is similar in shape to the first third of the surface-ratio GOR curve of Figure 18. The initial GOR for the field is represented by that point on the curve of Figure 19 that intersects the *y* axis at time zero.

The determination of initial or cumulative GORs is impossible to calculate accurately for reservoirs from which gas production has been reported only partially. It is easy to assume that a reservoir may not have a gas cap if a gas well is not reported for the field. This assumption could be an important pitfall if the field is considered a waterflood candidate. Case history 4 (Fig. 20) illustrates this point. This field was discovered in 1923, with wells A–M producing from the reservoir. The top of the reservoir served as the structural datum for the map contours. All the wells except well D reported oil production only. Wells C and E are updip from well D and also reported only oil production. It could be assumed that the gas production reported for well D was either an error or was possibly from unreported perforations in another reservoir. However, continued

TABLE 3. – Comparison of Gas/Oil Ratios in Oil Column, Gas Cap, and Partial Field

	Cumulative oil (BO)	Cumulative gas (MCF)	GOR
Part A			
Oil column	748,770	2,167,605	2,895/1
Gas cap	29,166	1,379,215	47,288/1
Partial field total	777,936	3,546,820	4,559/1
Part B			
Oil column	748,770	2,167,605	2,895/1
Hypothetical gas cap	29,166	9,654,505	331,019/1
Hypothetical partial field total	777,936	11,822,110	15,196/1

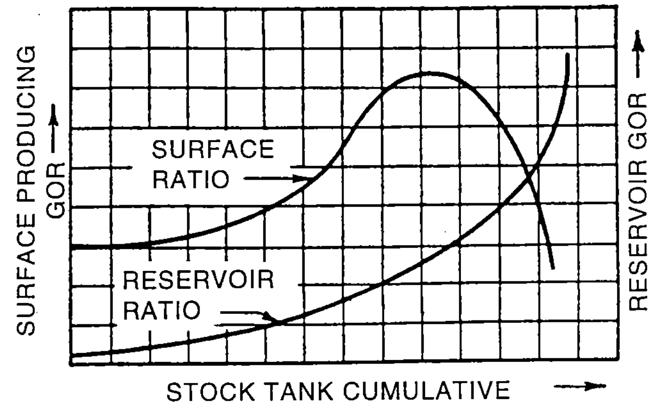


Figure 18. Typical surface and reservoir GOR curves for a solution-gas-drive reservoir. (Frick and Taylor, 1962, fig. 29-16; reprinted by permission of Society of Petroleum Engineers.)

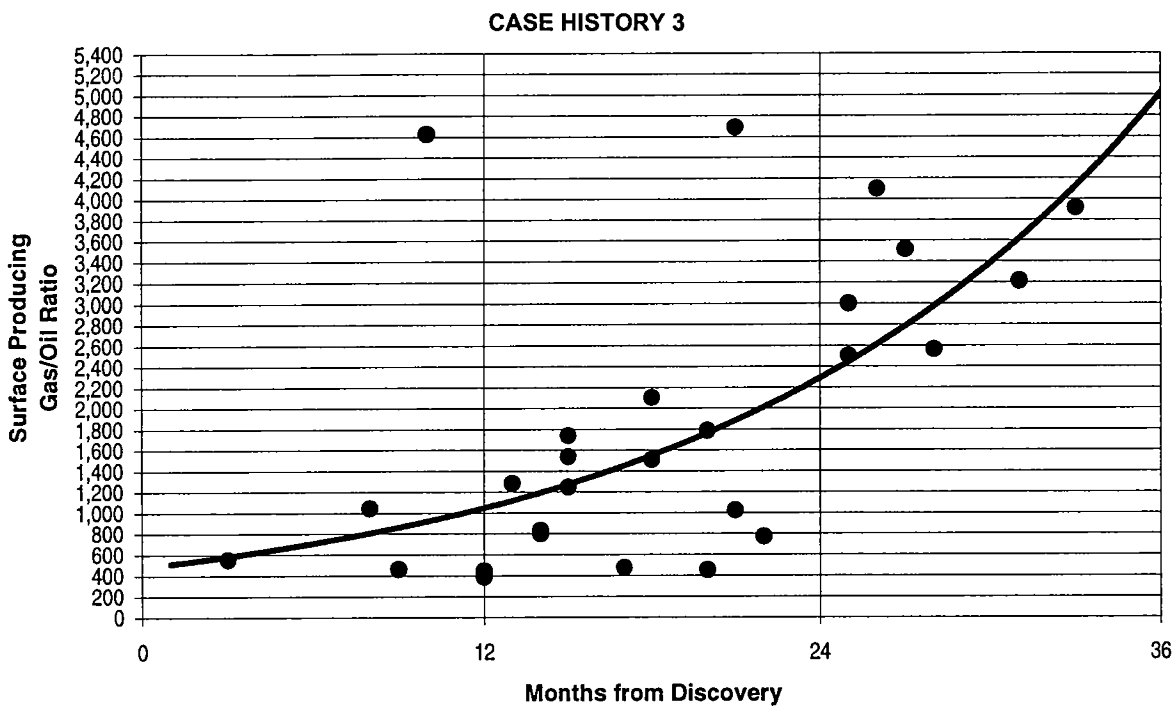


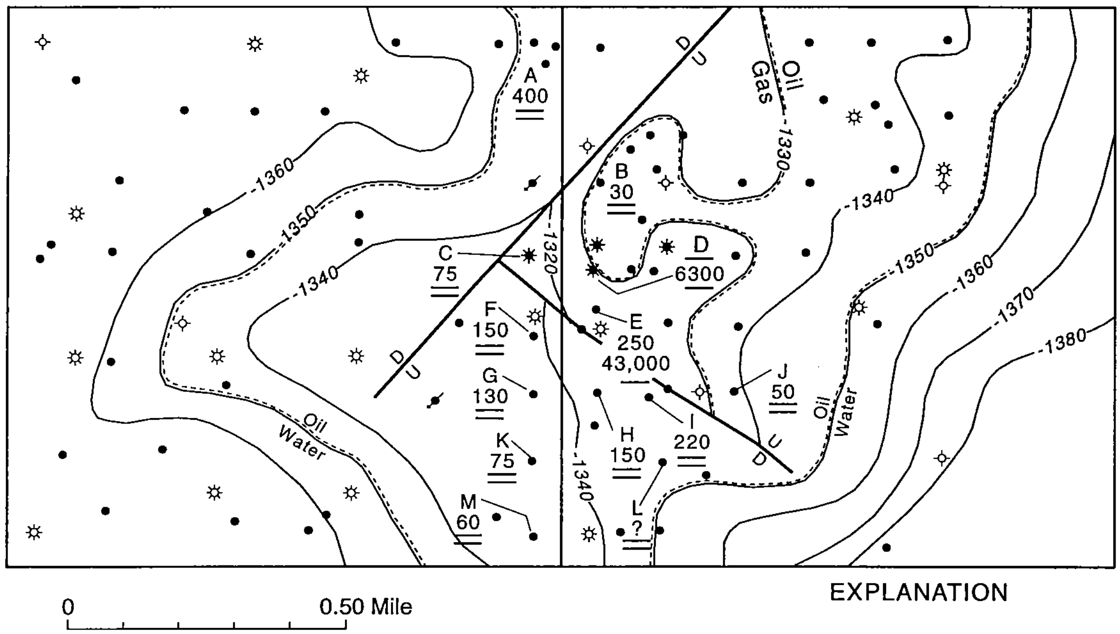
Figure 19. Plot of IP GOR versus time for wells drilled in first 3 years for the reservoir of case history 3A (central Oklahoma).

investigation in the drillers'-log files at the Oklahoma City Geological Society's library revealed another source that reported well E as having an associated 43 MMCFG production per day along with the 250 BOPD reported. This second well confirmed the presence of a gas–oil contact at approximately –1,332 ft. As gas production was not reported from this reservoir originally, the presence of the gas cap may have been missed or even overlooked. Reservoirs from which gas production is not reported need to be researched as thoroughly as possible to determine how much gas was present initially and its relationship to the oil. In this particular example, the gas cap constitutes a significant acre-foot percentage of the total reservoir, and if this reservoir were a waterflood candidate, the gas cap would need to be dealt with in the evaluation and planning of the waterflood project.

DETERMINING THE SOURCE OF WATER PRODUCTION

Understanding the source and calculating the saturation of formation water within the reservoir of a waterflood candidate is another crucial aspect of the evaluation. Water production can occur from many different processes. Four of the most common are:

CASE HISTORY 4



EXPLANATION

• E	Well number
250	Oil production
43,000	Gas production
0	Water production
—	No data

Figure 20. Oil-, gas-, and water-production data for part of the field (circled wells) of case history 4 (northern Oklahoma). Dashed line represents gas–oil contact, and dotted line represents oil–water contact derived from wells drilled subsequent to those drilled in this plot. Contour interval, 10 ft.

1. Formation-water saturations above the irreducible water-saturation percentage.
2. Formation water entering the wellbore inadvertently from a different reservoir by mechanical means—e.g., a hole in the casing, a bad cement job, etc.
3. Water introduced into the formation by mechanical means, such as a disposal or injection well.
4. Formation water encroaching naturally into the wellbore from the migration of an oil–water contact—e.g., a water-drive reservoir.

High water saturations from these four processes can drastically affect or determine the outcome of the waterflood project. We now will look at these four processes.

Formation-Water Saturations Above Irreducible

Some confusion exists within the industry for the use of the terms *connate water* and *formation water.*

Connate water is that water entrapped in the interstices of a sedimentary rock at the time of its deposition. The term is commonly misused to mean any water in the voids of a rock (Jackson, 1997). On compaction, and with subsequent dewatering of shales, fluids will migrate within the permeable rocks until their migration is inhibited by some means, such as entrapment. These fluids can be composed of any number of phases or compounds but usually are gas, oil or condensate, and water. Some gases consist of air or carbon dioxide. When these fluids are trapped and migration ceases, the percentage of pore space for each of the fluids with respect to the total pore space represents each fluid's saturation percentage. Because these fluids fill the entire pore space, the sum of all the individual fluids' saturating percentages must equal 100%.

Formation water, by definition, is the water present in a water-bearing formation under natural conditions, as opposed to introduced fluids such as drilling mud (Jackson, 1997). Therefore, formation-water saturation is that percentage of the pore volume occupied by water and is denoted by the symbol S_w. If the remaining fluid in the pore volume below the gas–oil contact is oil, then the oil saturation, S_o, is simply $1 - S_w$. The gas saturation, denoted by the symbol S_g, is $1 - S_w - S_o$.

The *irreducible water saturation,* denoted S_{wir}, is that percentage of water saturation that becomes immobile in the reservoir. S_{wir} is not a constant for all reservoirs, as many factors affect this value. Among these factors are the wettability, the porosity and permeability, and the capillary pressure of the rock. The following are definitions of these factors. *Wettability* can be defined as the tendency of a fluid to preferentially adhere to, or wet, the surface of a rock in the presence of other immiscible fluids (Smith and Cobb, 1987). *Permeability,* by definition, is the capacity of a porous rock, sediment, or soil for transmitting a fluid; it is a measure of the relative ease of fluid flow under unequal pressure. The customary unit of measurement is the millidarcy, abbreviated md (Jackson, 1997). *Relative permeability*, by definition, is the ratio between the effective permeability to a given fluid at a partial saturation and the permeability at 100% saturation. It ranges from zero at a low saturation to 1.0 at a saturation of 100% (Jackson, 1997). *Capillary pressure* is 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 (Jackson, 1997).

Figure 21 is a graphical representation of typical water–oil relative-permeability characteristics for strongly water-wet (Fig. 21A) and oil-wet (Fig. 21B) formations. The graphs illustrate the water saturations where the relative permeability to water is equal to zero. At this point, the water saturation is equal to the irreducible water saturation. A general rule of thumb is that water-wet reservoirs usually have irreducible water saturations of 20%–25% pore volume, and oil-wet reservoirs usually have less than 15% pore volume and commonly less than 10% (Craig, 1971).

Water saturations are not generally distributed uniformly within a reservoir. Figure 22 illustrates how these saturations may vary with a change of permeability and/or pore size (Bruce and Welge, 1947). This figure shows that water saturation decreases as permeability increases. Water saturations also might vary, owing to height above the water contact in a reservoir as illustrated by Figure 23 (Craft and Hawkins, 1959). As height increases above the water contact, the water saturation decreases until, at point *A*, the curve becomes essentially vertical. The water saturation at this point is equal to the irreducible water saturation. Thus, the formation-water saturation for any point in the reservoir below point *A* is higher than the irreducible water saturation, and water is capable of being produced along with the oil until the water saturation equals the irreducible value. The area of the reservoir that produces both oil and water is termed the *transition zone* and is illustrated in Figure 24 (Craft and Hawkins, 1959). Figure 25 illustrates a series of tables that can be used to estimate what the surface cut of water, in percentages, can be if S_{wir} and S_w are known for reservoirs containing oil of varying gravities. These figures represent a quick-look estimate and would be more accurate if the relative permeability for oil and water and the viscosity for oil and water were known.

A pitfall can arise in evaluating a waterflood candidate when water production is not considered a factor if the IP report of wells with high water-saturation calculations does not include water production. Operators, for one reason or another, do not always report the water IP. When water production is not reported, it is easy to assume that the reservoir does not produce water. Evaluators of waterflood candidates assume that if the water cut is not reported on wells with a high calculated water saturation, the electric-log water calculations may be in error owing to effects of mineralogy or variations in the resistivity of the formation water (R_w). Consider the reservoir in case history 5 (Fig. 26). This

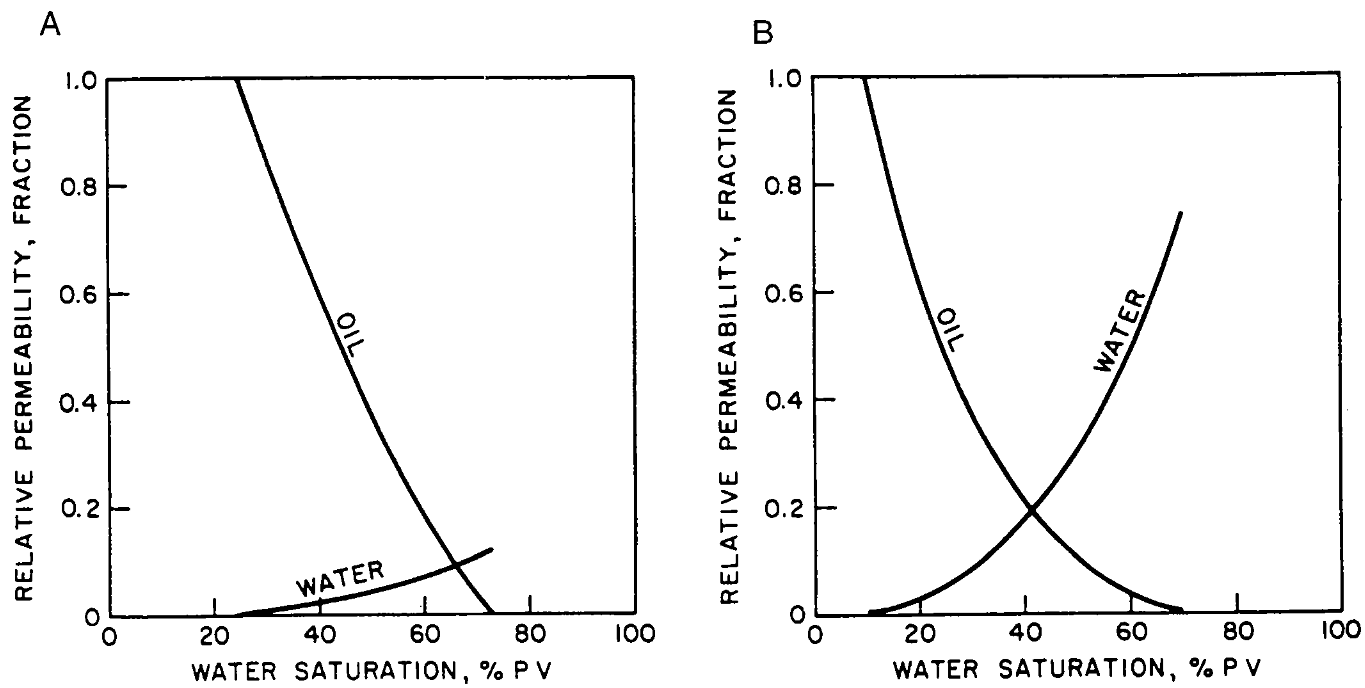


Figure 21. Typical water–oil relative-permeability curves for strongly water-wet (A) and oil-wet (B) rock. *PV* = pore volume. (Craig, 1971, figs. 2.16A and fig. 2.17A; reprinted by permission of Society of Petroleum Engineers.)

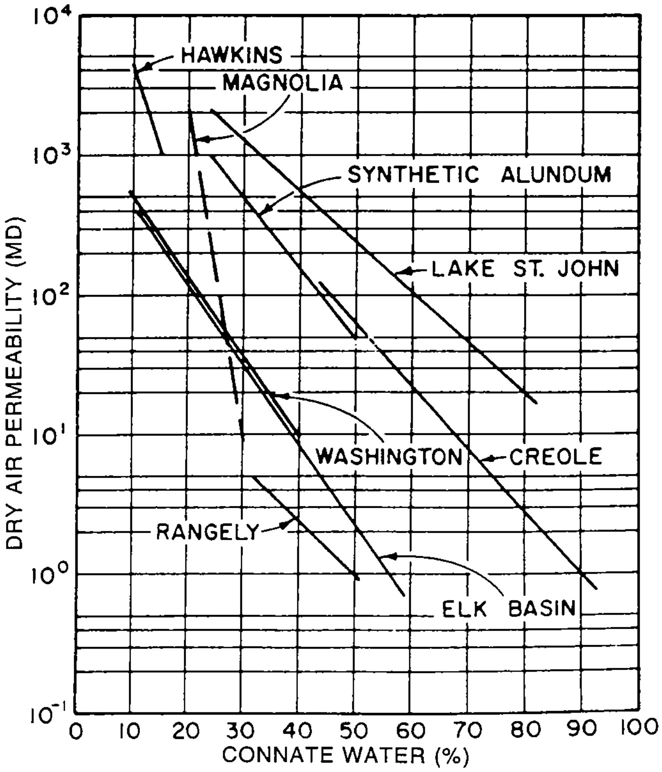


Figure 22. Plot of connate-water saturation versus permeability for various reservoirs. (Craft and Hawkins, 1959, fig. 1.5; reprinted by permission of American Petroleum Institute.)

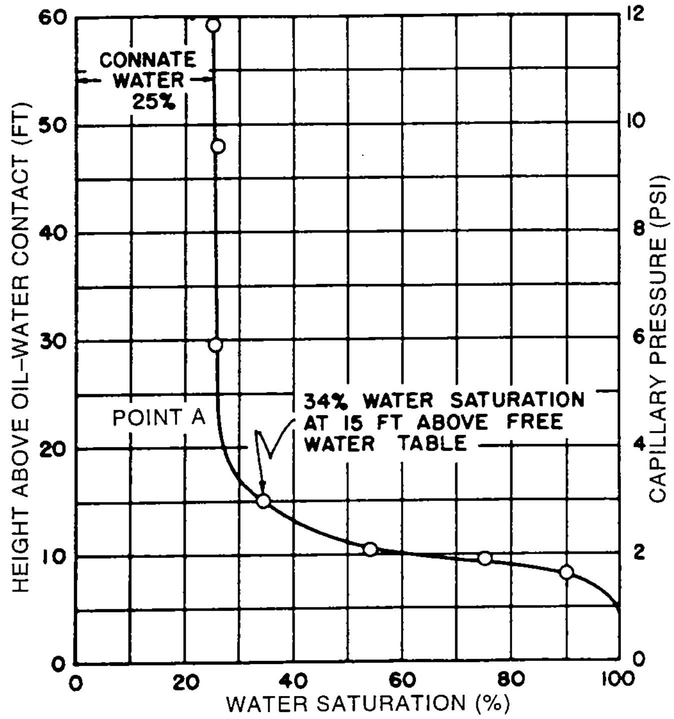


Figure 23. Typical capillary-pressure curve. Point *A* represents maximum height of water saturation above irreducible levels. (Craft and Hawkins, 1959, fig. 1.6; reprinted by permission of Prentice-Hall.)

figure indicates the IP for the wells from discovery to approximately 3 years after discovery. Of the 22 wells completed during this time, 12 did not report any water production, and wells D, E, AD, AK, and AJ reported only a small percentage of water cut. The remaining wells reported a significant water cut on initial completion. Figure 27 is a cross section of two wells at each end of the reservoir and at different structural positions. Well G is a structurally high well with a calculated S_w range from 50%(?) to 60%(?), and well Z, a structurally low well, has a calculated S_w range from 55%(?) to 65%(?). However, neither well reported any water production on initial completion. Assuming an S_{wir} of 25% and a gravity of 45°, Figure 25A suggests that the water cut should be approximately 20%–50% of the IP for the two wells on cross section *A–A′*. This water-cut scenario is cursory, so if the project proceeds to a more advanced evaluation, such factors as relative permeabilities and viscosities would need to be incorporated into this water-cut evaluation. Water saturations for this field in the range of 40%–50% at discovery should have been a major concern to the evaluator of the field for an enhanced-recovery candidate, owing to the correspondingly low oil saturations. At the time of unitization, the oil saturations for the field would have been even lower because of the primary oil production. Figure 28 illustrates the IPs of the wells drilled from approximately 3 to 8 years after discovery. Nine of the 17

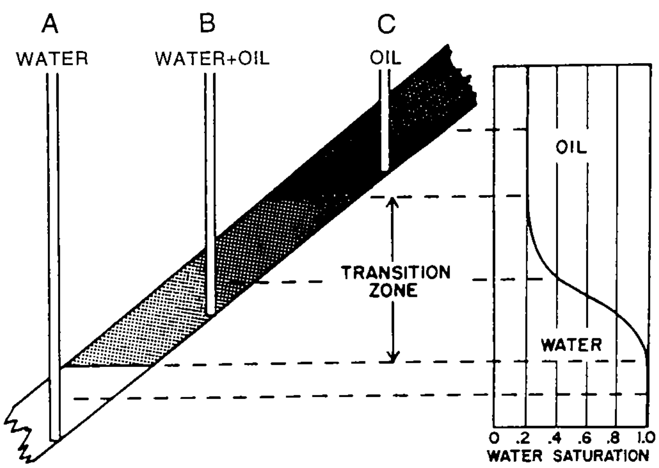


Figure 24. Schematic cross section illustrating varying water saturations in the transition zone from oil to water. (Craft and Hawkins, 1959, fig. 7.3; reprinted by permission of Prentice-Hall.)

wells had IPs of water greater than of oil. All the wells completed in the field probably had water cuts that were significant portions of the IPs. However, again for reasons unknown, water production was not reported for all the wells.

Figure 29 shows the production curve of a pilot waterflood, which incorporated wells M, Q, R, S, T, and U.

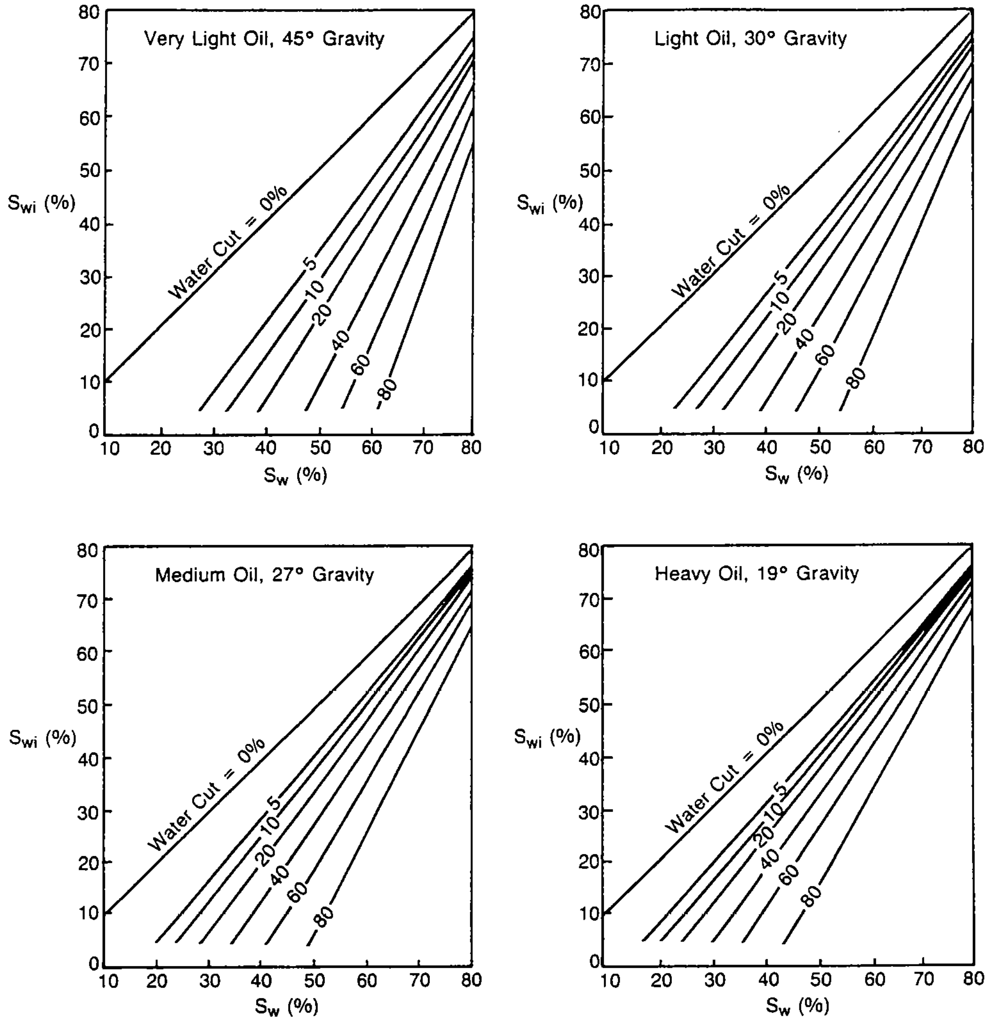


Figure 25. Charts for predicting production water cuts from reservoirs with oils of varying gravity. S_w = water saturation, S_{wi} = irreducible water saturation. (Courtesy of Schlumberger Oilfield Services.)

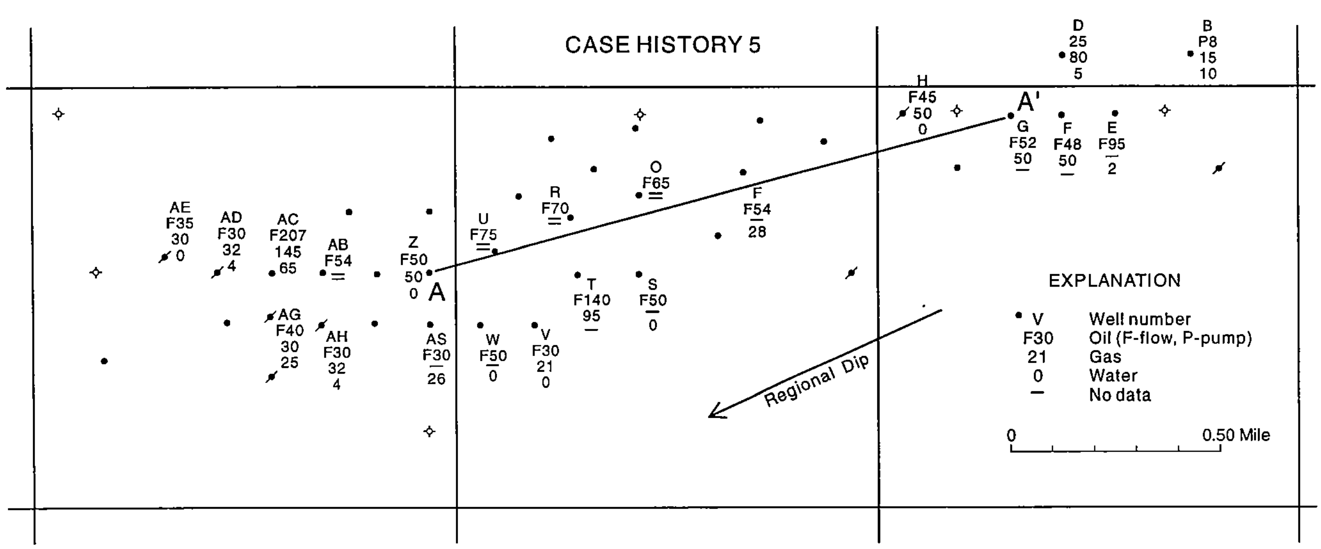


Figure 26. Oil, gas, and water IP values from field discovery to 3 years after discovery for the reservoir of case history 5 (northern Oklahoma). Line *A–A′* represents cross section of wells Z and G, shown in Figure 27.

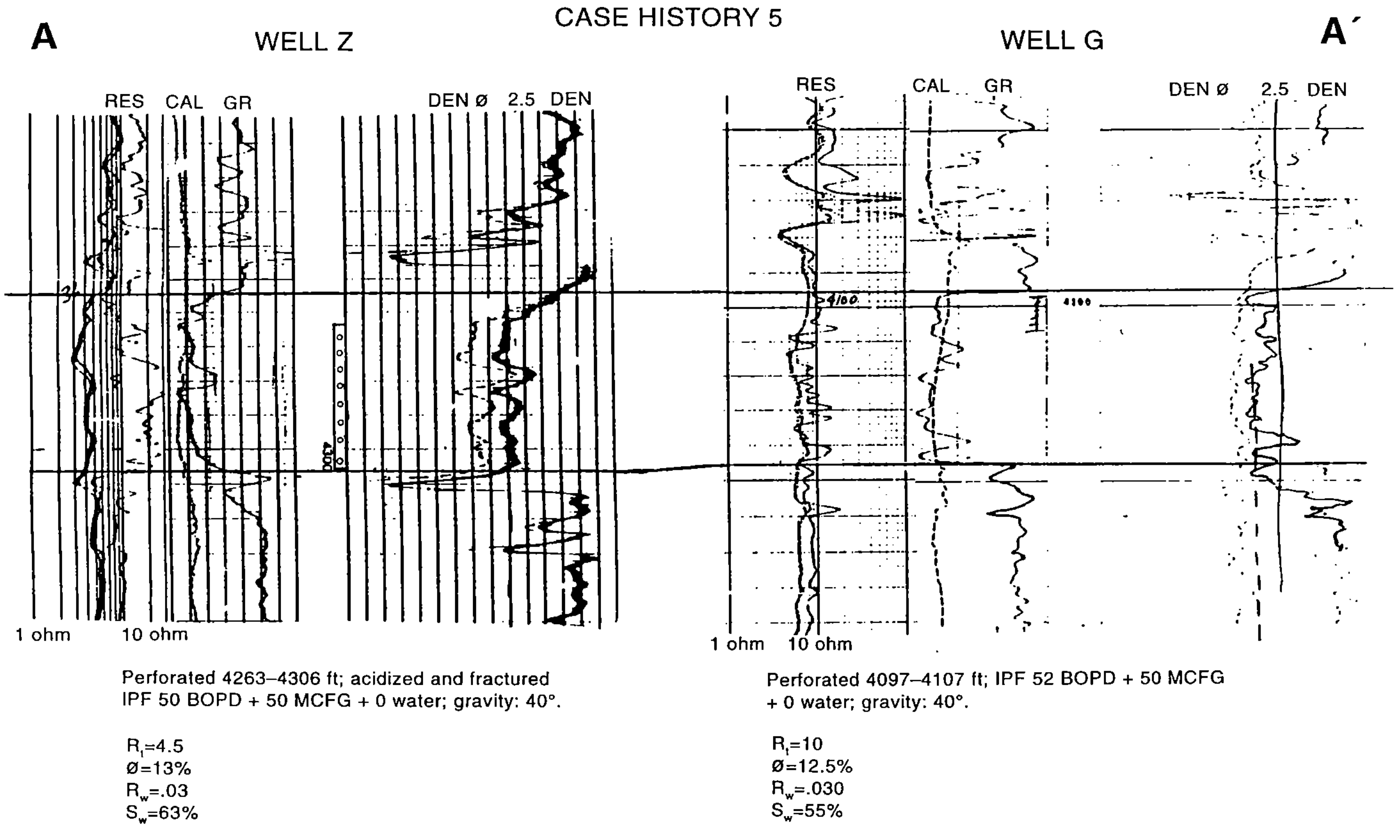


Figure 27. Cross section *A–A′* of wells Z and G, illustrating similarity of calculated water saturations from the reservoir of case history 5. *GR* = gamma ray, *RES* = resistivity, *CAL* = caliper, *DEN* = density, *DEN* ϕ = density porosity, ϕ = porosity, R_t = true resistivity of formation, R_w = resistivity of formation water, S_w = water saturation.

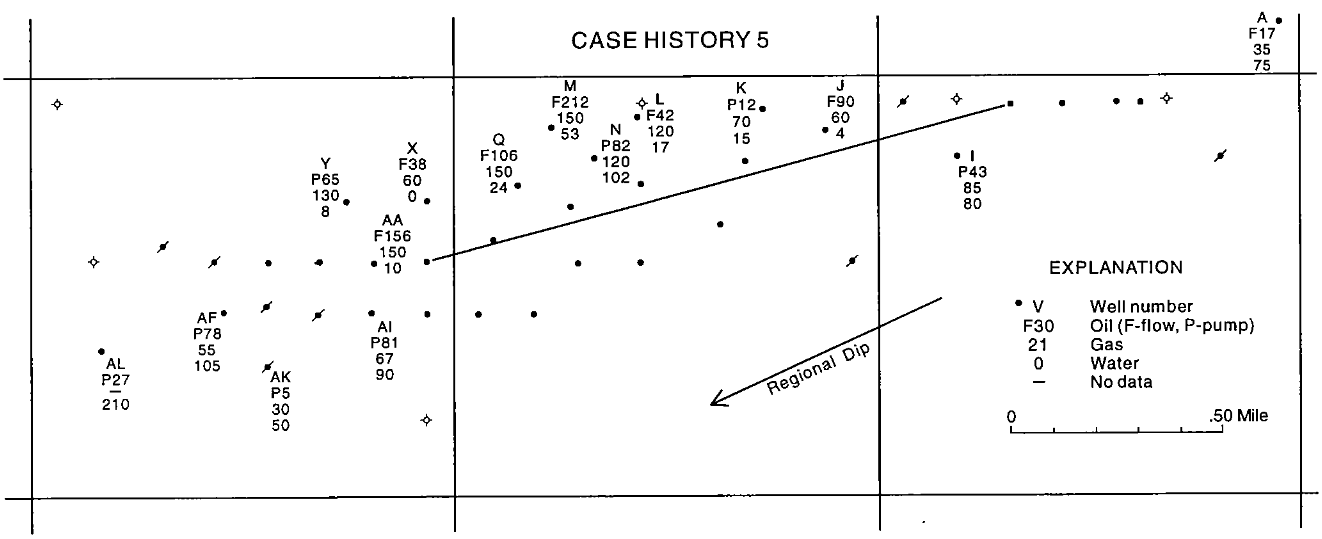


Figure 28. Oil, gas, and water IP values for wells completed 3 years after discovery in the reservoir of case history 5 (northern Oklahoma).

Point *A* represents the date of unitization. Well U was converted to injection; as of this writing, 565,000 BW was injected. The production curve does not indicate any response to injection for over 3 years, possibly confirming that insufficient oil was present to bank.

In conclusion, water-saturation calculations can be affected by such variables as invasion, mineralogy, and an inaccurate R_w variable. However, the field examination of a waterflood candidate's water-production history may indirectly suggest whether the S_w calculations are correct, and determine whether oil satu-

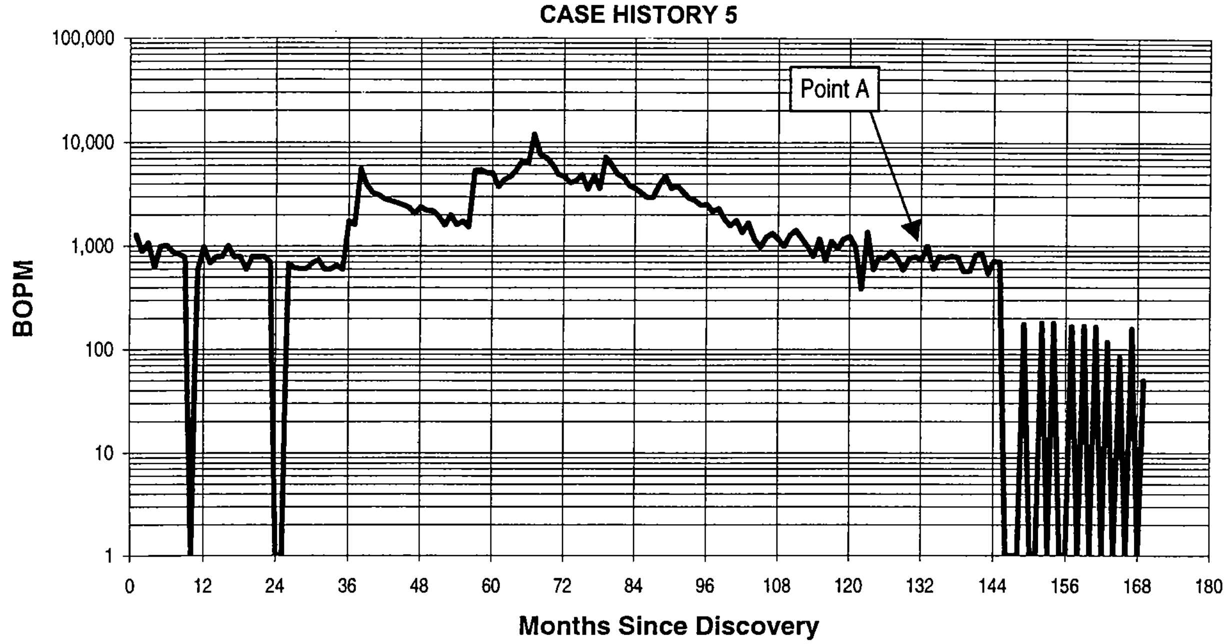


Figure 29. Production curve for the reservoir of case history 5. *BPOM* = barrels of oil per month.

rations are possibly too low for a viable waterflood candidate.

Formation Water Entering the Reservoir Inadvertently

Sometimes the water-production data reported for wells within a field do not correspond to the calculated water saturations for the individual wells of the reservoir. Consider case history 6 (Fig. 30). The map indicates the IP for oil, gas, and water for the field. All the wells in the field have a calculated water saturation in the range of 25%–35%. The gravity of the oil is approximately 40° API. The irreducible water saturation is approximately 25%. An examination of Figure 25A suggests that some water production should be expected, probably on the order of 5% or less. However, wells A, C, E, H, L, Q, R, and AI have a water cut exceeding 50%, and yet they are surrounded by wells that have low water cuts. Compartmentalization has been ruled out, as electric-log correlations and pressure data suggest common reservoir connectivity. Also, water calculations from open-hole electric logs for these eight wells are similar to those for wells with low initial water production.

Figure 31 lists the oil and water production from the reservoir for the first 4 years. Of the original eight high-water-cut wells, wells A, L, and Q have not produced significant water. Well R made large amounts of water on initial tests. A temperature survey was run in well R, and water was confirmed to have entered the wellbore from below the perforations. The perforations were squeezed, and only the upper part of the Bartlesville sandstone was perforated, resulting in an IP of 137 BO, 53 MCFGPD, and 7 BW per day. A similar situation occurred with well H. A temperature survey was run, which verified that water was entering only from the bottom of the wellbore. The perforations were squeezed with cement, and only the upper Bartlesville was perforated. However, the water was never successfully shut off.

Wells H and R were two of the first wells completed in the reservoir. As a result of experiences with water production from these two wells, the operators that subsequently developed the field avoided drilling the lower one-third of the Bartlesville, thinking that this was the source of the water. However, even wells C, E, and AI were completed only in the upper one-third of the pay zone, and ultimately all produced significant quantities of formation water.

This field was unitized, and a pilot waterflood was begun with injection into wells D, AJ, L, and M. Within a short time after injection commenced, well E, which had been shut in for a number of years and which was one of the original high-water-producing wells, was scheduled for a workover in anticipation of a possible response to the pilot injection. It was immediately apparent that the well was making a considerable amount of water, as water was at the surface of the wellbore. Possible explanations for this water were threefold: (1) the formation-water saturation was higher than calculated, (2) bottom water was invading the upper zones, or (3) water production was the actual response from the injection, indicating either unknown fracturing or early water breakthrough possibly with no oil bank.

This example illustrates the need for the operator to have understood the source of the high water production in the original eight wells prior to installation of

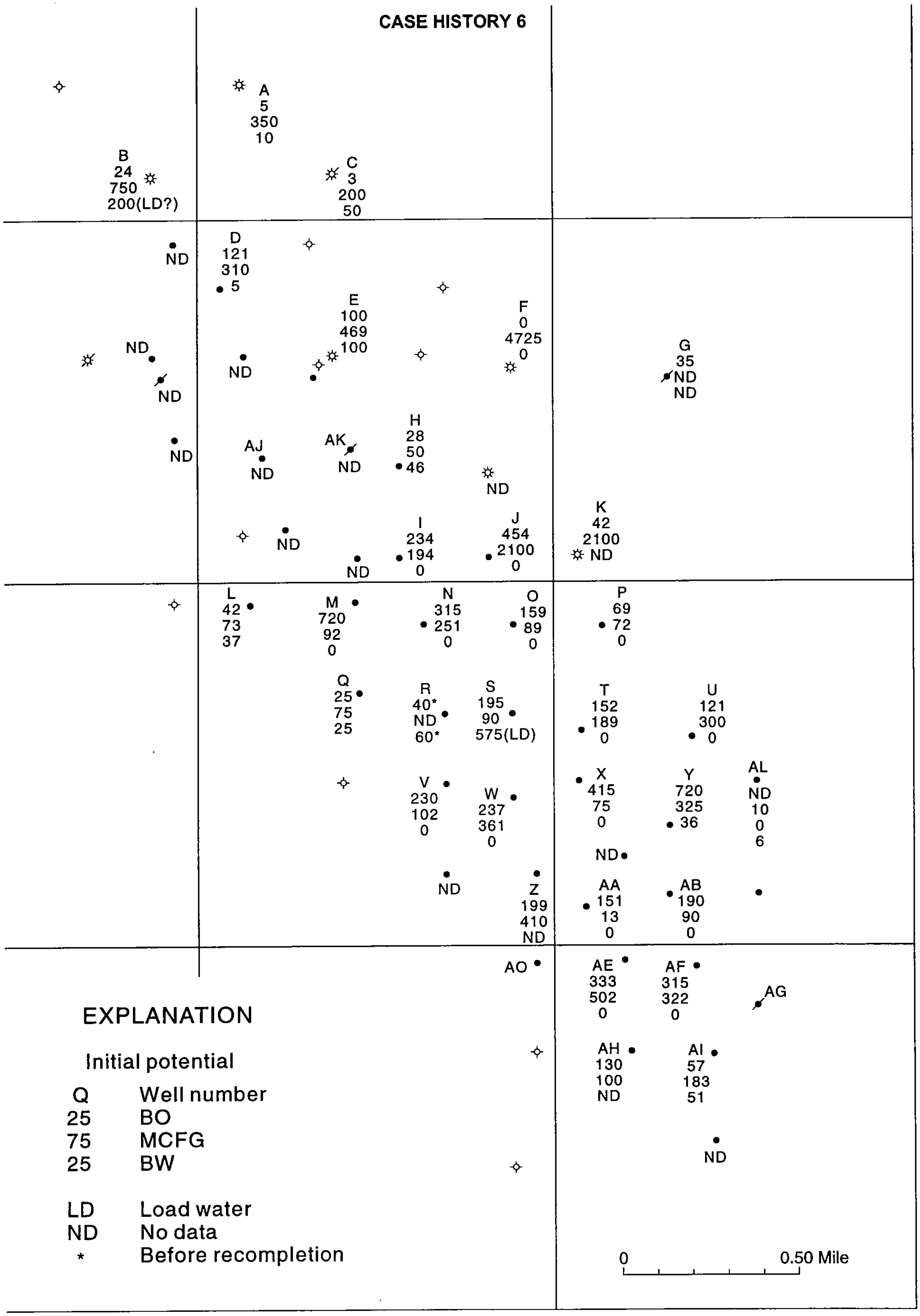


Figure 30. Oil, gas, and water IP data for the reservoir of case history 6 (central Oklahoma).

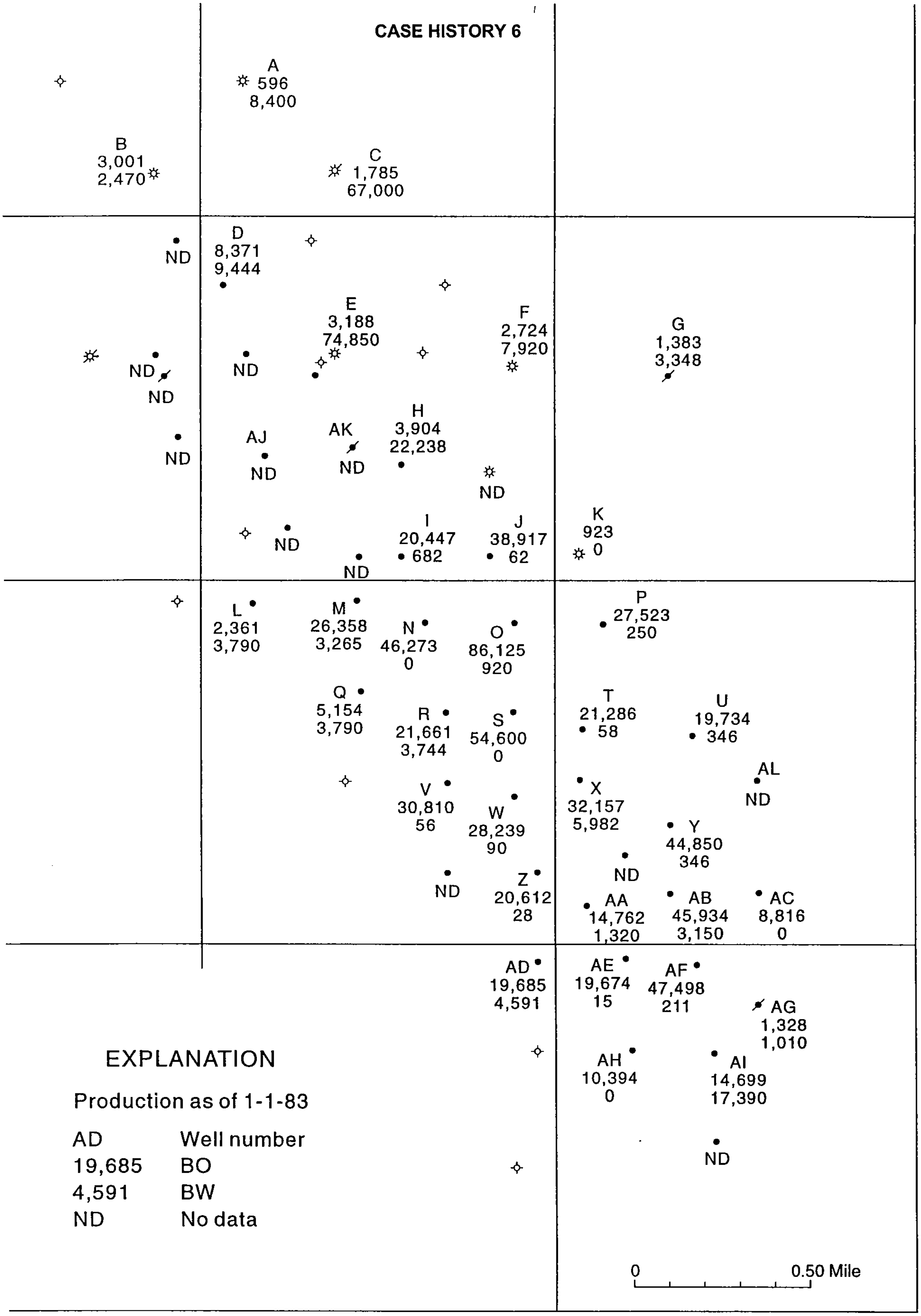


Figure 31. Cumulative oil and water production for the first 4 years since discovery for the reservoir of case history 6 (central Oklahoma).

TABLE 4. – Water Analysis of Bartlesville and Formations Directly Above and Below

Well number or formation		Cations			Anions		
		Na	Ca	Mg	Cl	HCO_3	SO_4
Layton	WSW 1	75,187	11,040	2,391	123,000	12	nil
Red Fork		64,446	14,080	1,952	130,000	177	29
High Bartlesville water producers	Well E	59,823	11,200	2,538	119,000	116	725
	Well N	NA[a]	11,444	15,626	113,313	nil	1,000
	Well H	NA[a]	12,578	2,875	123,488	nil	461
Low Bartlesville water producers	Well AF	51,799	10,400	1,903	104,000	153	nil
	Well AK	62,132	13,040	2,050	125,000	171	33
Mississippian		57,316	11,360	2,220	115,000	116	34
Hunton		60,007	10,160	2,318	117,000	104	450

[a] Not available.

the pilot waterflood. Capital dollars were immediately at risk because of the unanswered questions of why wells produced high water volumes after the pilot flood had been installed. After careful review, it was determined that the water-saturation calculations were indeed correct. Also, examination of water saturations for the lower one-third of the Bartlesville in those wells that had penetrated this interval proved that this zone was not the source of the water. The only apparent alternative to explain this high water productivity was for the water to have entered from another formation or to have been a response from the pilot flood. The concept of water having come from another formation was considered with skepticism, because temperature surveys that were run by the operator in those wells that were high water producers clearly indicated that the water was coming from below the perforations. The reservoir below the perforations is made up of approximately 30–40 ft of intercalated layers of limestone and shale of the Mississippian limestone, which is not capable of producing these rates or quantities of salt water.

Table 4 is a summary of water analysis for several of the high- and low-water-producing wells in the reservoir and of the supply water for the injectors and those water-bearing zones above and below the Bartlesville. What is readily apparent is the similarity of the concentration of sulfate ions for the Hunton Group to those for the high-water-producing Bartlesville wells. Figure 32 is a sketch depicting the anticipated result of the fracture treatments for the Bartlesville producers. The fracture treatment was intended to stay within the Bartlesville reservoir, but Figure 33 depicts what probably hap-

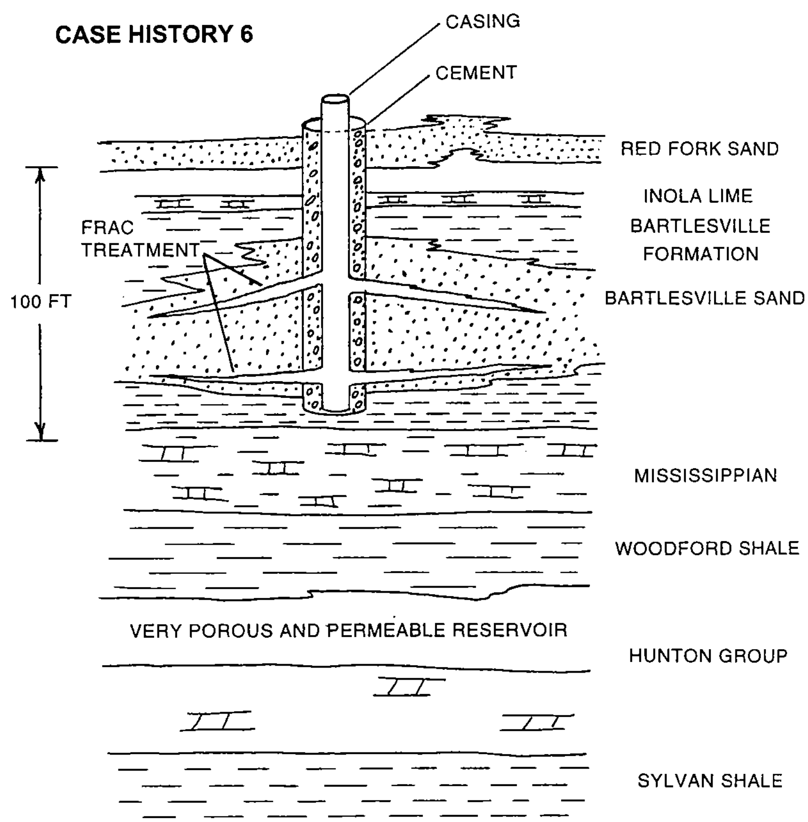


Figure 32. Expected result of fracture treatment for the Bartlesville sand in case history 6.

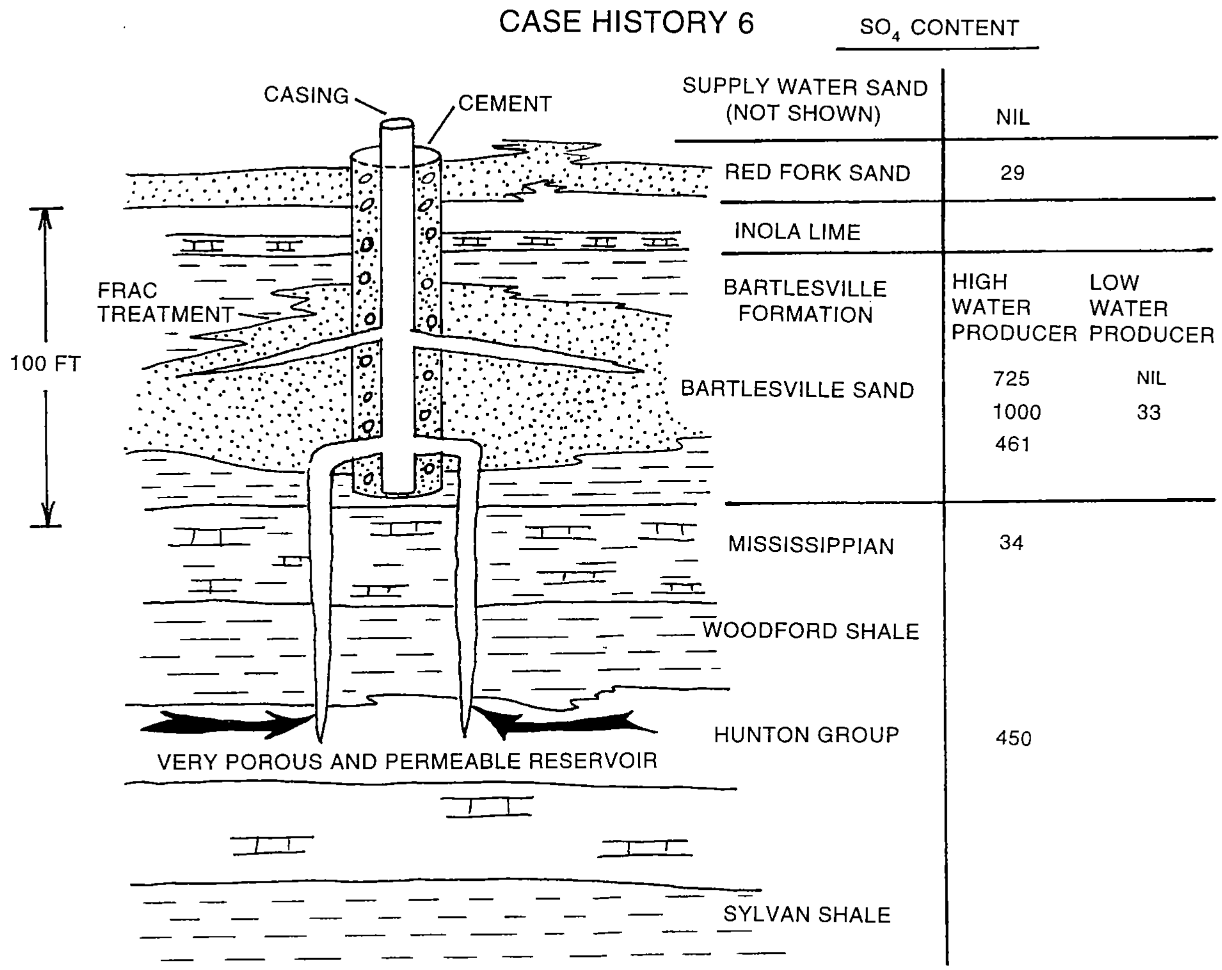


Figure 33. Most likely result of fracture treatment for the Bartlesville reservoir in case history 6, on the basis of chemical water analysis.

pened to wells C, E, H, and AI of Figure 31. Part of the fracture treatment evidently penetrated the underlying fractured Mississippian and the fissile shale of the Woodford Formation and entered the highly permeable aquifer of the Hunton Group.

In this case history, the unexpected water in well E was thought to have occurred from water injection. The lack of oil production suggested to the operators the possibility that the pilot waterflood had water breakthrough, which jeopardized the economics of the project. But it was actually determined that the water was coming from another formation. This example demonstrates the importance of why reported water production must be investigated to ascertain its source because of the problems, both geologic and engineering, that result from its presence.

Water Introduced into the Formation Mechanically

Many times in the course of waterflood-prospect evaluation, the producing wells are all plugged, leaving virtually no firsthand knowledge of current water production. To compound this problem, operators in Oklahoma are not required to report water production. Thus, the evaluators of a prospect are faced with this dilemma: should they continue with the evaluation, which could lead to eventual unitization and installation, or should they attempt to determine the current water and oil saturation for the field? The pitfall in this problem is the fact that if such parameters as reservoir-fluid saturations, drive mechanism, and fluid contacts are known initially—and that they are not suspected to have changed with depletion and abandonment—the evaluators probably would continue, without ascertaining current water saturations.

Consider case history 7 (Fig. 34), a net-sand isopach map of part of a reservoir in central Oklahoma. The field produced in primary mode for approximately 30 years before being completely plugged out. No water production was reported for the field. Adjacent wells were producing from other zones. The drive mechanism was solution gas. The available electric logs did not indicate the presence of either bottom water or a downdip water contact. The reservoir had produced over 2 MMBO in primary mode, with over 1.5 MMBO expected from secondary operations. Figure 35A is part of a log from a well drilled earlier at point *A* (Fig. 34) during development of the reservoir. The sand at dis-

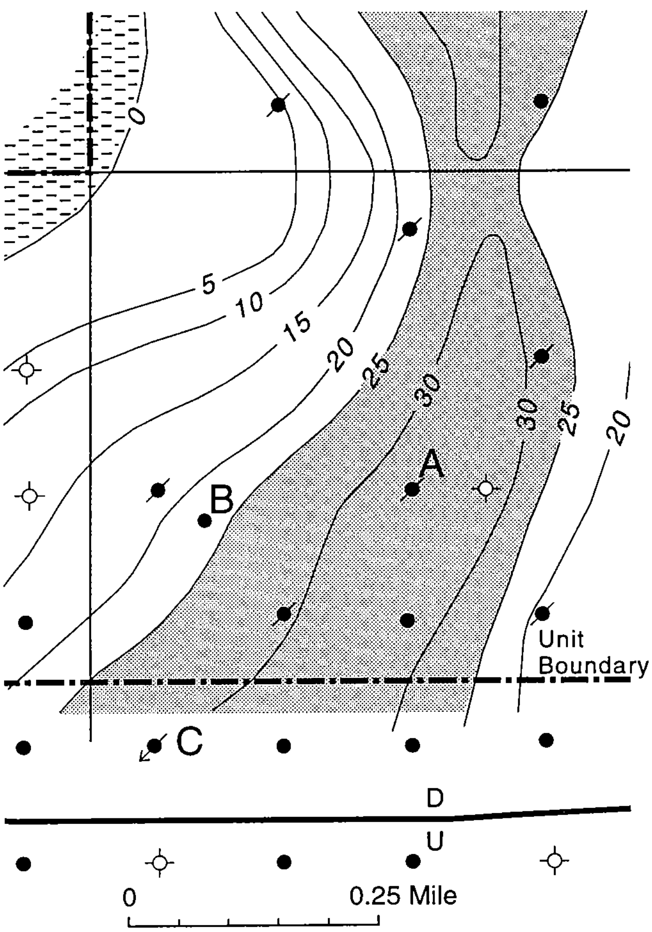


Figure 34. Isopach map of net sand for the reservoir of case history 7 (central Oklahoma). Shaded area illustrates sand exceeding 25 ft in net thickness. Contour interval, 5 ft.

covery calculates to approximately 36% S_w and 74% S_o. With a normal solution-gas drive, the water saturations should not have increased appreciably. The operator unitized the reservoir and installed the surface equipment. Part of this installation called for the drilling of several new wells. One of the first wells drilled was the well at point *B* in Figure 34. The electric log indicates a current water saturation of over 75% in the pay zone, which was a considerable surprise to the operator. The source of the water is unknown. After a more thorough investigation of the surrounding leases, it was determined that an old water-disposal well at point *C* (Fig. 34) was active early in the life of the reservoir and was injecting salt water into the unitized reservoir. Injection amounts were unknown, but they must have been enough to have swept the reservoir to the north. Unfortunately for the operator, re-evaluation of the prospect indicated that secondary reserves were cut almost in half. This conclusion was based on the oil having been previously swept by the water from the old injection well, which lowered the potential return on investment for the project with respect to the original cost of the installation.

Formation Water Encroaching Naturally

Old plugged-out fields have one problem in common, the lack of present-day reservoir information. As seen in the last example, water can be introduced by totally unexpected means. Sometimes an original water contact is known, but present information might not shed light as to its current position. The evaluator, again, is faced with the dilemma of either continuing with the evaluation, which includes eventual unitization and installation, or making an attempt by some means to establish the current oil–water contact (OWC). Consider case history 8 (Fig. 36). This field was discovered and developed in the early 1950s. Contour *A* was the position of the original OWC. The field was essentially plugged out and abandoned in the 1970s. Unfortunately, no water-production data are available, leaving the evaluator to ponder the present position of the OWC, which was later determined to be at contour *B*.

Figure 37A is an electric log from well 1 in Figure 36. The well produced water-free oil. The evaluator of this waterflood prospect was faced with the two scenarios mentioned previously. Fortunately for the evaluating company, a decision was made to drill a well to evaluate the reservoir at point 2 prior to installation and unitization, as seen in Figure 36. Figure 37B is the electric log for this newly drilled well. The average porosity across the interval is 14%. The calculated salt-water saturations exceed 80%. This result implies that the water contact had indeed moved up to the revised position of contour *B* (Fig. 36), effectively cutting anticipated secondary reserves by more than 50%.

The authorization for expenditure (AFE) for this project was over \$2.5 million, less acquisition costs. The test-well cost of \$200,000 seems expensive, but in this case it meant money saved by not spending money to install a potential failure.

DRILLSTEM-TEST AVAILABILITY

Bottom-hole-pressure data, both initial and current, are another critical factor in the evaluation of a waterflood candidate. Pressures affect such PVT variables as formation volume factor, GOR, percentage of depletion, oil viscosity, and oil and gas compressibility. All these variables are used by the reservoir engineer in the waterflood-candidate evaluation. This publication does not go into these relationships, which would need to be addressed in another workshop dealing with engineering pitfalls of waterflooding. This workshop will deal with the availability of pressure data. It is important for geologists to ascertain the initial bottom-hole pressure of a waterflood prospect as well as the current bottom-hole pressure. Pressure data are recorded initially in various ways: pressure-buildup bombs or tests, comparison of analogous pressures from reservoirs at similar depths, calculations of the pressure gradient,

CASE HISTORY 7

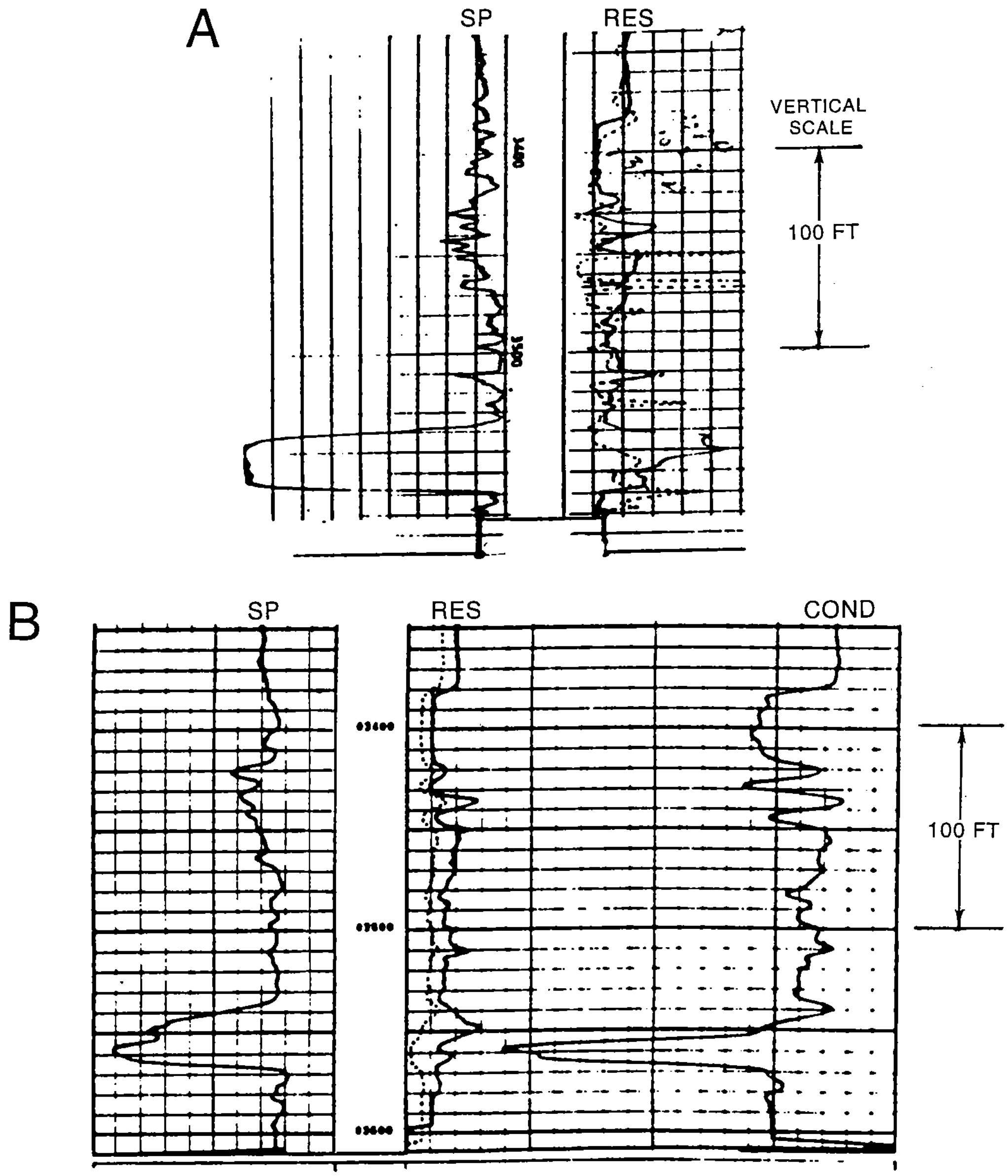


Figure 35. (A) Electric log recorded during field development of the reservoir of case history 7 drilled at point *A* in Figure 34. Log indicates productive oil saturation throughout pay section with no indication of bottom water. (B) Electric log recorded as part of waterflood-project installation (point *B*, Fig. 34). Log indicates very high water saturation throughout pay section. *SP* = spontaneous potential, *RES* = resistivity, *COND* = conductivity.

and pressures obtained from drillstem tests (DSTs). Of these procedures, DSTs are the most commonly used method for obtaining pressure data. DST pressure data are generally obtained by scout-card information, or the data might be available from the company that ran the test or that currently owns the wellbore. Obviously, obtaining the actual test data is preferable to information supplied on scout tickets. If the original DST data are available, considerable reservoir information can be inferred in addition to pressure data. However, DST information on scout tickets or similar sources often requires more of an intuitive approach or interpretation because of the lack of an actual chart. The following summary comments on DST information was supplied by Mr. George Tew, Tew Testers, Perry, Oklahoma.

Important information to look for on scout cards:

1. Bottom-hole pressure. If the prospect is a waterflood candidate, DST data from scout tickets are generally from wells drilled early in the life of the reservoir. Bottom-hole pressures near original pressures from wells drilled late in the life of a reservoir could indicate

the presence of a water-drive mechanism. Important factors to be considered include:

- Shows of hydrocarbons in recovery.
- Absence of formation water in recovery. This would be especially important to the evaluation of the waterflood candidate late in the life of the reservoir.
- Minimum shut-in periods recommended are 2 hours. In this regard, if the final shut-in pressure is less than the initial shut-in pressure, it doesn't imply depletion. The difference may simply be a function of time and permeability.

2. Recovery water with 25,000 ppm of chlorides or less could be filtrate water.

3. Low-flowing pressures of reservoirs expected to be at or close to initial reservoir pressures could be caused by zone damage, etc.

4. Don't be discouraged by bottom-hole-pressure drops (final lower than initial). Often this is just a time function, and the final bottom-hole pressure will extrapolate back to the initial bottom-hole pressure.

5. Short shut-in periods of 1 hour or 30 minutes do not let tight reservoirs build up.

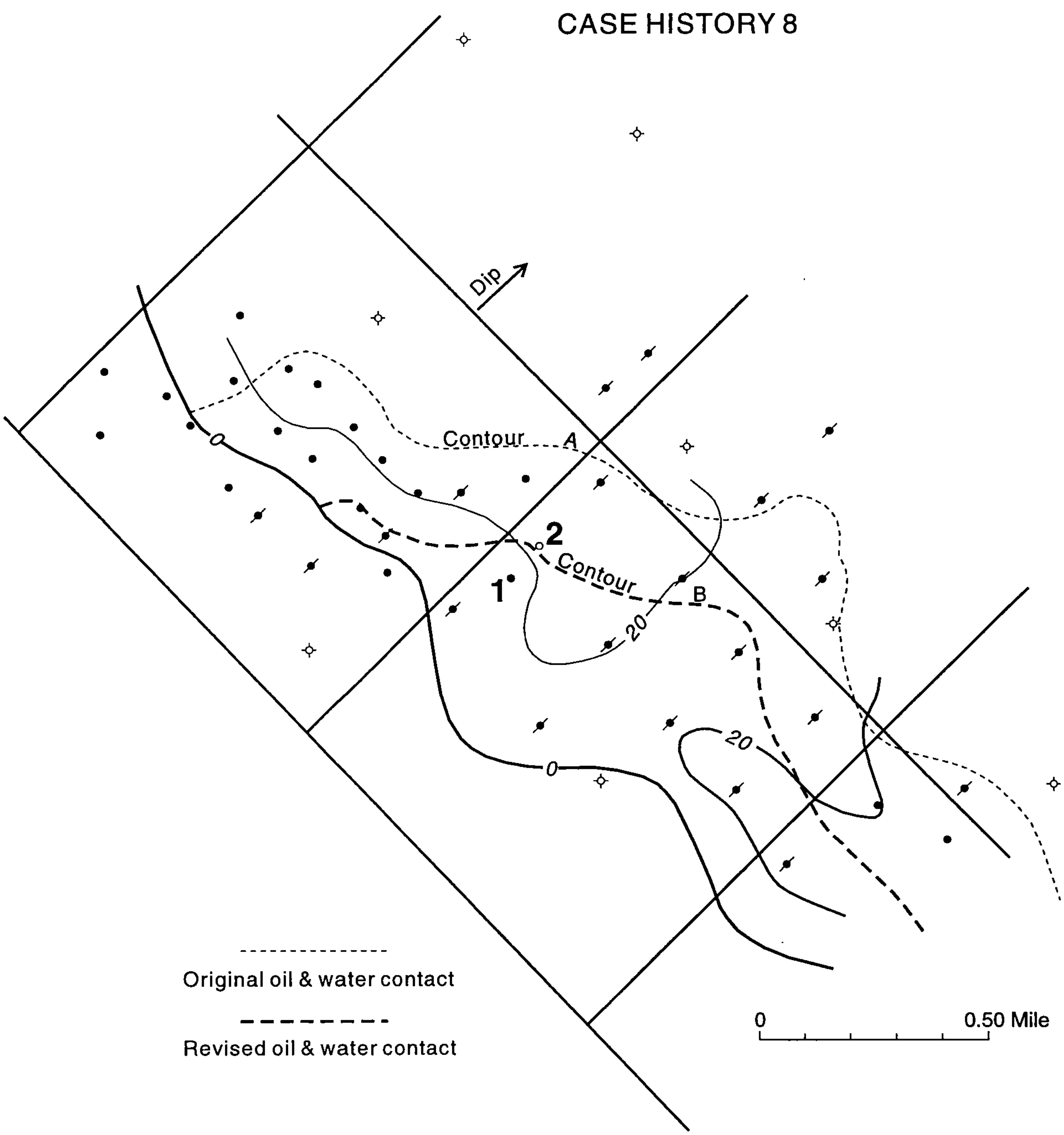


Figure 36. Isopach map of net sand for the reservoir of case history 8 (north-central Texas). Heavy dashed line (contour *B*) represents current oil–water contact. Light dashed line (contour *A*) represents original oil–water contact. Contour interval, 20 ft.

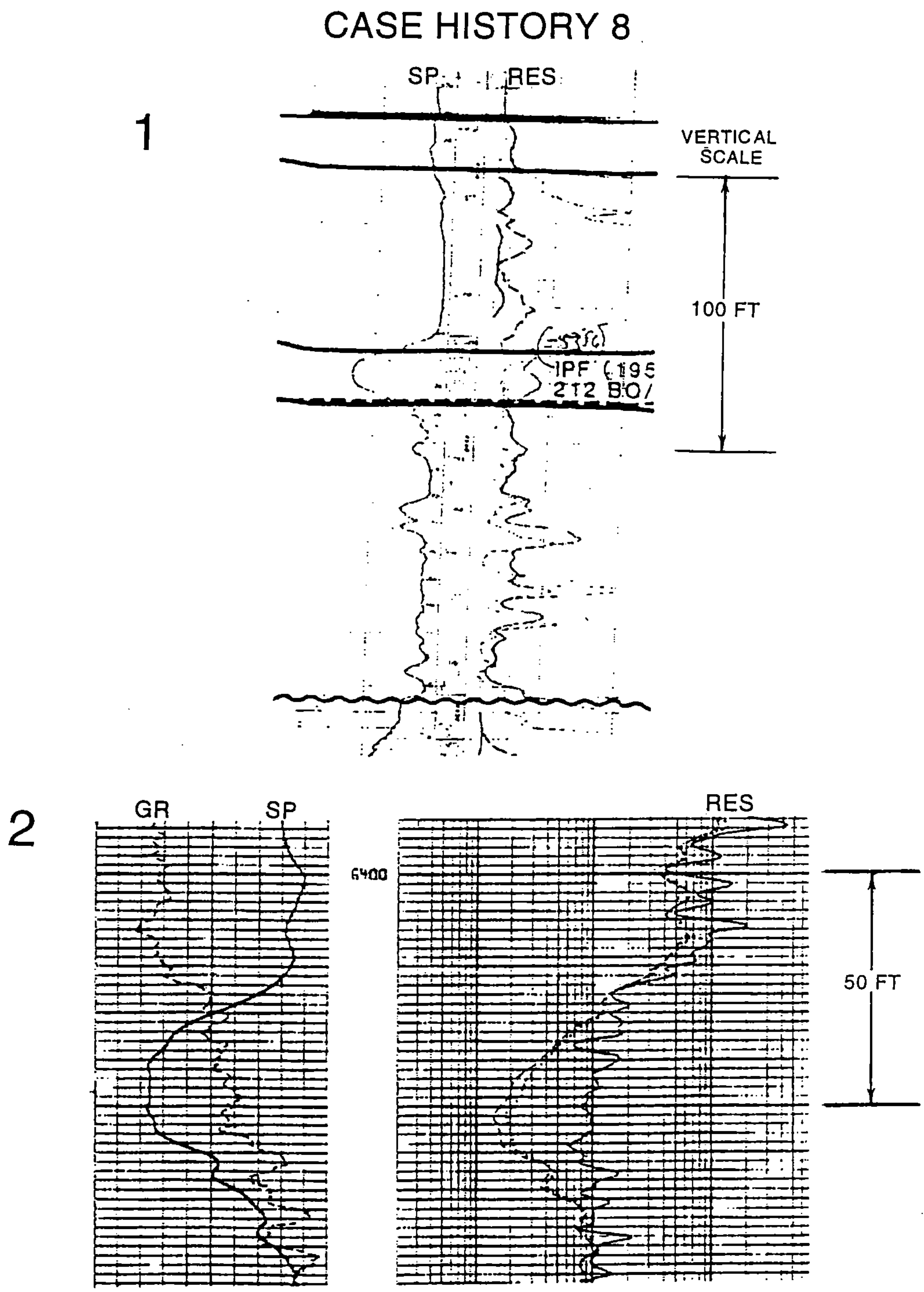


Figure 37. (1) Electric log of a well (well 1 in Fig. 36) drilled at discovery of the reservoir of case history 8. The log indicates productive oil saturation throughout the pay interval. (2) Electric log of a well (well 2 in Fig. 36) drilled after abandonment of the reservoir of case history 8. The log indicates high water saturation throughout pay interval.

CORE AVAILABILITY

For the evaluation of a waterflood candidate, core analysis of the reservoir is very important. We will discuss various topics of core analysis and its ramifications later in this volume. However, we will mention at this time that the geologist is responsible for determining the availability of core information for waterflood-prospect evaluation.

3

Analyzing Production History

CHAPTER 3

Analyzing Production History

INTRODUCTION

During the course of the waterflood-prospect evaluation, the production history of the field must be analyzed, for two basic reasons. First, the primary recovery should be analyzed to help determine if the current oil saturation is sufficient for waterflooding and thus ascertain if the expected reserves from secondary operations will meet company objectives. Second, the production history should be analyzed to predict potential problems from the reservoir that could impede a successful waterflood project. This chapter illustrates various examples of the second analytical step.

DRIVE MECHANISM INFERRED FROM PRODUCTION CURVE

To gain a better understanding of drive variations or unknown production factors for the reservoir, production curves should be reviewed as helpful examples. Figure 38 is an example of field production, GOR, and pressure curves for a solution-gas-drive mechanism (Clark, 1969). The figure illustrates an early peak in oil production associated with initial reservoir pressure. As the reservoir pressure declines, the production declines, until the reservoir is essentially depleted.

Figure 39 is an example of production, GOR, and pressure curves for a gas-cap-drive reservoir (Clark, 1969). As the pressure drops in the producing oil column, the gas cap expands, acting as a medium to drive the oil toward the producing wellbores. In the ideal case, gas does not break through, which would be indicated by a dramatic increase in the producer's GOR. This drive mechanism is more efficient than the solution-gas drive mentioned previously.

Figure 40 is an example of production, GOR, and pressure curves for a water-drive mechanism (Clark, 1969). Here, the water leg of the reservoir is driven to the void created by production in the hydrocarbon portion of the reservoir. Two types of water drives should be mentioned. The first is a normal water drive, in which reservoir pressure is only partially depleted prior to depletion of the hydrocarbon portion of the reservoir. The second type is a partial-drive mechanism, in which the water-drive mechanism is responsible for only a part of the production, at which time solution gas would be the predominant mechanism.

Figure 41 is a chart illustrating average recovery factors for the three primary drive mechanisms described (Clark, 1969). The drive mechanisms and the associated recovery factors are two variables that are crucial to the evaluation of a waterflood candidate. A water-drive mechanism is essentially a natural waterflood process. If it is determined that all or part of a field has produced by means of a water drive, it would be useless to consider that portion of the field as a waterflood candidate.

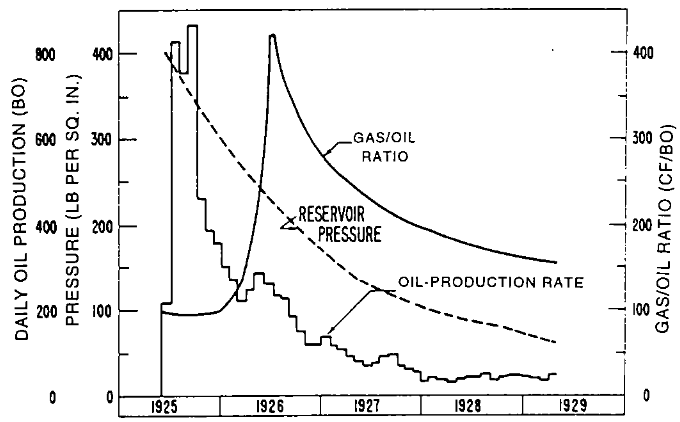


Figure 38. Example of reservoir-pressure, gas/oil-ratio (GOR), and oil-production curves for a typical solution-gas-drive reservoir. (Clark, 1969, fig. 62; reprinted by permission of American Petroleum Institute.)

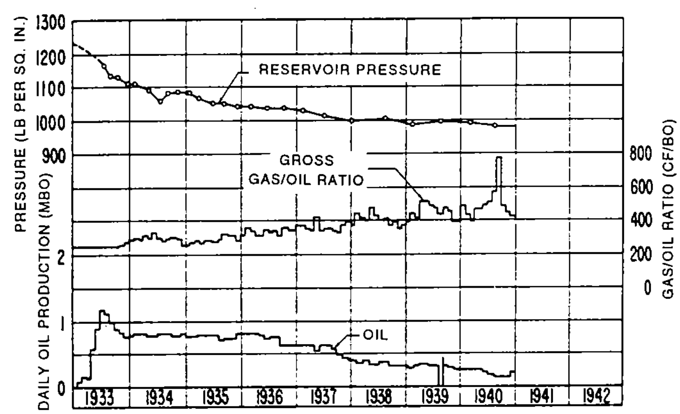


Figure 39. Example of reservoir-pressure, GOR, and oil-production curves for a typical gas-cap-drive reservoir. (Clark, 1969, fig. 64; reprinted by permission of American Petroleum Institute.)

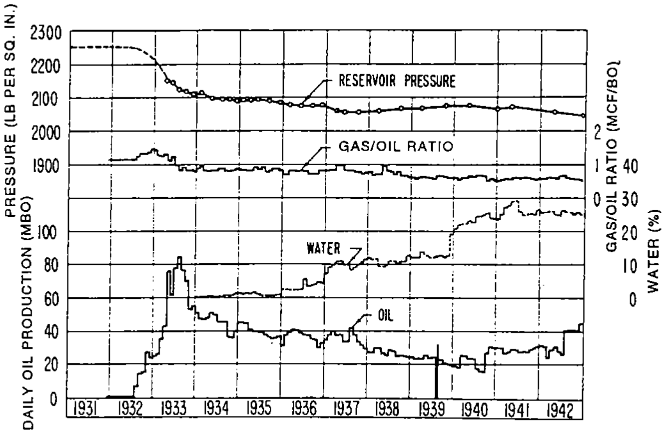


Figure 40. Example of reservoir-pressure, GOR, and oil-production curves for a typical water-drive reservoir. (Clark, 1969, fig. 66; reprinted by permission of American Petroleum Institute.)

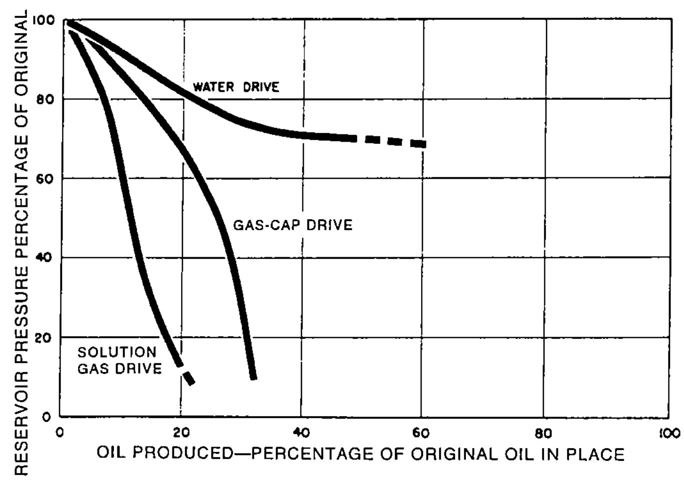


Figure 41. Plot of percentage of oil produced versus pressure for water-, gas-cap-, and solution-gas-drive reservoirs. (Clark, 1969, fig. 69; reprinted by permission of American Petroleum Institute.)

PRODUCTION-CURVE ANALYSIS

A detailed production history, which includes oil, gas, and water information displayed on a cumulative-production curve, can give valuable insight as to the viability of a potential waterflood candidate. This information yields approximate GORs on a field, partial-field, or well (lease) basis. The production history, along with volumetrics of the reservoir, allows for the calculation of current oil saturations. Drive mechanisms may be inferred from the shape of the production curve and from the calculated recovery factor. Also, production history identifies the fluid content of the reservoir.

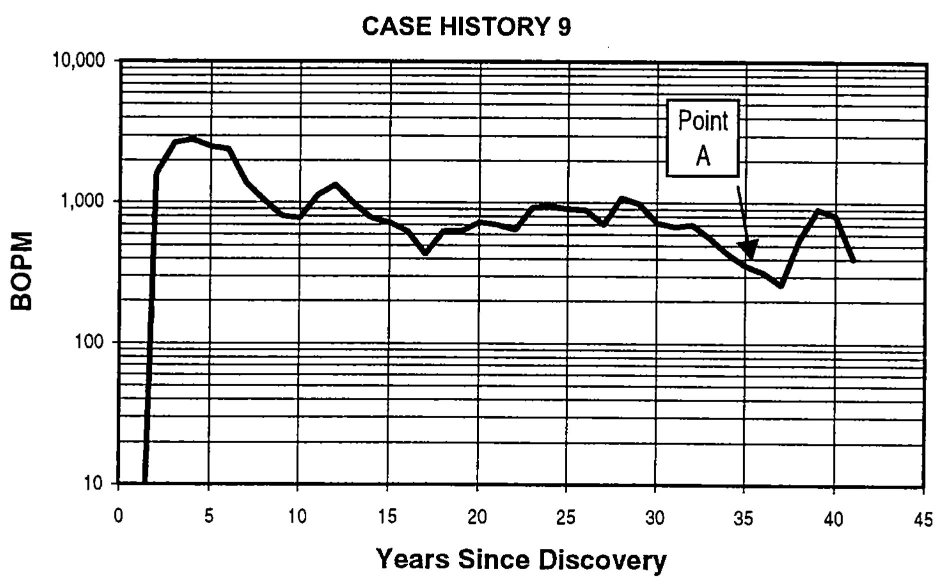


Figure 42. Cumulative-production curve since discovery of the field of case history 9. Point *A* represents time of unitization.

This complete information set is not often found, however, especially in Oklahoma, where produced-water data are not required to be reported. It is up to the evaluator to use the oil and gas cumulative-production curve, along with data concerning water production gained from physical examination of the field, to evaluate a reservoir's complete production history. If a cumulative-production curve does not show irregularities of production or reservoir performance, the production history often is not analyzed in further detail.

Consider case history 9 (Fig. 42). This is a cumulative-production curve for a reservoir in eastern Oklahoma. Gas production was only partially reported, and its source was interpreted to be dissolved gas. Water production was evaluated from field examination and was not considered significant. The oil-decline curve indicates a fairly normal solution-gas curve with irregularities considered to be associated with the addition or deletion of producers, changes in pumping procedures, recompletions, and workovers. The field was unitized at point *A*, and water injection commenced. The field responded with only a subtle increase in production—considerably less than expected, especially for the 6 years since injection started. Analogous reservoirs in the immediate vicinity responded almost immediately after injection started. Further evaluation of the project clarified the reason for the overall lack of anticipated response. Figure 43 illustrates the production curves for four of the main producing leases in the unit. An examination of all four curves shows an initial

CASE HISTORY 9

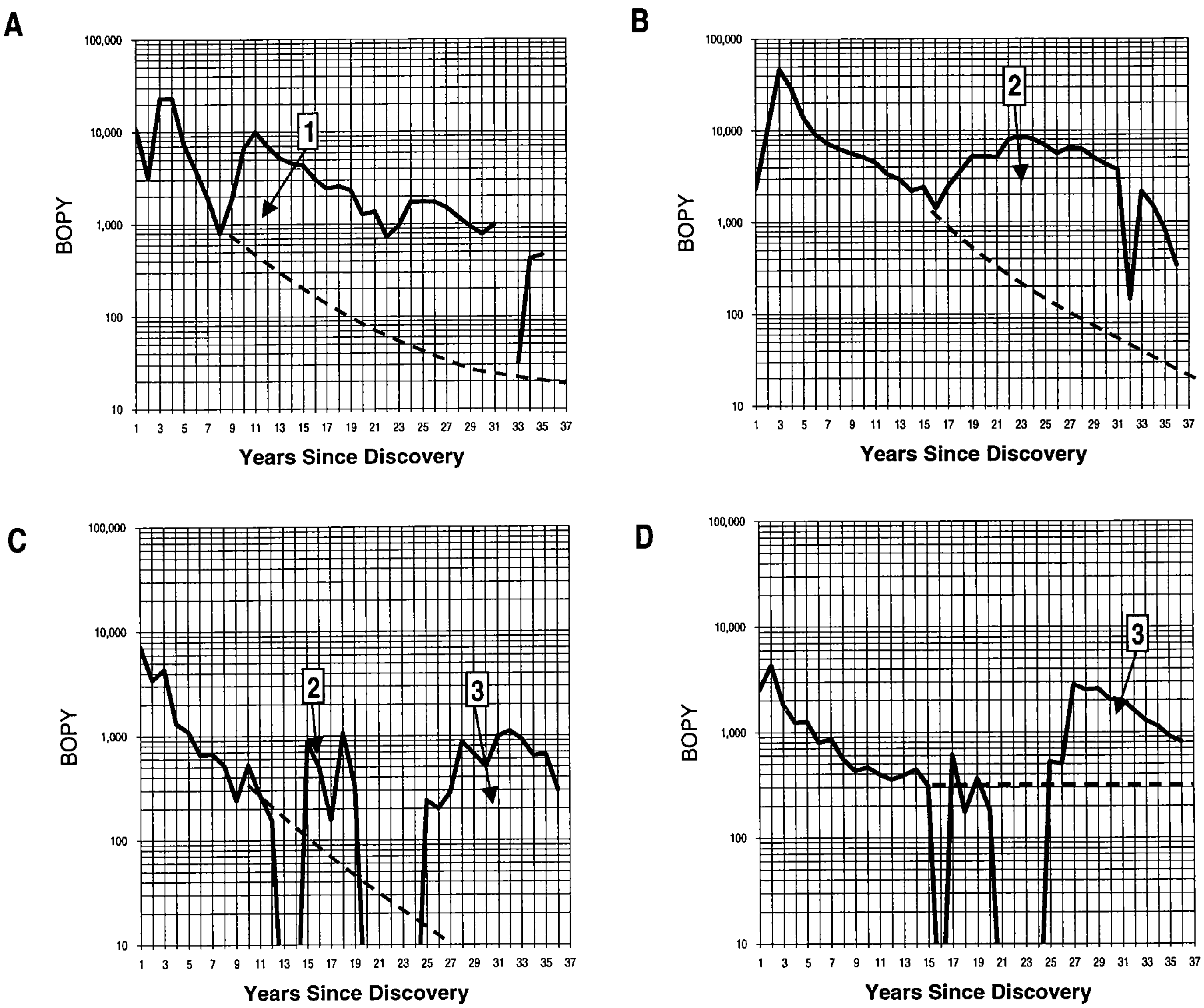


Figure 43. Four lease cumulative-production curves for the field of case history 9. Points 1, 2, and 3 represent the time when three water-disposal wells were respectively activated in this field.

peak primary production, with a subsequent decline in production. All four curves then show a substantial increase in production at various respective times. Figure 43A shows an increase in year 8, B shows an increase in year 16, C shows increases in years 16 and 24, and D shows an increase in year 24. Further investigation into the field's history revealed that salt-water-disposal wells were permitted near years 8, 16, and 24. Therefore, the production increases demonstrated by points 1, 2, and 3 on the individual lease-production curves of Figure 43A–D are actually secondary-oil-production responses as a result of injection from the salt-water-disposal wells. Because the secondary production increased at different times, the cumulative-production curve for the field (Fig. 42) did not clearly show the individual lease responses because these responses (in years 8, 16, and 24) occurred at staggered times that essentially averaged each other out, allowing the field-production curve to appear relatively smooth. For instance, when the response from lease A, whose peak occurred in year 8, started to decline, responses from leases B and C occurred in year 16. When the responses from leases B and C started to decline, responses occurred from leases C and D in year 24.

The pitfall for this example is that the smoothing effect masked any indication of secondary-production response, which actually did occur in this reservoir and which led to the lack of response after the field was unitized. This illustration demonstrates the importance of analyzing individual lease- or well-production curves to ascertain production irregularities that might not be noticed on field-production curves.

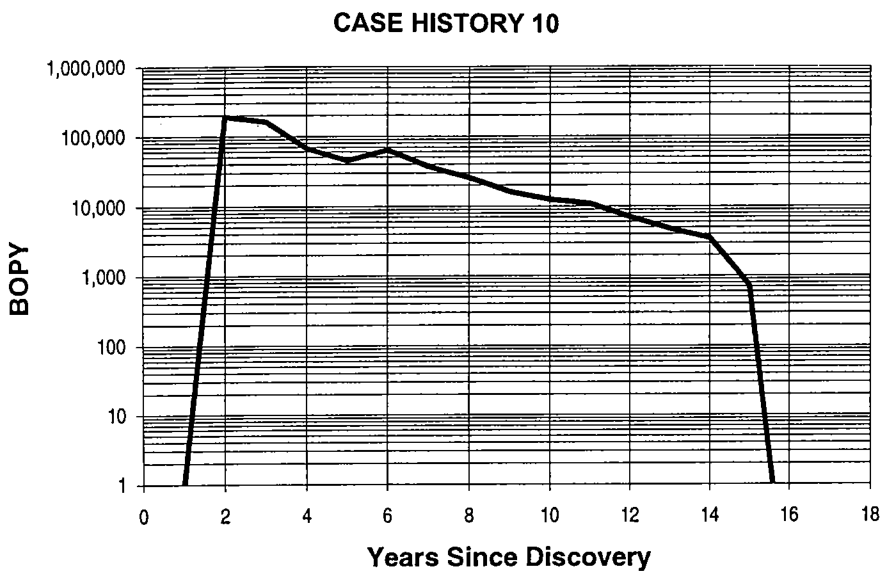


Figure 44. Cumulative-production curve since discovery for the field of case history 10.

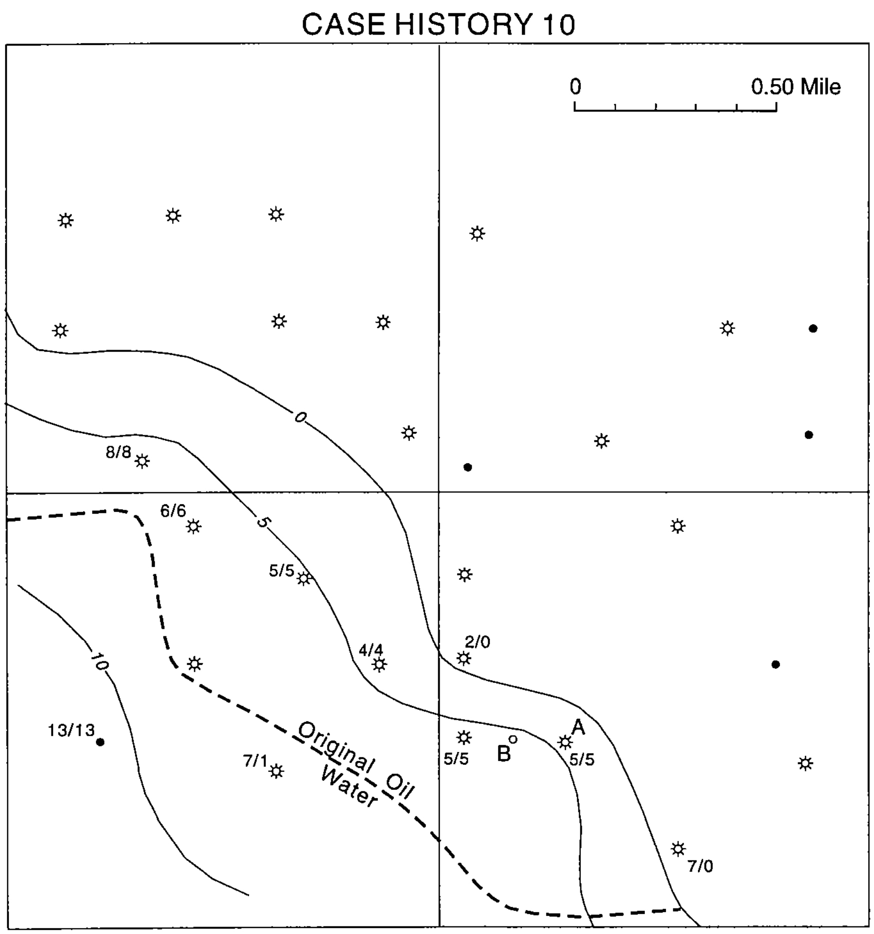


Figure 45. Isopach map of net sand for the field of case history 10 (north-central Oklahoma). Dashed line represents position of original oil–water contact (OWC). Contour interval, 5 ft.

Field cumulative-production curves not only mask production variations of individual wells or leases, as illustrated by the previous example, but can also mask recompletions of individual wells. Thus, recompletion information is another critical factor to consider when evaluating a waterflood candidate because of the possible cumulative-production variations that can occur when a well is recompleted in another reservoir.

Consider case history 10 (Fig. 44). This figure depicts the cumulative-production history of a Misener (Devonian) field in north-central Oklahoma, illustrated in Figure 45. The prospect was submitted for consideration of infill-drilling the Misener field, with the primary location being well B. The production history did not include water or gas information. Gas-production information is known and is only minor, whereas water-production data were unknown and considered insignificant by the originator of the prospect. Examination of the production curve from well A (Fig. 46) indicates a drop in production from month 10 to approximately month 30. This variation was not explained in the original prospect proposal. An investigation by the evaluator of the prospect of the completion history of well A (from the original operator) indicated that this well had been recompleted from another zone and that all the production after month 30 was actually from that zone. In fact, the well required recompletion, because the Misener had totally watered out, which was unknown by the originator of the prospect. Figure 47 illustrates the presumed position of the oil–water contact in the prospect. Well B was eventually drilled by another operator to the Misener, and was water productive.

The pitfall with the evaluation of the cumulative-production curve of Figure 44 is that the evaluator should not have assumed that the reported producing zone, as identified by the service company providing the data, is correct. It is surprising—though no fault of the service provider—how often wells have been recompleted and not reported, or have not been picked up by the service provider.

GENERATING A PRODUCTION CURVE FROM OTHER SOURCES

Almost all the oil fields that predate 1937 have no available production history or have only a partially reported history. This is a major problem for the evaluator, because primary-production history and the primary-recovery factor are major criteria in evaluating a waterflood candidate. This section highlights some concepts and techniques that should be considered in generating a production curve.

Figure 48 (case history 11) is a production curve constructed by using several sources of production information for a field discovered in 1928. The production curve has been divided into three parts.

Curve *A* was generated from the production history reported since 1970, which was reported by a production service company. The accuracy of the data is good, assuming that no wells have been recompleted in the producing zone. Water-production data, together with oil-production data, indicate that the field drive mechanism is probably solution gas. Variations in production, both by lease and for the unit, are discern-ible. Such variations should be checked for recompletions, additions, and/or deletions.

Curve *B* of Figure 48 was compiled from old Vance Rowe Reports and Petroleum Information data. These data are fairly accurate but have limitations. The production information from Vance Rowe was provided on a monthly, quarterly, semiannual, and annual basis. Detailed monthly production is available at Petroleum Information's offices on microfiche. However, most of the information readily available refers to semiannual or annual production. These data comprise two reported types of oil production: cumulative lease production and average daily production. The

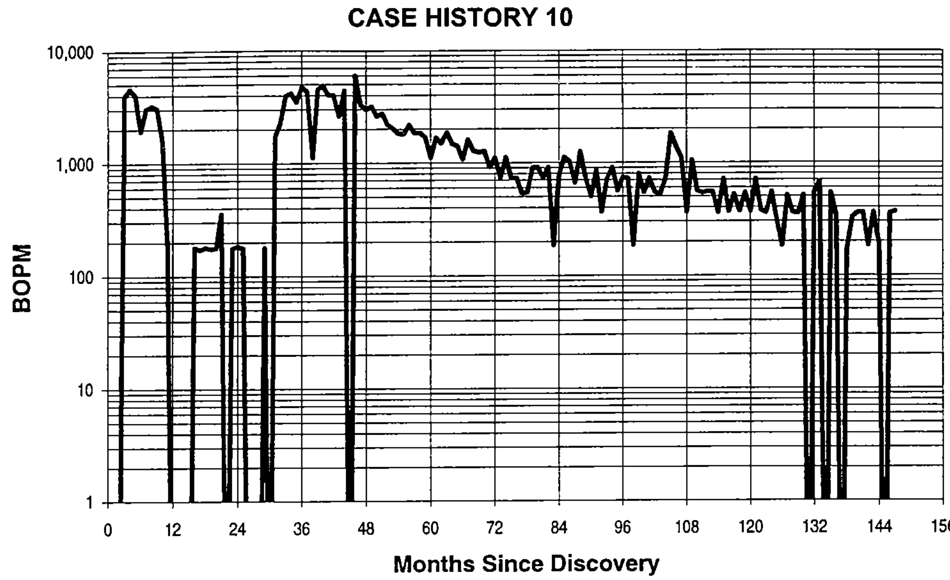


Figure 46. Cumulative-production curve for well A in the field of case history 10 in Figure 45.

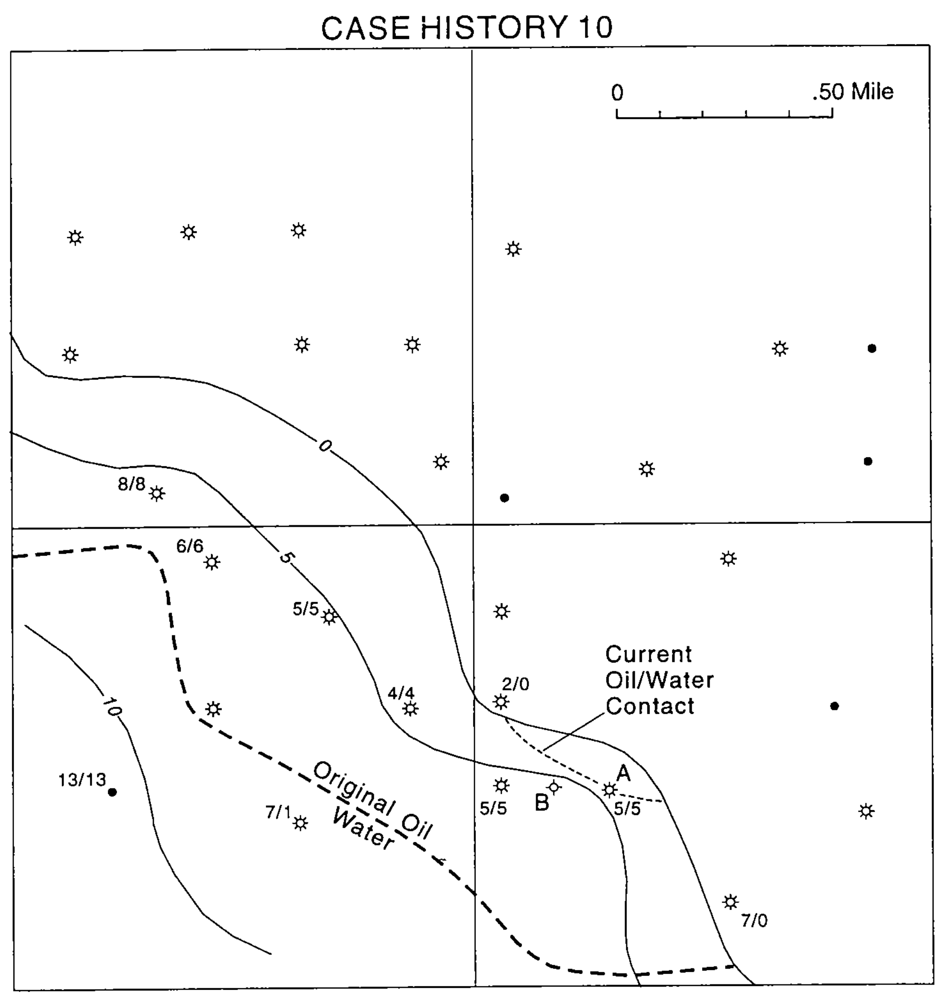


Figure 47. Isopach map of net sand for the field of case history 10. Heavy dashed line represents original OWC. Light dashed line represents current OWC. Contour interval, 5 ft.

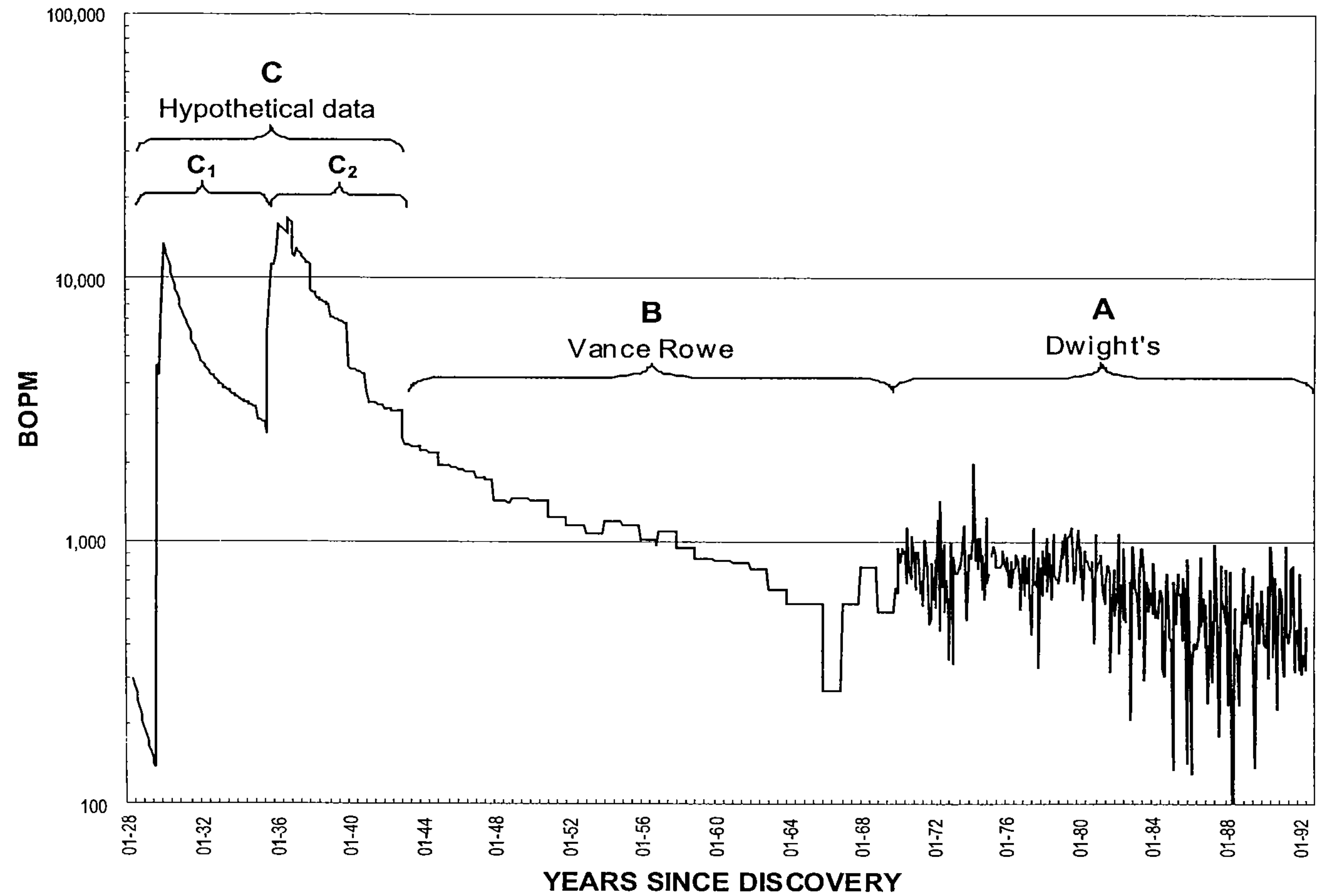


Figure 48. Hypothetical composite cumulative-production curve, incorporating actual data and extrapolated data, for a reservoir in eastern Oklahoma.

figures for average daily production were calculated by dividing the last month's production for the reporting period by 30 days. If the well was not productive for this last month, the daily figure was reported as "no runs." The quarterly, semiannual, and annual production figures do not reflect production variations such as recompletions, additions, or deletions of pay zones. The number of producing wells on a lease is reported; no reference by name, however, is made to any wells that might have been added or deleted. Only correlation with completion or plugging reports would furnish this information. Another drawback to these oil-production data is the lack of location information pertaining to each well or lease. Considerable confusion can arise when reconstructing production history, especially if the field has similar lease names drilled by different operators. If one operator were to buy out another operator's wells, it would be practically impossible to tell which lease is which without going back to the beginning and reconstructing the field's history, and identifying a particular lease by cumulative-production data and discovery-date information.

Part *C* of Figure 48 is the hypothetical decline curve generated for the field. Reconstructing approximate production data with limited data is very tricky and should be considered an estimate only. The portion of the curve labeled C_1 was created by using the following available data and assumptions:

1. The field initially was at or near the bubble point.
2. The reservoir drive mechanism was solution gas.
3. The decline rate was similar to known decline rates for similar reservoirs with similar characteristics.
4. The initial-potential flow rate was cut in half, as a rule of thumb, to account for the initial production value.
5. All available data were incorporated into the hypothetical curve, including completion data from completion reports and final producing rates and production period from the plugged-and-abandoned forms.
6. Individual curves were created for each well and lease; actual periodic data were incorporated into the curve where available.

The portion of the production curve labeled C_2 in Figure 48 was created without incorporating any known production data other than initial-potential data and final-rate data.

The composite production curve of Figure 48 was therefore generated partly from actual production information and from a hypothetical curve incorporating all available data including actual production where available. This curve, thus, is only an estimate of production and should be used cautiously. The main reason for estimating primary production is because reported production from the service-company provider is often substantially different. If the ecovery factor for the reservoir is in line with similar reservoirs for which actual production data are known, a degree of confidence then can be assumed for the hypothetical cumulative-production value created.

LEASE-USE GAS

Production-service companies distribute only information that is reported from sales of oil and gas. However, if evaluation of a waterflood candidate includes a material-balance analysis, production data from sales often are not complete. Sometimes operators use produced gas as a fuel for operating their pumping units. This gas is called *lease-use gas.* The amount of gas consumed in this manner can be substantial. Consider the amount of lease-use gas estimated from case history 11A in Table 5. This particular field in north-central Oklahoma has been using lease gas for its pumping units for an average of 10 years per well. Information gathered from the field included the engine type, the horsepower rating, and the estimated number of days used. The column on the right in Table 5 is the estimated gas used for each pumping unit. The total estimated gas used for the pumping units in the field is over 600 MMCF.

Sales from the field amounted to 3.9 BCFG, plus the 600 MMCF of lease-use gas, for a total of 4.5 BCF of produced gas. If the 3.9 BCFG is used in the material-balance calculation, it means that only 87% of the gas produced is being accounted for and used in the calculations.

TABLE 5. – Estimated Gas Consumed from Lease Engines (Case History 11A)

Lease	Production period	Engine type & horsepower		Number of days used	Estimated MCF used
Well 1	Aug '81 – Apr '92	C-66	14 HP	3,896	27,272
Well 2	Aug '80 – May '92	C-66	14 HP	4,291	30,037
Well 3	Jan '80 – Jul '91	C-66	14 HP	4,199	29,393
Well 4	Jun '81 – Aug '86	C-66	14 HP	1,887	13,209
Well 5	May '80 – Apr '92	C-66	14 HP	4,353	30,471
Well 6	May '80 – Apr '92	C-66	14 HP	4,353	30,471
Well 7	Jun '80 – Mar '86	C-66	14 HP	2,099	14,693
Well 8	Jun '80 – Mar '86	C-66	14 HP	2,099	14,693
Well 9	Jan '82 – Jan '84	C-66	14 HP	730	5,110
Well 10	Oct '80 – Jul '91	C-66	14 HP	3,925	27,475
Well 11	Mar '80 – Jan '92	C-66	14 HP	4,323	30,261
Well 12	Mar '80 – Jan '92	C-66	14 HP	4,323	30,261
Well 13	Sep '79 – Sep '86	503	20 HP	2,557	17,899
Well 14	Oct '79 – Jun '92	C-66	14 HP	4,627	32,389
Well 15	Oct '79 – Mar '81	C-66	14 HP	516	3,612
Well 16	Oct '79 – Mar '81	C-66	14 HP	516	3,612
Well 17	Oct '79 – Mar '81	C-66	14 HP	516	3,612
Well 18	Jan '80 – Aug '85	C-66	14 HP	2,039	14,273
Well 19	Mar '79 – Apr '90	346	18 HP	4,049	28,343
Well 20	Oct '79 – Feb '92	C-66	14 HP	4,506	31,542
Well 21	Dec '79 – Feb '92	C-66	14 HP	4,445	31,115
Well 22	Mar '80 – Jan '92	C-66	14 HP	4,323	30,261
Well 23	Mar '80 – Jan '92	C-66	14 HP	4,323	30,261
Well 24	Nov '79 – Jan '82	C-66	14 HP	792	5,544
Well 25	Nov '79 – Jan '82	C-66	14 HP	792	5,544
Well 26	Jan '80 – Jan '89	346	18 HP	3,288	23,016
Well 27	Jan '80 – Jan '89	346	18 HP	3,288	23,016
Well 28	Jan '80 – Jan '89	346	18 HP	3,288	23,016
Well 29	Mar '81 – Mar '83	C-66	14 HP	730	5,110
Well 30	May '80 – Jan '82	C-66	14 HP	610	4,270
Well 31	Jan '84 – Jan '89	C-66	14 HP	1,827	12,789

Total estimated use: 612,570 MCF

Note: Above chart uses an average of 7 MCF/day for gas engines.

4

Determining Net Pay

CHAPTER 4

Determining Net Pay

INTRODUCTION

Determining net pay for a waterflood candidate is another crucial aspect of the evaluation. Net-pay calculations affect OOIP values, reserve estimates, economics, and performance characteristics. Properties that affect the determination of net pay that are discussed in this chapter include porosity–permeability correlations, average porosity and thickness, impermeable parts of the reservoir, and fluid contacts. Water-saturation cutoff values will be discussed in the second part of this series, which will deal with engineering pitfalls. It is assumed that all the examples included in this chapter are at or near irreducible water saturation. The following examples (case histories) deal with pitfalls that may arise when determining net pay.

DEFINITION OF NET PAY

The parameters of area, porosity, salt-water saturation, and height in the OOIP formula are the principal components of net pay. *Porosity* is defined as the percentage of the bulk volume of a rock or soil that is occupied by interstices, whether isolated or connected (Jackson, 1997). In an undersaturated oil reservoir, the interstices are initially filled with one of two fluids, either oil or water. Net pay is reduced by the value of $1 - S_w$ in the OOIP formula, but, as mentioned in the introduction, we assume that the water saturation is at irreducible conditions. *Height* is simply the vertical thickness of porous reservoir above water. *Area* is the areal extent of porous reservoir. The height and area of a reservoir can include porous reservoir containing oil, water, or a combination of oil and water such as a transition zone. The height, areal extent, and porosity, when multiplied together, give the amount of pore volume for the reservoir. When the pore volume is multiplied by $1 - S_w$, the result is the hydrocarbon pore volume for the reservoir.

Net pay can be defined in several ways—for example, in gross feet, net feet, porous feet, or hydrocarbon pore volume. Net pay is commonly expressed in net feet, in which the total feet of pay is calculated by adding the total thickness of pay that exceeds a minimum value of porosity. The values for height and porosity in the OOIP formula are ones that a geologist should be extremely careful in determining. The method for determining average thickness (H) and average porosity (ϕ) for a reservoir should be as exact as possible.

Consider case history 12 of Figure 49, which shows the planimetered result of a net-sand isopach map for a reservoir in central Oklahoma. The net sand for each wellbore was determined by adding the total feet of oil-bearing pay with a porosity value over a minimum value determined by the operator. The values for each wellbore were contoured and planimetered, resulting in this isopach map. For calculating OOIP for the reservoir, the OOIP formula uses an average height for the reservoir. Some geologists and engineers tend to use either an arithmetic average for the variable height or some other quick-look estimate. Either method can lead to considerable error, as this example illustrates. As the contour interval is zero to 30 ft, the average height would be 15 ft if the reservoir were shaped like a triangle.

Table 6 illustrates the variables used to calculate the OOIP value. Model 1 calculates over 5 MMBO in place, using an average height of 15 ft. Determining a weighted-average height is a second technique often used by geologists and engineers. This value is derived by finding the mathematical average height and adjusting its value either up or down, depending on whether most of the reservoir appears to be thicker or thinner than the mathematical average. Model 2 calculates 4.2 MMBO in place, using a weighted-average height. However, the correct way to obtain the calculated average height is to obtain the total acre-feet for the reservoir and divide by the area (Fig. 49); this results in a calculated thickness of 10.6 ft. Model 3 of Table 6 uses the same variables in the OOIP formula but substitutes 10.6 ft for average height. The corresponding OOIP is 3.7 MMBO. The difference between the average height and the calculated height in the OOIP formula is 1.5 MMBO, or a 41% increase. The difference between the weighted-average height and the calculated height in the OOIP formula is 494 MBO, or a 13% increase. These errors in OOIP would be significant when calculating current oil saturations, potential secondary-recovery production, and justifying capital expenses for recovering this inflated volume of oil.

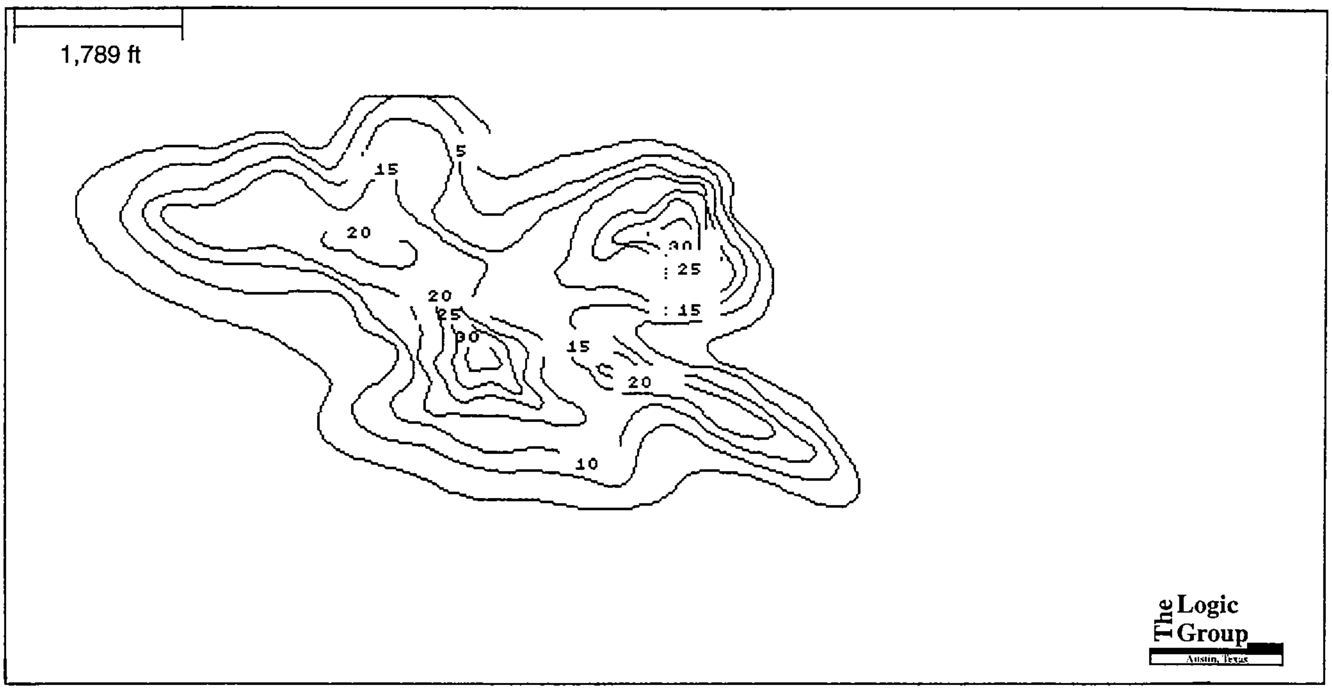
Estimating average porosity for the OOIP formula will also have problems similar to those described in case history 12 of Figure 49. Consider Figure 50, which shows the planimetered result of the porosity isopach map for the same reservoir, using a minimum-porosity cutoff of 10%. The contour interval is 10% to 24%, and the apparent mathematical average porosity would be 17%.

Table 7 illustrates the original oil in place, using the same variables as those of Table 6. Model 1 calculates the OOIP, using 17% as the average porosity, which results in a value of 4.2 MMBO. The planimetered porosity-foot value of Figure 50, divided by the area, yields a calculated average porosity of 15%. Model 2 calculates 3.7 MMBO of OOIP, using this value. The difference between models 1 and 2 is 500 MBO, or a difference of 13%, which again is a significant change.

MINIMUM VALUES FOR POROSITY AND PERMEABILITY

The interstices, or pore spaces, in a reservoir are filled by one or more fluids such as oil, gas, and water. For these fluids to reach the wellbore, the pore spaces must be connected, and the fluid must be able to migrate through the interstices of the reservoir. *Permeability*, by definition, is the capacity of a porous rock, sediment, or soil for transmitting a fluid; it is a measure of the relative ease of fluid flow under unequal pressure (Jackson, 1997). The customary unit of measurement is the millidarcy (md). During primary production, all hydrocarbon-bearing reservoirs with effective porosity and permeability will yield primary reserves. If this last statement were completely valid, all wells with hydrocarbon-bearing reservoirs should be successful. The reason why economic failures occur is because there are minimum economic limits to porosity and permeability. Less than minimum values of porosity yield noncommercial quantities of recoverable hydrocarbons in relation to the cost of developing those hydrocarbons. Less than minimum values of permeability

CASE HISTORY 12



CONTOUR DATA:

h, Ft	Area, ft2	Area, Ac
30	167,440.5	3.8439
25	715,249.8	16.4
20	1.7672E+06	40.6
15	6.2667E+06	143.9
10	1.1414E+07	262.0
5	1.5916E+07	365.4
0	2.2037E+07	505.9

Delta thickness of top layer: 2
Sink Hole Volume subtracted: 0 Acft

VOLUMETRICS:

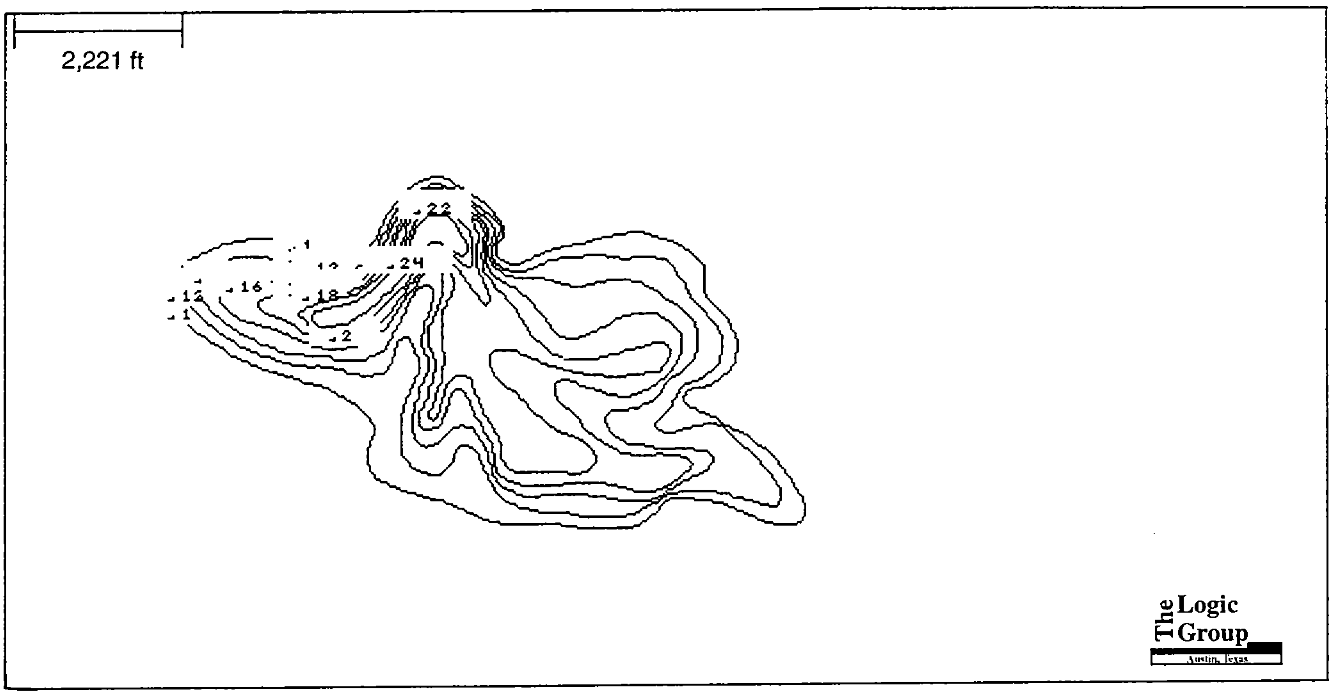
Method	Vol, ft3	Vol, Acft
Trapezoid	2.3608E+08	5,419.6
3/8 Rule	2.3184E+08	5,322.3
Trap/Pyra	2.3452E+08	5,383.8
Pyramid	2.3316E+08	5,352.5
Quadratic	2.6052E+08	5,980.7
Simpson	2.3377E+08	5,366.6
Ratio	2.4273E+08	5,572.3
Step	1.8124E+08	4,160.6

Figure 49. Planimetered isopach map of net sand with volumetric and contour data for the reservoir of case history 12 (central Oklahoma). Contour interval, 5 ft.

TABLE 6. – Comparison of Average Height, Weighted Average, and Calculated Height in the OOIP Formula

Model	BO/acre-ft constant	Average porosity (%)	S_w (%)	Area (acres)	Average height (ft)	B_{oi}[a]	OOIP (reservoir BO)	Delta OOIP (BO)	Difference (%)
1	7,758	15	3	505.9	15	1.2502	5,297,595	1,553,961	42
2	7,758	15	3	505.9	12	1.2502	4,238,076	494,442	13
2	7,758	15	3	505.9	10.6	1.2502	3,743,634	0	0

[a] Initial formation volume factor for oil.



CONTOUR DATA:

h, Ft	Area, ft2	Area, Ac
.24	258,187.8	5.9272
.22	742,497.7	17.0
.2	1.3453E+06	30.9
.18	4.6107E+06	105.8
.16	8.5408E+06	196.1
.14	1.2377E+07	284.1
.12	1.6972E+07	389.6
.1	2.1878E+07	502.3

VOLUMETRICS:

Method	Vol, ft3	Vol, Acft
Trapezoid	3.3009E+06	75.8
3/8 Rule	3.2957E+06	75.7
Trap/Pyra	3.2973E+06	75.7
Pyramid	3.2915E+06	75.6
Quadratic	3.2337E+06	74.2
Simpson	3.2913E+06	75.6
Ratio	3.3523E+06	77.0
Step	3.0847E+06	70.8

Delta thickness of top layer: 0
Sink Hole Volume subtracted: 0 Acft

Figure 50. Planimetered isopach map of net porosity with contour and volumetric data for the reservoir of case history 12 (central Oklahoma). Contour interval, 5 ft.

TABLE 7. – Comparison of Average Porosity and Calculated Porosity in the OOIP Formula

Model	BO/acre-ft constant	Average porosity (%)	S_w (%)	Area (acres)	Average height (ft)	B_{oi}[a]	OOIP (reservoir BO)	Delta OOIP (BO)	Difference (%)
1	7,758	17	30	505.9	10.6	1.2502	4,242,785	0.5 MM	13.3
2	7,758	15	30	505.9	10.6	1.2502	3,743,634	0	0

[a] Initial formation volume factor for oil.

yield noncommercial quantities of recoverable hydrocarbons in relation to the time of developing those hydrocarbons.

Essentially, minimum values for porosity and permeability dictate the volume of recoverable oil and the time necessary to produce this oil versus the related costs. The minimum values for porosity and permeability are arbitrary and are established by the operator on the basis of experience and economic parameters. Smith and Cobb (1987) suggest that the minimum values for porosity in carbonate reservoirs should be 6% and in cemented-sandstone reservoirs, 12%–15%. Operators in the Midcontinent probably tend to use 10% as a minimum value for cemented-sandstone reservoirs. Smith and Cobb (1987) also state that minimum values of 0.5–1.0 md for air permeabilities in carbonate reservoirs and 0.5–2 md for consolidated-sandstone reservoirs are frequently used.

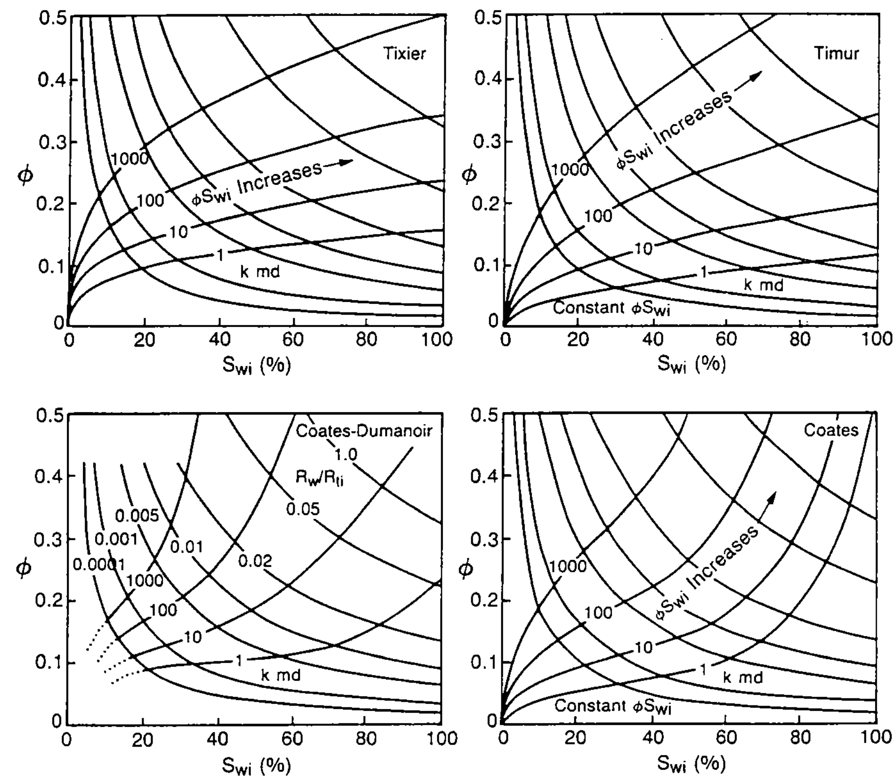


Figure 51. Charts for estimating permeability (k) from effective porosity (ϕ) and irreducible water saturations (S_{wi}). (Courtesy of Schlumberger Oilfield Services.)

Effective porosity, by definition, is the percentage of the total volume of a given mass of soil or rock that consists of interconnected interstices (Jackson, 1997). A reservoir can have high porosities, but if the pore spaces are not connected naturally or artificially, the reservoir will not produce. Distinguishing effective porosity from porosity is difficult and requires not only various types of data, including cores, open-hole logs, and volumetric calculations, but also a certain amount of intuitive instinct gained from practical experience. This instinct may be all that is available when evaluating some waterflood candidates for which very little additional data are initially available.

Effective porosity is related to permeability, because both definitions are based on the interconnectivity of the interstices. Low effective porosities are usually synonymous with low permeabilities. Core analysis is the most accurate method for determining porosities and permeabilities. Unfortunately, many fields being considered as waterflood candidates lack core data. In this event, charts, illustrated in Figure 51, are available for estimating permeability if effective-porosity and irreducible-water-saturation values are known. These charts were derived from data from Gulf Coast reservoirs.

One factor that probably should be addressed is the comparison of calculated average porosity and effective porosity. Consider Table 8A,B. Part A gives the parameters for the reference reservoir. The drive mechanism is solution gas, and the field's pressure is depleted after a primary recovery of 219,600 BO. The primary-recovery factor is 17.4%. Consider, for instance, that the reservoir of Table 8B is similar in all respects to that of the reference reservoir, except that it produced only half as much primary oil. Models 1–5 multiply an effective-porosity percentage times the porosity value until the recovery factor is similar to that of the reference example. The 50% value is required for

TABLE 8. – Comparison of Calculated Average Porosities and Effective Porosities for Similar Reservoirs of Known Recovery Factor and Drive Mechanism

Model	BO/acre-ft constant	Porosity (%)	Effective porosity (%)	S_w (%)	Area (acres)	Average height (ft)	B_{oi}[a]	OOIP (BO) of reservoir w/effective porosity	Recovery factor (%)
A — Calculated average porosity is 100% effective for a reservoir with 219,600 BO of primary production									
1	7,758	12.5	100	25	252.9	8.6	1.2502	1,265,286	17.4
B — Estimation of effective porosity for a reservoir whose hydrocarbon pore volume is similar to example A but produces only 109,800 BO of primary production									
1	7,758	12.5	100	25	252.9	8.6	1.2502	1,265,286	8.7
2	7,758	12.5	75	25	252.9	8.6	1.2502	948,965	11.6
3	7,758	12.5	50	25	252.9	8.6	1.2502	632,643	17.4
4	7,758	12.5	25	25	252.9	8.6	1.2502	316,322	34.7
5	7,758	12.5	10	25	252.9	8.6	1.2502	126,529	86.8

[a] Initial formation volume factor for oil.

the two recovery factors to be equal. This implies that only 50% of the porosity is actually effective porosity. Table 8B also illustrates that only 632 MBO, of the 1.265 MMBO in place, has been affected by production.

EFFECTS OF COMPACTION, CEMENTATION, AND SORTING ON POROSITY AND PERMEABILITY

Many primary factors influence porosity and permeability values in reservoirs after deposition. Three factors that we discuss are compaction, cementation, and sorting.

Compaction, by definition, is the reduction in bulk volume or thickness of fine-grained sediments in response to the increasing weight of overlying material that is continually being deposited, or to pressures resulting from earth movements (Jackson, 1997). The tighter packing of sedimentary particles results in a decrease in porosity. This implies that as the pore spaces become smaller, the pathway through the rock becomes more tortuous, resulting in generally lower permeabilities.

A second factor that influences porosity and permeability is *cementation*, the diagenetic process by which coarse clastic sediments become lithified or consolidated into hard, compact rocks, usually through deposition or precipitation of minerals in the spaces among the individual grains of the sediment (Jackson, 1997). The deposition of the cement occurs in the pore spaces, reducing the porosity and permeability. Pressure solution that can occur with burial also reduces the porosity and permeability.

A third factor that affects porosity and permeability is *sorting*, the dynamic process by which sedimentary particles having some particular characteristic (such as size, shape, or specific gravity) are naturally selected and separated from associated but dissimilar particles by the agents of transportation (Jackson, 1997).

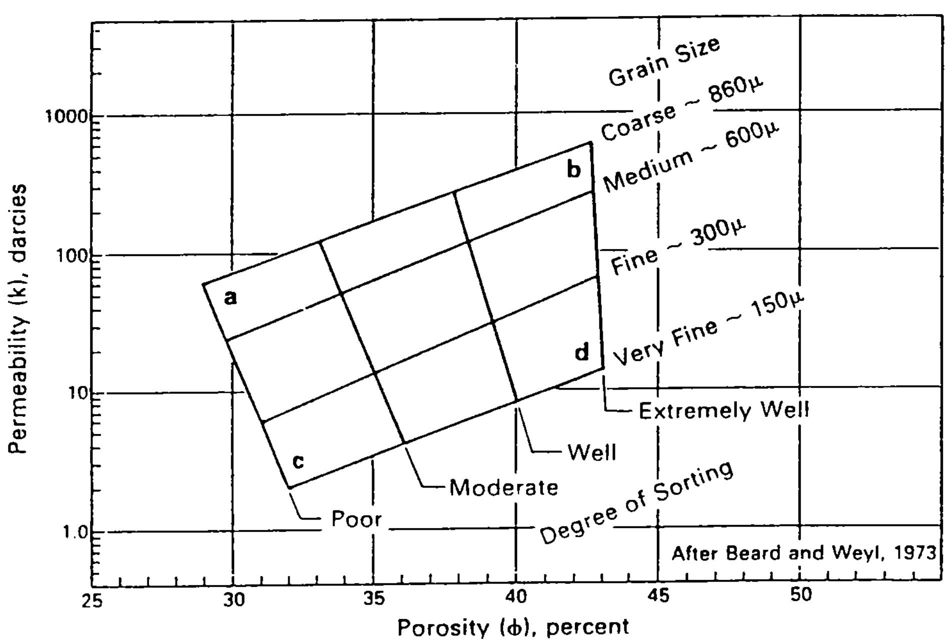


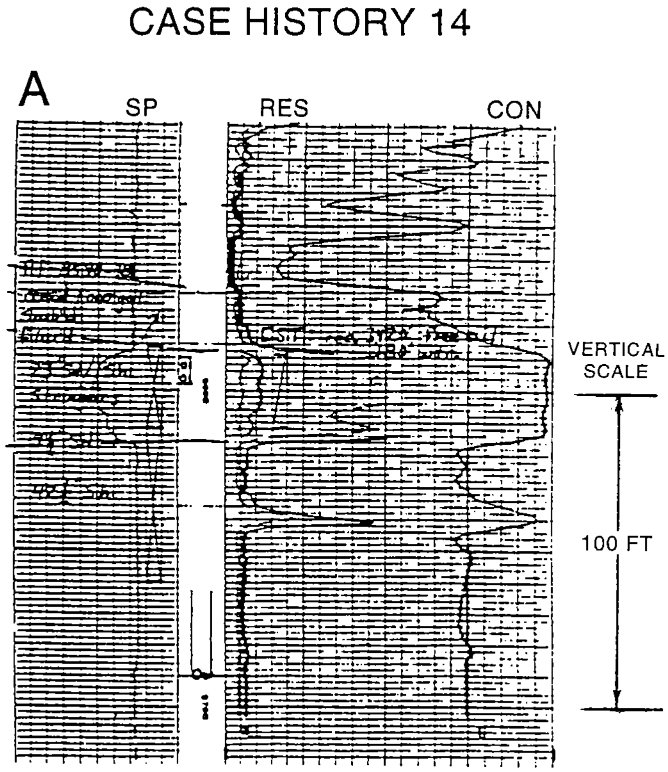
Figure 52. Effects of sorting and grain size on porosity and permeability. Measurements derived from hand-packed samples. Modified from Beard and Weyl (1973). (Courtesy of Schlumberger Oilfield Services.)

Figure 52 is a chart illustrating the effect of grain size and sorting on porosity and permeability from man-made sand packs studied by Beard and Weyl (1973). They studied samples of varying grain size and sorting, which contained natural hand-packed samples using sands obtained from the Texas Gulf Coast. The chart shows that permeability is more sensitive to grain size, whereas porosity is more sensitive to sorting. The values given in this chart cannot be used for buried sandstone reservoirs, but the implication is valid. This leads into the practicality of intuitive instinct, mentioned previously. Geologists' training should make them aware of the various factors that influence porosity and permeability. As porosity and permeability information from cores, advanced logging tools, or production results and practices often is not available, geologists commonly are left with nothing more than old-fashioned open-hole logs for distinguishing minimum effective porosity and/or minimum permeability.

Consider the log curves of case history 14 (Fig. 53). This well is an upper Morrow producer in the Texas Panhandle. It is part of a reservoir being considered as a waterflood candidate. Electric-log calculations (Fig. 53A) indicate that the zone should contain a water saturation >35% and a porosity ≥10%. However, examination of the gamma-ray curve (Fig. 53B) indicates that the lower 10 ft of the pay zone is characterized by a higher shale or clay content and possibly poorer sorting. In light of the implications of the chart from Figure 52, this section of reservoir should not contribute the same amount of BO/acre-foot as the upper 17 ft.

Table 9 is a core analysis obtained later in the evaluation of the project. The lower 6 ft of the analysis—actually the upper 6 of the 10 ft of the shaly section as seen on the gamma-ray and spontaneous-potential (SP) curves—is characterized by a permeability below the cutoff value of the reservoir and no oil saturation. Therefore, the bottom 10 ft of this pay section contributed no oil to the primary production. Figure 54 is a porosity–permeability scatterplot for the well of case history 14.

If core data are available, porosity–permeability correlation curves can be created to determine minimum values. A semi-log plot is prepared similar to Figure 54. The permeability cutoff can be used to define the corresponding porosity cutoff, and vice versa.



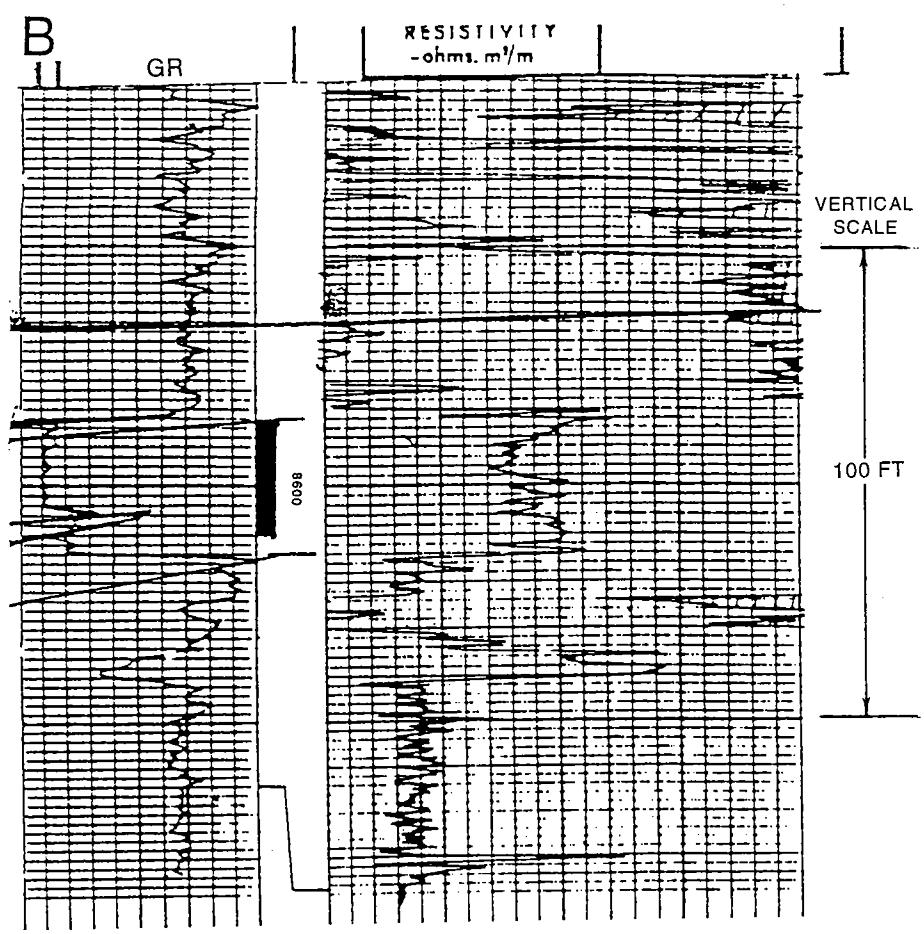


Figure 53. Electric (A) and gamma-ray and sonic logs (B) for reference well of case history 14 (Texas Panhandle).

PICKING NET-PAY VALUES

Table 10 illustrates how percentage differences of various porosity and thickness values affect OOIP. In *A*, the average height is increased by 10% increments. The percentage difference of oil in place also is increased by 10% increments. In *B*, porosity values are increased by 10%, with similar results. In *C*, porosity and average height are increased by 10% increments, and the resulting percentage differences increase markedly. This table demonstrates the importance of determining average height and porosity values as accurately as possible.

Table 11 gives the summary of vertical resolution, sampling interval, and resolution for various Schlumberger logging services. As can be seen in the first column, vertical resolution varies from a few tenths of inches to several feet, depending on the type of tool. Vertical resolution must be kept in mind when attempting to determine net pay thicknesses because of the magnitude of error in OOIP calculations that can result, as illustrated by Table 10. Figure 55 compares the density-log response for a 6-in. sampling rate and a 1.2-in. sampling rate. Obviously, the latter's zone definition is much clearer, which results in greater accuracy for net-pay thicknesses. Figure 56 illustrates similar results, comparing standard-induction, phasor-induction, and enhanced-phasor-induction resolutions. Both layers A and B are

TABLE 9. – Core Analysis from Well of Figure 53

Sample no.	Depth (ft)	Permeability (md)	Porosity (%)	Residual saturation (percentage of pore space) Oil	Water	Total
1	8,587.0–88.0	57.0	15.5	8.4	43.2	51.6
2	88.0–89.0	123.0	15.6	9.6	48.0	57.6
3	89.0–90.0	95.0	14.6	10.3	44.5	54.8
4	90.0–91.0	60.0	13.7	9.5	40.9	50.4
5	91.0–92.0	52.0	15.1	8.6	46.3	54.9
6	92.0–93.0	91.0	15.3	7.8	43.9	51.7
7	93.0–94.0	102.0	16.9	8.9	46.1	55.0
8	94.0–95.0	53.0	14.6	8.9	38.4	47.3
9	95.0–96.0	76.0	12.1	9.1	25.6	34.7
10	96.0–97.0	115.0	16.6	9.0	39.9	48.9
11	97.0–98.0	80.0	16.6	6.6	40.4	47.0
12	98.0–99.0	21.0	16.1	8.1	42.8	50.9
13	99.0–00.0	44.0	13.3	8.3	42.8	51.1
14	8,600.0–01.0	36.0	15.9	9.4	40.2	49.6
15	01.0–02.0	161.0	12.9	8.5	34.8	43.3
16	02.0–03.0	12.0	12.4	10.5	38.8	49.3
17	03.0–04.0	50.0	13.8	8.0	33.3	41.3
18	04.0–05.0	0.1	13.2	0.0	47.0	47.0
19	05.0–06.0	0.2	12.0	1.7	48.3	50.0
20	06.0–07.0	0.4	12.5	0.0	45.6	45.6
21	07.0–08.0	0.3	13.0	0.0	46.2	46.2
22	08.0–09.0	0.6	12.9	0.0	41.1	41.1
23	8,609.0–10.0	0.2	12.8	0.0	44.5	44.5

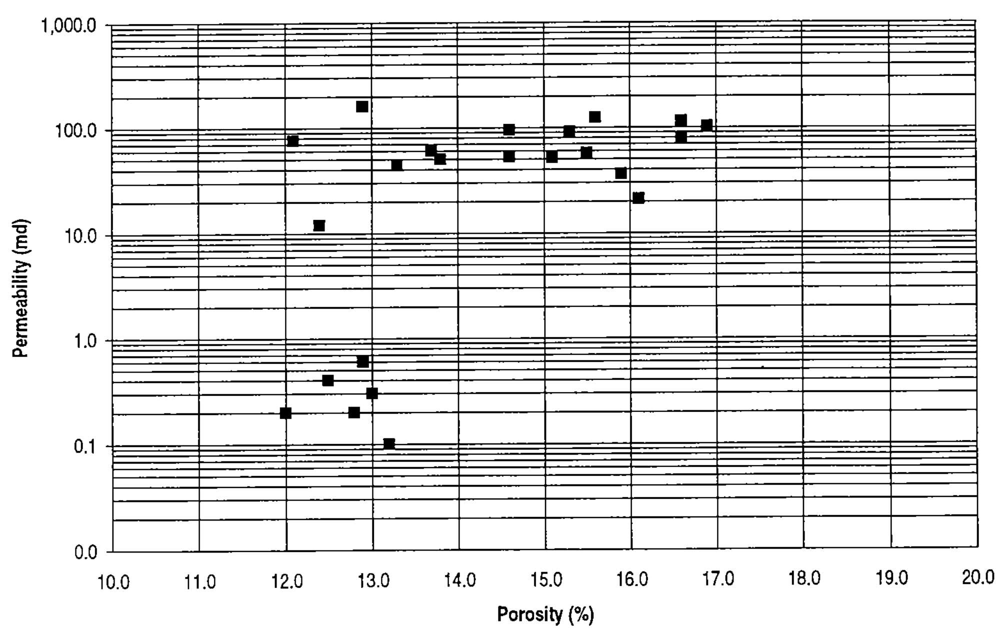


Figure 54. Porosity–permeability scatterplot of core analysis from well in Figure 53.

TABLE 10. – Comparison of OOIP Values for Various Porosity and Thickness Values

Model	BO/acre-ft constant	Average porosity (%)	S_w (%)	Area (acres)	Average height (ft)	B_{oi}[a]	OOIP (reservoir)
A							
1	7,758	10	30	1,000	10	1.25	4,654,800
2	7,758	10	30	1,000	11	1.25	5,120,280
3	7,758	10	30	1,000	12	1.25	5,585,760
4	7,758	10	30	1,000	13	1.25	6,051,240
Percentage difference:		Model 2	10%				
		Model 3	20%				
		Model 4	30%				
B							
1	7,758	10	30	1,000	10	1.25	4,654,800
2	7,758	11	30	1,000	10	1.25	5,120,280
3	7,758	12	30	1,000	10	1.25	5,585,760
4	7,758	13	30	1,000	10	1.25	6,051,240
Percentage difference:		Model 2	10%				
		Model 3	20%				
		Model 4	30%				
C							
1	7,758	10	30	1,000	10	1.25	4,654,800
2	7,758	11	30	1,000	11	1.25	5,632,308
3	7,758	12	30	1,000	12	1.25	6,702,912
4	7,758	13	30	1,000	13	1.25	7,866,612
Percentage difference:		Model 2	21%				
		Model 3	44%				
		Model 4	69%				

[a] Initial formation volume factor for oil.

approximately 10 ft thick. Not interpreting the inflection point for the standard-induction curve correctly could easily result in a 1- or 2-ft error, which, as illustrated in Table 10, results in a 10% or 20% error for OOIP.

IMPORTANCE OF DETERMINING NON-RESERVOIR PAY ZONE

Figure 57 is the reference log for the field of case history 15. As the figure illustrates, the sandstone interval has been divided into six layers. Figure 58 is a net isopach map of the fourth Tonkawa sandstone interval, shown in Figure 57. Reservoir C is producing from this interval. The trapping mechanism for reservoir C is stratigraphic, and the trap is sealed by shales to the north, northeast, and east. Of interest in this example is the trapping mechanism of the reservoir to the northwest and west. Figure 59 is a north–south cross section from the low-energy deposits on the north to reservoir C on the south. The fourth sand is apparent in both wells 1 and 3 and is missing in the tidal-channel deposits of well 2. It is apparent from the net isopach map of this sandstone that the reservoir appears continuous from reservoir C to the northwest and west, so what is the trapping mechanism? Examination of the fourth Tonkawa sandstone interval on the reference well log of Figure 57 indicates that the sand is characterized by a higher gamma-ray curve, denoting shalier or more poorly sorted reservoir constituents than sands of the sixth interval. This implies that the sand is shalier and not as well sorted as the cleaner sands. The trapping mechanism to the northwest and west is probably a permeability barrier induced by the poor reservoir quality of the low-energy deposits. The net sandstone for the isopach map of Figure 58 was picked for all wells by using a 50% cutoff between the shale baseline and the cleanest gamma-ray point. This criterion is commonly used by geologists and engineers. As can be seen on the log of well 1 in the cross section of Figure 59, the 50% formula for determining net pay would indicate that the fourth Tonkawa sand in this well should be considered net pay. However, this well is in that portion of the depositional environment characterized by low-energy, poorly sorted and shaly deposits, which are impermeable and have created the trapping mechanism for reservoir C. Understanding the depositional environment and the physical characteristics of the sand deposit, together with the trapping mechanism reveals that the use of a 50% cutoff to establish reservoir-quality strata was too optimistic in this case. A more pessimistic pick, perhaps one-fourth to one-third of the distance between the cleanest gamma-ray point and the shale baseline, would result in less net sand, but the trapping mechanism and the volume of the reservoir would have been more correct and obvious.

UNDERSTANDING THE IMPORTANCE AND GEOMETRY OF THE OIL–WATER CONTACT

Figure 60 is a net-sandstone isopach map (case history 16) of a Red Fork reservoir in north-central Oklahoma. The dashed contour in the southwestern part of the sand body represents the upper limit of the oil–water contact (OWC). The definition of this contact is the boundary surface between an accumulation of oil and the underlying bottom water (Jackson, 1997). Often, on an isopach map the boundary is drawn at the point at which the bottom water constitutes the complete pay zone. Figure 61 is a southwest–northeast

TABLE 11. – Vertical Resolution, Sampling Interval, and Optimal Resolution for Schlumberger Logging Services

Measurement	Intrinsic Vertical Resolution	Sampling Interval	Optimal Resolution Reported on the Log
Formation MicroScanner* tool	0.2 in/5 mm	0.1 in/3 mm	0.2 in/5 mm[1]
Stratigraphic High-Resolution Dual Dipmeter* tool	0.4 in/1 cm	0.1 in/3 mm	0.4 in/1 cm
High-Resolution Dipmeter (HDT*) tool	0.5 in/13 mm	0.2 in/5 mm	0.5 in/13 mm
Electromagnetic Propagation (EPT*) tool			
attenuation[2]	~2 in/5 cm	2 in/5 cm 0.4 in/1 cm	~4 in/10 cm ~2 in/5 cm
transit time	2 in/5 cm	2 in/5 cm 0.4 in/1 cm	~4 in/7-10 cm 2 in/5 cm
Microlog	2-4 in/5-10 cm	2 in/5 cm	2-4 in/5-10 cm
Micro-spherically Focused Log	2-3 in/5-7.6 cm	2 in/5 cm 0.4 in/1 cm	4 in/10 cm 2-3 in/5-7.6 cm
Standard[3] and Phasor* Induction			
deep	7-8 ft/~2 m	6 in /15 cm	7-8 ft/~2 m
medium	5-6 ft/~1.5 m	6 in/15 cm	5-6 ft/~1.5 m
Enhanced Resolution Phasor Induction			
deep/medium	3 ft/91 cm	6 in/15 cm	3 ft/91 cm
Spherically Focused (SFL*) log	30 in/76 cm	6 in/15 cm	30 in/76 cm
Laterolog[3]	24 in/61 cm	6 in/15 cm	24 in/61 cm
Spontaneous potential	not applicable	6 in/15 cm	~5 ft/1.5 m
Litho-Density* tool			
Standard density	15 in/38 cm	6 in/15 cm 1.2 in/3 cm	18 in/46 cm 15 in/38 cm
Enhanced Resolution processing density	4 in/10 cm	6 in/15 cm 1.2 in/3 cm	12 in/31 cm 4 in/10 cm
P_e	2 in/5 cm	6 in/15 cm 1.2 in/3 cm	18 in/46 cm 4 in/10 cm
Compensated Neutron (CNL*) log			
Standard porosity[4]	15 in/38 cm	6 in/15 cm	18 in/46 cm
Resolution-matched porosity[4]	24 in/61 cm	6 in/15 cm	30 in/76 cm
Standard porosity	15 in/38 cm	1.2 in/3 cm	15 in/38 cm
Resolution-matched porosity	24 in/61 cm	1.2 in/3 cm	24 in/61 cm
Enhanced Processing porosity	12 in/31 cm	6 in/15 cm 1.2 in/3 cm	18 in/46 cm 12 in/31 cm
Gamma-ray Log, Natural Gamma-ray Spectrometry (NGS*) tool	8-12 in/20-31 cm	6 in/15 cm	18 in/46 cm
Array Sonic* tool			
Standard	4 ft/1.2 m	6 in/15 cm	4 ft/1.2 m
6-in Δt mode	6 in/15 cm	6 in/15 cm	~12 in/31 cm
Borehole-Compensated Sonic tool	24 in/61 in	6 in/15 cm	24 in/61 cm

[1]The Formation MicroScanner tool is capable of detecting fractures open as little as a few microns.
[2]Optimal values for the attenuation measurement assume no pad standoff and sufficient attentuation contrast between the oil and shale
[3]Resolution values after correction for shoulder bed effect.
[4]Resolution-matched porosity measurements are systematically much better than the standard, with respect to borehole corrections Vertical resolution of the Enhanced Resolution Phasor processing measurements is only slightly better than that of the standard measurements, but it is superior in both borehole behavior and statistics

*Mark of Schlumberger

SOURCE: Schlumberger Oilfield Services.

cross section through the body of the reservoir. Point 1 on cross section *A–A′* is generally the point picked as the OWC. Point 2 is considered the upper limit of this contact. The upper limit of the OWC can be defined as that point on an isopach map at which the thickness of the bottom water goes to zero. In evaluating a waterflood candidate, both the lower and upper limits of the OWC must be determined, because bottom water has a major impact in calculating recoverable waterflood reserves. Figure 62 is an isopach map of the initial-production data for the field. Notice how the oil potential decreases and the water potential increases in a downdip direction, starting from the upper limit of the OWC. The importance of understanding the extent of this area between the upper and lower water contacts is illustrated in Table 12. The operator of the field confirmed that 70% of the primary oil was recovered above the upper limit of the OWC, whereas 30% was recovered below the contact. With unitization and injection, however, 85% of the secondary oil was recovered above the upper limit of the OWC, and only 15% of the secondary oil was recovered below the contact. Moving oil by injection in that part of a reservoir that contains bottom water is difficult because of the likelihood that injected water will channel or remain confined to the water leg. If that portion of the reservoir between the lower and upper water contact is treated the same as that portion without bottom water, overly optimistic or exaggerated secondary reserves might be forecast; as this example illustrates, those reserves may be difficult to recover.

TABLE 12. – Recovery Factors for Case History 16

	Oil produced	Recovery percentage	Oil produced above oil–water contact	Oil produced below oil–water contact
Primary	586,000	64%	70%	30%
Secondary	336,000	36%	85%	15%

MAPPING THE OIL–WATER CONTACT

Figure 63 (case history 17) is the same reservoir used in case history 8 (see Figs. 36, 37). Contour *A* represents the position of the original OWC. This contact, as discussed previously, is generally regarded as that level below which the entire pay section is water saturated. The problem of determining accurate volumetrics for a reservoir with an OWC occurs when geologists and engineers do not interpret the geometry of the contact correctly when mapping the net pay. A common error occurs when the OWC is interpreted as the edge of the oil reservoir but not the zero limit of the oil column. Cross section *A–A′* in Figure 64 illustrates this point. The OWC in the cross section indicates a reservoir more than 20 ft thick at the contact. Often, geologists and engineers will assume that the oil column directly updip of the OWC will be as thick as the pay, regardless of the fluid saturations. A major pitfall occurs when they calculate volumetrics for the reservoir and fail to modify the isopach interval to reflect the thickness of the oil column instead of the thickness of the reservoir adjacent to the OWC. Planimeter programs calculate volumetrics by layering the reservoir according to the contour interval. If the OWC is used as the zero reservoir limit without regard to the thickness of the oil column, results similar to those of Figure 64A will occur. Figure 64B is a structural interpretation of cross section *A–A′* and shows the correct interpretation and geometry of the OWC.

To demonstrate the magnitude of error that can occur by not correctly mapping the geometry of the OWC, consider Table 13. Model A represents the planimetered volumetrics for case history 17 and treats the OWC as a vertical plane, as illustrated by part A of cross section *A–A′* (Fig. 64). The planimetered average height is 20.5 ft. By using the planimetered area of 931.5 acres, the total is 19,095.8 acre-ft. The reservoir porosity, salt-water saturations, and BO values are 13%, 30%, and 1.33, respectively. This equates to an OOIP value of more than 10.1 MMBO. The reservoir's primary production of 1.4 MMBO results in a recovery factor (RF) of 13.7%. This low RF could suggest a drive mechanism of solution gas and probably indicates sufficient current oil saturations for secondary-recovery evaluation. Figure 65 incorporates the correct mapping

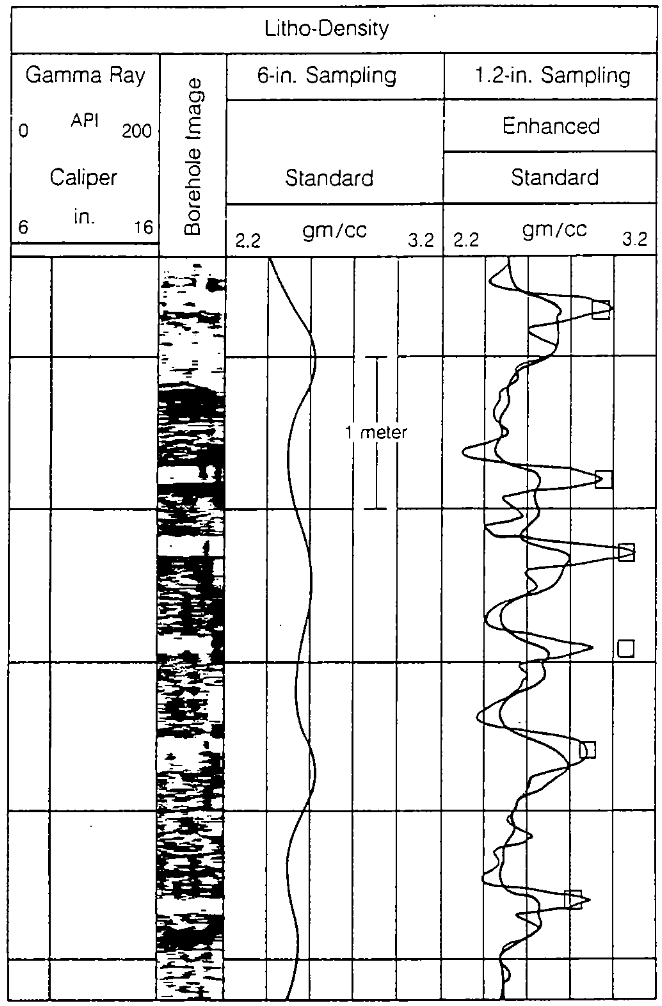


Figure 55. Expanded vertical view of a litho-density log, with an acoustic borehole image and core-derived data of a sand–shale sequence. Shales contain siderite-rich layers 2–10 in. thick. (Courtesy of Schlumberger Oilfield Services.)

TABLE 13. – Comparison of Volumetric OOIP and RF Calculations Honoring and Not Honoring Geometry of the Oil–Water Contact

Model		Average height (ft)	Area (acres)	Acre-ft	OOIP (BO)	Recovery factor
A	Volumetrics do not honor oil–water contact	20.5	931.5	19,095.8	10,136,225	13.7%
B	Volumetrics honor oil–water contact	11.1	931.5	10,339.7	5,488,395	25.4%

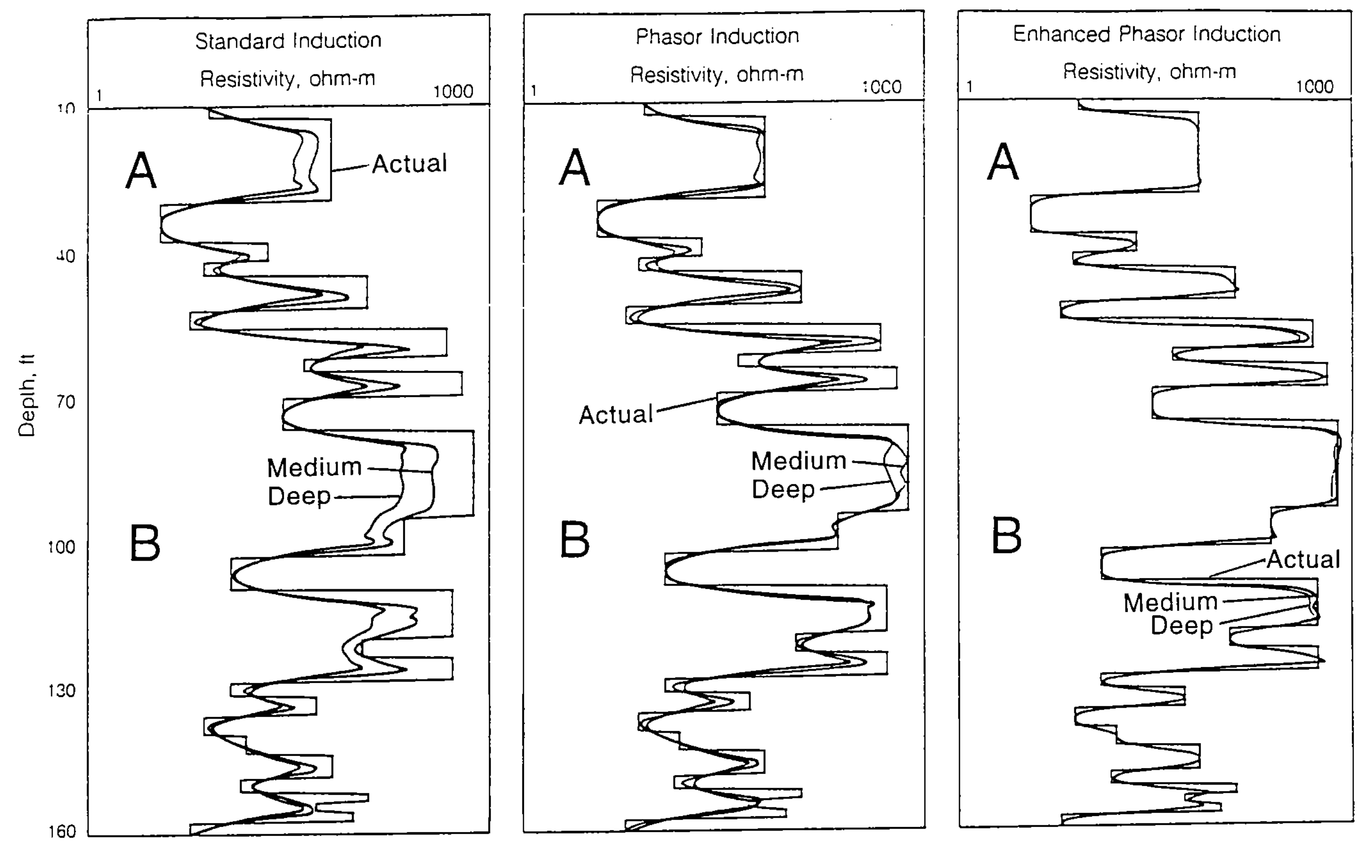


Figure 56. Comparison of curve shapes and delineation for standard, phasor-processed, and enhanced-resolution phasor-processed logs, simulating a noninvaded formation in Oklahoma. *A* and *B* refer to layers A and B (see text). (Courtesy of Schlumberger Oilfield Services.)

procedure for the net-sand isopach of case history 17 and incorporates the thickness of the oil column. The planimetered reservoir of Figure 65 yields an average height of only 11.1 ft and planimetered volumetrics of 10,339.7 acre-ft. The corresponding OOIP calculation of 5.5 MMBO has an RF of 25.4%, which strongly indicates a drive mechanism other than solution gas, as was suggested in case history 8 (see Figs. 36, 37). The OOIP calculation is also almost half that for Figure 63, which would have tremendous impact on the evaluation of this reservoir as a potential waterflood candidate.

MAPPING THE GAS–OIL CONTACT

The geometry of the gas–oil contact (GOC) is similar in principle to that of the OWC. The dimension of areal extent and boundaries of the upper and lower GOC are important for waterflood-prospect evaluations. The primary purpose of establishing the position and boundary of the gas cap is to design the injectors in such a manner as to saturate the gas cap with water and prevent the oil from migrating into the gas cap and resaturating it with oil. This subject will be discussed in more detail in the second workshop, which will deal with engineering pitfalls of waterflooding.

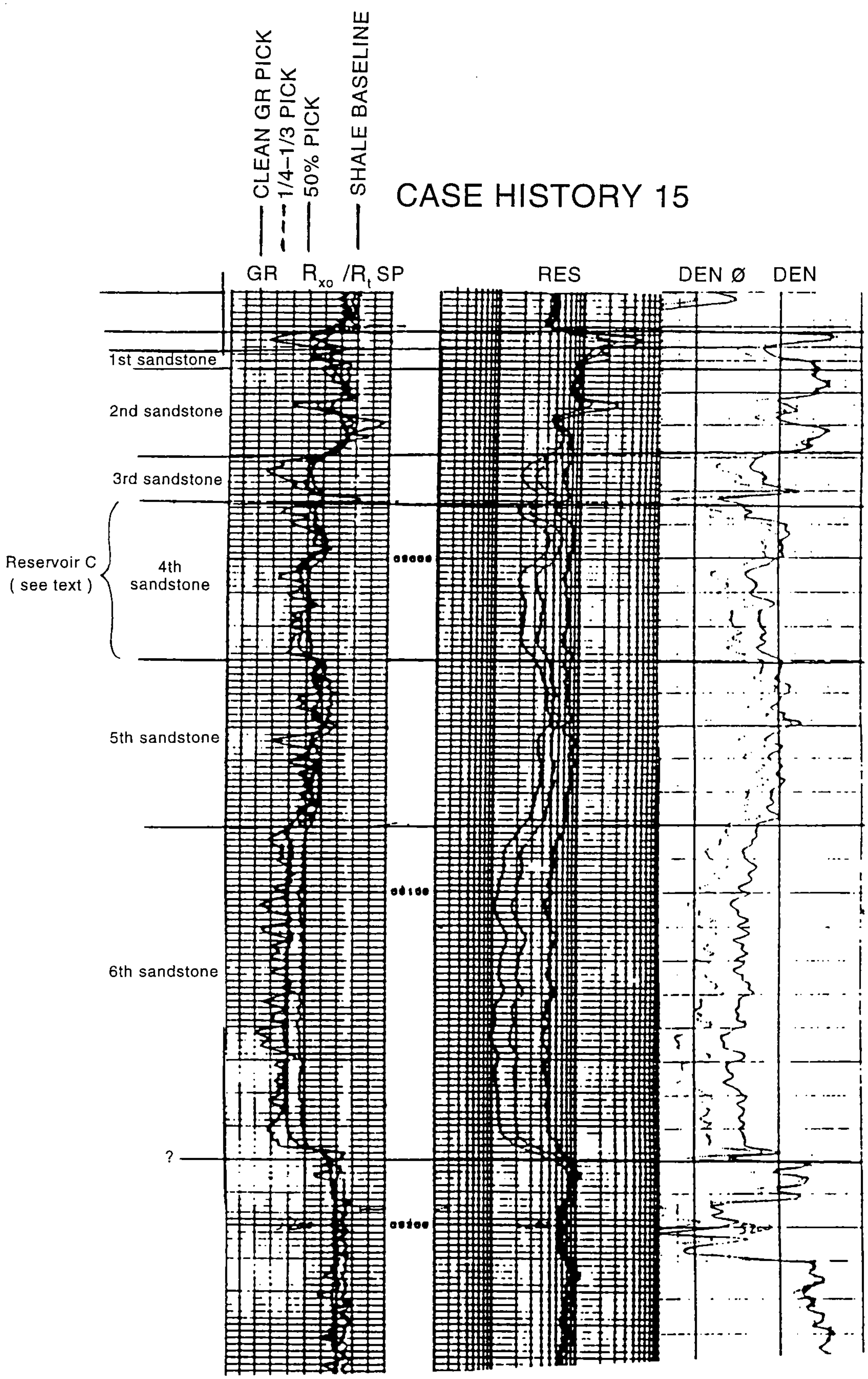


Figure 57. Reference log for Tonkawa sandstone of case history 15 for a reservoir in western Oklahoma. *SP* = spontaneous potential, *GR* = gamma ray, *RES* = resistivity, *DEN* = density, *DEN* ϕ = density porosity, R_{xo} = resistivity of flushed zone, R_t = resistivity of uninvaded zone (true resistivity).

CASE HISTORY 15

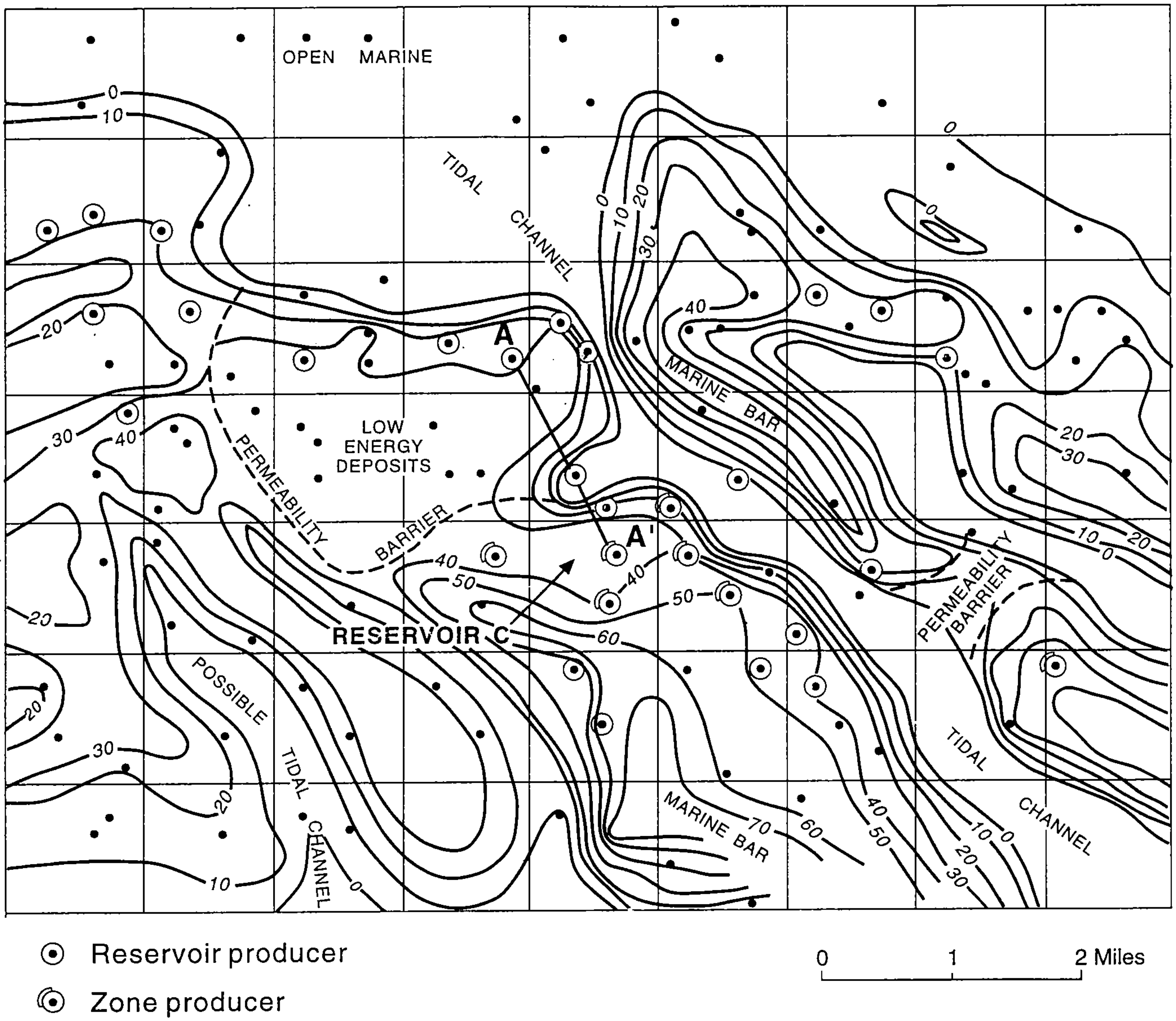


Figure 58. Isopach map of the fourth Tonkawa sand (reservoir C), as depicted on the reference log of Figure 57. Contour interval, 10 ft. Cross section *A–A′* is shown in Figure 59.

DETERMINING AN OIL COLUMN FROM CORE FLUORESCENCE

Occasionally, cores are used to establish or verify oil columns in the reservoir by observing the amount of fluorescence emitted by oil saturation in response to ultraviolet light ("black light"). Case history 17A, illustrated in Figure 66, is a photograph, under natural light, of a sandstone core taken from a well in eastern Oklahoma. Each column is a 2-ft section of core, which has been slabbed, or longitudinally cut in half. Figure 67 shows the same core before it was slabbed, as seen under ultraviolet light; this photograph suggests that the oil saturation, based on the fluorescence, is present from 2,330 to 2,334 ft and that the remaining core has little or no oil saturation. Figure 68 is the slabbed core of Figure 66 observed under ultraviolet light. Notice that the fluorescence is apparent all the way through the core.

Examination of these photographs points to a common error, which is to judge oil saturation from core that has been washed. If the core has low permeability or was taken under depleted conditions, the oil saturation will wash off and will not be easily replaced or observed, as can be seen in Figure 67. Only by slabbing the core will the true extent of the oil column in the core be revealed.

CASE HISTORY 15

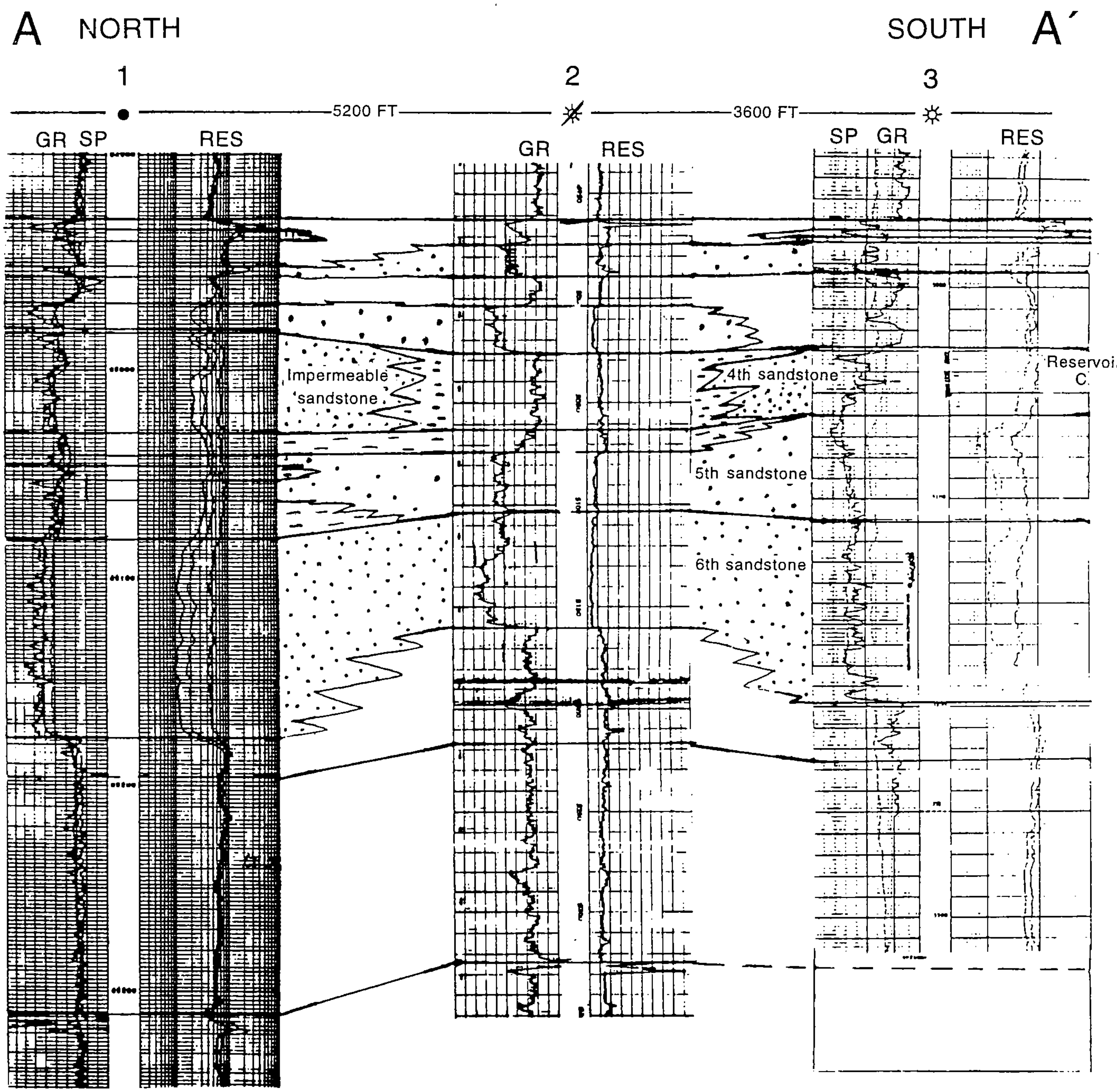


Figure 59. North–south stratigraphic cross section *A–A′*. Line of section is shown in Figure 58.

CASE HISTORY 16

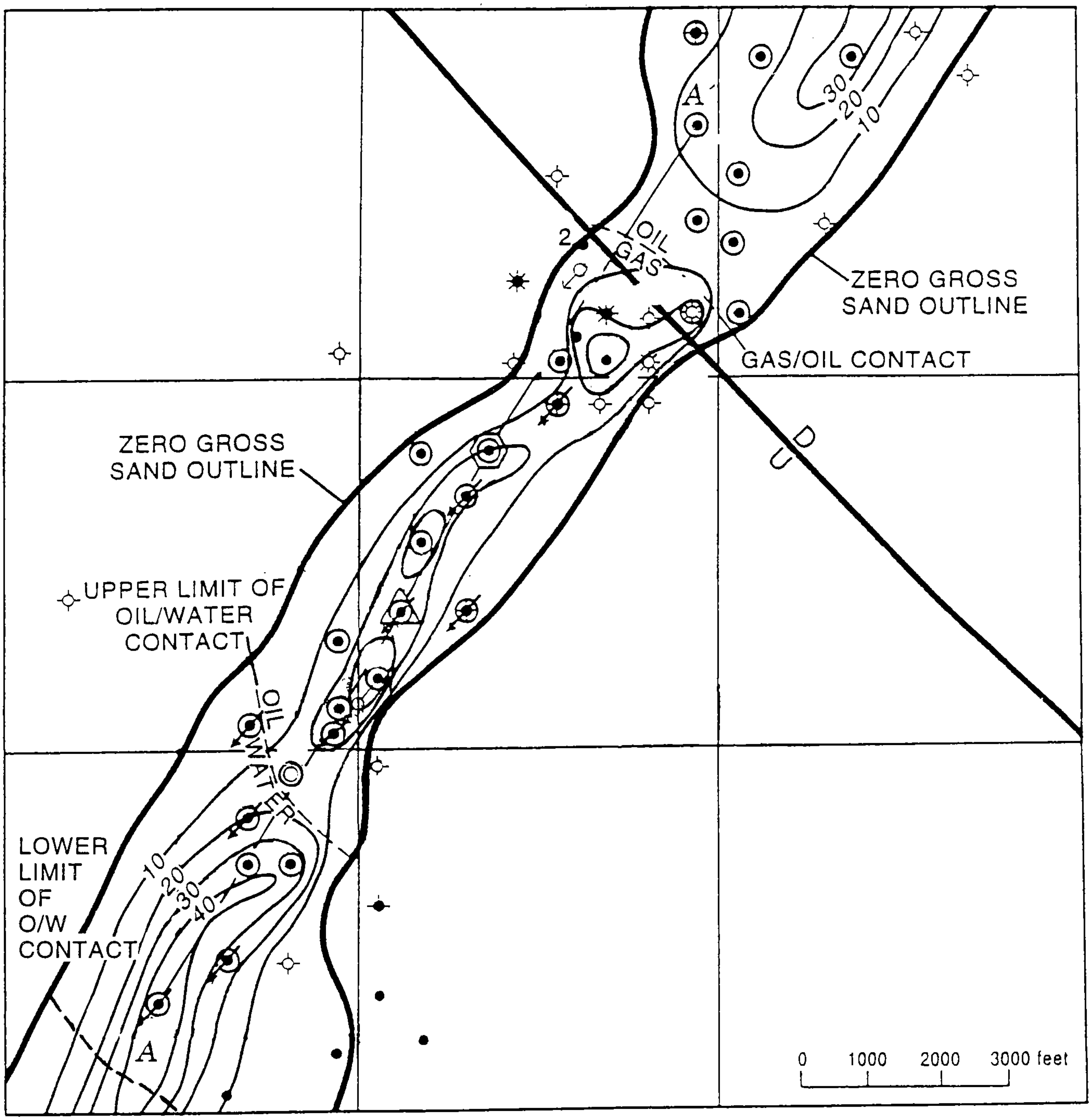


Figure 60. Net-sand isopach map for the reservoir of case history 16 (north-central Oklahoma). Dashed contour represents upper boundary of OWC. Contour interval, 10 ft. Cross section *A–A′* is shown in Figure 61.

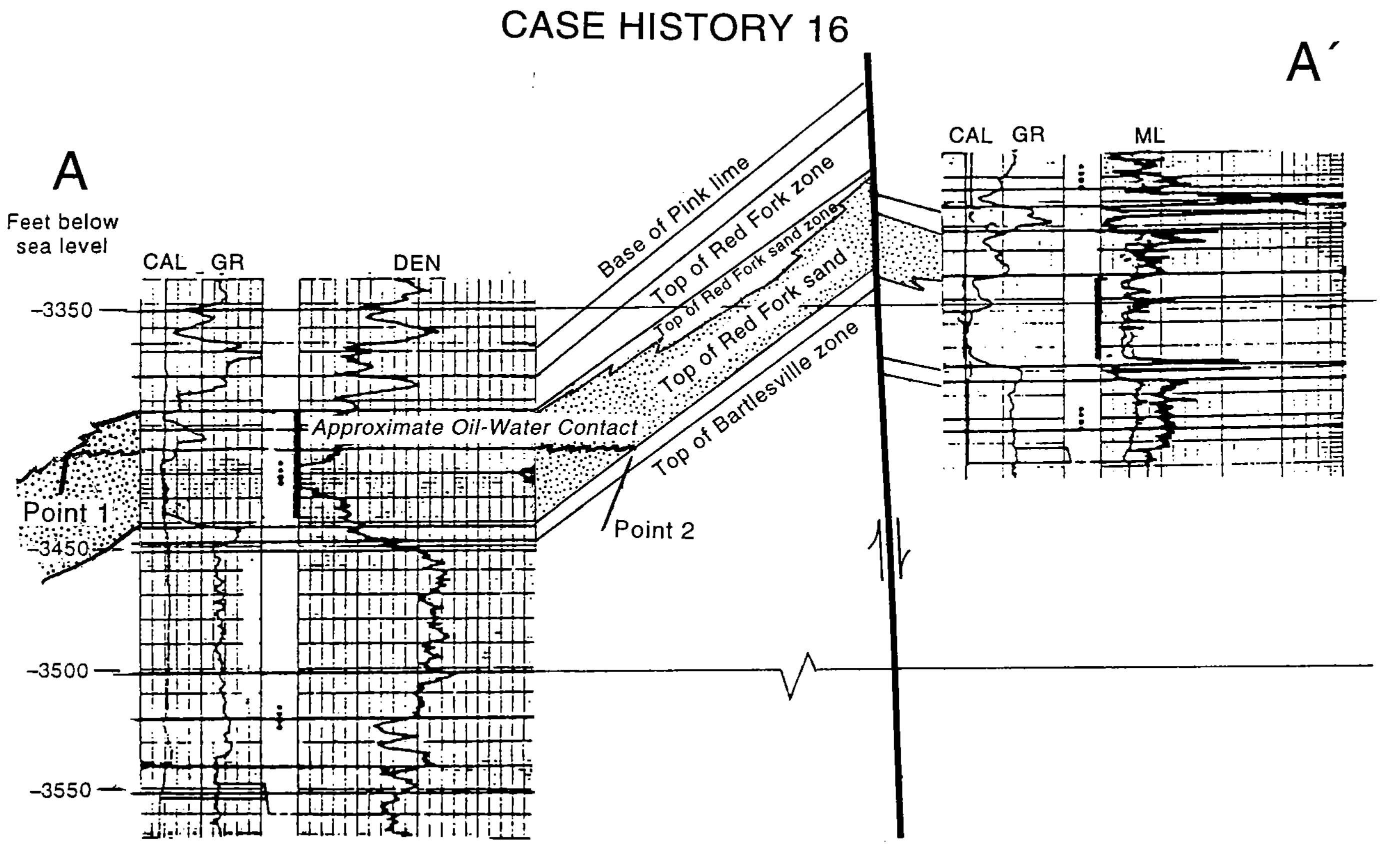


Figure 61. Stratigraphic cross section *A–A′* for the reservoir of case history 16, illustrated in Figure 60. Point 2 represents position of upper limit of OWC, as shown in Figure 60. *GR* = gamma ray, *CAL* = caliper, *DEN* = density, *ML* = microlog.

CASE HISTORY 16

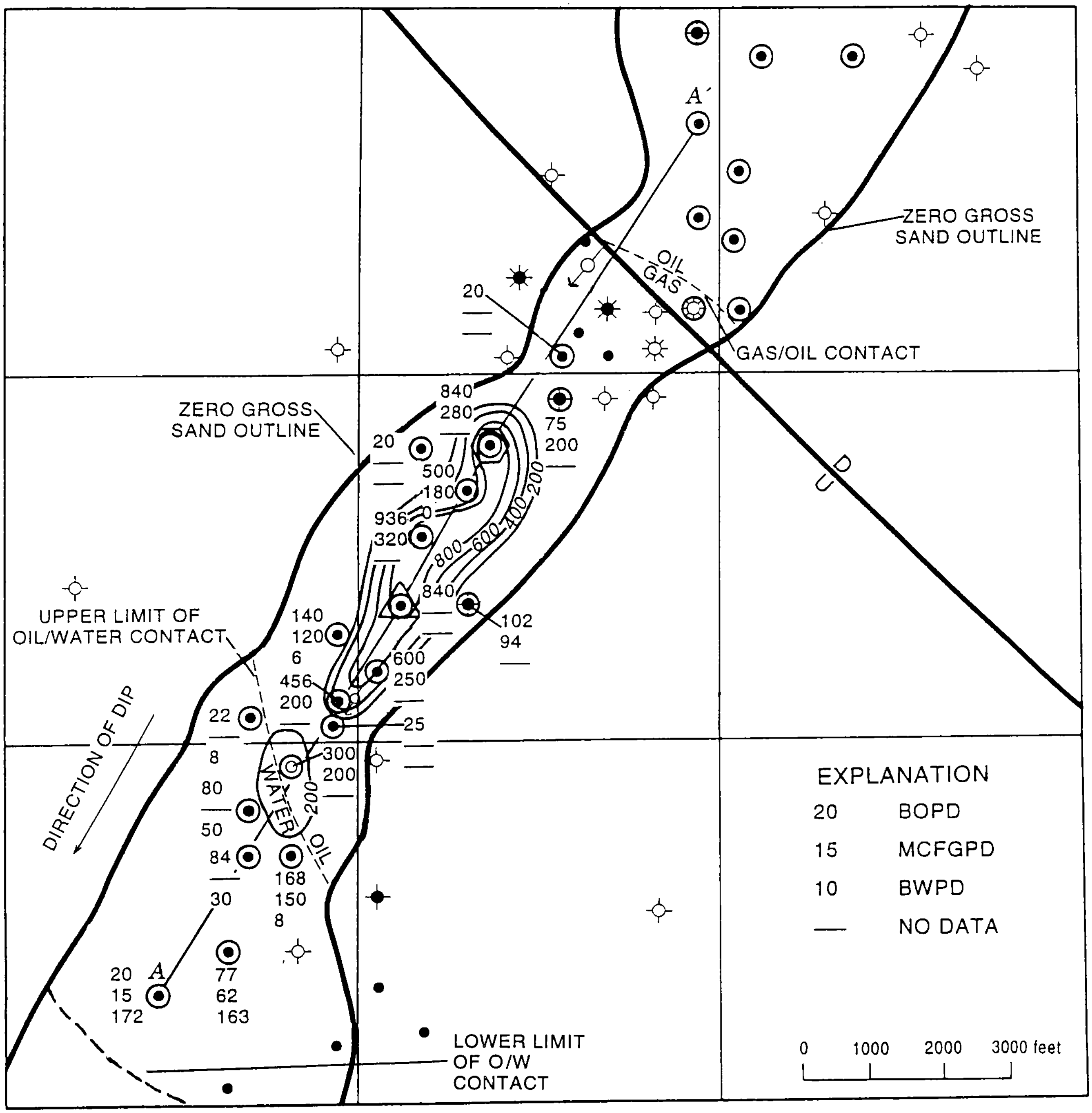


Figure 62. Initial-potential production data for case history 16. Contour interval, 200 BOPD.

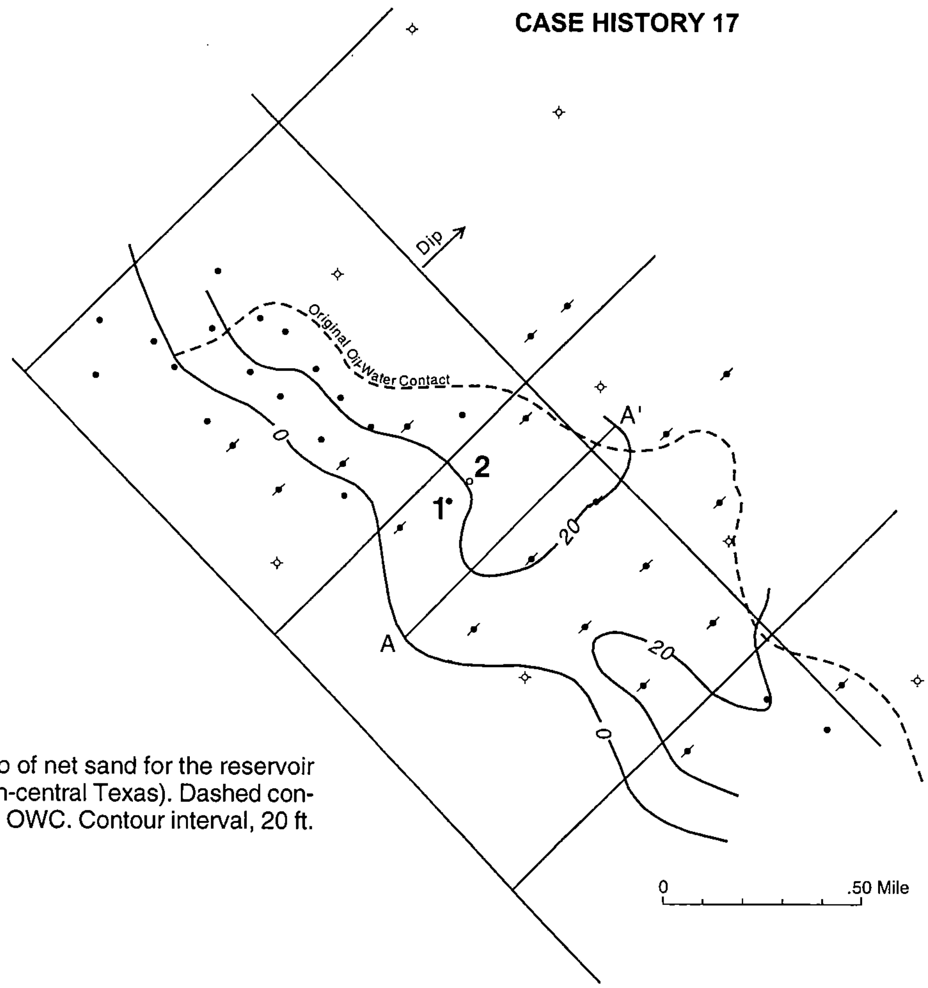


Figure 63. Isopach map of net sand for the reservoir of case history 17 (north-central Texas). Dashed contour represents original OWC. Contour interval, 20 ft.

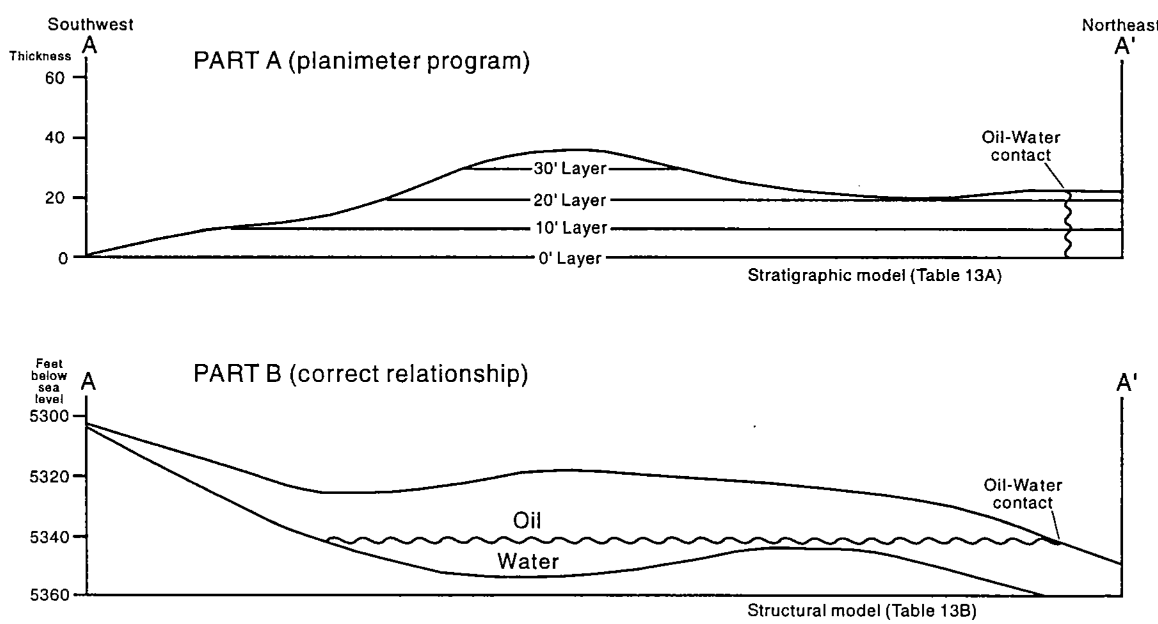


Figure 64. Stratigraphic (A) and structural (B) cross section *A–A′* for the reservoir of case history 17. Line of section is shown in Figure 63. Part A illustrates layers used for planimeter programs to calculate volumetrics. Such programs view the OWC as a vertical plane. Part B represents the correct relationship of the OWC.

CASE HISTORY 17

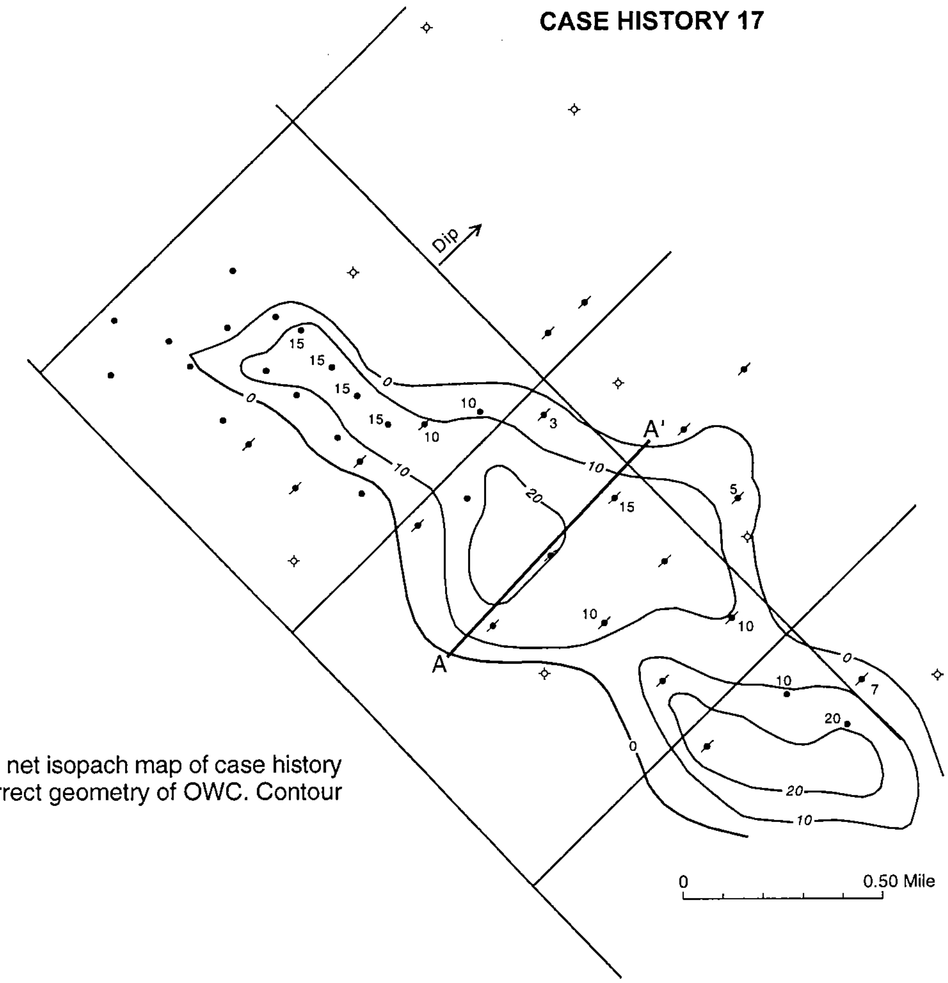


Figure 65. Corrected net isopach map of case history 17, incorporating correct geometry of OWC. Contour interval, 10 ft.

CASE HISTORY 17A

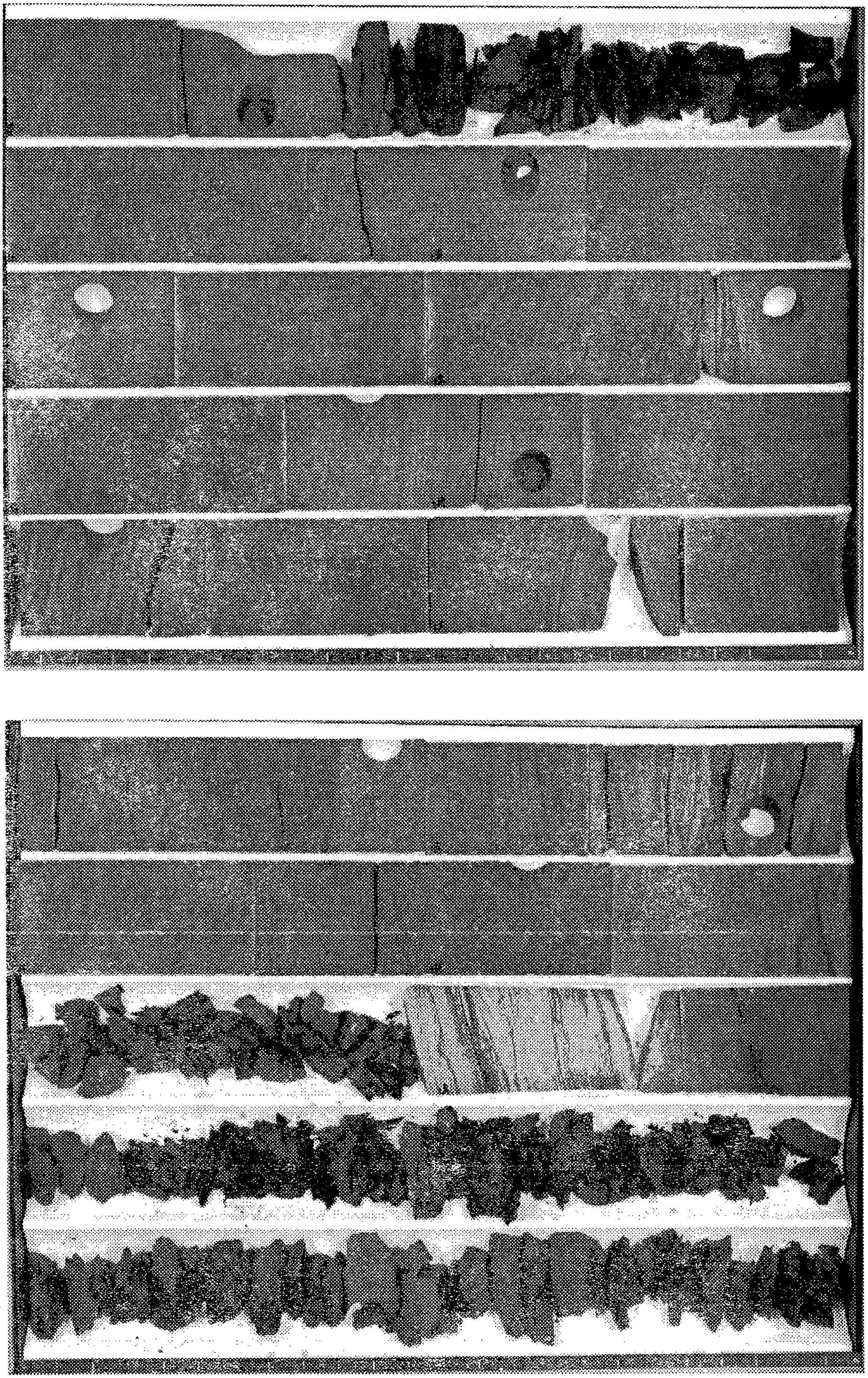


Figure 66. Photograph of a slabbed core that includes the pay zone of the reservoir of case history 17A (eastern Oklahoma). (Natural light.)

CASE HISTORY 17A

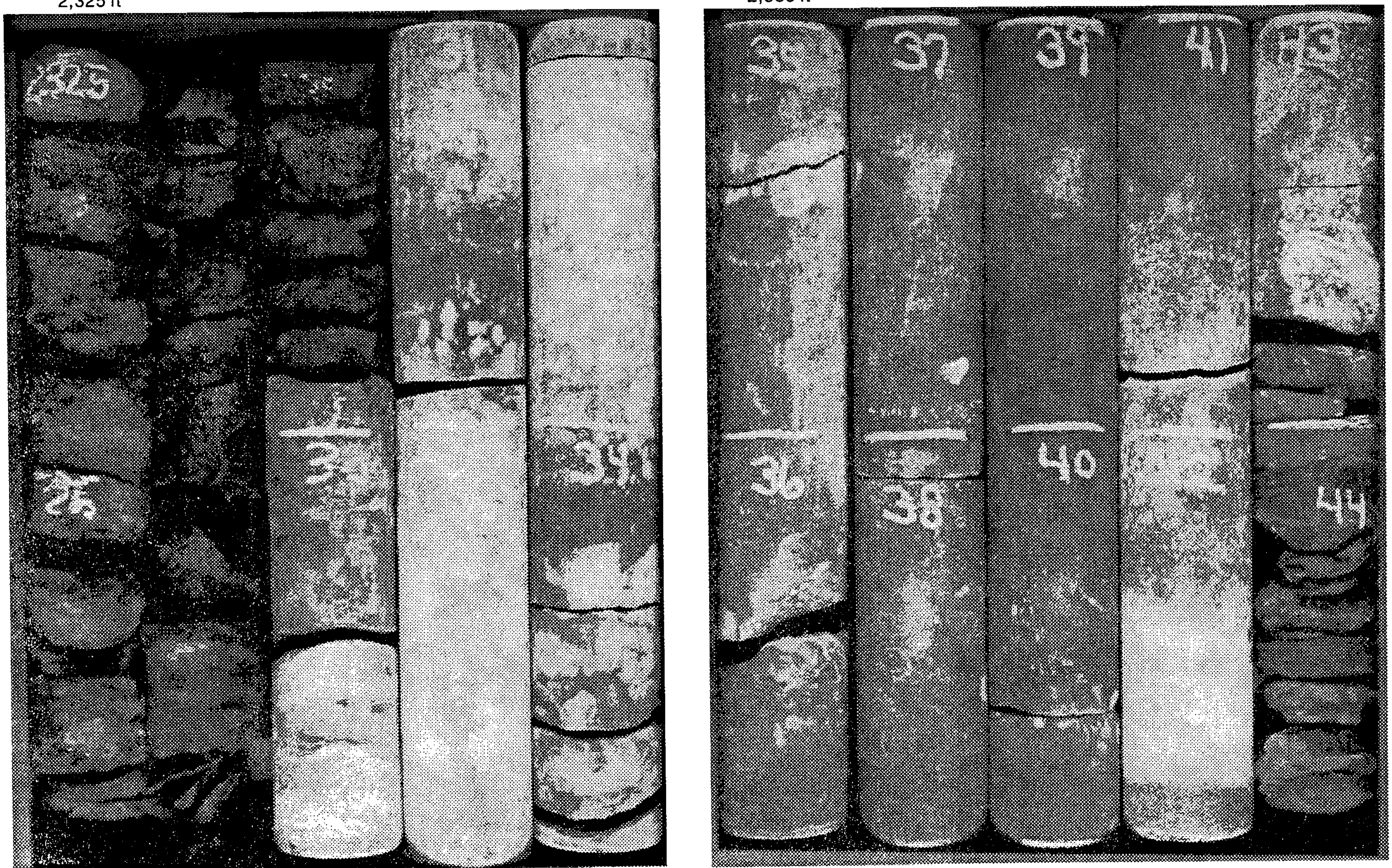


Figure 67. Photograph of the same core of case history 17A before it was slabbed. Apparent OWC, based on fluorescence, is at 2,334 ft. (Ultraviolet light.)

CASE HISTORY 17A

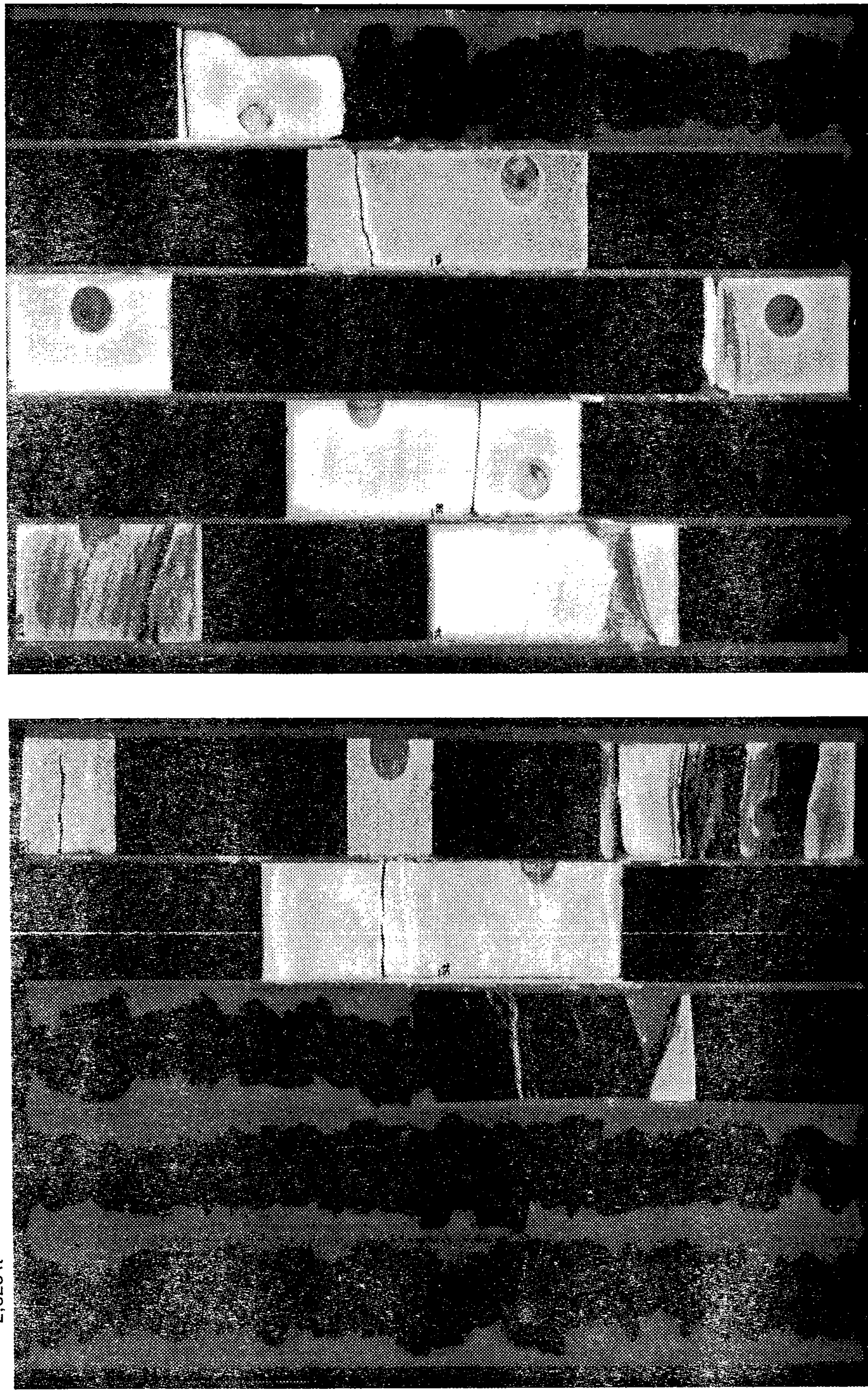


Figure 68. Photograph, under ultraviolet light, of the slabbed core shown in Figure 66. Oil fluorescence is indicated throughout the pay interval.

Mapping Net Pay

5

CHAPTER 5

Mapping Net Pay

INTRODUCTION

Mapping the net-pay interval is perhaps the primary contribution the geologist makes in the evaluation of a waterflood candidate. Such mapping is the foundation on which data, conclusions, and decisions for the waterflood prospect or project will be based. There are several ways in which to represent a reservoir, such as mapping optimistically perhaps to influence management, or mapping pessimistically for land or economic reasons. However, when it comes to waterflood evaluation, nothing is as important as accurate mapping. The following examples will demonstrate this point.

ENVIRONMENT-OF-DEPOSITION VERSUS "CONNECT-THE-DOT" MAPPING

Figure 69 is a model that illustrates various environments of deposition for reservoirs found in the Midcontinent. Each depositional environment has its unique set of criteria, such as reservoir geometry, permeability trends, and reservoir petrographic characteristics. Determining the geometric configuration of the reservoir on the basis of depositional environments will lead to more accurate definition for volumetric calculations, natural-permeability orientations, and reservoir characteristics. The isopach mapping of data points only, without regard for depositional environments, reservoir geometry, or trends, is what the author refers to as "connect-the-dot" mapping. This type of mapping can be disastrous for a waterflood project.

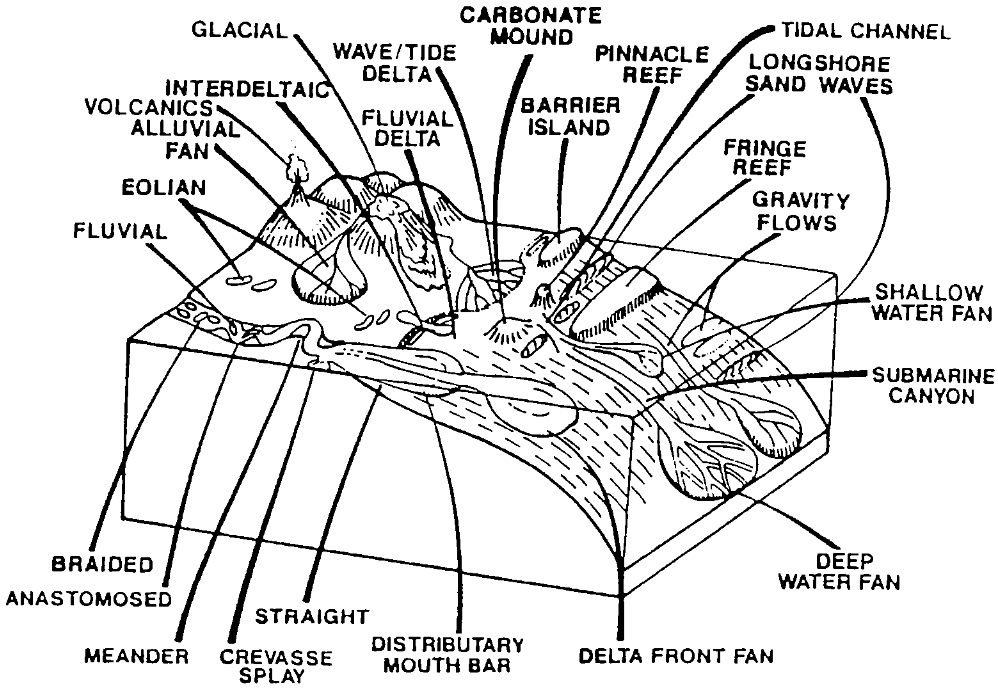
Case history 18 (Fig. 70) is a net-sand isopach map of a Red Fork sandstone reservoir in eastern Oklahoma, based on log examination. This isopach-mapping procedure is typical, because it simply honors the numerical values of the thicknesses without considering the source, trends, or depositional environments. The three wells labeled A, B, and C in the northwest part of the field produce oil that is characteristically green and has an API gravity of 41°. Well D in the eastern part of the reservoir produces black oil with a gravity of 35° API. This difference in oil characteristics is enough to suggest a possible barrier between these wells.

The electric-log signatures for the productive interval of all the wells in the mapped area were examined to determine possible depositional traits or characteristics. Figure 71 is a revised depositional-environment map showing the sand's geometry and depositional environment based on interpretations of the log signatures, regional correlations, and trends. Wells A, B, and C are interpreted to be in a fluvial-channel facies, and well D is interpreted to be in a marine environment. The fluvial channel cut into the marine deposits, and a barrier was formed, separating the oils. Figure 72 is a revised net-sand isopach map that incorporates depositional-environment characteristics and trends. This map more accurately interprets the reservoir geometry, continuity, and complexity. If the mapping procedure had not incorporated the concept of depositional environments, the barrier separating the oils would have hindered injection in the field. This barrier would not have been recognized or accounted for if the project had been installed by using Figure 70 for representation of the net reservoir.

Often, a reservoir can be characterized by multistoried productive intervals. Correlations of each layer between wells is questionable, and continuity between wellbores thus is not known for certain. Figure 73 is a cross-section example of seven porous layers between two wells. The hydrocarbons from layer 4 will migrate to well 1, and the hydrocarbons of layer 5 will migrate to well 2 during primary production. However, during waterflooding, if well 1 were an injector perforated in layer 4, it would not be connected to layer 5 or well 2. Both wells 1 and 2 would have isopach values for layers 4 and 5, respectively. The goal of incorporating depositional environments and geometric trends is to indicate or suggest a reason why these two layers would be mapped discontinuously rather than just "connecting the dots," with no interpretation offered between wells. Thus, an isopach map is more useful when meaningful interpretations are taken into account. At least, discontinuity in a reservoir may be expected or anticipated and factored into the installation plan.

George and Stiles (1978) addressed statistical methods for calculating net pay in reservoirs characterized by thick, uncorrelatable productive layers where unconnected layers may be present. For limestone reservoirs, this approach may be all that is available because of the commonly random orientation of porosity trends. However, for sandstone reservoirs, there is another approach. Consider case history 19 in Figure 74. This figure is the reference log for a field in east-central Oklahoma. The log of the pay interval suggests that a number of thin productive layers make up the pay zone. The original operators used a statistical approach to calculate the reservoir's hydrocarbon acre-foot value. The calculations were derived by examining all 22 cores from the field. Nine of the cores contained a "best sand," of which porosity was >10% and core wa-

Depositional Environments



Fluvial Channel Systems

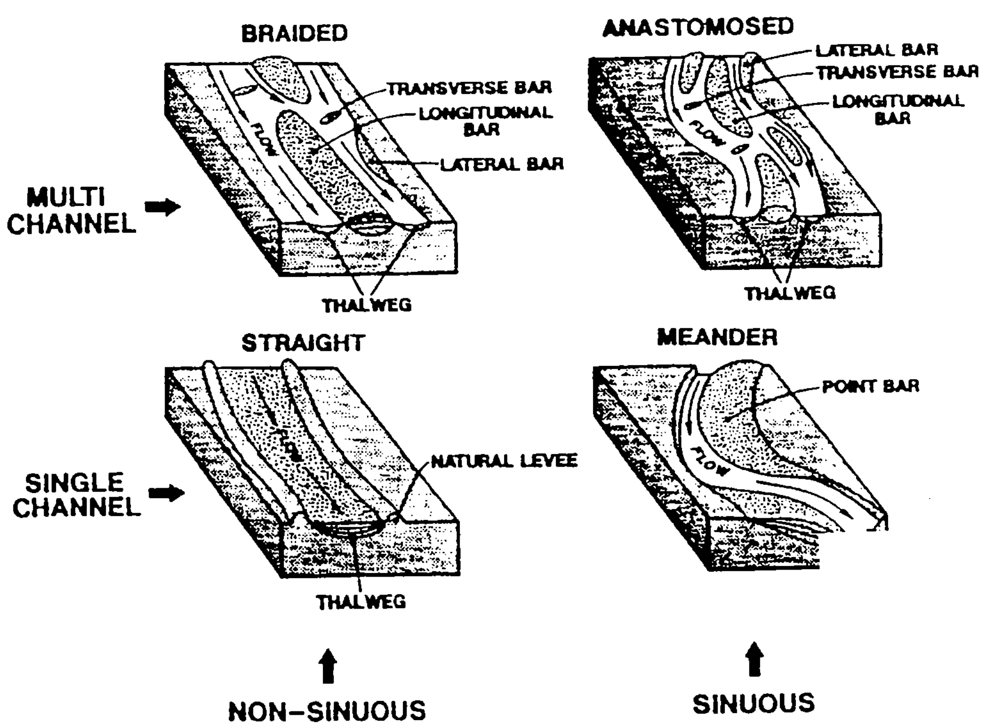


Figure 69. Model depicting various environments of deposition found throughout the geologic column in the Midcontinent. (Courtesy of Schlumberger Oilfield Services.)

CASE HISTORY 18

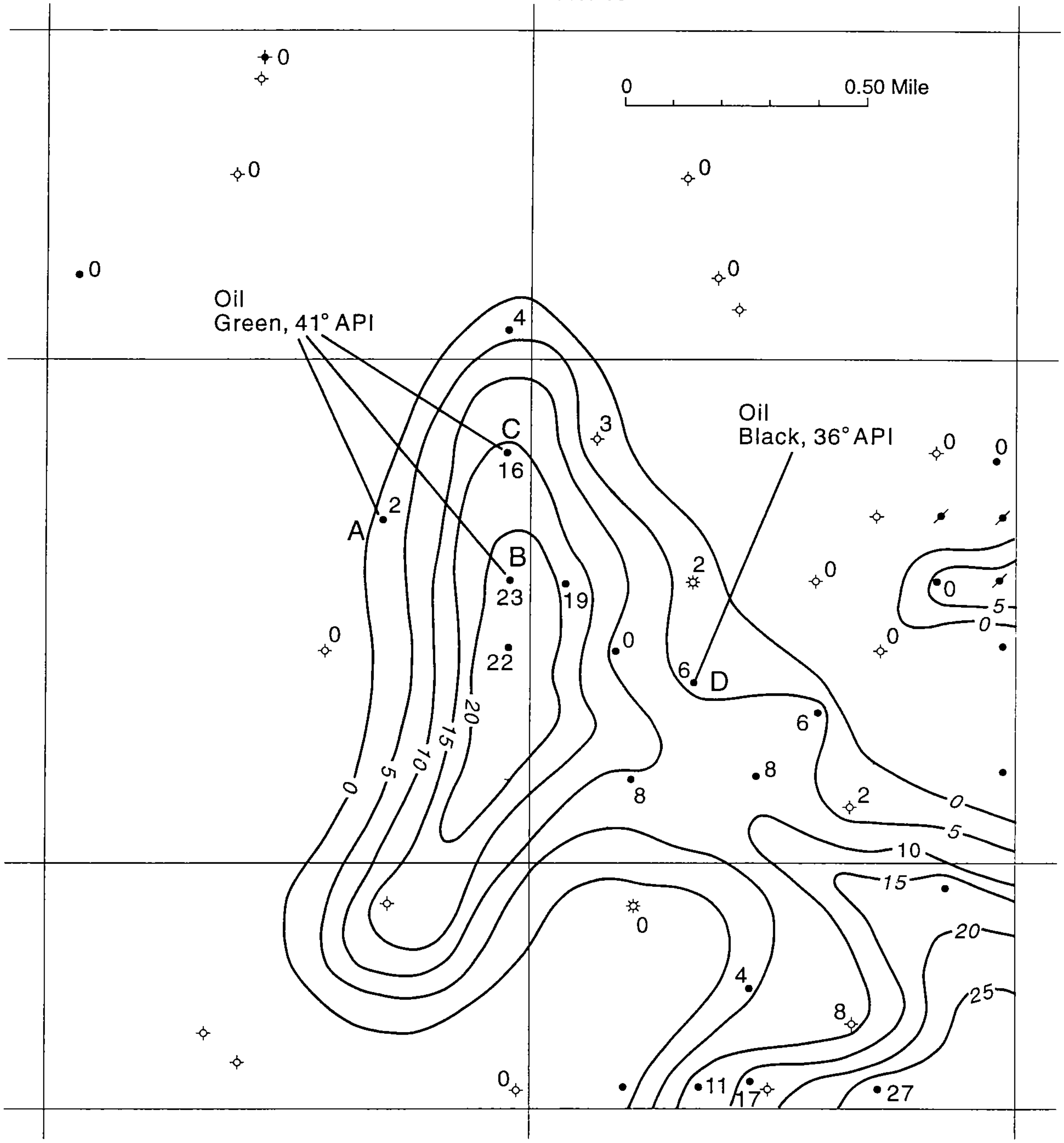


Figure 70. Net-sand isopach map of reservoir of case history 18 (eastern Oklahoma). This map does not incorporate environment of deposition. Wells A, B, and C produce green oil of 41° API gravity, while well D produces black oil of 36° API gravity. Contour interval, 5 ft.

ter saturation was <60%. The total of 151 ft of "best sand" constituted 17.7% of the total of 852 ft of core. All the oil- and gas-productive layers were characterized on open-hole electric logs by resistivity values >10 ohms, which represented 18.4% of the total core thickness. Figure 75 is an isopach map of the thickness of the layers with resistivities >10 ohms. Three thick reservoir pods (labeled A, B, and C) are apparent on this map, which is another "connect-the-dot" map. Neither depositional environment nor sand geometry was considered in the contouring.

Table 14 illustrates three ways in which OOIP was calculated for this reservoir. Case 1 derives the 9,400-acre-ft value by multiplying the planimetered acre-foot value from Figure 75 by the estimated 18% net-pay value determined by analyzing the "best sand" in the 22 cores. The OOIP value of 3.6 MMBO, combined with the 1.2 MMBO of primary production, equates to a re-

CASE HISTORY 18

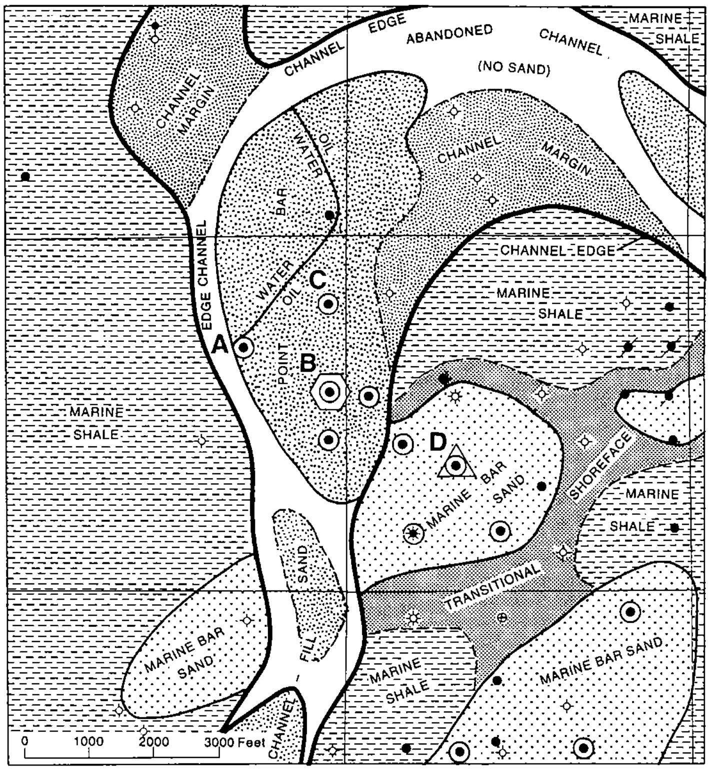


Figure 71. Environmental-facies interpretation of the pay zones of case history 18. (Modified from Andrews, 1997, fig. 51.)

CASE HISTORY 18

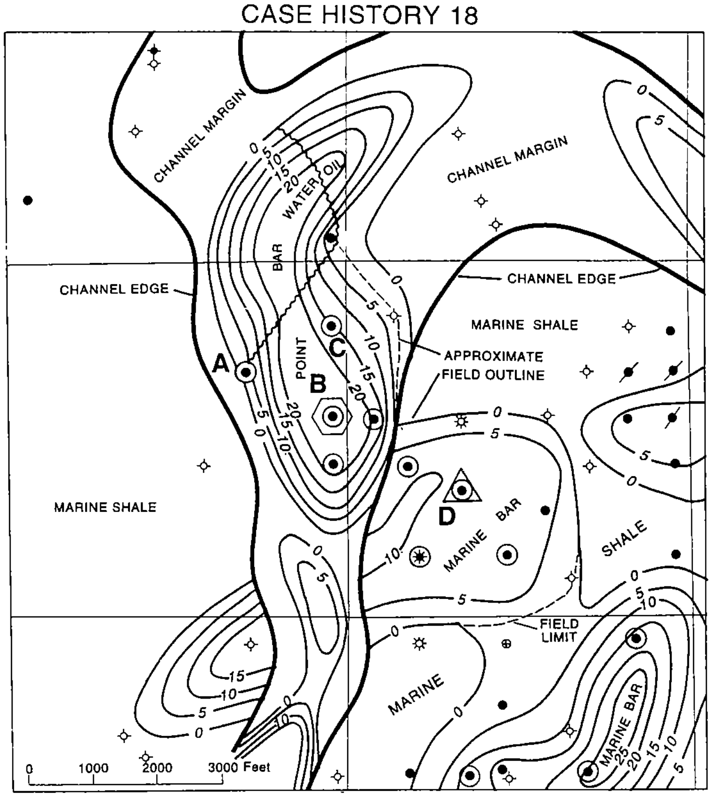


Figure 72. Corrected net-sandstone isopach map of case history 18, incorporating environmental-facies interpretations. Contour interval, 5 ft. (Modified from Andrews, 1997, fig. 49.)

covery factor of 33.3% and a current oil saturation of 27.8%.

Case 2 (Table 14) is the second scenario used to analyze OOIP for this reservoir. The planimetered acre-foot value for Figure 75 was used. The porosity was reduced to represent an average over the entire >10-ohm-resistivity interval. The OOIP calculation was 17.6 MMBO, with a recovery factor of 6.8%.

Both these cases have unrealistic conclusions for a solution-gas-drive reservoir. Case 1 has a recovery factor too high, and case 2 has a recovery factor too low. Pressure data from the reservoir indicate that the reservoir was in complete continuity and that the effective porosity was equal to the calculated porosity.

Case 3 (Table 14) is an alternative method for evaluating this reservoir. The correlation of electric logs for this reservoir reveals that the sands were deposited in four primary layers, or genetic increments, labeled, in descending order, A, B, C, and D (Fig. 74). These layers were observed to be correlatable on a regional scale and were isopached as illustrated in Figures 76–79. The regional interpretation of the pay zone suggested that the individual layers were deposited as fluvial channels. Each layer was characterized by its unique geometry and orientation, although all were in hydraulic communication. In order to accurately determine the acre-foot volume and geometry of the reservoir, isopach contours of the four individual layers were superposed, as illustrated in Figure 80. The composite isopach map derived from the addition of the contours of all four sand layers is illustrated in Figure 81. This isopach map honors the geometry and environment of deposition for each of the four pri-

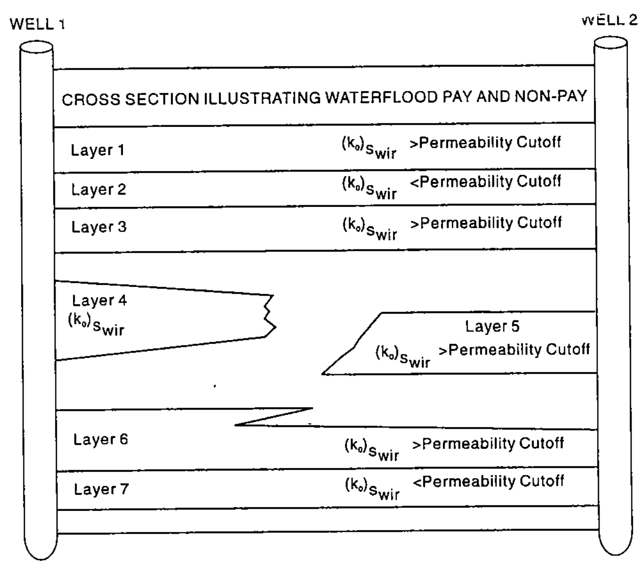


Figure 73. Hypothetical cross section between two wellbores, illustrating various permeability and continuity scenarios. (Schematic drawing courtesy of William M. Cobb & Associates, Inc.)

TABLE 14. – Comparison of Oil-in-Place and Recovery-Factor Calculations for Various Methods of Calculating Acre-Feet

	Case 1 Best sand, 9 cored wells	Case 2 Based on >10 ohms	Case 3 Honors sand geometry
Volumetric acre-feet	9,400	52,254	16,266
Porosity	12.7%	8.6%	12.5%
Water saturation	50.0%	35.0%	25.0%
B_{oi}[a]	1.2845	1.2845	1.2549
OOIP	3,605,099	17,641,967	9,427,417
Primary production	1,199,952	1,199,952	1,199,952
Recovery factor	33.3%	6.8%	12.7%
Current oil saturation	27.8%	50.5%	55.8%

[a]Initial formation volume factor for oil.

mary layers observed in the reservoir. Of major interest is the difference between this isopach map and the original operator's isopach map (Fig. 75). Pod B has disappeared; actually the northeast quarter of this section contains very little reservoir. The thickness of Pod C has been replaced by a reentrant sand body. This change in sand geometry would affect any injector–producer pattern established for the reservoir, as isopached in Figure 75. If the injector–producer pattern were installed on the basis of the isopach map of Figure 75, individual sand geometry probably would influence anticipated response. If individual sand geometry is taken into consideration when using the isopach map of Figure 81 and incorporated into the waterflood pattern, the project should have the greatest chance of success.

LAYER ISOPACHING VERSUS TOTAL ISOPACHING

Total-sand isopaching, or mapping the total of the net pay zones, is a common method for mapping multiple layers of reservoirs. The main weakness of this method, however, is its inability to represent environment of deposition and sand geometry, which are essential for accurately designing injector–producer patterns and for determining natural permeability orien-

CASE HISTORY 19

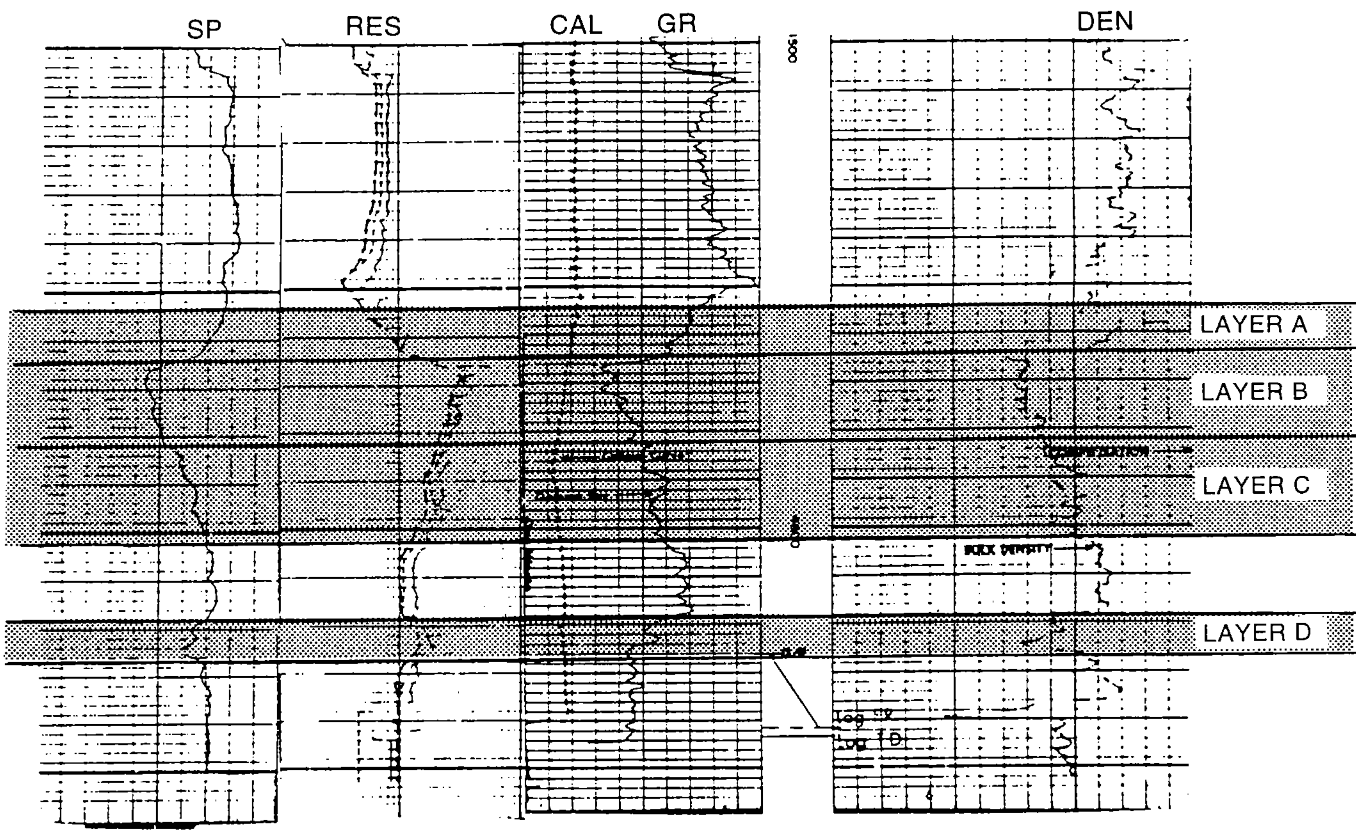


Figure 74. Reference log for the field of case history 19 (east-central Oklahoma). *SP* = spontaneous potential, *GR* = gamma ray, *RES* = resistivity, *CAL* = caliper, *DEN* = density.

CASE HISTORY 19

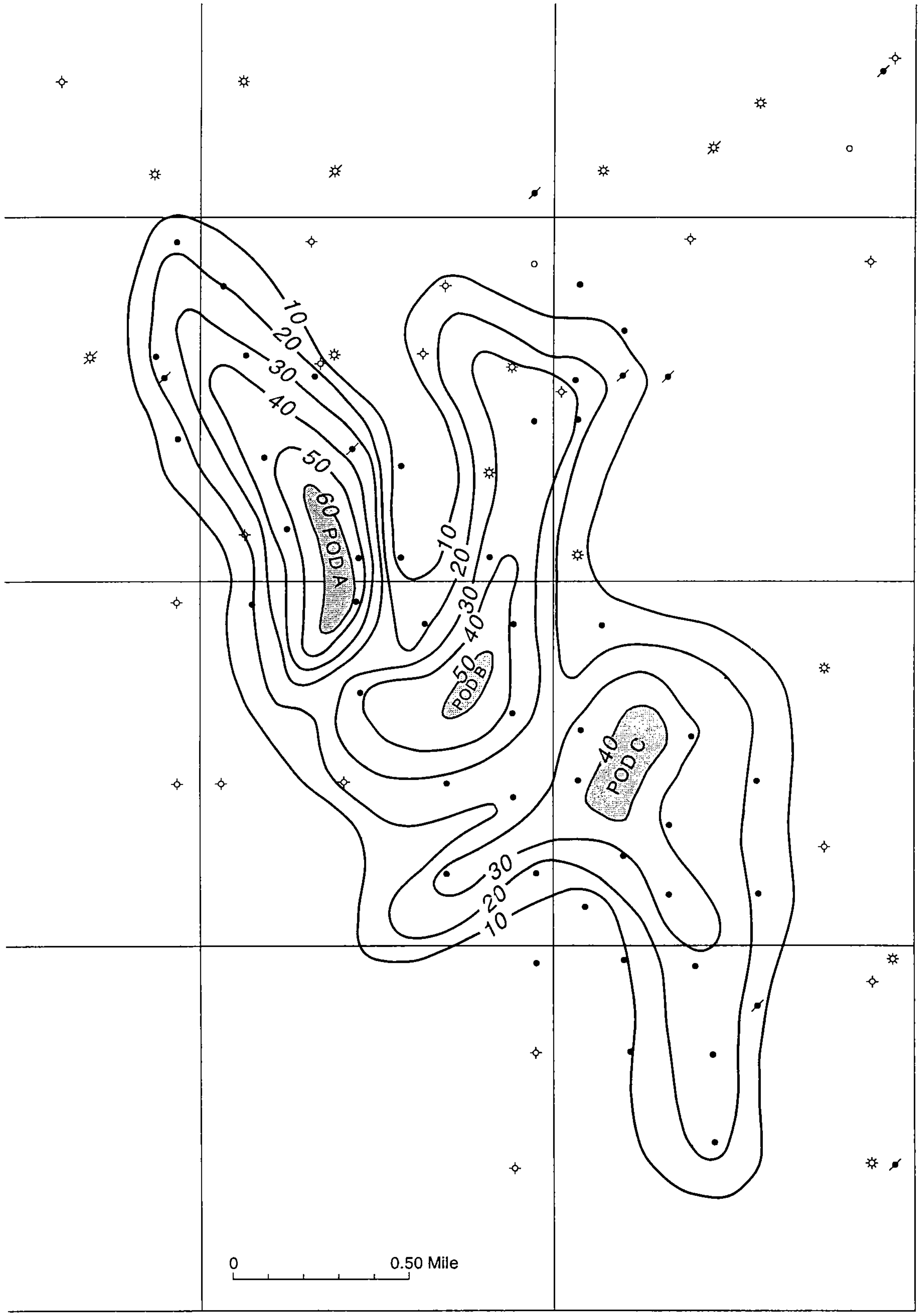


Figure 75. Isopach map of reservoir of case history 19, representing thicknesses of layers >10 ohms resistivity as interpreted from open-hole electric logs (east-central Oklahoma). Pods A, B, and C are interpreted as isopach thicks. Contour interval, 10 ft.

CASE HISTORY 19

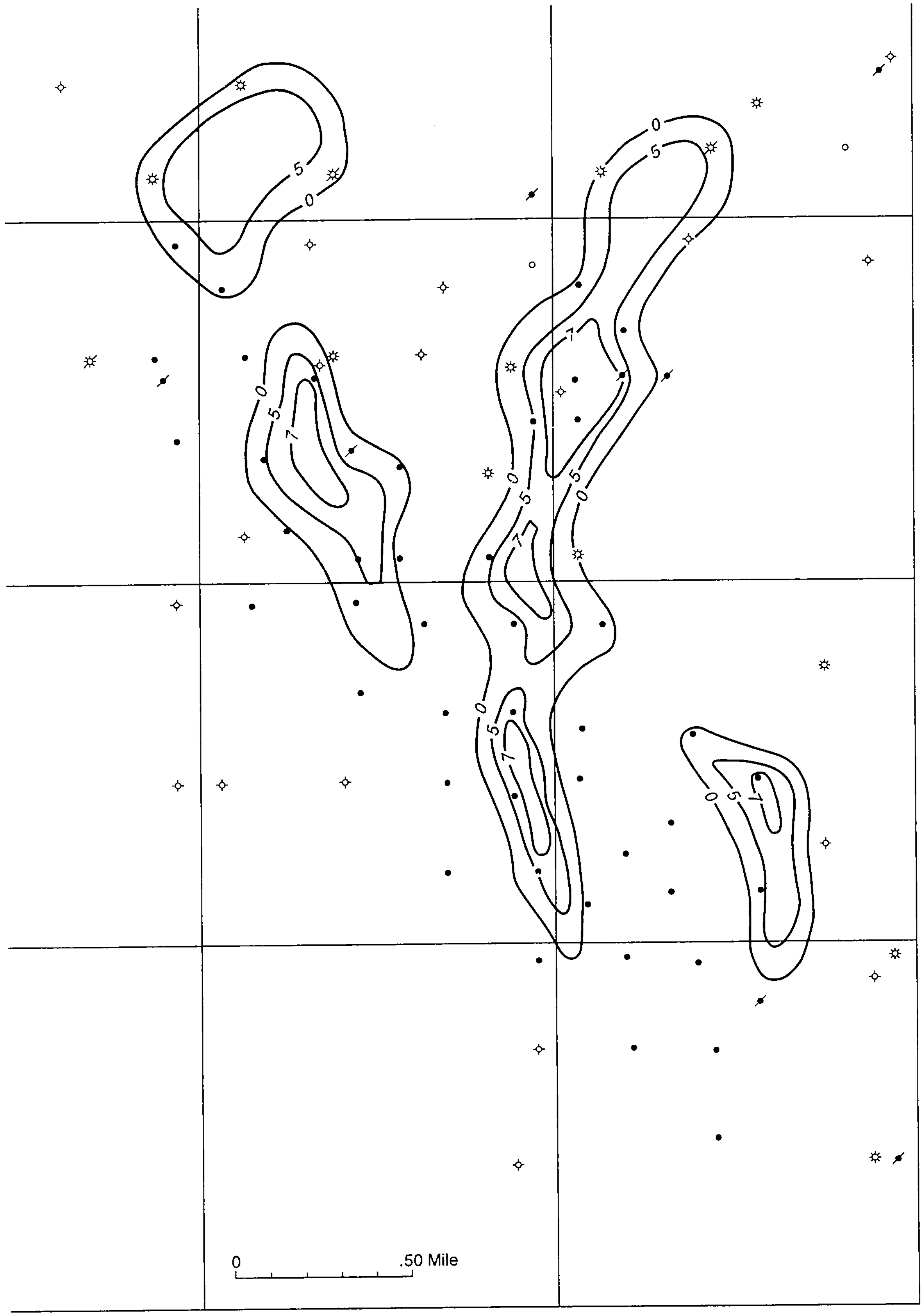


Figure 76. Isopach map of sand layer A (see Fig. 74), the topmost of four layers constituting the reservoir of case history 19. Contour interval, 5 ft.

CASE HISTORY 19

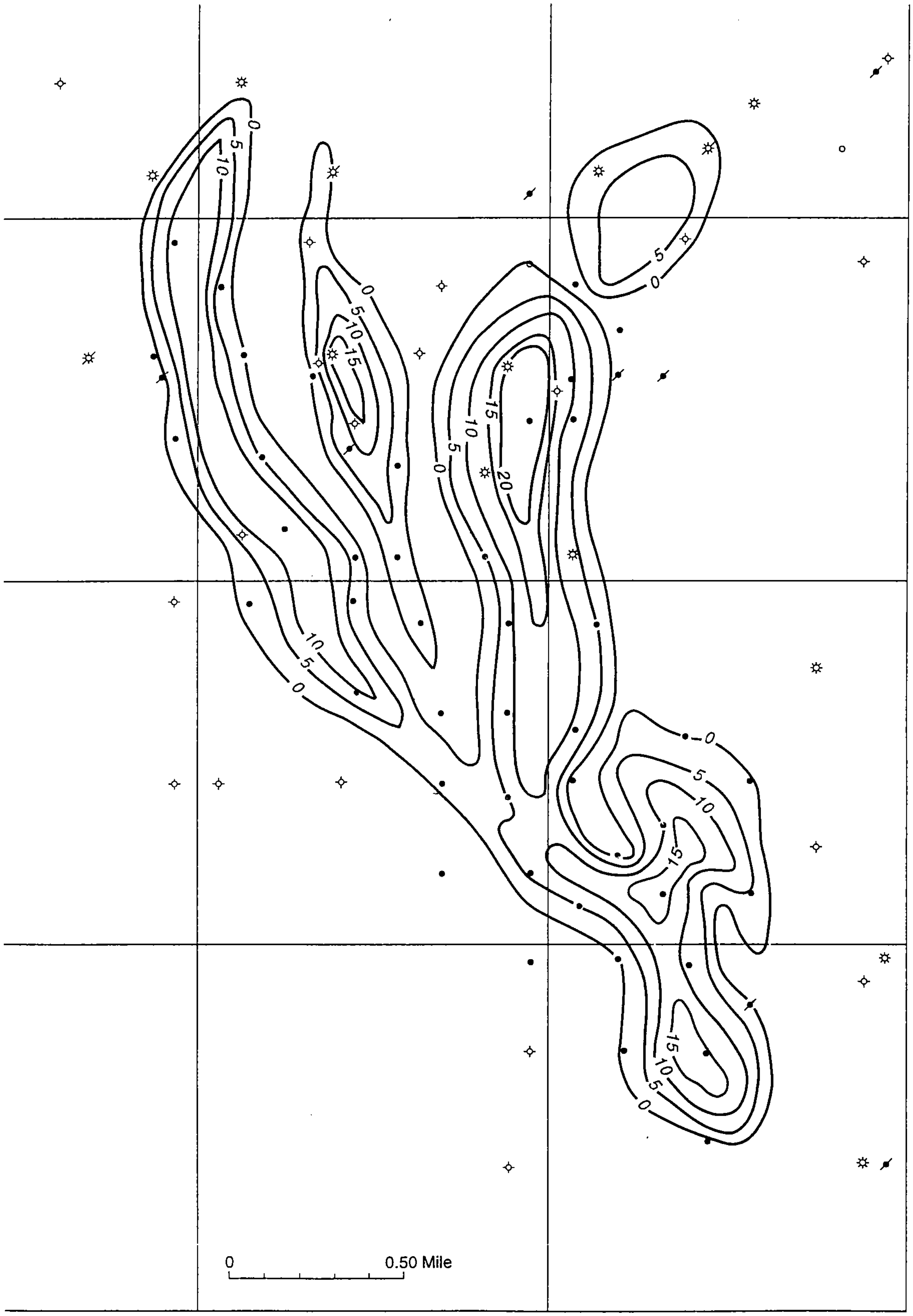


Figure 77. Isopach map of sand layer B (see Fig. 74), the second of four layers constituting the reservoir of case history 19. Contour interval, 5 ft.

CASE HISTORY 19

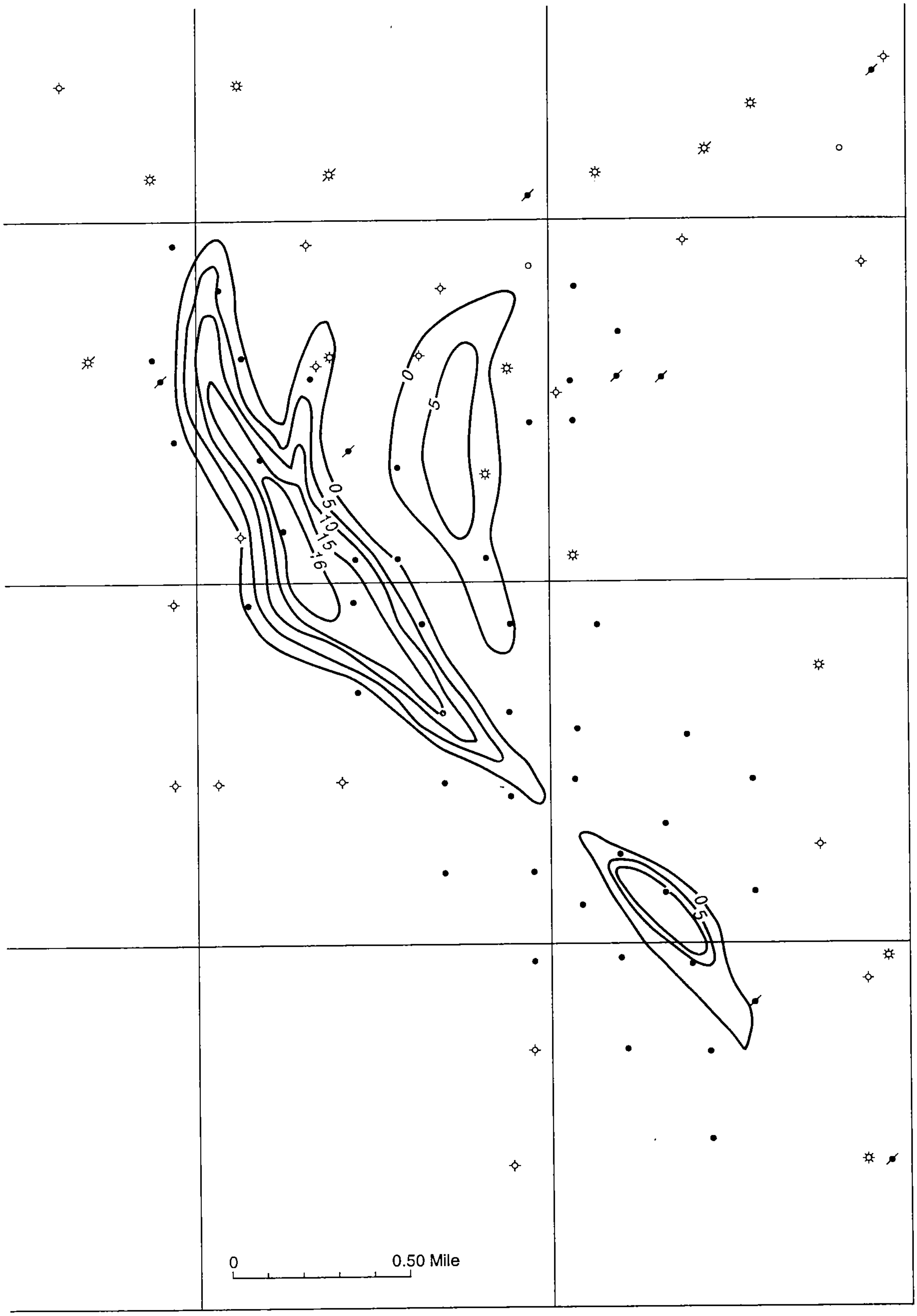


Figure 78. Isopach map of sand layer C (see Fig. 74), the third of four layers constituting the reservoir of case history 19. Contour interval, 5 ft.

CASE HISTORY 19

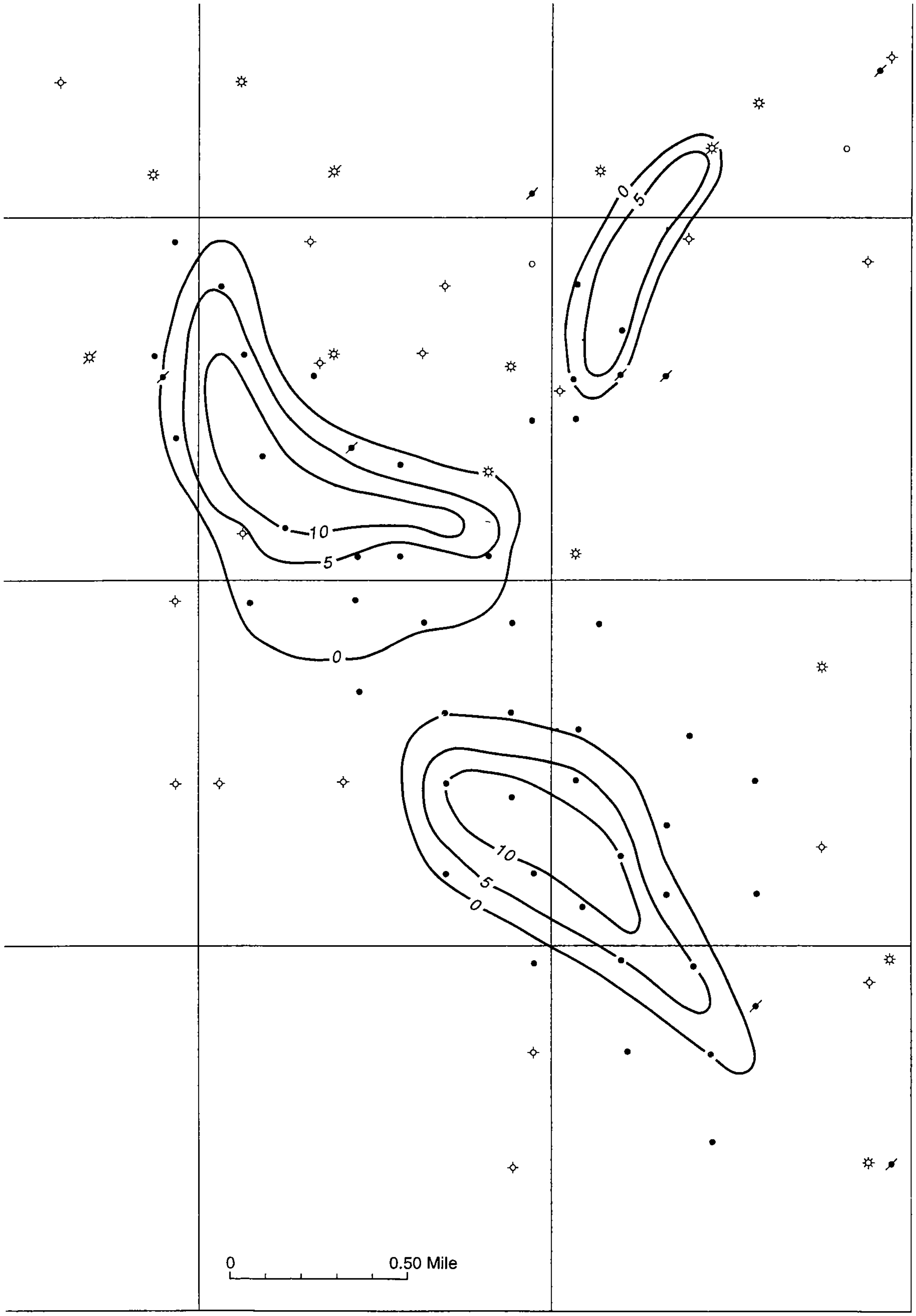


Figure 79. Isopach map of sand layer D (see Fig. 74), the bottommost of four layers constituting the reservoir of case history 19. Contour interval, 5 ft.

CASE HISTORY 19

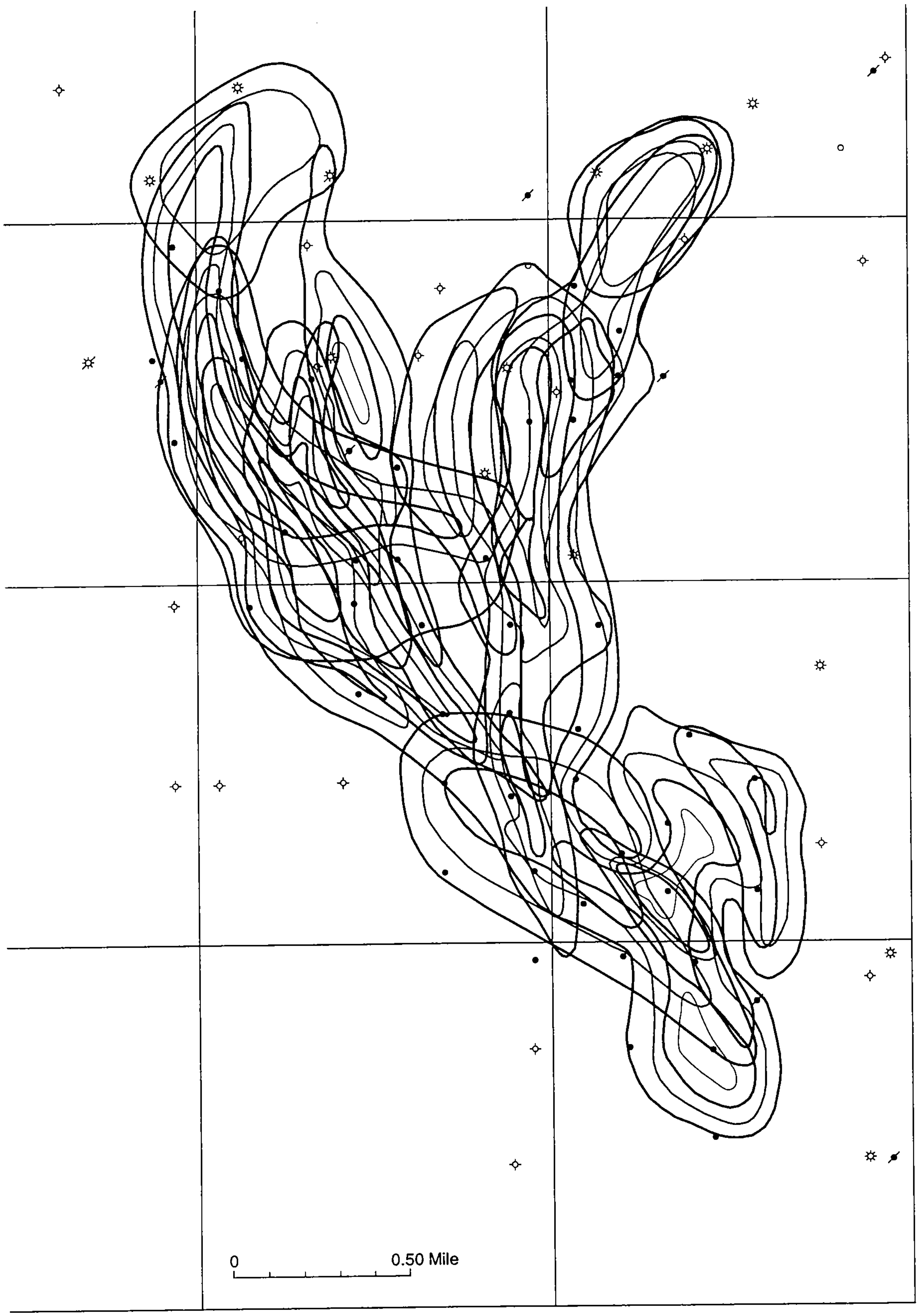


Figure 80. Superposition of layers A–D of the reservoir of case history 19. Addition of the contours that intersect account for the total net sand for those positions.

CASE HISTORY 19

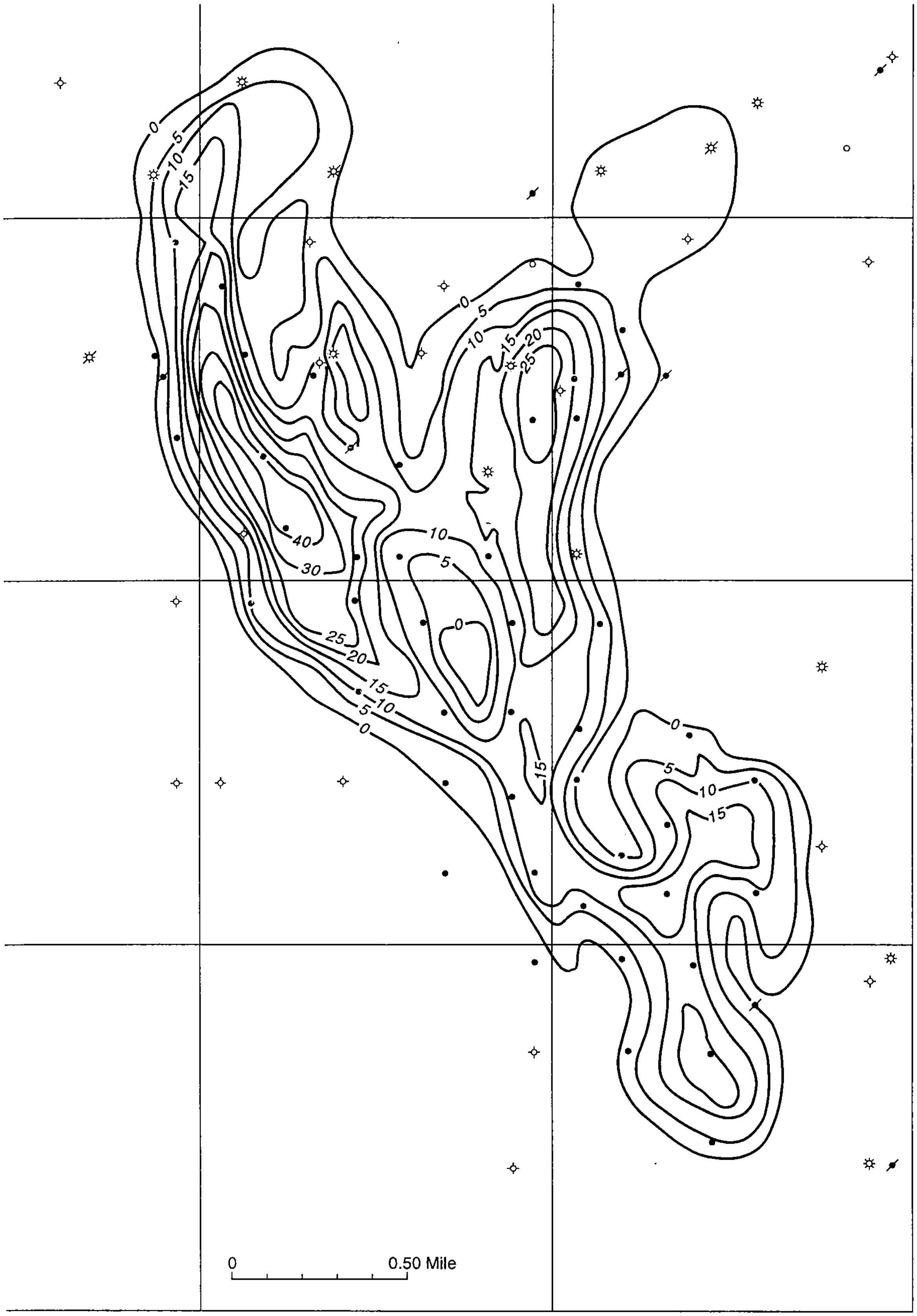


Figure 81. Composite isopach of the reservoir of case history 19, incorporating geometry and environmental-deposition interpretations for each of the four layers, results in a total net-sand isopach map that represents the most correct sand geometry of the reservoir. Contour intervals, 5 ft and 10 ft.

tations. The following two examples illustrate this point.

Case history 20 (Fig. 82) is a total net-sand isopach map of a field in southern Oklahoma. The isopach contours show the sum of the net pay for three distinct reservoirs, and this map was used as the primary map for installation of the waterflood. The project did not perform as anticipated, and a more thorough evaluation was undertaken. Figure 83 illustrates the results of that evaluation and shows isopachs of two of the three primary unitized reservoirs. As can be seen from the overlay of the two reservoirs, the fluvial-channel geometric characteristics of the sands are obvious. Distinct natural-permeability assumptions can be suggested on the basis of this interpretation. The injector–producer pattern was based on the geometry of the total-sand isopach, which suggested continuity between all the wellbores. However, the individual reservoirs are separated by shale intervals, and these reservoirs are not continuous, as Figure 82 suggests. The only communi-

CASE HISTORY 20

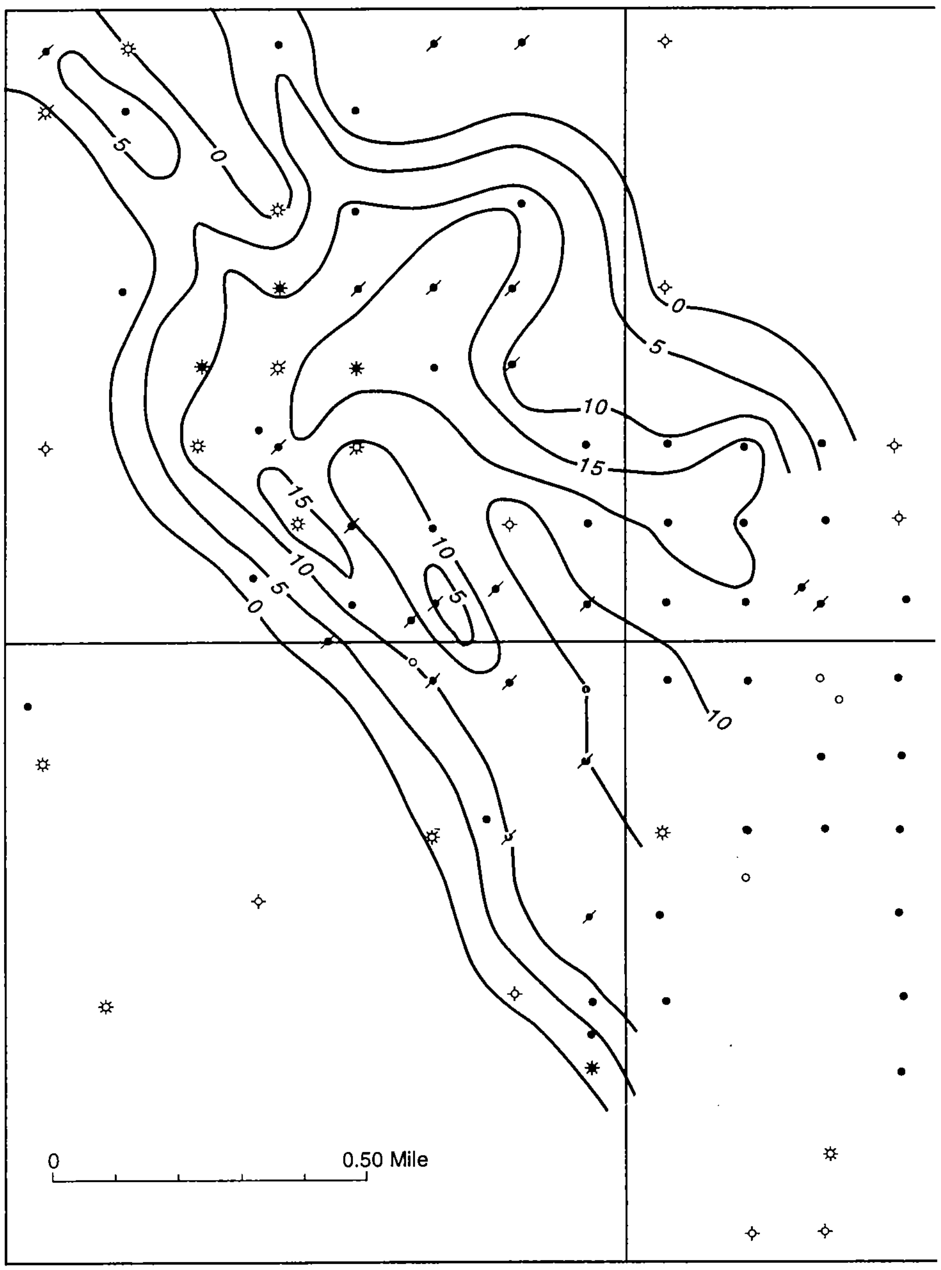


Figure 82. Total net-sand isopach map of the field of case history 20 (southern Oklahoma). The total net-sand isopach is derived by the addition of the net-pay zones for three separate reservoirs in each well. Contour interval, 5 ft.

cation that might occur would be as a result of fracturing or through perforations in the wellbores. The breakdown and isopaching of the field by individual reservoirs offers a more accurate model to gauge injection patterns and anticipated well response. Area A of Figure 83 is an example of how detailed layer mapping may influence the injector–producer pattern. This is an area that would be difficult to waterflood, owing to the lack of reservoir rock; however, the total-sand isopach of Figure 82 does not suggest any reservoir problems for this area. In conclusion, a reservoir should be broken down into the smallest correlatable depositional units, which then should be mapped individually. This layer isopaching offers the greatest opportunity to understand sand geometry and, it is hoped, sand continuity. Such isopaching also is the best method for evaluating the injector–producer pattern for a project.

The second analog for this point of view is illustrated by case history 21. Figure 84 is a net isopach map of a unitized reservoir in eastern Oklahoma. The waterflood

CASE HISTORY 20

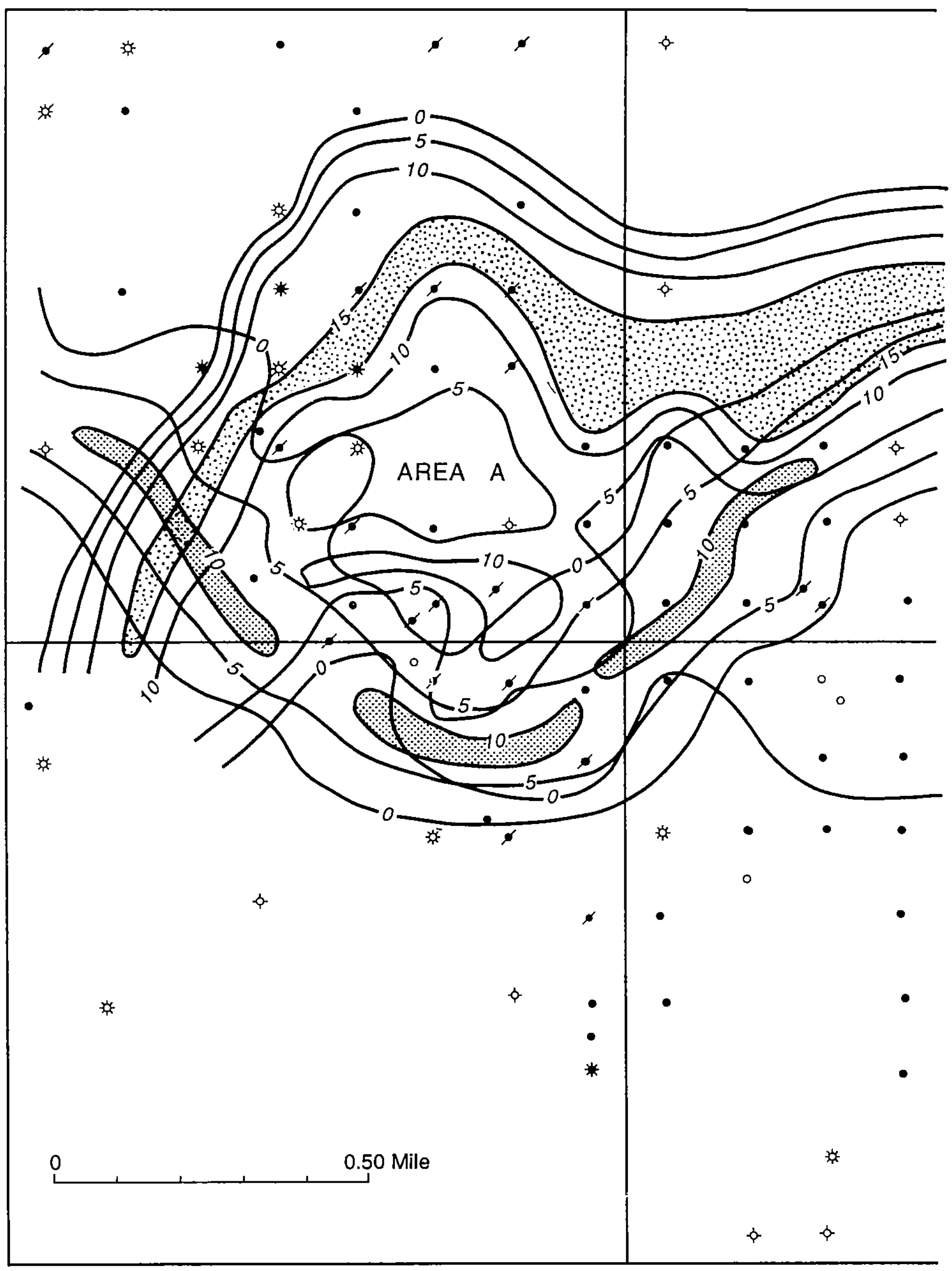


Figure 83. Isopach maps of two of the three reservoirs in the field of case history 20, incorporating sand geometry from environment-of-deposition interpretations. Contour interval, 5 ft.

was under injection for several years, and water breakthrough occurred in all active producers. Wells A and B were the only ones producing oil, at rates of 40 and 2–3 BOPD, respectively.

A chemical-tracer survey was initiated to try to determine the source of the oil from these two producers. Figure 85 illustrates the results of this survey. The field was divided into northern and southern parts. The southern survey was run from February 12 through February 23, and the northern survey, from February 22 through February 27. The lack of tracer chemicals from well C to well A in the southern survey suggested

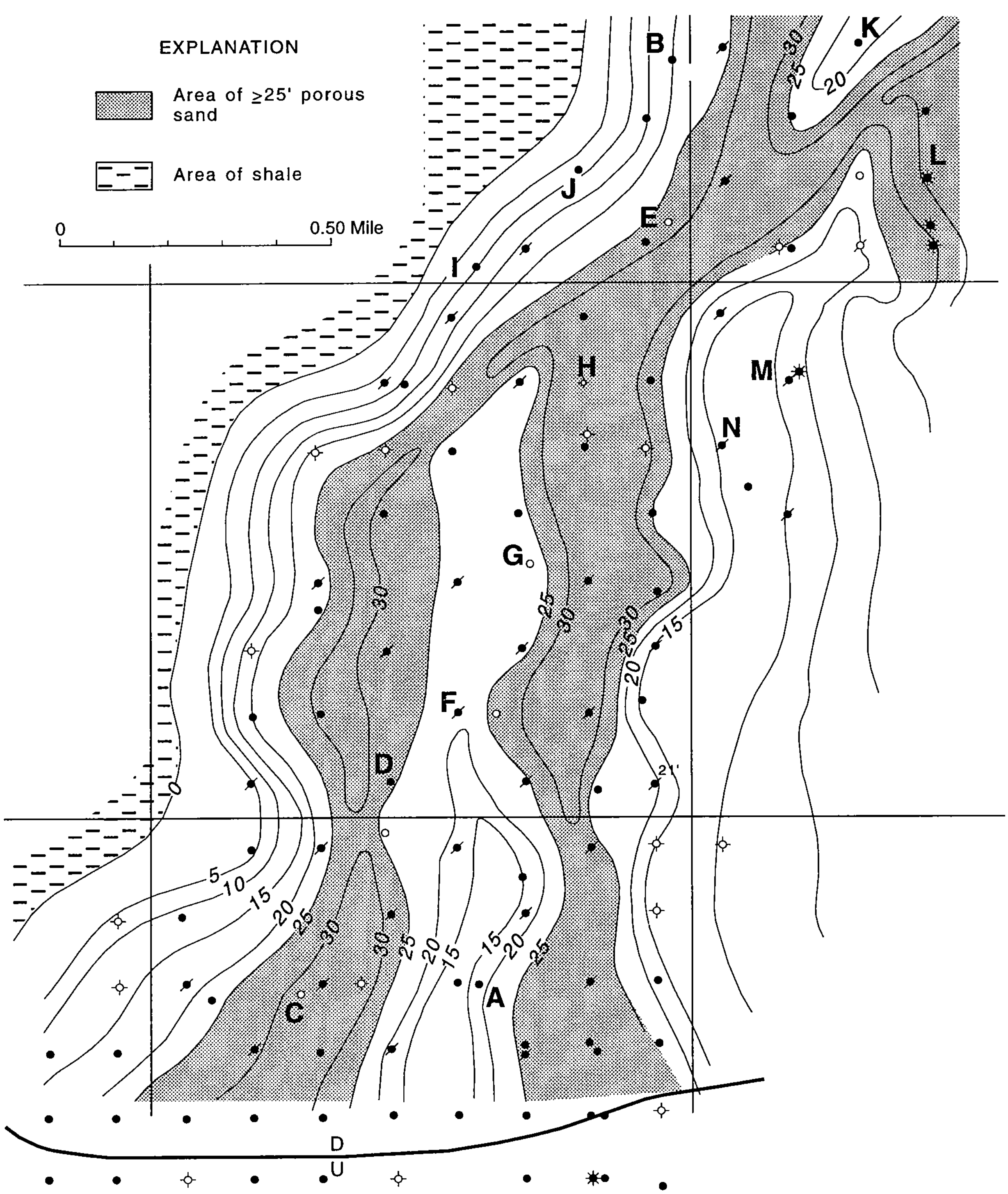
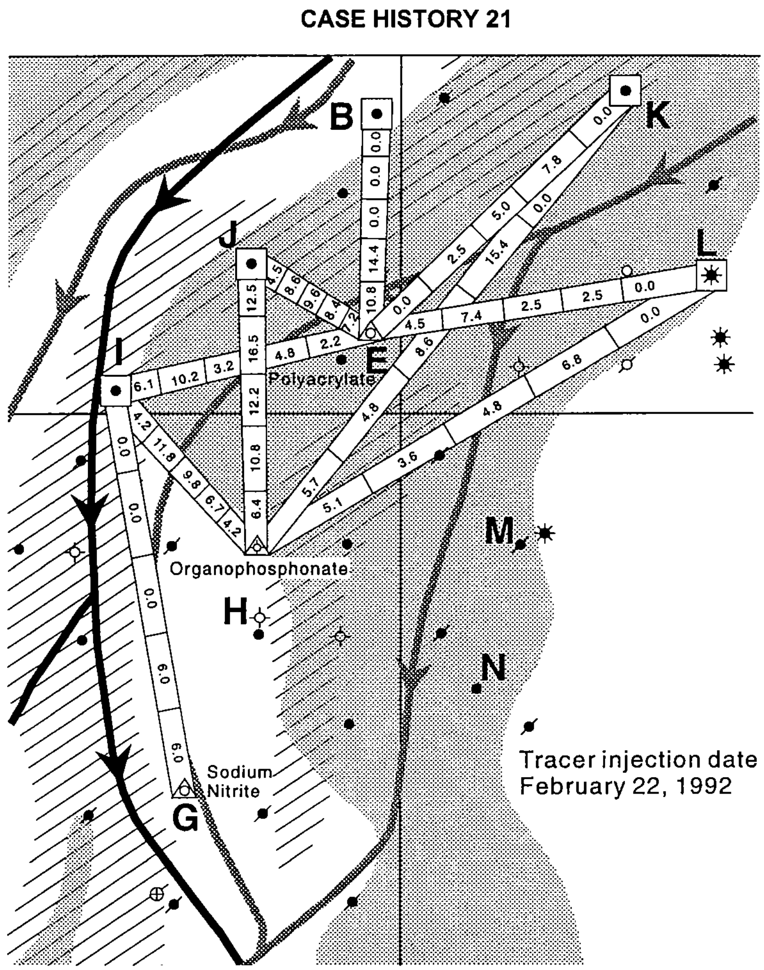
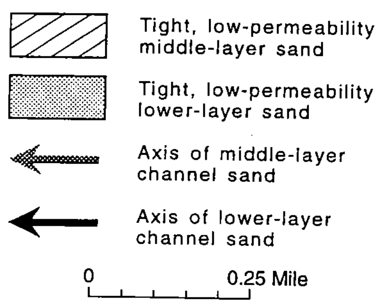
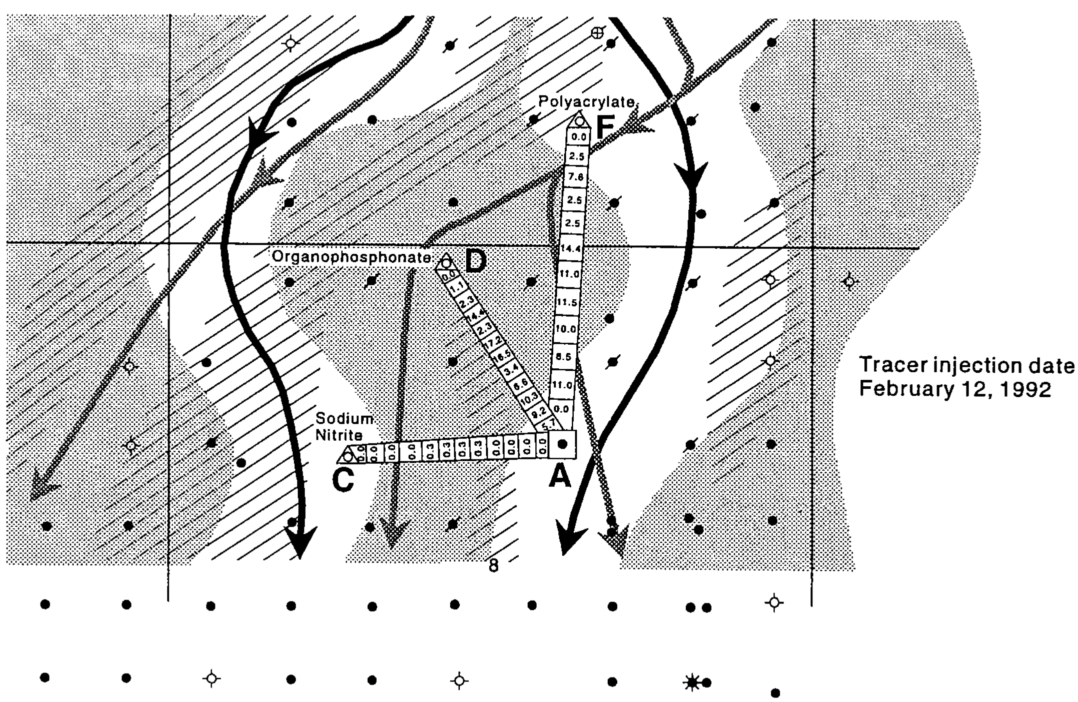


Figure 84. Isopach map of gross-sand thickness for the reservoir of case history 21 (eastern Oklahoma). Contour interval, 5 ft.

Figure 85. Results of the first chemical-tracer survey for the reservoir of case history 21 (eastern Oklahoma). Tracer chemicals were introduced into injection wells F, D, and C on February 12, and into injection wells E, H, and G on February 22. Daily water samples were collected from producers A (February 12 survey) and J, B, I, K, L, M, N, and A (February 22 survey). The divisions on the connections drawn between the injection wells and the producers represent 24-hr increments; in each case, day 1 is adjacent to the producer, and subsequent days proceed toward the injector. The amounts, measured in parts per million, of tracer chemicals in daily water samples are recorded for each day of the survey. Wells M and N did not respond to the tracer survey.







that the tighter, less permeable reservoir was probably not being swept as fast as the more permeable channels. However, injection from well D appeared to have influenced well A almost immediately through this same less permeable reservoir. In the northern survey, injection from well E seemed to influence all the producers in the vicinity almost immediately, even through the less permeable strata. What was perplexing was the simultaneous lack of oil response from the waterflood, especially in light of the results of the tracer survey, which suggested that the highy oil-saturated reservoir in the less permeable strata was being swept.

A more thorough investigation of the reservoir was initiated. Figure 86 is the reference log for the reservoir. It was determined that three layers (upper, middle, and lower) constitute the reservoir and that these layers are uniformly correlatable and genetically related on a regional scale. The three layers were isopached and are illustrated in Figures 87–89, respectively. On the basis of the geometry of the highly permeable channel axes of the three layers, it was proposed that injected water was not sweeping the less permeable strata but instead was confined to the highly permeable channels.

A second tracer survey was designed to verify this theory. Figure 90 illustrates the results of this survey. Wells A and B are situated in the high-permeability channel of the lower layer, as seen in Figure 87. The injection of tracer chemicals into this channel from wells F, G, and H resulted in the almost immediate presence of the tracer chemicals in wells A and B, on either end of the reservoir. The conclusion reached at the end of the second tracer survey was that injected fluids were confined to the highly permeable strata of the channels of the three layers. Fluids were cross-flowing from one channel to another, which provided the communication from injectors to producers. The layer isopach maps were the only maps to suggest the presence of these permeable channels. The total-sand isopach map of Figure 84 reflects no permeability variations for the separate layers, as do the isopach maps of the individual layers.

RESERVOIR BOUNDARIES

On isopach maps, the zero contour represents the boundary or limit of the reservoir. If the isopach map represents a total net isopach, the contours are customarily drawn in a uniform manner, with equal spacing between. The boundary in this scenario is simply an extrapolation of the point at which the zero limit should be based on the contour-interval spacing. How-

CASE HISTORY 21

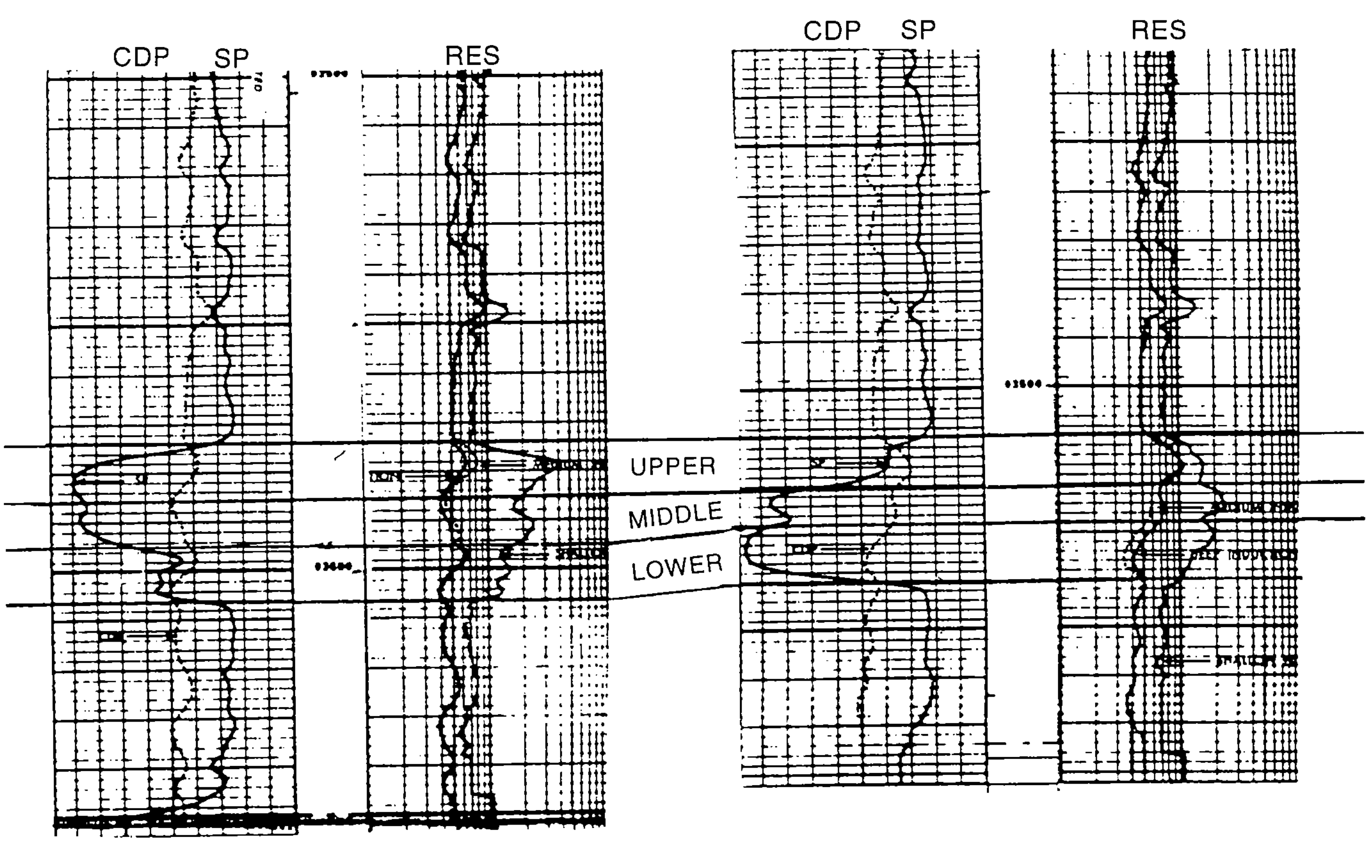


Figure 86. Reference log for case history 21. The three predominant upper, middle, and lower genetic depositional units making up the reservoir are shown. *SP* = spontaneous potential, *RES* = resistivity, *CDP* = conductivity-derived porosity.

ever, as previously illustrated, if the environment of deposition is incorporated into the isopach interpretation, the boundary, or zero contour, should be the maximum extent of the reservoir on the basis of depositional geometry. When a reservoir is unitized on the basis of zero contours of the total isopach, which incorporates uniform contour intervals, significant reserves may be left out or lost.

Case history 22, illustrated in Figure 91, indicates the importance of knowing the boundary of a reservoir on

CASE HISTORY 21

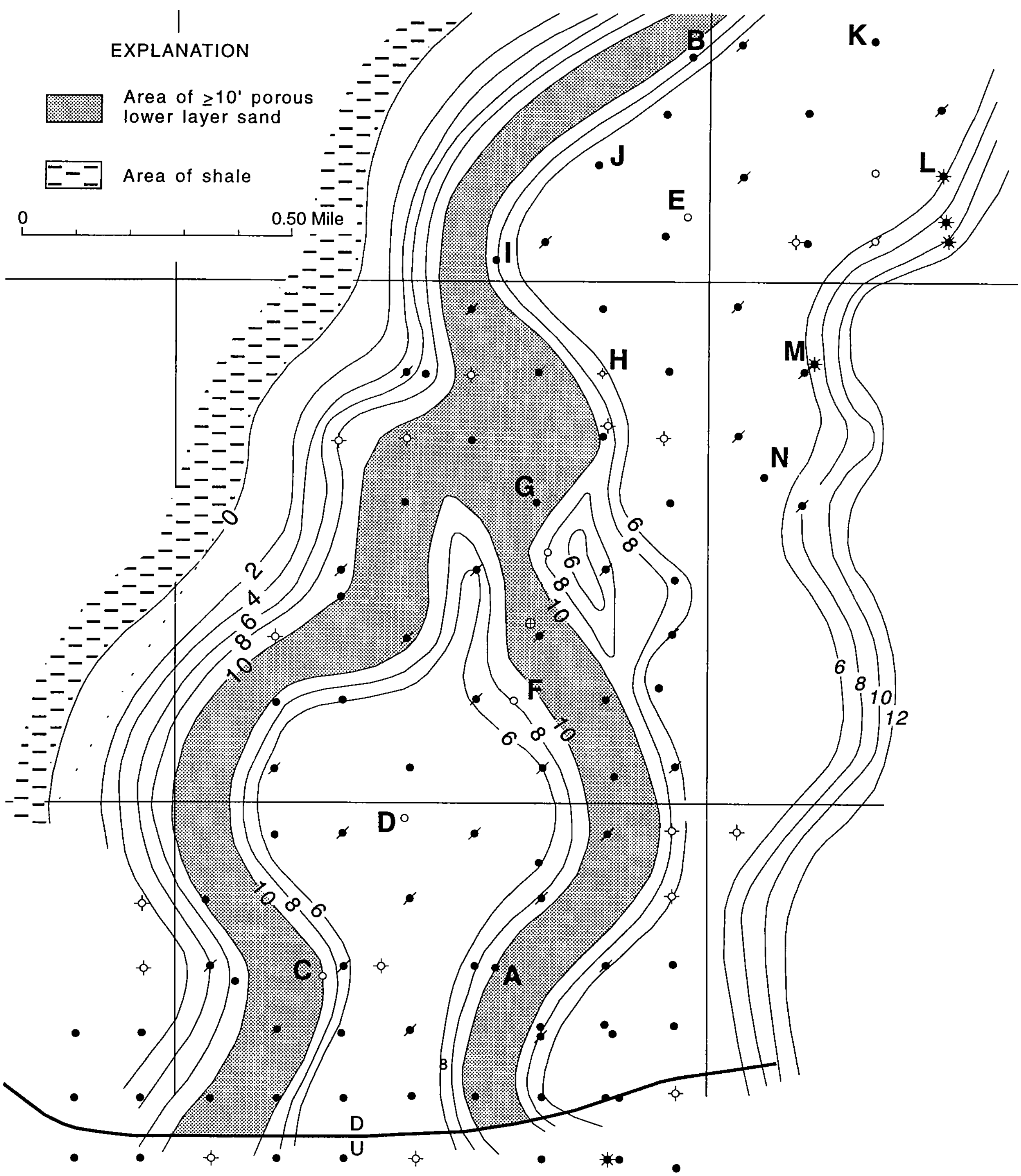


Figure 87. Isopach map of net-sand thickness of the lower layer for the reservoir of case history 21. Contour interval, 2 ft.

the basis of geometry. The heavy solid line represents a part of the unit boundary. The dashed contour lines represent the original unitized contours for the reservoir, which were drawn with equidimensional spacing. Well A had been completed and contained approximately 3 ft of the unitized pay zone; at this time it was probably not known whether this pay zone was part of the unitized reservoir or was considered insignificant. In any case, the original operator unitized the field but did not include well A.

CASE HISTORY 21

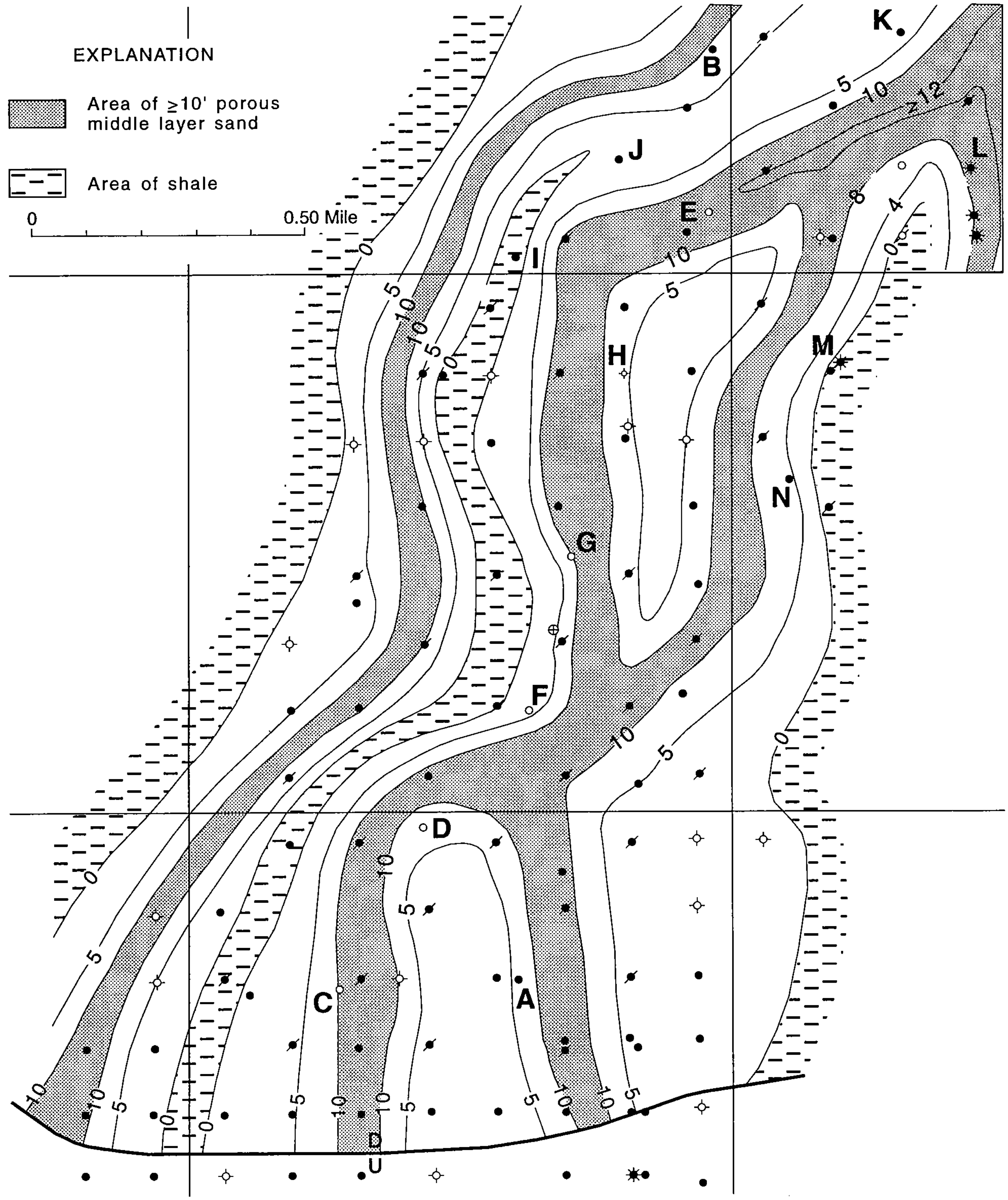


Figure 88. Isopach map of net-sand thickness of the middle layer for the reservoir of case history 21. Contour interval, 5 ft.

Shortly after injection commenced, the mineral owners adjacent to the unit boundary drilled well B. The solid contour lines represent the revised version of the isopach map on the basis of these new data. Figure 92 shows the production curve for well B. After 3 years of production, response from the adjacent field started to influence the production of this well. The increase in production from months 36 through 101 represents response to the waterflood. The cumulative production for well B is approximately 82,000 BO, which constitutes

CASE HISTORY 21

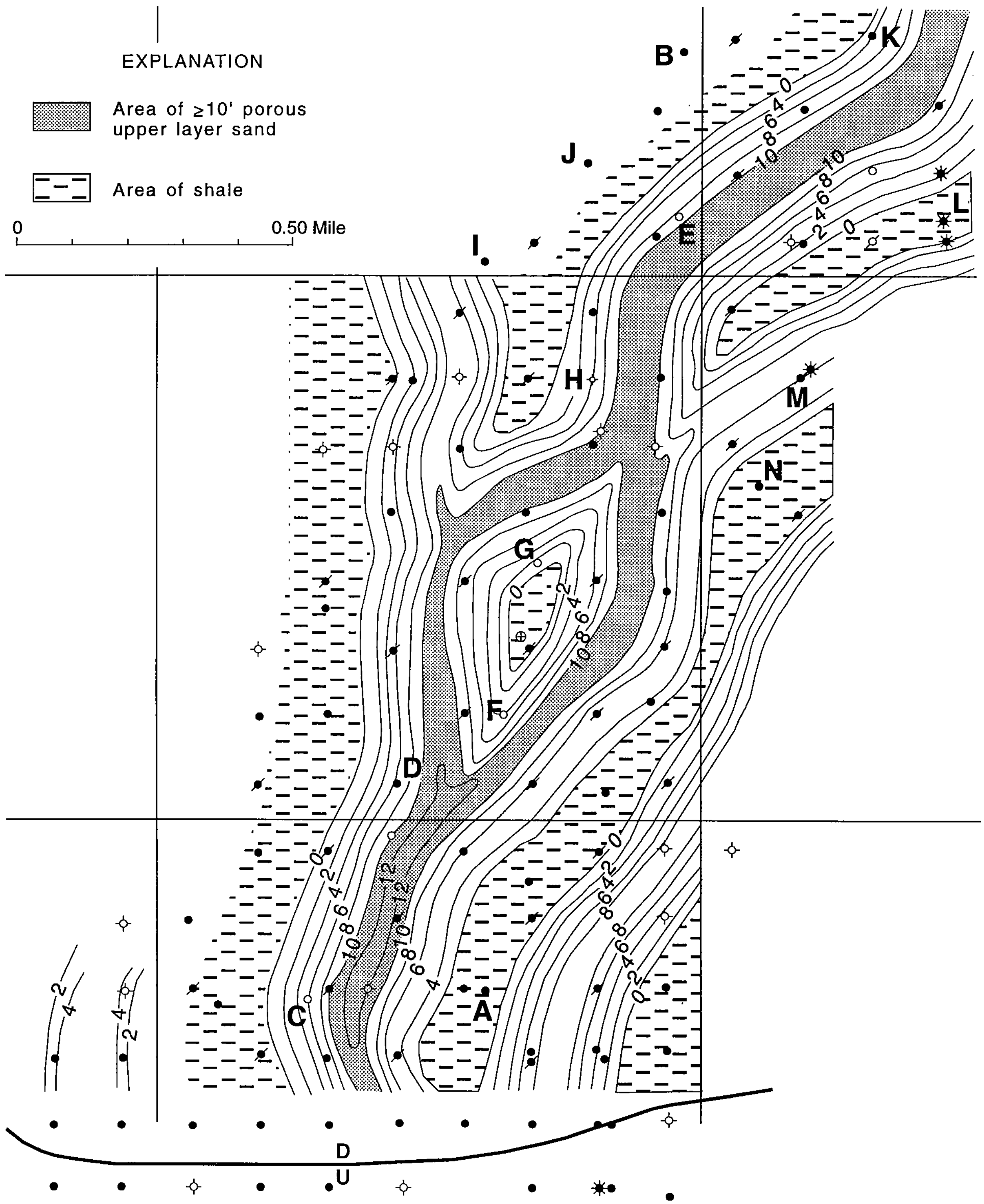


Figure 89. Isopach map of net-sand thickness of the upper layer for the reservoir of case history 21. Contour interval, 2 ft.

CASE HISTORY 21

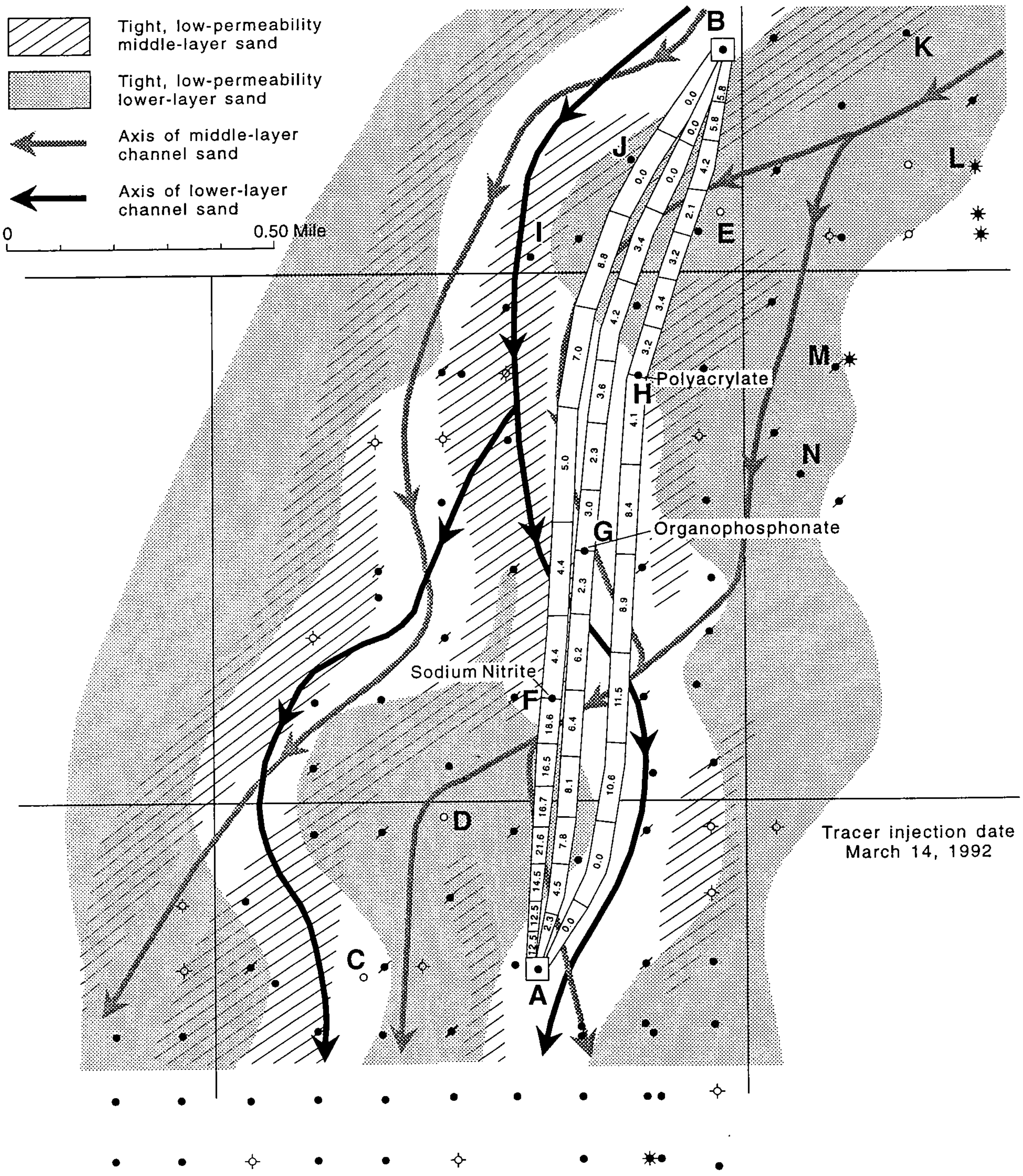


Figure 90. Results of the second chemical-tracer survey for case history 21 (eastern Oklahoma). Chemical tracers were introduced into injection wells H, G, and F on March 14. Daily water samples were collected from producing wells B, M, N, and A. The divisions on the connections drawn between the injection wells and the producers represent 24-hr increments; in each case, day 1 is adjacent to the producer, and subsequent days proceed toward the injector. The amounts, measured in parts per million, of tracer chemicals in daily water samples are recorded for each day of the survey. Wells M and N did not respond to the tracer survey.

approximately 12% of the secondary reserves of the adjacent field. This production could have been obtained by the unit's operators, had they honored and incorporated the geometric-zero limits of the reservoir initially.

COMPARING MATERIAL-BALANCE TO VOLUMETRIC CALCULATIONS

Material-balance equations are actually volumetric-balance equations. Craft and Hawkins (1959) refer to the material-balance equation as "simply a volumetric balance, which states that since the volume of a reservoir (as defined by its initial limits) is a constant, the algebraic sum of the volume changes of the oil, the free gas, and the water volumes in the reservoir must be zero." Reservoir engineers generally use the material-balance equation for determining the initial oil in place, calculating water influx, or predicting reservoir pressures. This section discusses the importance of comparing the oil-in-place values calculated by material-balance and volumetric-balance equations.

George and Stiles (1978) suggest that if all data are accurate, original oil in place calculated by volumetric methods should represent the true value and should be

CASE HISTORY 22

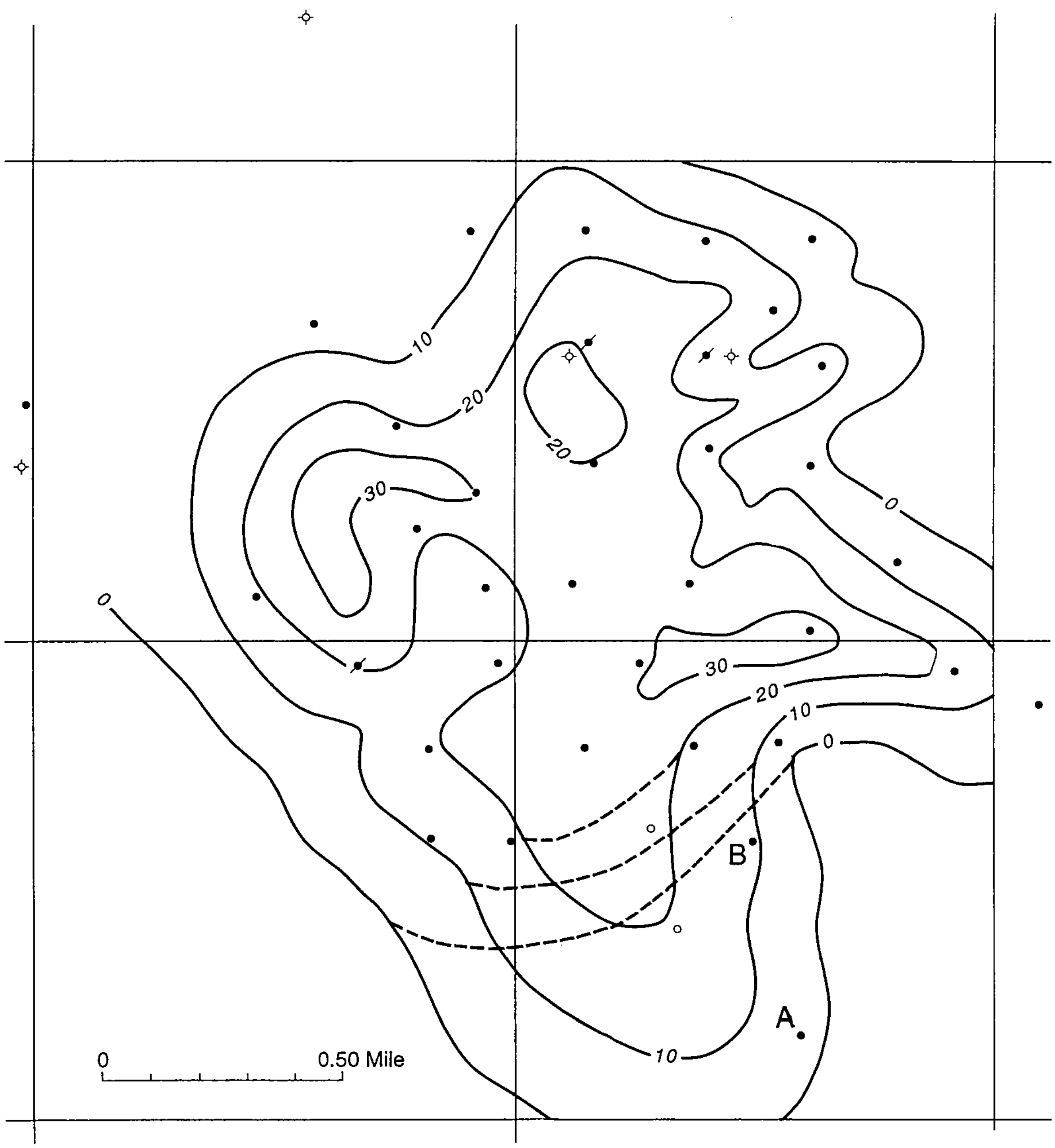


Figure 91. Net isopach map of the reservoir of case history 22. Dashed contours represent isopach contours prior to drilling well B, and solid contours incorporate data from well B into the revised isopach map. Contour interval, 10 ft.

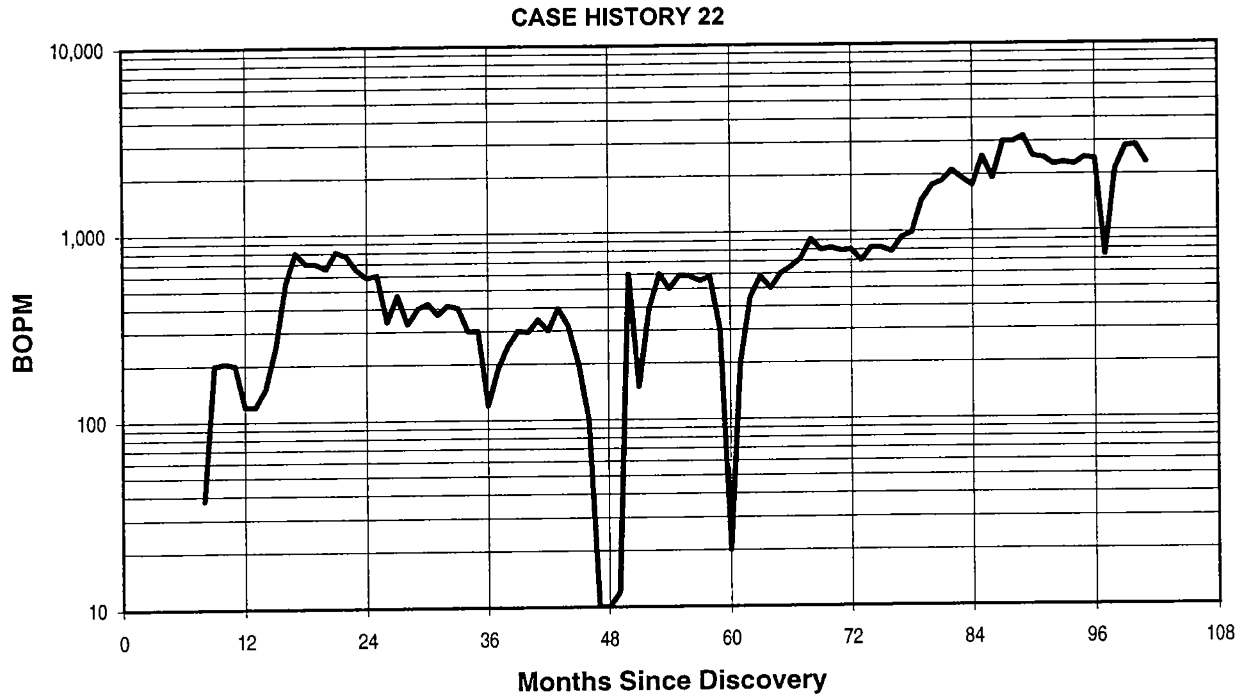


Figure 92. Production curve for well B of case history 22.

independent of well spacing, whereas original oil in place calculated by material-balance methods represents only that part of the reservoir contacted by the producing wells.

Two scenarios exist for the material-balance equation. First, not all pay stringers are continuous throughout the reservoir; therefore, only those porous zones that have been reached by completed wells affect the material-balance equation. Second, porous zones that are continuous but have not been reached by completed wells do not affect material-balance equations.

Furthermore, George and Stiles (1978) suggest that the ratio of material-balance OOIP to volumetric OOIP can be considered a measure of reservoir continuity dependent on well spacing and completions. As an example, Stiles (1976) refers to the material-balance OOIP calculation of 738 MMBO for the Fullerton Clearfork Unit. The volumetric OOIP calculation, using a 6%-porosity cutoff, was 1.029 MMBO in place. Assuming the accuracy of all parameters, the ratio of material-balance to volumetric OOIP of 0.72 is a measure of reservoir continuity and effective well completions for the reservoir.

If volumetric OOIP calculations are considered representative for the reservoir, assuming that the parameters are known and accurate, what are the ramifications if the ratio of material-balance to volumetric OOIP values exceeds 1.0? Consider case history 23, illustrated in Figure 93, which is a net-sand isopach map of a reservoir in central Oklahoma. Table 15 gives an independent engineering firm's volumetric and material-balance calculations for this reservoir. The firm states in the feasibility study of the reservoir that the "close agreement (94%) between material-balance and rate/time predictions of ultimate primary reserves suggests the validity of the material-balance estimate of OOIP." Furthermore, the recovery efficiency of 24% for the material-balance OOIP is more reasonable than the volumetric recovery efficiency of 34%, as seen in Table 15. The independent engineering firm suggested increasing the porosity value and decreasing the water saturation to bring the adjusted volumetric OOIP to more closely approximate the OOIP value calculated from the material-balance equation. A problem exists, however, because the original values of porosity and water saturation were derived from good electric-log and core data.

Rather than accepting this proposal changing the porosity and salt-water values, the operator incorporated a more thorough regional perspective of the reservoir. Well A in Figure 93 was a small producer in the same reservoir as the unit. The operator considered it part of their field and subsequently drilled well B, illustrated in Figure 94. Well B encountered a thick, depleted reservoir that was obviously connected to the operator's field. The increase in volumetric acre-feet allowed the volumetric OOIP value to more closely approximate the material-balance OOIP value. In this example, the material-balance OOIP value reflected the true volumetrics of the reservoir. The volumetric calculation of OOIP was too low because of an undetermined amount of the reservoir that was influencing production.

CASE HISTORY 23

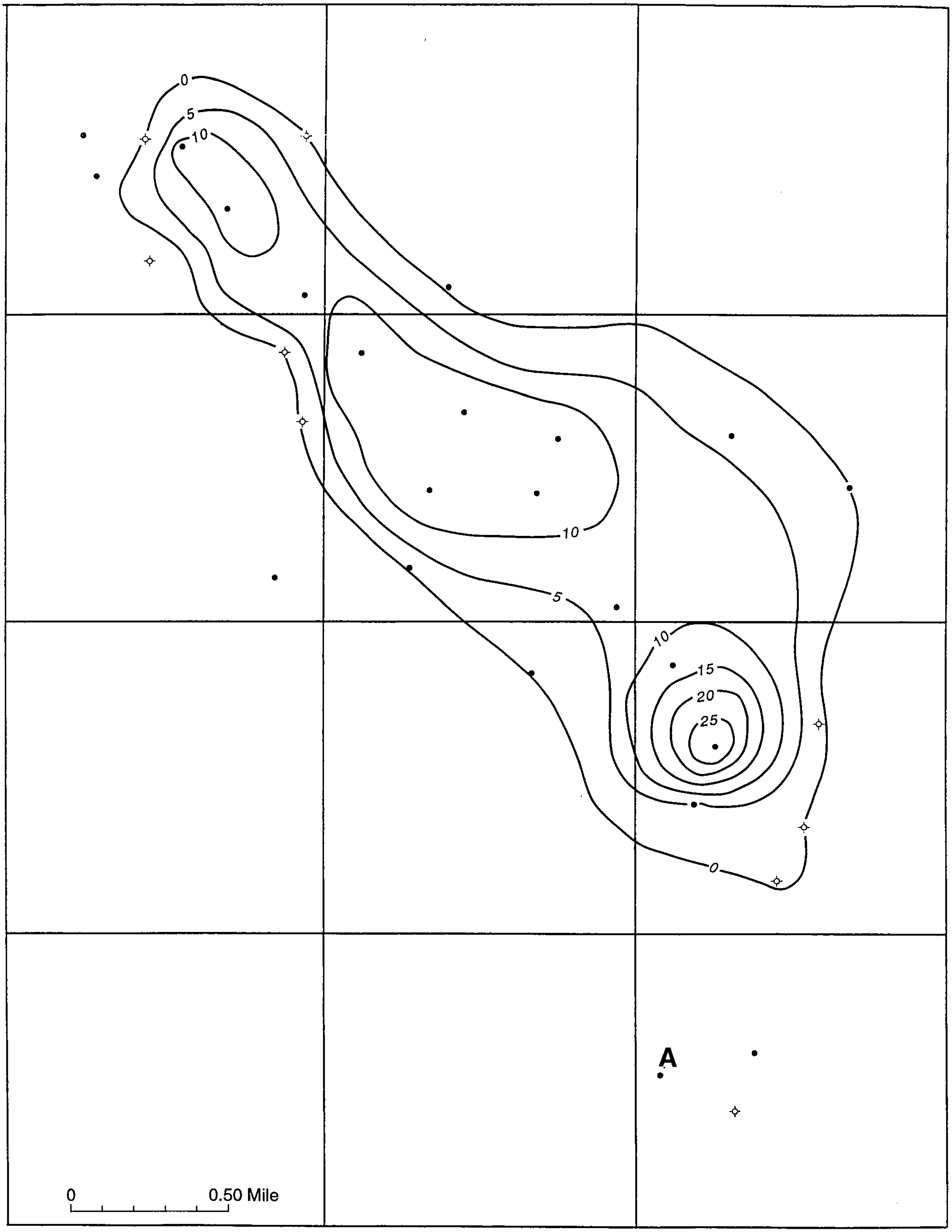


Figure 93. Isopach map of net sand in the reservoir of case history 23 (central Oklahoma). Contour interval, 5 ft.

CASE HISTORY 23

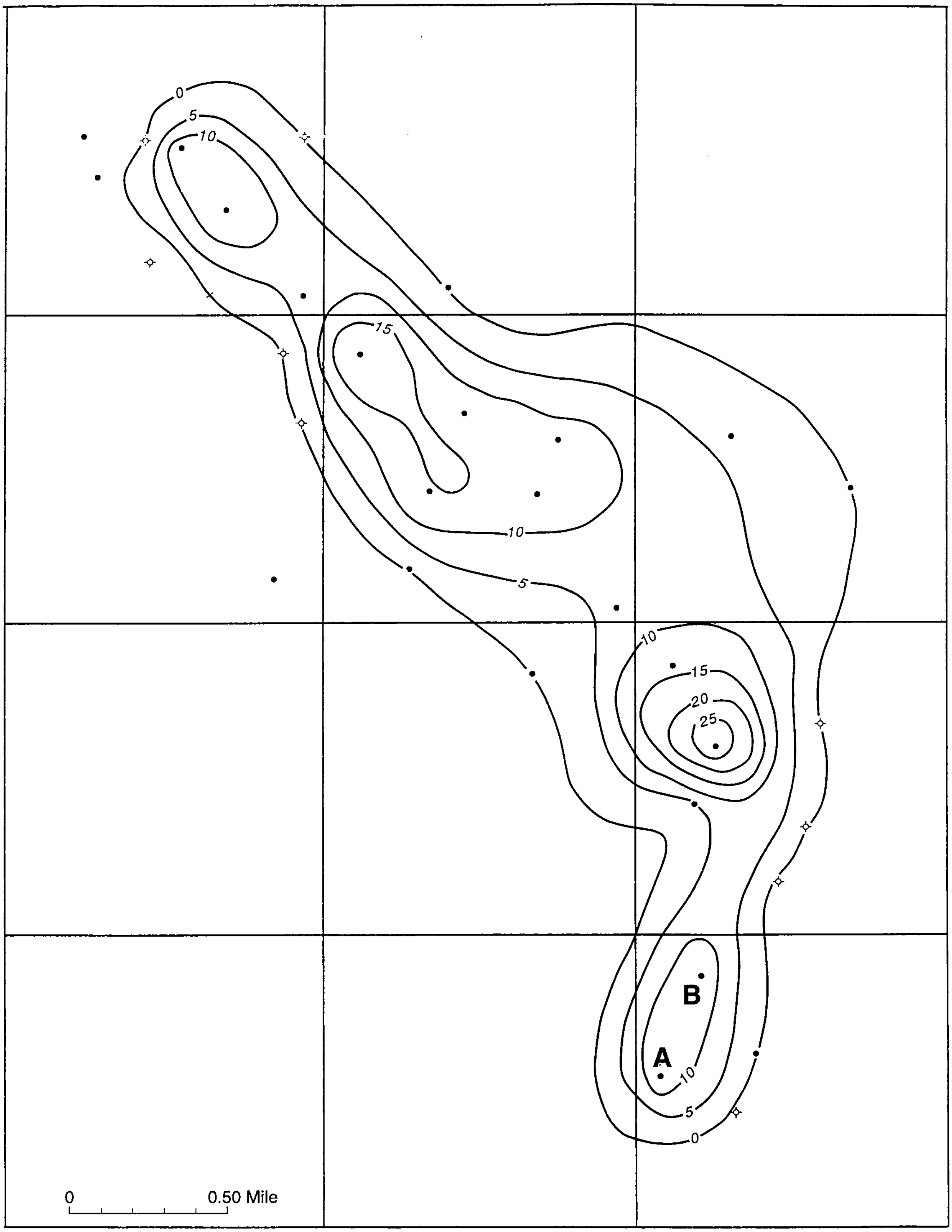


Figure 94. Revised isopach map of net sand in the reservoir of case history 23 (central Oklahoma). Contour interval, 5 ft.

TABLE 15. — Comparison of Material-Balance and Volumetric Oil-in-Place Calculations for Case History 23

	OOIP (MMBO)	Primary Recovery efficiency	Ratio of m-b/vol
Material-balance results	5,653,000	24%	
Volumetric results (using 11.5% porosity and 24% water saturation)	3,952,000	34%	143%
Suggested adjusted volumetric results (using 15% porosity and 17% water saturation)	5,635,130	24%	100%

ISOPACHING CUMULATIVE PRODUCTION AND INITIAL POTENTIAL

Maps of cumulative production and initial potential are intended to display information concerning the potential productivity of a reservoir. Practically, however, this may not be what is shown. An *isopach*, by definition, is a line drawn on a map through points of equal true thickness of a designated stratigraphic unit or group of stratigraphic units (Jackson, 1997). Therefore, the term *isopach* refers to thick-nesses of stratigraphic units. Cumulative production and initial potential, therefore, are not thicknesses but values.

Probably a more correct term for these maps is *isopleth*—maps of cumulative production or initial potential. The definition of *isopleth* is a general term for a line, on a map or chart, along which all points have a numerically specified constant or equal value of any given variable, element, or quantity, especially a contour (Jackson, 1997). In practical terms, iso-cumulative maps and iso-potential maps are used in the petroleum industry today but are not recognized formally.

The question should be asked now, what do the contours on isopleth maps imply? Theoretically, cumulative-production and initial-potential maps, when overlain on their respective virgin-state undrilled reservoirs, should provide minimum potential productivity in cumulative stock-tank barrels, and initial-potential-flow rates for the reservoir. The maximum values for these data are not presented on these maps.

For these two types of maps to be correct, all parameters for the maps should be equal. The two most important parameters are (1) order in which wells are drilled, and (2) state of depletion of the reservoir when drilled. This means, in an ideal case, that all the wells in the reservoir must be drilled at the same time and produced under the same circumstances for the two maps to be technically correct.

For example, consider case history 23A, illustrated in Figure 95. Model 1 represents a hypothetical reservoir drilled by two wells. This reservoir is considered to be homogeneous, with uniform, equidimensional permeability. The zero contour represents the net physical boundary of the reservoir. Suppose well 1 was drilled in the southern half of the reservoir and produced oil for a certain length of time. The reservoir becomes partially pressure depleted when well 2 is drilled. Owing to the depletion of pressure, well 2 produces only one-third the oil that well 1 has produced. The contours of cumulative production for model 1 are drawn in response to the production that actually occurred. The pitfall in this example is that geologists and engineers tend to state that the "sweet spot" of the reservoir is in the southern half of the reservoir without regard to the order of drilling or the state of depletion.

This point is confirmed by considering model 2. This is the same reservoir, except that well 1 was drilled in the northern half, and after partial pressure depletion of the reservoir, well 2 is drilled in the southern half. The resulting contours of cumulative production are now inverted from those of model 1, and the corresponding "sweet spot" of the reservoir appears to be in the northern half.

The isopleths for models 1 and 2 represent the value of cumulative production for the reservoir with respect to the order in which the wells were drilled and the state of depletion of the reservoir only. The isopleths do not represent the true cumulative production potential of the reservoir. For the cumulative-production isopleths to be accurate, the pressure and the order of drilling need to be factored in.

Isopleths of cumulative production may offer insight into the accuracy of a reservoir's isopach contours. As the contours of a cumulative-production map indicate the actual value of production for the reservoir, contours that are too close together may be an indication of production that exceeds the calculated capacity of production, in BO/acre-feet, and that exceeds the calculated reservoir capacity in that part of the field. Consider case history 24, as seen in Figure 96. Tract 1 has a cumulative production of 152,000 BO. The recovery factor for the 60-acre tract is 211 BO/acre-ft, which is almost 2.5 times the average recovery factor of 84 BO/acre-ft for the field. The close proximity of the isopleths to the zero sand limit of the reservoir could suggest that an additional part of the reservoir, possibly to the northeast, is contributing to production, as suggested by the dashed contours.

CASE HISTORY 23A

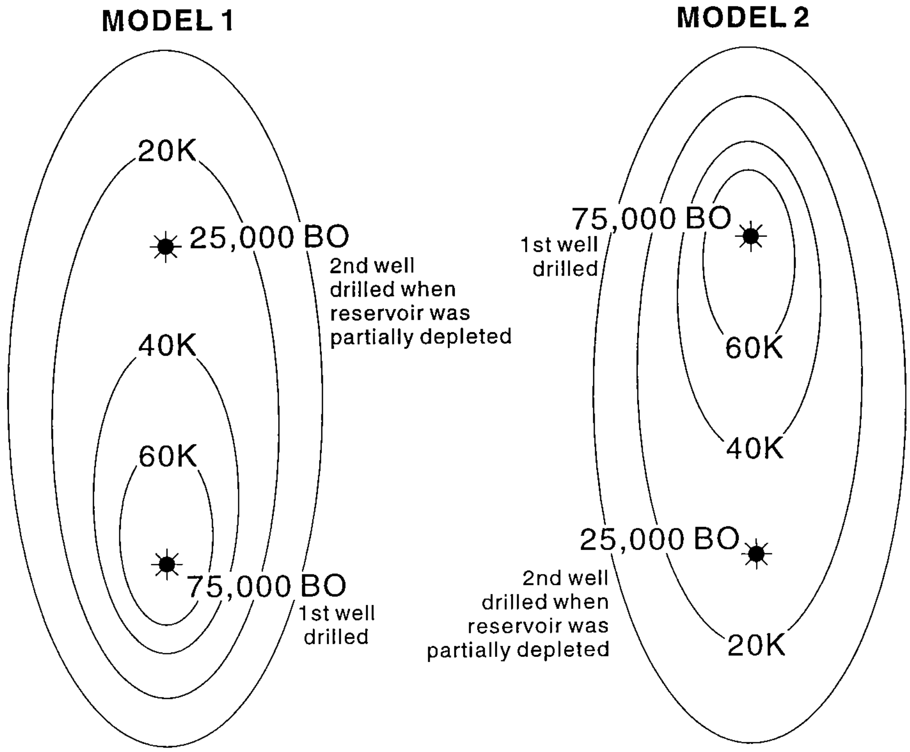


Figure 95. Hypothetical reservoir with properties of uniform porosity and permeability. Well 1 was drilled first in both models 1 and 2. Well 2 was drilled after the reservoir was partially depleted. Contour interval, 20,000-BO increments.

CASE HISTORY 24

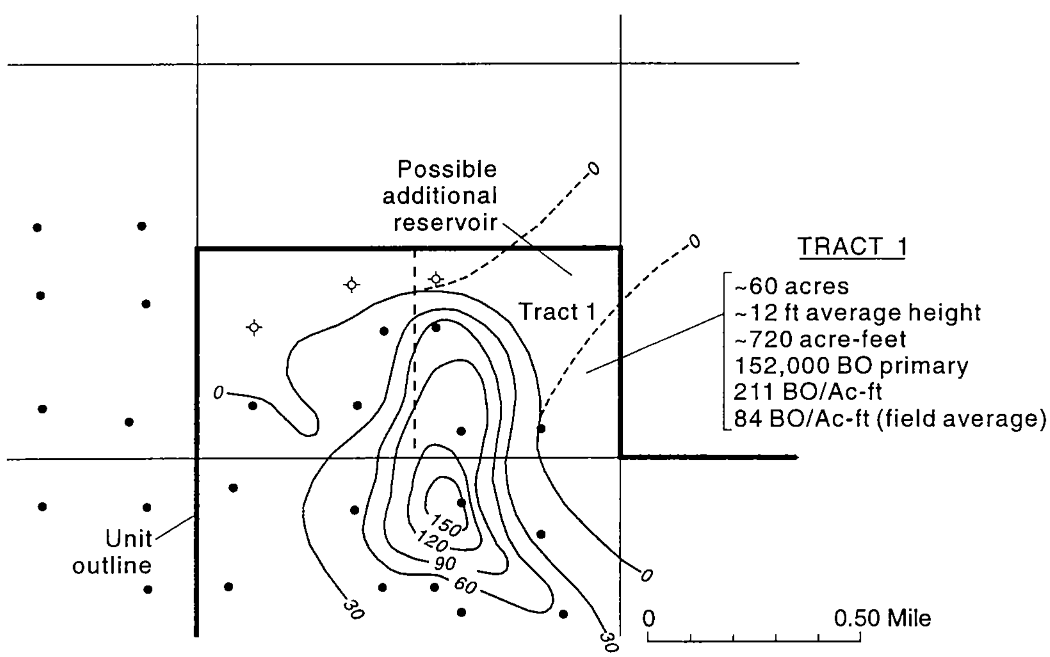


Figure 96. Map of cumulative production for a part of the reservoir of case history 24 (northern Oklahoma). Dashed contours represent a possible additional part of the reservoir. See text for explanation. Contour interval, 30,000-BO increments.

Structure

6

CHAPTER 6

Structure

INTRODUCTION

The structure of a waterflood candidate is often the least intensely evaluated aspect of the reservoir, but its effect on waterflood performance can be dramatic and disastrous. The main influences of structure are faulting and degree of dip, whether homoclinal, anticlinal, or synclinal. This workshop does not deal with the effects of structure on water injection. The following examples illustrate potential problems in interpreting structure for a waterflood candidate.

EFFECT OF FAULTING ON WATERFLOODS

Case history 25 (Fig. 97) is a reservoir in southern Oklahoma. The heavy line represents a partial unit boundary for field A. This field was unitized, and injection began in the pattern on the south (upthrown) side of the fault, as shown. Fault 1 separates the injectors on the south side of the fault from the producers on the north side. Figure 98 shows the production curve for field A. As can be seen, field A was unitized 8 years after discovery. Field B was a four-well lease producing adjacent to field A. Figure 98 also illustrates unit B, which was unitized 20 years after discovery of field A. Injection in the two injectors of field B occurred simultaneously with unitization. Fields A and B are producing from the same contiguous reservoir. Notice the response or increase in production at point C in Figure 98. This increase in production was from the wells on the north side of fault 1 in field A, which responded to injection from field B. These north-side wells had not responded to any injection from their field on the south side of the fault for over 12 years. This example demonstrates the effects that a fault can have on a waterflood pattern. The fault acts as a boundary, and its orientation must be incorporated into the waterflood design.

In this example, fault 1 may not have been known to the operator of field A, although the fault should have been readily apparent from local structural control. Two scenarios possibly exist if the fault had been known. First, the operator of field A might not have wanted injectors on the north side of fault 1 to push oil to producers outside the unit. A second possibility might have been that the operator of field A was waiting for unitization and injection from adjacent leases to drive oil to his unit. In any case, this fault probably caused cash flow from reserves on the north side of the fault to be delayed to the operator of field A for a number of years, thus affecting payout and rate-of-return parameters.

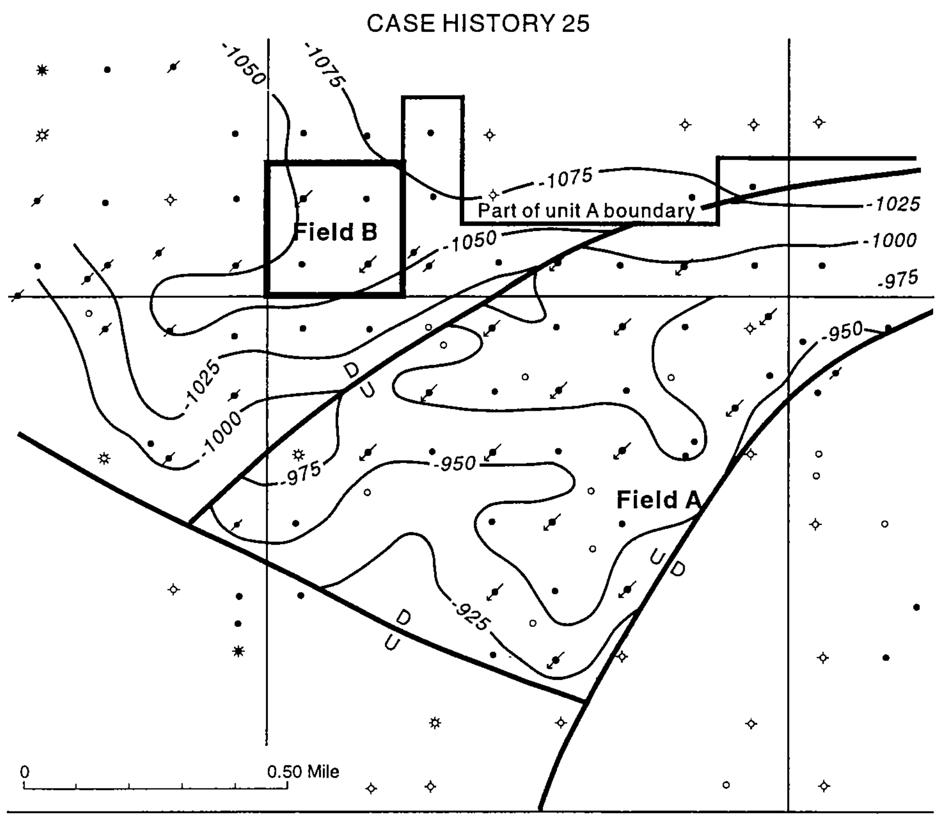


Figure 97. Structure-contour map of a part of the reservoir of case history 25 (southern Oklahoma). Contour interval, 25 ft.

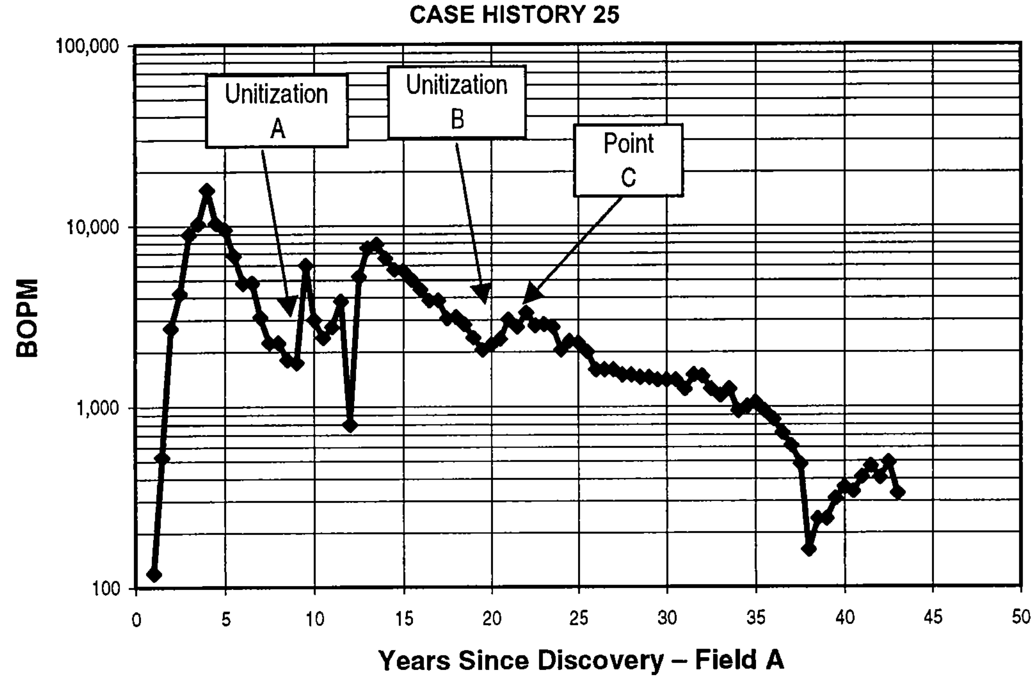


Figure 98. Production curve for a part of the reservoir of case history 25. Field A was unitized 8 years after discovery. Field B was unitized 20 years after discovery of Field A. The increase in production at point *C* is the response from the injectors of field B to the producers on the north side of fault 1 of field A. See text for explanation.

FAULT DETERMINATION

Case history 26, illustrated in Figure 99, is a structure map of a reservoir in north-central Oklahoma. The structural datum is the top of the Viola Formation (Upper Ordovician). A southeast-trending normal fault is present in the northeast part of the map, and an apparent south-trending nose is present in the center. A small closure lies just south of the nose. Well A was drilled at the leading edge of the nose. Cross section *A–A′* (Fig. 100) shows log correlations from well A to well B. Of interest is the total lack of Viola in well A, for which there are two possible explanations.

First, an unconformity might exist between the overlying regional Sylvan Shale and the Viola, which would be responsible for removing the Viola. This concept is dismissed, because of the thousands of wells observed in northern Oklahoma, no unconformity has ever been documented or observed in this stratigraphic interval.

Second, the missing section might have been cut out by faulting. If so, the throw would be approximately 150 ft. A problem with this explanation is the lack of any indication of faulting in the other wellbores. A second problem is the lack of displacement between fault blocks that would account for the 150 ft of missing section.

It is the author's opinion that a missing section in a wellbore, with no subsurface evidence of local faulting or unconformities, actually occurs rather commonly. Notice the overall shape of the resistivity curve and the SP curve for the Sylvan Formation for well A, and compare it to the shape of the Sylvan curves for well B. Regional correlation in northern Oklahoma verifies that the shape of the SP and resistivity curves for well B would be considered a type curve. The curves for well A appear to be upside down or opposite in profile from those of well B. Well A actually cut faults in at least three places, as shown in Figure 101. The dashed and solid lines associated with points 1, 2, and 3 represent what a normal Sylvan resistivity curve would look like for the Sylvan section of fault block C; however, only the solid curve is seen on the log. Points 3, 4, and 5 represent what the Sylvan section would look like for fault block D; the solid curve is observed on the electric log. The position of these two sliver faults and their structural relationship coincidentally align the Sylvan section in each fault block to make it appear on the electric log as a complete section. The wellbore crosses another fault at point 4 and goes into fault block F at or near a marker in the lower Viola Formation or upper Simpson Group. The position of various strata in fault blocks C and D suggests that the blocks have moved, relative to one another, at least three separate times to cause this juxtaposition. Because of this multiple movement, it is probably coincidental that blocks A and B have almost aligned themselves structurally. Figure 102 is a corrected structure map depicting the top of the Viola Formation. Notice that the fault-block trend happens to orient itself between wells, accounting for the lack of faulting in the other wells. The Mississippian

CASE HISTORY 26

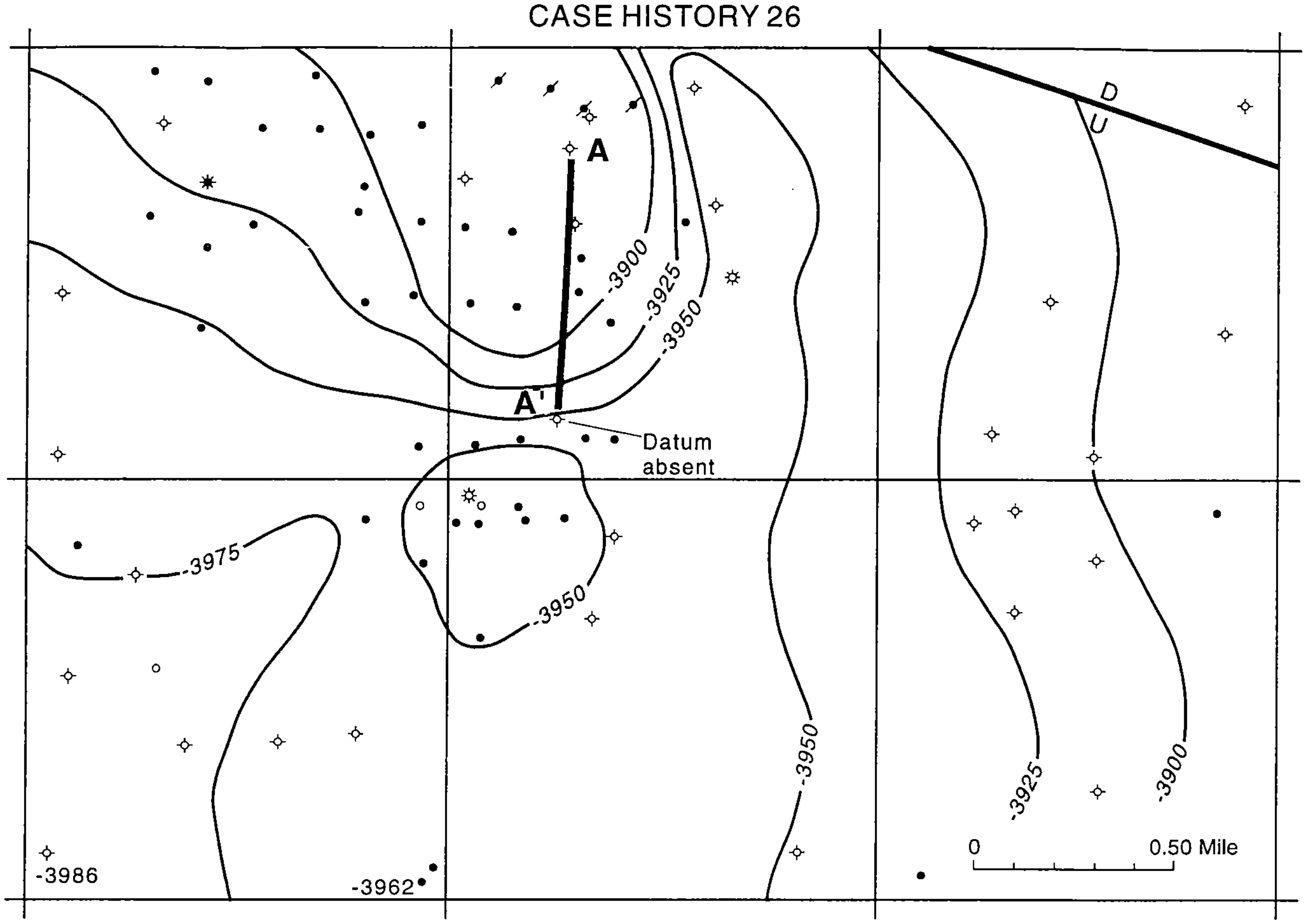


Figure 99. Structure-contour map of an area of case history 26 (north-central Oklahoma). Map datum is top of Viola Formation, which is absent in well A′. Contour interval, 25 ft. Cross section *A–A′* is shown in Figure 100.

formation in fault blocks A and B ranges in thickness from zero (eroded) to approximately 70 ft. The Mississippian in well A is approximately 140 ft thick.

The type of fault in case history 26 is difficult to determine because of the structural relationship of fault blocks A and B. However, the effect of this fault on a waterflood would be dramatic. It probably would act as a barrier to injection or as a thief of injected fluids.

Sometimes the existence of a fault is suspected, but the evidence is lacking. Structural mapping of Pennsylvanian and Permian strata in the Anadarko basin suggests that most faulting was pre-Pennsylvanian or earlier. Case history 27 in Figure 103 illustrates how to determine the possible position of suspected faults in Pennsylvanian strata. This figure is a structure map contoured on a regional limestone marker just above the Mississippian–Pennsylvanian unconformity. In the Anadarko basin, a Mississippian isopach map often suggests faulting by varying patterns of thicknesses of strata prior to erosion and deposition of Pennsylvanian sediments. These Mississippian thickness changes are associated with fault blocks, especially in central, northern, and eastern Oklahoma, and can be seen in Figure 101. Notice the varying thicknesses of Mississippian strata below the unconformity.

Figure 104 is a Mississippian isopach map for case history 27. The extreme thickness variations clearly locate the position of the fault, whose throw approximates 275 ft.

Figure 105 is a revised structure map contoured on the same datum as that of Figure 103. The position of the fault and approximately 25 ft of throw have been incorporated in the mapping. All the producers on this map have a reservoir thickness of less than 25 ft. This fault would dramatically affect injection performance if it is not factored into the injector–producer pattern.

Where deeper control is lacking for a waterflood candidate, the presence of faulting could be suggested by seismic records. The costs of seismic acquisition would be minimal in light of the costs of modifying an injector–producer pattern in response to an unknown fault.

PRIMARY AND SECONDARY GAS CAPS

As oil and gas are introduced into a reservoir, solubility relationships occur between these fluids in re-

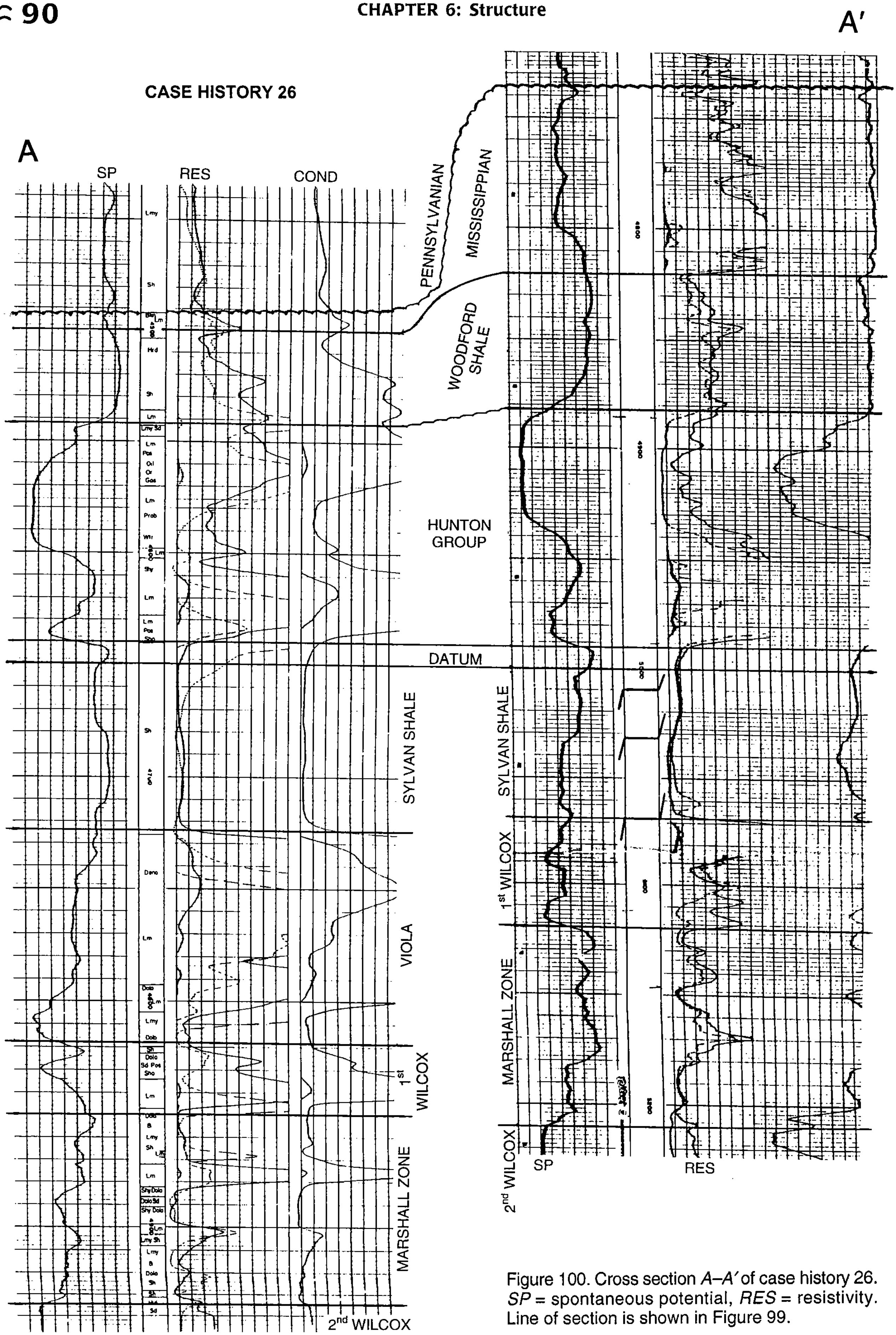


Figure 100. Cross section *A–A′* of case history 26. *SP* = spontaneous potential, *RES* = resistivity. Line of section is shown in Figure 99.

CASE HISTORY 26

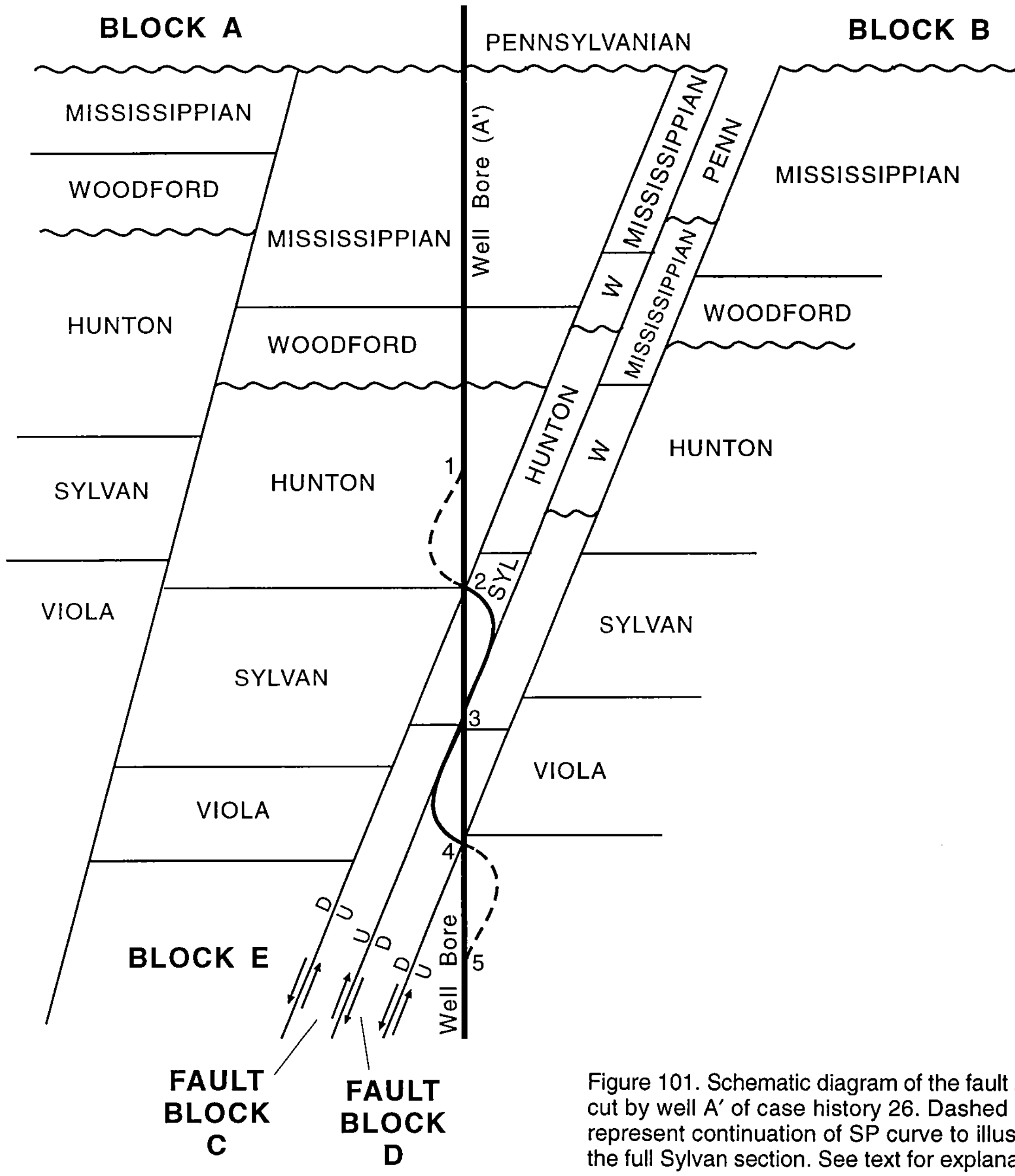


Figure 101. Schematic diagram of the fault zone cut by well A′ of case history 26. Dashed lines represent continuation of SP curve to illustrate the full Sylvan section. See text for explanation.

sponse to pressure, temperature, and the composition of the oil and gas. Under reservoir conditions, gas is dissolved in the crude oil, thereby increasing the volume of the crude oil in the reservoir. The formation volume factor (symbol B_o, abbreviated FVF) at any pressure can be defined as the volume in barrels that one stock-tank barrel occupies in the formation (reservoir), i.e., at reservoir temperature and with the solution gas which can be held in the oil at that pressure (Craft and Hawkins, 1959). A reservoir crude oil can be said to be saturated if additional gas introduced into the reservoir does not become absorbed into the crude; thus, the reservoir would contain free gas. Over geologic time, density differences between the reservoir's oil, gas, and water phases segregate the fluids in the reservoir. Free gas is almost always found confined to the highest structural position of the reservoir. With production, pressure declines in a reservoir, and solution gas begins to break out of the crude. This action of gas breaking out of solution, owing to reservoir-pressure decline, decreases the physical volume of the reservoir crude. Some of the solution gas is produced along with the crude, whereas some remains in the reservoir as free gas.

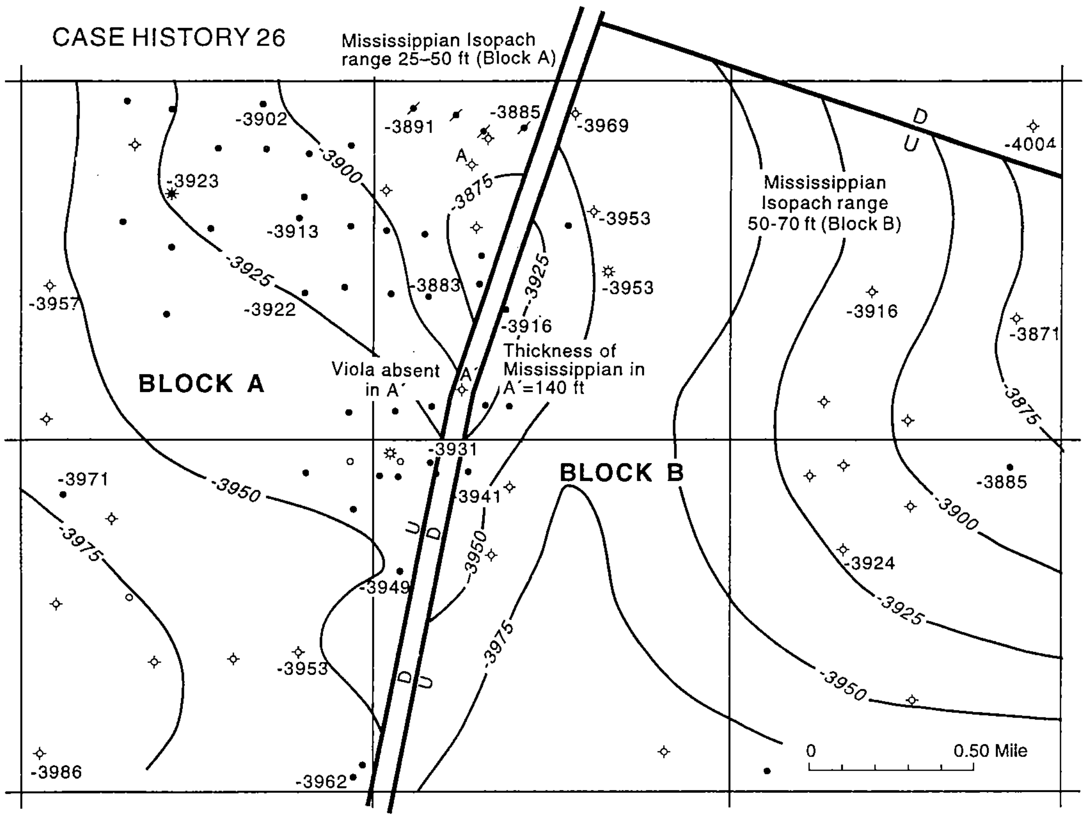


Figure 102. Revised Viola structure map of case history 26, which incorporates the fault complex in the mapping. Contour interval, 25 ft.

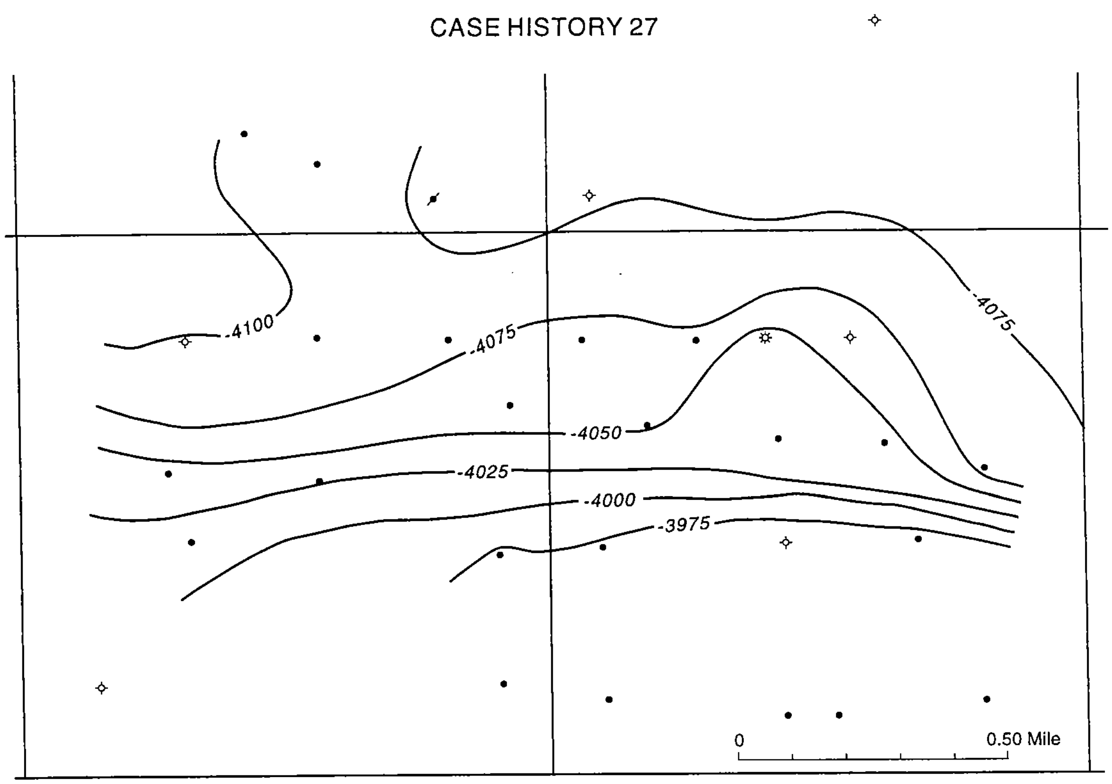


Figure 103. Structure map of case history 27, contoured on a regional limestone marker just above the Mississippian–Pennsylvanian unconformity (northern Oklahoma). Contour interval, 25 ft.

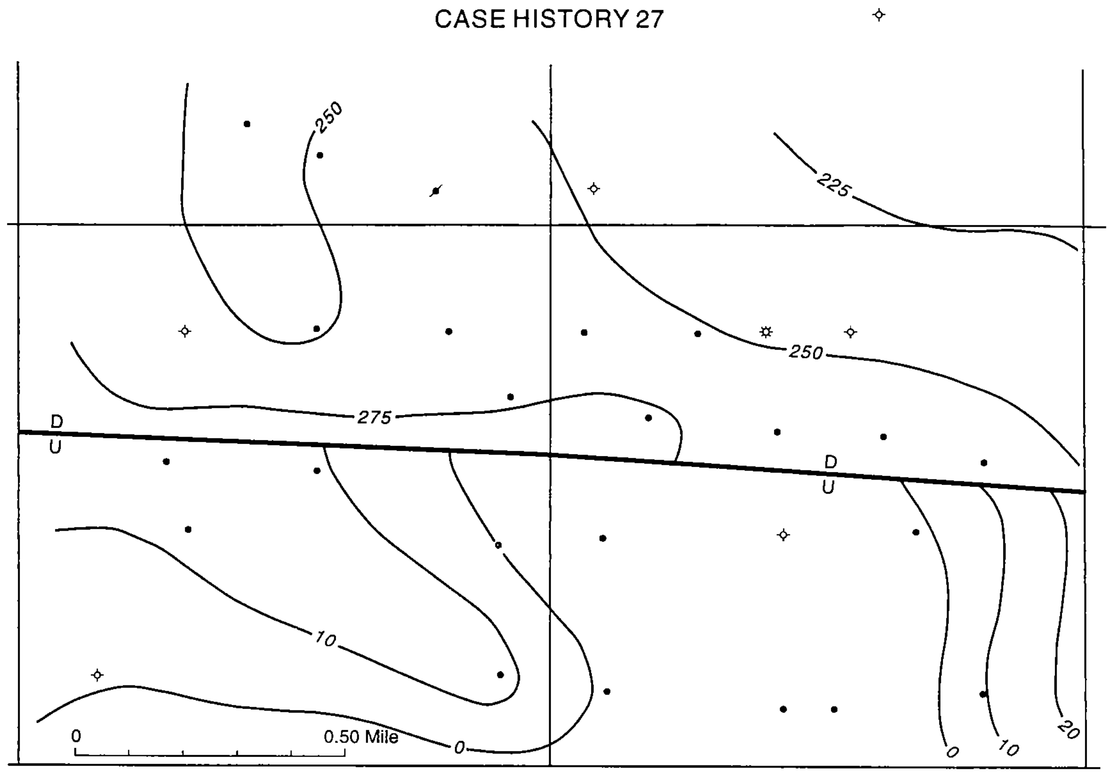


Figure 104. Isopach map of Mississippian strata in the area of case history 27 (northern Oklahoma). Contour interval, 25 ft.

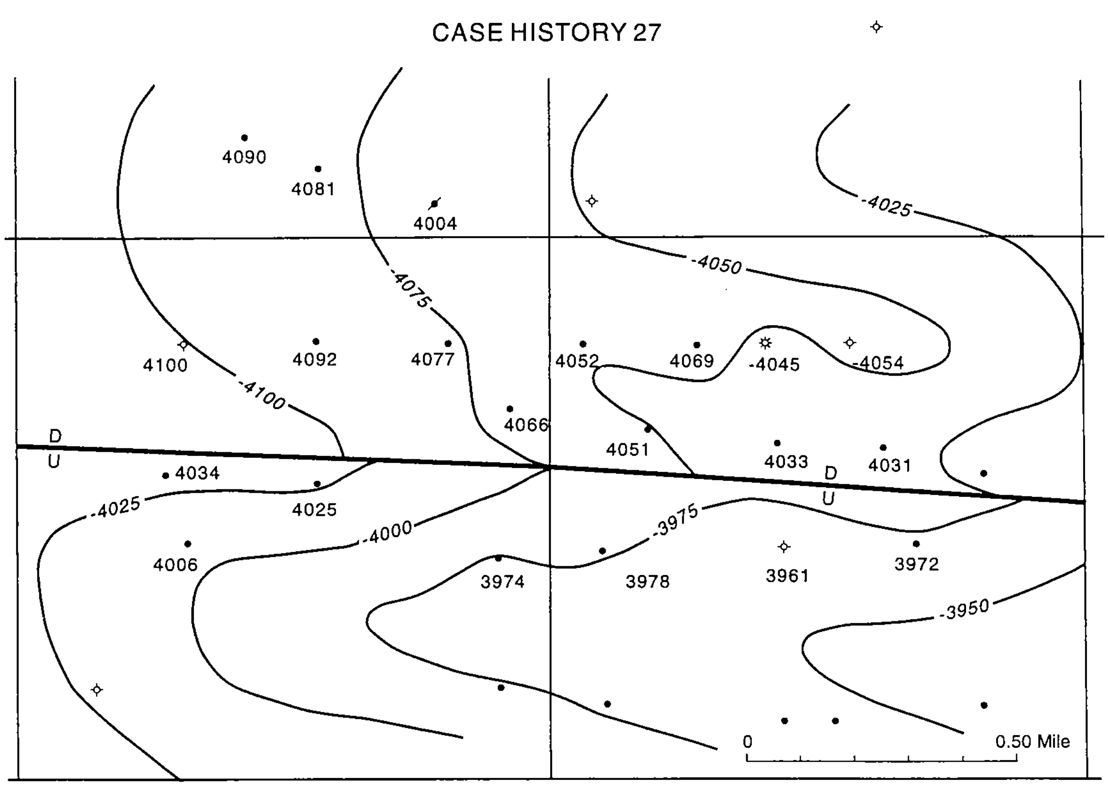


Figure 105. Revised structure map of case history 27, contoured on a regional limestone marker just above the Mississippian–Pennsylvanian unconformity. Contour interval, 25 ft.

If permeability in the reservoir is sufficient to allow rapid migration of the free gas to the highest structural position of the reservoir, a secondary gas cap forms, or else a primary gas cap would be enlarged. However, because permeabilities in reservoirs are seldom great enough to allow migration to occur in the brief period of time available, almost all the free gas remains at or near the vicinity where it originated. Thus, if free gas is able to congregate to areas of higher permeability locally, displacing oil in those areas in the process, localized areas of high gas saturation may form. These areas then would be called secondary gas caps. Secondary gas caps, then, could be defined as those areas in a reservoir where free gas has migrated while lowering the amount of oil and/or water saturations in the process. The word *cap* implies that the gas is found in the highest structural position of the reservoir. This would be the case only if sufficient time has elapsed.

Case history 28 (Fig. 106) illustrates how a gas cap formed in a lower structural part of a reservoir. This reservoir was under primary production for more than 60 years before it was unitized. Wells A–F were newly drilled in the reservoir. Well F was cored, and the porosity–permeability crossplot is shown in Figure 107. This crossplot reveals a large variance in permeability values over a few percentage increases in porosity. For instance, a minimum porosity of 10%–11% has a corresponding permeability range of 1–5 md, whereas a porosity value of 15% has permeabilities of 100–500 md.

Figure 108 highlights two logs characterized by porosity values that approximate these extremes. Well A

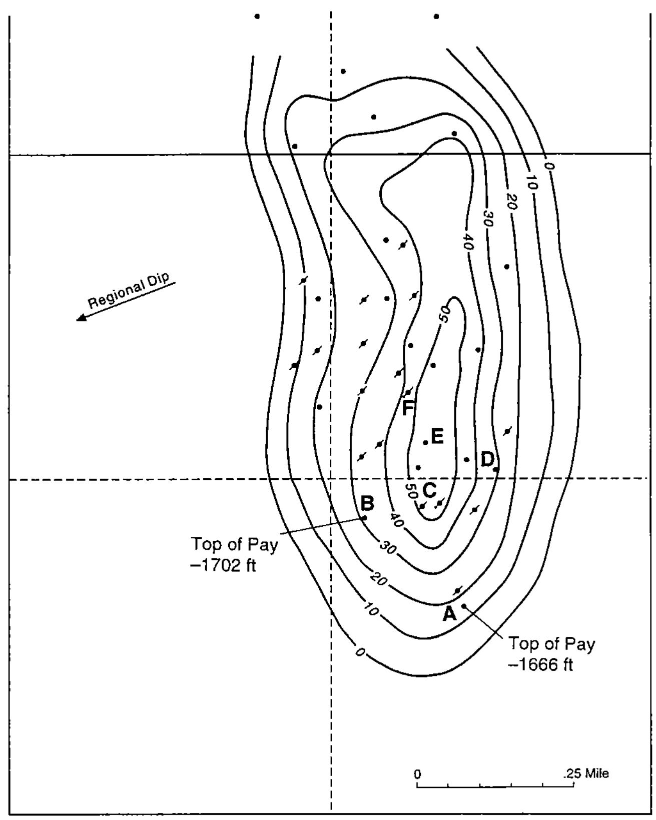


Figure 106. Net-sand isopach map of a reservoir of case history 28 (eastern Oklahoma). Contour interval, 10 ft. Cross section *B–A* is shown in Figure 108.

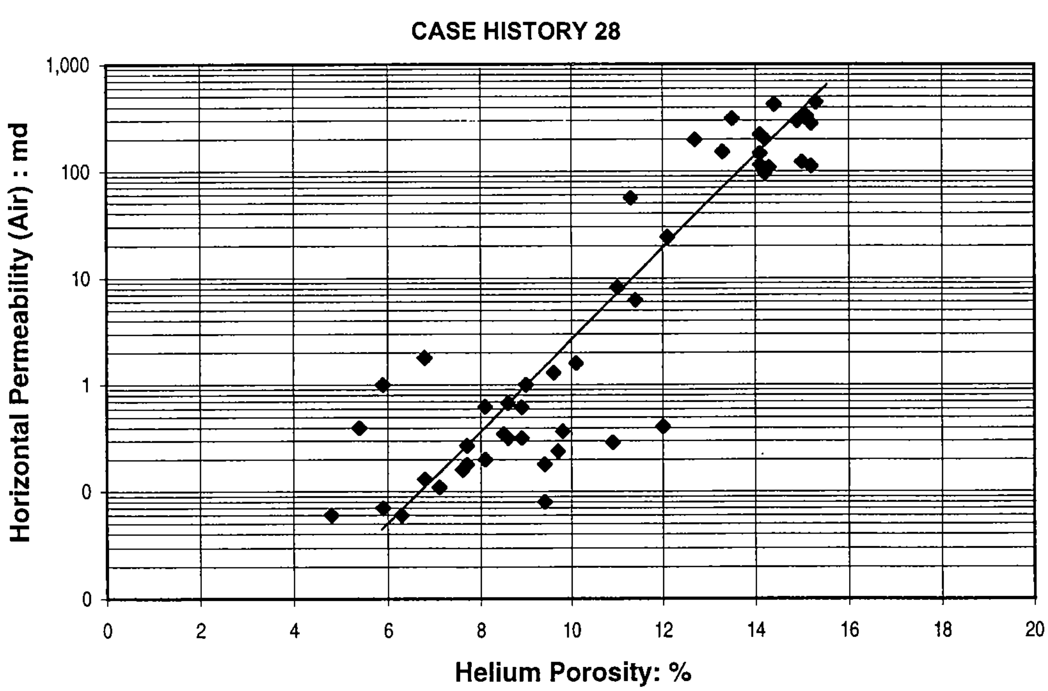


Figure 107. Crossplot of porosity versus permeability for well F, completed in the reservoir of case history 28.

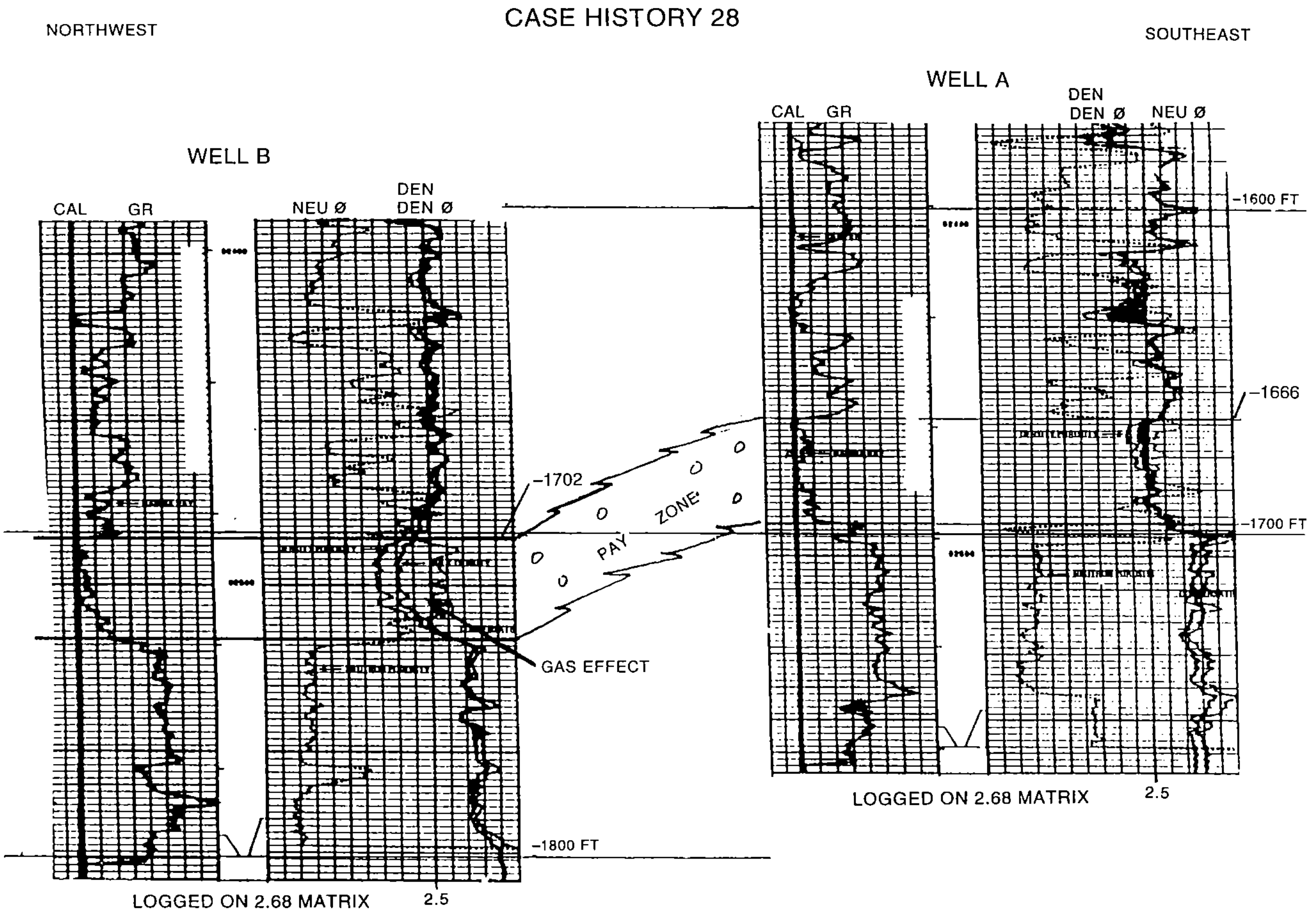


Figure 108 *(above)*. Reference logs of wells A and B, drilled in the reservoir of case history 28. Well A has an average porosity of 11% and a corresponding average permeability of <10 md. Well B has an average porosity of 15%, with a corresponding average permeability of 100–300 md (see Fig. 107). The arrow indicates an interval in the log of well B called *gas effect*. *GR* = gamma ray, *CAL* = caliper, *DEN* = density, *DEN* ϕ = density porosity, *NEU* = neutron porosity. Line of section is shown in Figure 106.

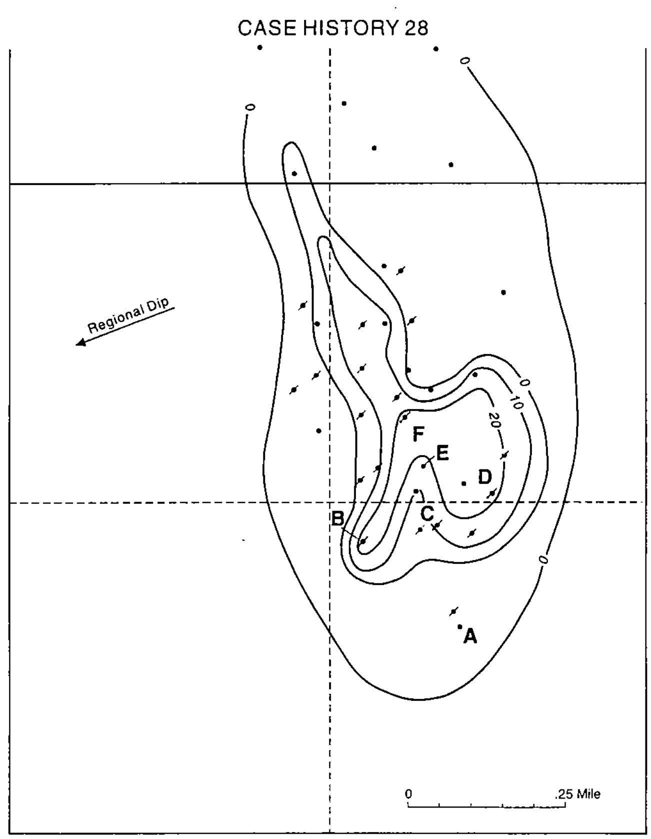


Figure 109 *(right)*. Isopach map of the thickness of gas effect, as interpreted from density–neutron-porosity logs of the reservoir of case history 28. Contour interval, 10 ft.

has an average porosity of 11%. Notice that the crossplot of the density and neutron curves does not indicate gas saturation. Well B has an average porosity of 15%. The part of the pay zone with high porosity and associated high permeability, as suggested by Figure 107, has significant gas saturation, as suggested by the crossplot of the density and neutron curves. The gas saturation in well B is 36 ft lower structurally than the top of the net pay zone in well A. In this example, all the wells indicated were predominantly oil wells initially, as this portion of the reservoir was in the oil column. Wells C and F were converted to injectors, and almost immediately wells B, D, and E watered out with little or no oil production.

Figure 109 is an isopach map of the gas effect observed from the neutron–density-porosity logs of the newly drilled wells. As can be seen, wells B–F are in an area of the reservoir where gas saturation is high. Gas has probably congregated in this area because of high permeability. The lack of mobile oil probably indicates a migration of the oil, because of density differences, to lower structural positions in this high-permeability area. The isopach map of high gas saturation (Fig. 109) probably represents a secondary gas cap that has formed in the highly permeable part of the reservoir. Wells B and D were converted to injectors to fill this secondary gas cap with water. The reservoir was subsequently waterflooded, with profitable results.

Analogies

7

CHAPTER 7

Analogies

INTRODUCTION

As waterflood projects are characterized by a high capital expense up front, a common and practical method of calculating a project's risk is to compare its features to an analogous reservoir. Ideally, features that should be compared are production similarities and facies and reservoir parameters. If all the characteristics of a candidate waterflood prospect and a mature secondary unit are similar, then, by deduction, the performance of the candidate should also be similar. However, the pitfall in this scenario is that in nature no two reservoirs are alike. It is the responsibility of the geologist or engineer to determine the similarities as well as the differences and to ascertain the impact the differences would have on the waterflood candidate's performance.

PRODUCTION SIMILARITIES

Production similarities are composed of three facets—amount of oil production, amount of water production, and drive mechanism. The amount-of-production comparisons are discussed in this chapter. Water saturation and production would need to be covered in another workshop on engineering pitfalls. This section will deal primarily with the comparison of drive mechanisms.

The evaluation of drive mechanisms is critical when comparing a mature waterflood to a waterflood candidate, because at the start of the waterflood it is important to know whether the oil saturations of the prospect are similar to those of the mature analogy. Figure 41 illustrates the varying average recovery percentages of OOIP for the three primary types of drive mechanisms—water, gas cap, and solution gas. If the drive mechanism of a waterflood candidate is different from that of an otherwise analogous reservoir, the corresponding oil saturation, at depletion, would be markedly different, thus invalidating the comparison of the two reservoirs. Normally, determining the differences in drive mechanisms is an obvious procedure; occasionally, however, situations arise that may confuse the interpretation.

Consider case history 29 (Figs. 110,111). Figure 110 is a production curve from a sandstone field under consideration as a waterflood candidate. Figure 111 is the production curve for a mature waterflood a few miles away that produced from the same reservoir and had similar reservoir properties. The field represented by the production curve of Figure 111 was the analogy presented for the waterflood candidate represented by the production curve of Figure 110. The physical shape of the two decline curves is similar on these two plots, and because of this, it would be easy to assume that the decline rates for the two fields are the same.

There are two types of decline rates, however: the *nominal decline rate* and the *effective decline rate* (Frick and Taylor, 1962). The latter incorporates actual production rates and is more commonly used. By definition, then, the effective decline rate is the drop in production rate from q_i to q_l over a period of time equal to unity (1 month or 1 year) divided by the production rate at the beginning of the period (Frick and Taylor, 1962). Visually comparing the slope of the decline rate for Figures 110 and 111 could lead the evaluator to assume that the decline rate is similar, leading to the assumption that the drive mechanism was similar and, at least preliminarily, to the assumption that current oil saturations would be similar.

However, to compare the two curves accurately, the x axis for both curves must have the same scale. Figure 112 reduces the x-axis scale of Figure 111 to match the x-axis scale of Figure 110. It is now readily apparent that the two decline rates are markedly different for the two fields. Commercial suppliers of production information provide data on graphs using the same x- and y-axis scales. However, production curves created by using a spreadsheet program often do not have the same scales. Thus, an effort should be made to calculate the actual rate of decline. In this example, the decline rate for Figure 110 is approximately 10%, whereas the decline rate for Figure 111 is approximately 35%. These two decline rates are significantly different and imply different drive mechanisms.

Further investigation into the waterflood candidate represented by the production curve of Figure 110 revealed that all the wells with high gas saturations were left shut in and that the practice for completing the oil wells was to perforate the very bottom of the porous reservoir. In fact, this field had a gas cap, which effectively expanded, driving oil to the perforations. The corresponding recovery factors for the primary production from the two fields was different, implying that oil saturations at depletion are different. Thus, these two fields are not analogous.

Sometimes, production curves reveal the effect of one field's waterflood on an adjacent field within a

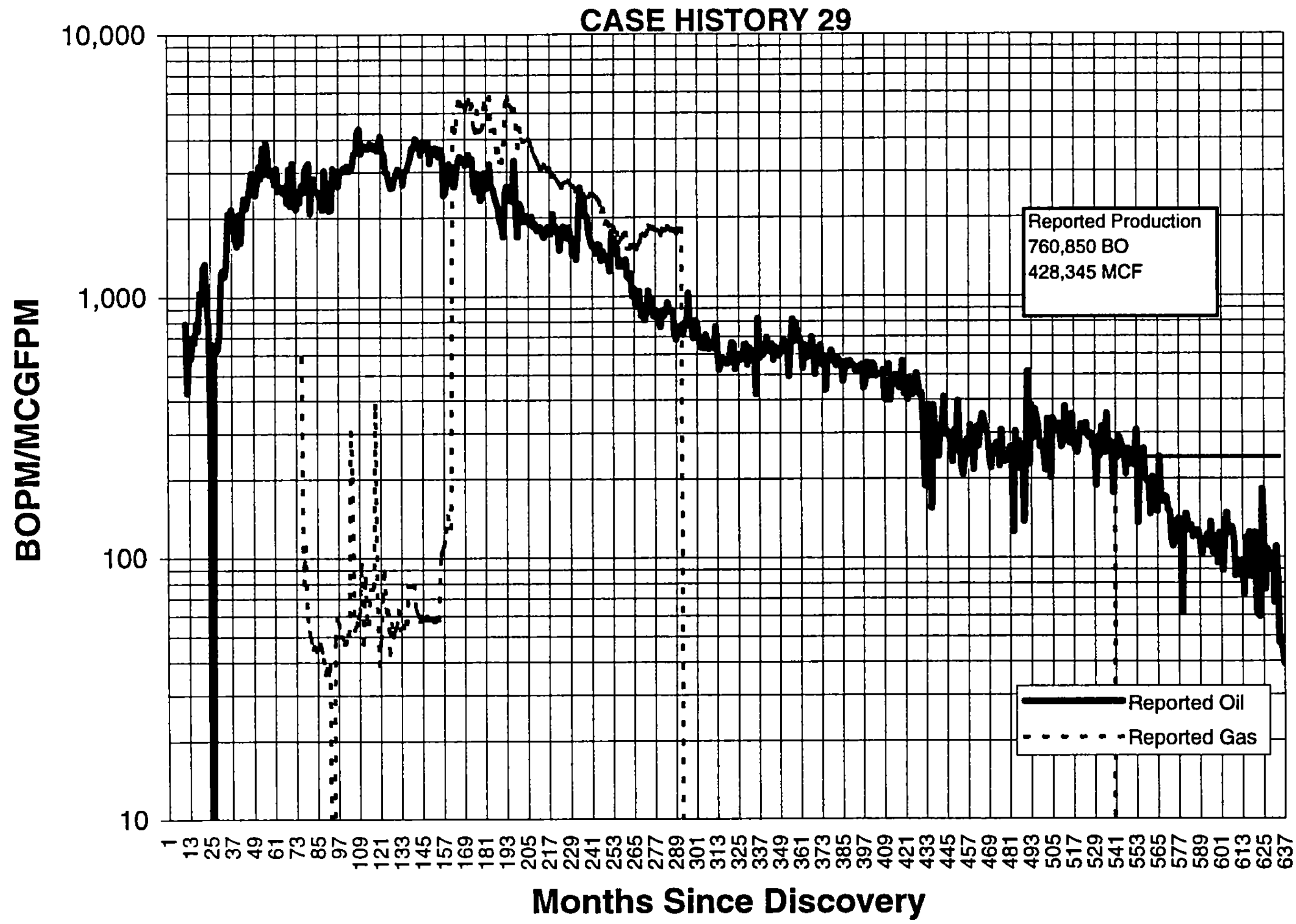


Figure 110. Production curve for the reservoir of case history 29, which is under consideration as a waterflood candidate (north-central Texas).

common and connected reservoir. Consider case history 30 (Fig. 113). Fields A and B are two limestone fields over a mile apart. Field A was unitized 5 years after discovery and was a successful waterflood with a secondary- to primary-recovery ratio of 42%. Field B was submitted as a prospect for evaluation under the assumption that it should be just as successful as field A.

Figure 114 shows the production curve for field A. The response to injection occurred approximately 14 years after discovery. Figure 115 shows the production curve for field B. This curve indicates an increase in production in year 17. Figure 116 is a comparison of the production curves from Figures 114 and 115. The increase in production in the prospect (Fig. 115) occurred several years after response in the analogy. As the two fields are in the same reservoir, with communication between the two occurring in the water column, it is likely that the increase in production in the prospect occurred as a result of injection in the analogous reservoir.

In conclusion, all production curves must be analyzed on a field, as well as on a lease, basis to ascertain any sign of response from injection. This means that analogies must be scrutinized as thoroughly as the waterflood candidate to determine all possible relationships or comparisons, good or bad.

APPARENT ANALOGY SUCCESSES

Analogies are useful only if the evaluator understands the essence of the analogy. Often, an analogous field is reviewed until the evaluator finds enough criteria that justify the use of the analogy, at which point the evaluation of the analogy often stops. Consider case history 31 (Fig. 117), a net isopach map of a limestone field in north-central Oklahoma. The field is under primary production and to date has a recovery factor of approximately 5.7%. An identical field in the same reservoir, which is under secondary recovery, is about a mile away and is illustrated in Figure 118. The secondary-recovery book gives the following information for this field: (1) primary production, 190,000 BO; (2) secondary production, 400,000 BO.

It would appear, from this information, that the analogous waterflood was successful and should encourage

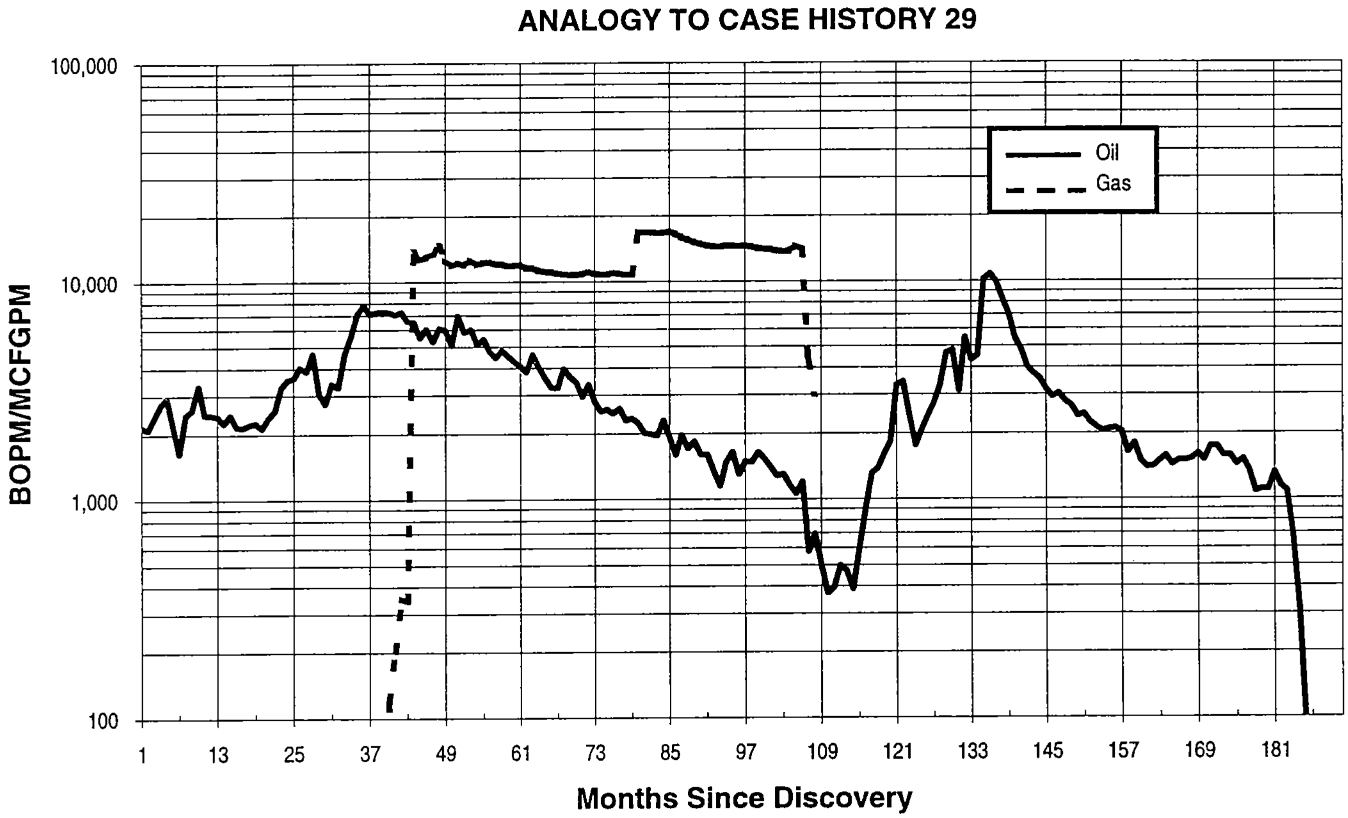


Figure 111. Production curve for the successful waterflood field used as an analogy for the reservoir of case history 29. Response to injection occurred at month 115.

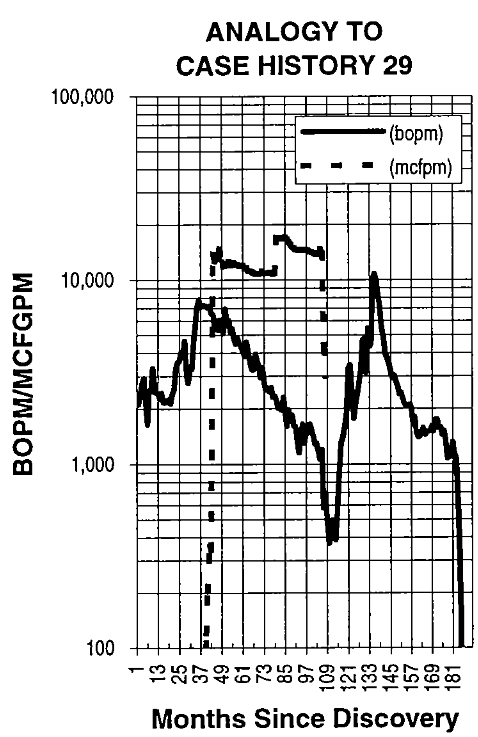


Figure 112. Production curve of Figure 111, with the *x* axis being the same horizontal scale as the *x* axis of Figure 110. For comparison purposes, the scales must be the same.

a positive evaluation of the waterflood project for the field shown in Figure 117. But what do the preceding figures actually represent? Primary production was obtained by totaling the primary production for the wells or leases producing from the field in question up to the point of unitization. Once those wells and leases are unitized, production is termed *secondary*, regardless of whether the wells are still on primary decline or not.

Pitfalls arise when evaluators conclude that their prospect is viable because the amount of production reported as secondary production from an analogy is a profitable and significant portion of the cumulative production. In this case, the analogy, whose primary production was similar to that of the candidate waterflood, produced enough secondary oil (according to production sources) to indicate a similar amount of secondary oil for the prospect. Thus, the evaluator needs to look into the pertinent facts of the apparent valid analogy in more detail.

Figure 119 shows the production curve for the analogous field. The field was unitized, and water injection commenced in year 14. By definition, all the oil produced post-unitization is classified as secondary, but by examining the production curve it is obvious that a significant portion of the reported secondary production is actually primary. Continued evaluations of the analogy by isopaching and planimetering the reser-

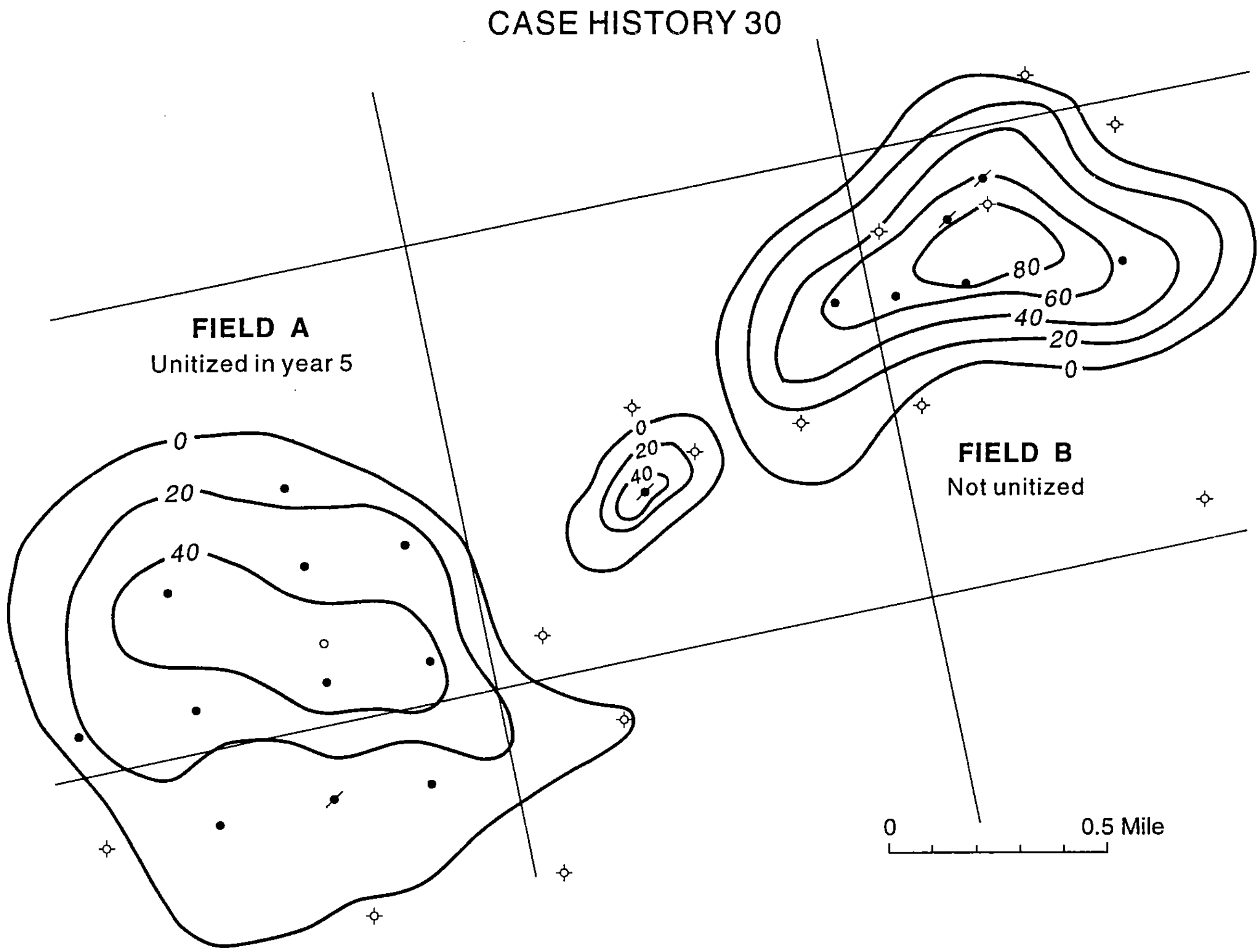


Figure 113. Isopach map of net pay zone for two fields within a common reservoir for case history 30 (north Texas). Field A was unitized and waterflooded and is the analogy for the waterflood prospect of field B. Contour interval, 20 ft. (Field A comprises 5 producers and 5 injectors; location of injectors is unknown.)

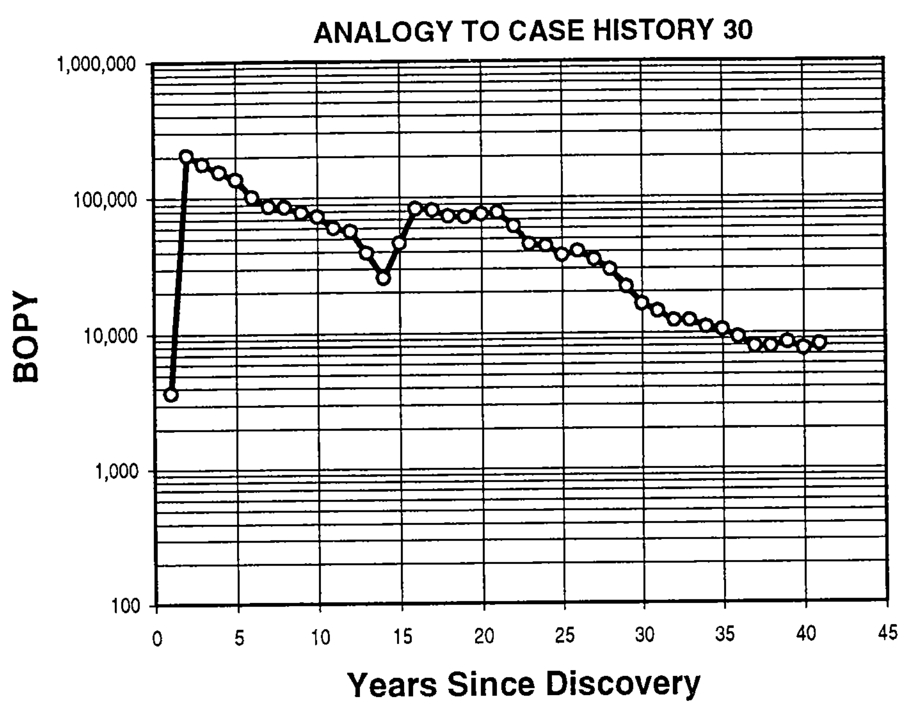


Figure 114. Production curve for field A of case history 30. Response to injection occurred at year 14. This field was discovered 1 year earlier than field B.

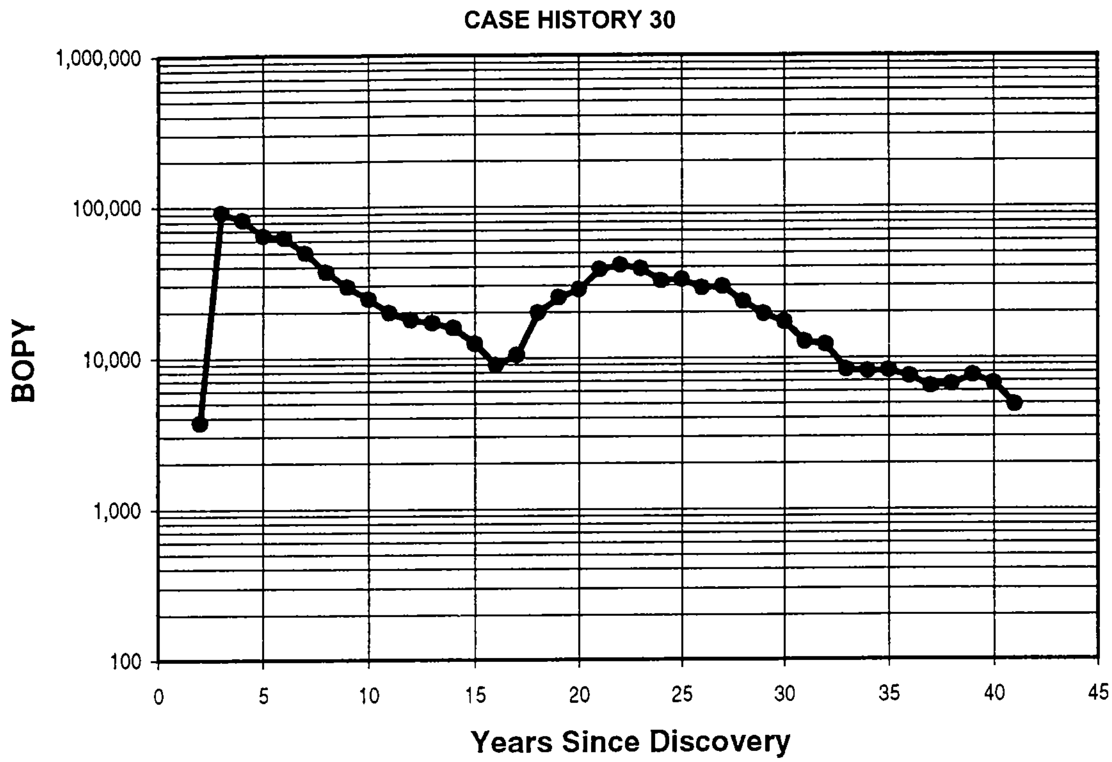


Figure 115. Production curve for field B of case history 30. An apparent increase in production is noted at year 17 (from an unknown origin?). This field was discovered 1 year later than field A.

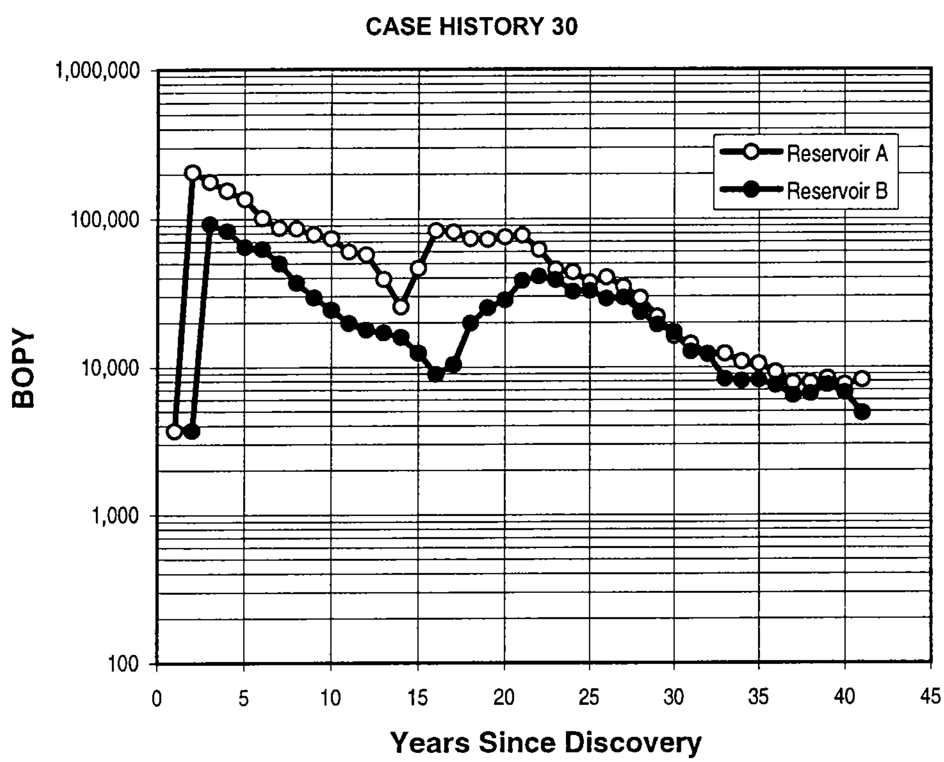
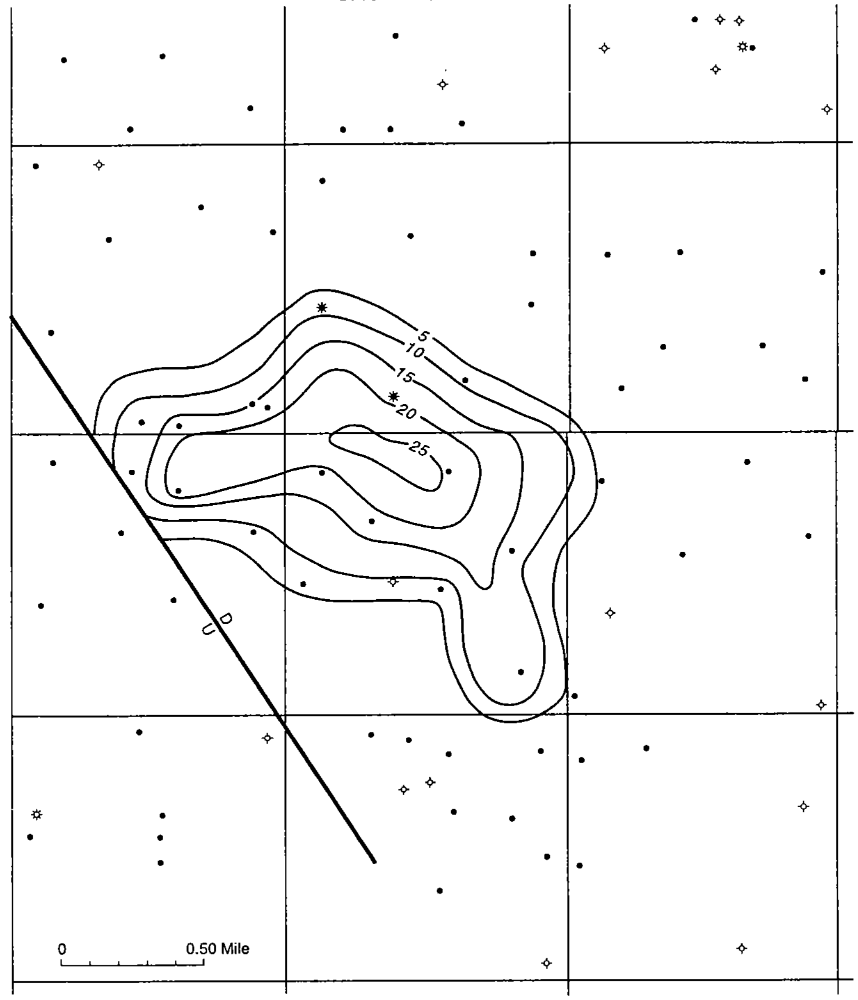


Figure 116. Comparison of the production curves for fields A and B of case history 30. Apparent response in field B at year 17 is probably from benefit of water injection from field A, as fields are in communication through the water column in the common reservoir.

Figure 117. Isopach map of net pay for the field of case history 31 (north-central Oklahoma). Contour interval, 5 ft. OOIP = 3,459,000 BO; primary recovery = ~200,000 BO; recovery factor = 5.7%.

CASE HISTORY 31



ANALOGY TO CASE HISTORY 31

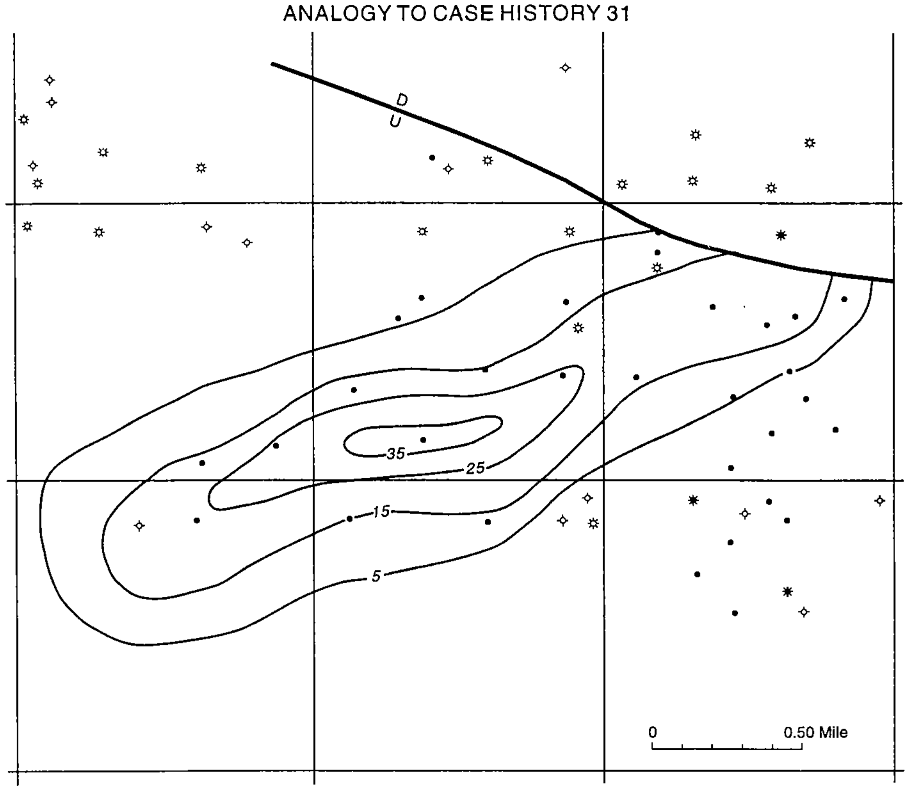


Figure 118. Isopach map of net pay for a reservoir analogous to the waterflood candidate of case history 31, illustrated in Figure 117. Contour interval, 10 ft. OOIP = 4,460,332 BO; primary recovery = ~190,000 BO; secondary recovery = ~400,000 BO (1989); primary-recovery factor = 4.2%; cumulative-recovery factor = 13.4%.

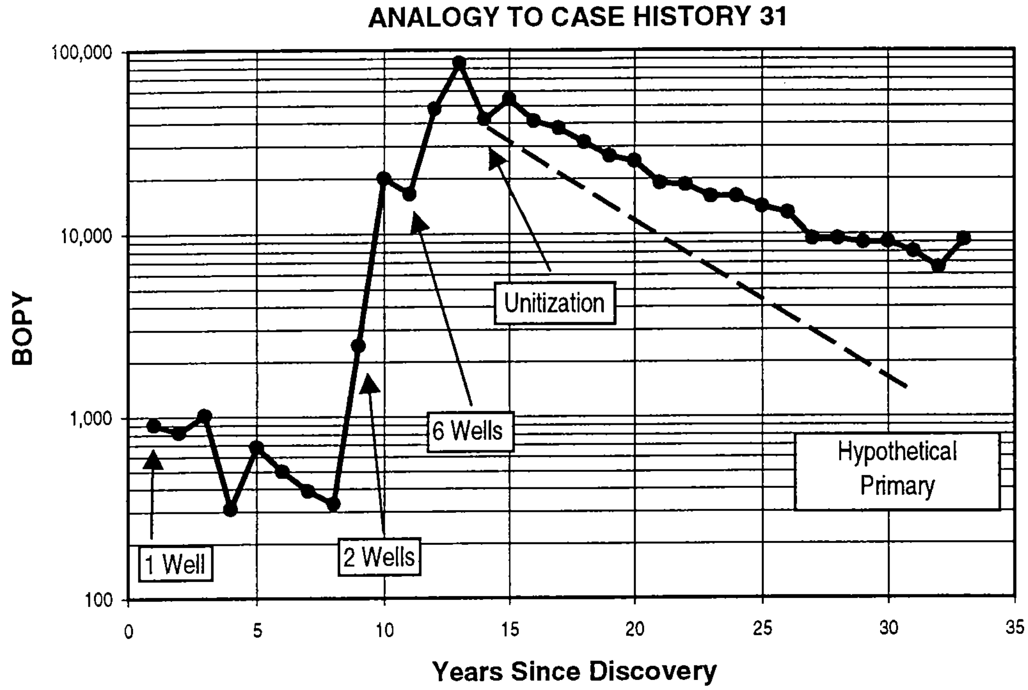


Figure 119. Production curve for the reservoir illustrated in Figure 118, which is the analogy for the waterflood prospect of case history 31.

voir revealed the following data: (1) OOIP, 4,460,332 BO; (2) primary recovery factor, 4.2%; (3) cumulative recovery factor, 13.4%.

As secondary oil is produced along with primary oil in the case of the analogy, it is difficult to differentiate the two types of production. Other analogies need to be evaluated, if possible, to determine potential secondary/primary-production ratios for this type of reservoir. Figure 120 is an isopach map of a limestone field with similar characteristics to case history 31. Evaluation of the production curve indicates that the field was produced to depletion prior to commencement of secondary operations. This reservoir has the following parameters: (1) OOIP, 49,905,000 BO; (2) primary production, ~6,600,000 BO; (3) secondary production, ~117,524 BO; (4) primary-recovery factor, ~13.3%; (5) cumulative-recovery factor, ~13.4%.

Figure 121 is the production curve since unitization for the field shown in Figure 120. Notice the almost complete lack of response. Furthermore, the cumulative-recovery factor of 13.4% for primary and secondary recovery is almost identical to the recovery factor for the first analogy illustrated in Figure 118. These data support the assumption that limestone reservoirs with these characteristics may not be suitable for waterflooding. More importantly, the evaluator needs to continue to research similar reservoirs and not stop at the first good sign of success.

IMPORTANCE OF FACIES COMPARISONS

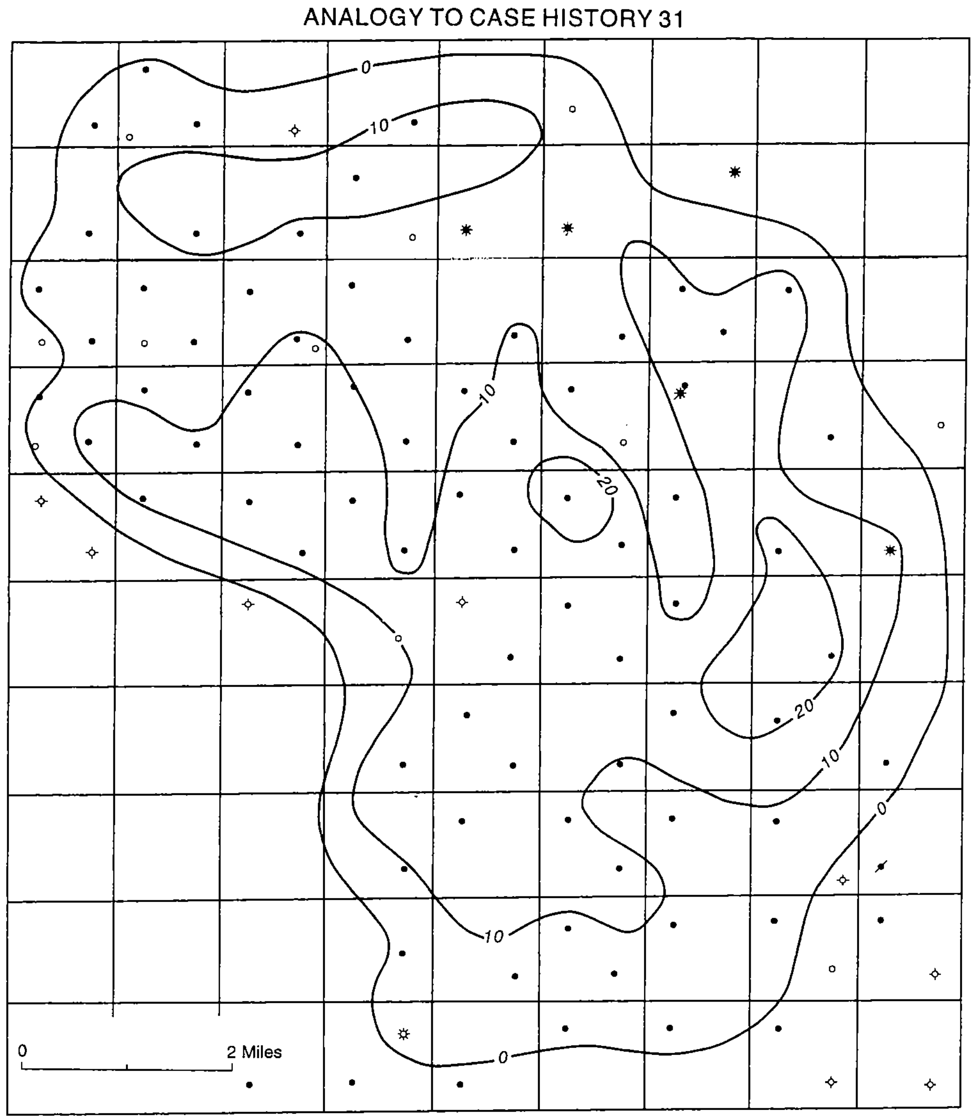
Figure 122 shows the primary-cumulative-production curve for a sandstone field under consideration as a waterflood candidate (case history 32). Figure 123 is the secondary-production curve for a sandstone field a few miles from the candidate. This field was considered a good analogy, because production characteristics, field size, and well spacing were similar to those of the candidate. The two fields were also producing from the same formation. As can be seen, the analogy had a good response and was a profitable venture. Figure 124 is a superposition of the production curves, since unitization, for the two fields. An analysis of the two curves illustrates that the candidate has not responded as dramatically as the analogy, even though it was suggested that the two fields were similar in almost every respect.

This example illustrates the importance of the need for similarity of all reservoir parameters between the candidate and the analogy. These two fields were producing from the same reservoir and were similar in areal extent.

Figure 125 is a series of core photographs of a pay zone similar to that of the analogy. Each column is 2 ft long. The section consists predominantly of sand and coarse sand. The last 2 ft of the pay section consists of a conglomeratic facies composed of limestone fragments.

Figure 126 is a series of core photographs from a well drilled in the waterflood candidate. Notice that the upper 20 ft of the reservoir consists of a sandstone facies, whereas the lower 12 ft consists of a conglomeratic facies. A core analysis revealed that the sandstone facies was oil-wet and the conglomeratic facies was strongly water-wet. Furthermore, the secondary-producing wells in the candidate field produced oil from predomi-

Figure 120. Net isopach map of a limestone field with similar reservoir characteristics as the waterflood prospect and an analogy for case history 31. Contour interval, 10 ft. OOIP = 49,905,000 BO; primary recovery = ~6,600,000 BO; secondary recovery = ~117,524 BO; primary-recovery factor = 13.3%; cumulative-recovery factor = 13.4%.



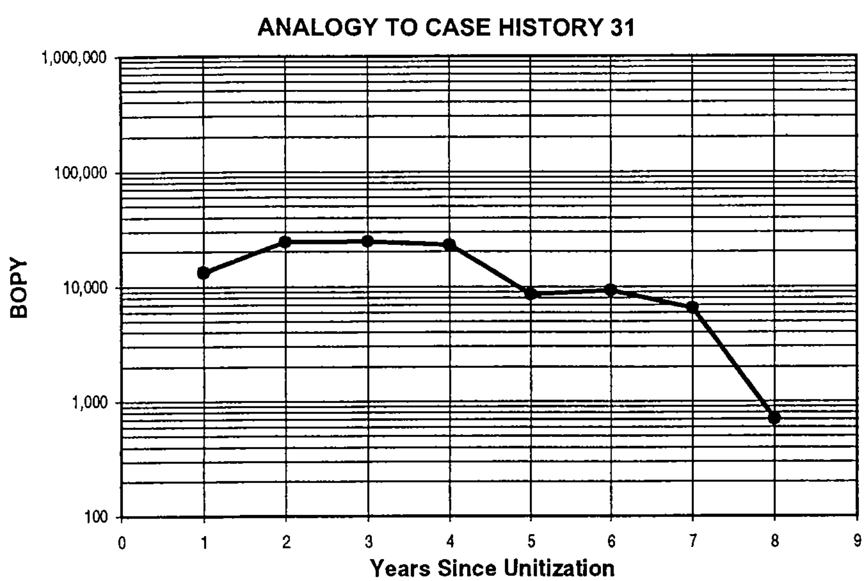


Figure 121. Production curve since unitization for the reservoir illustrated in Figure 120. Notice the almost complete lack of response.

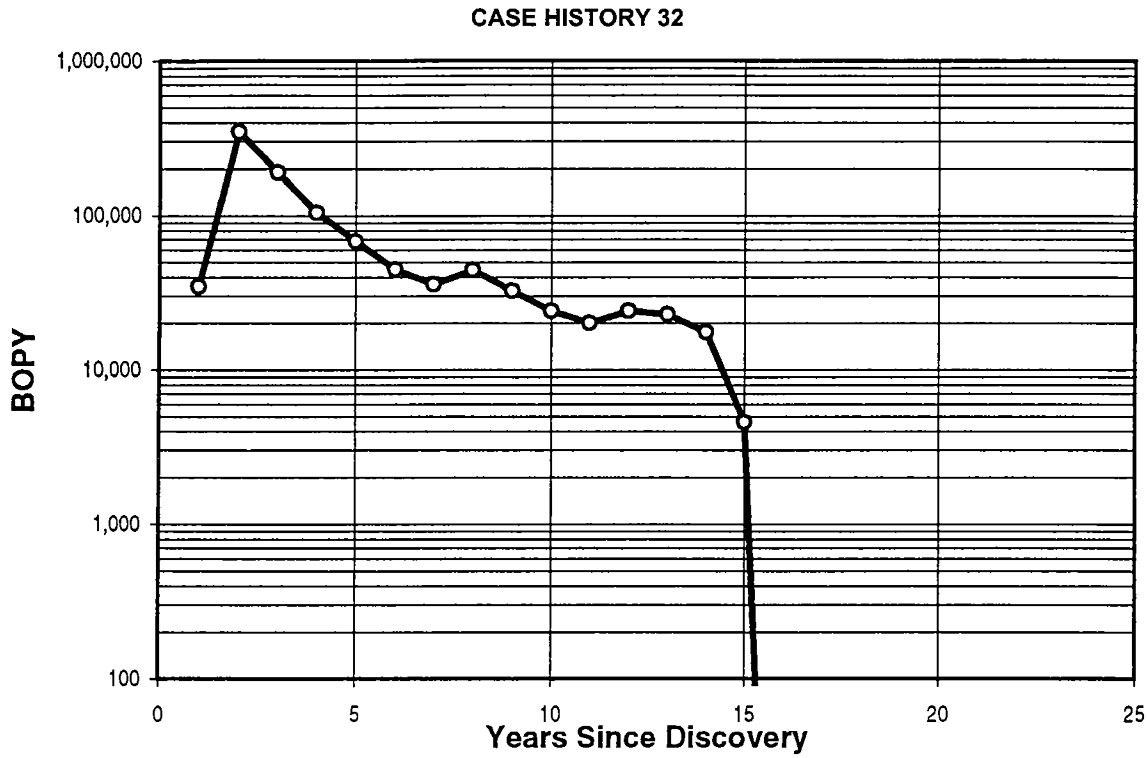


Figure 122. Production curve since discovery for the waterflood candidate of case history 32 (eastern Oklahoma).

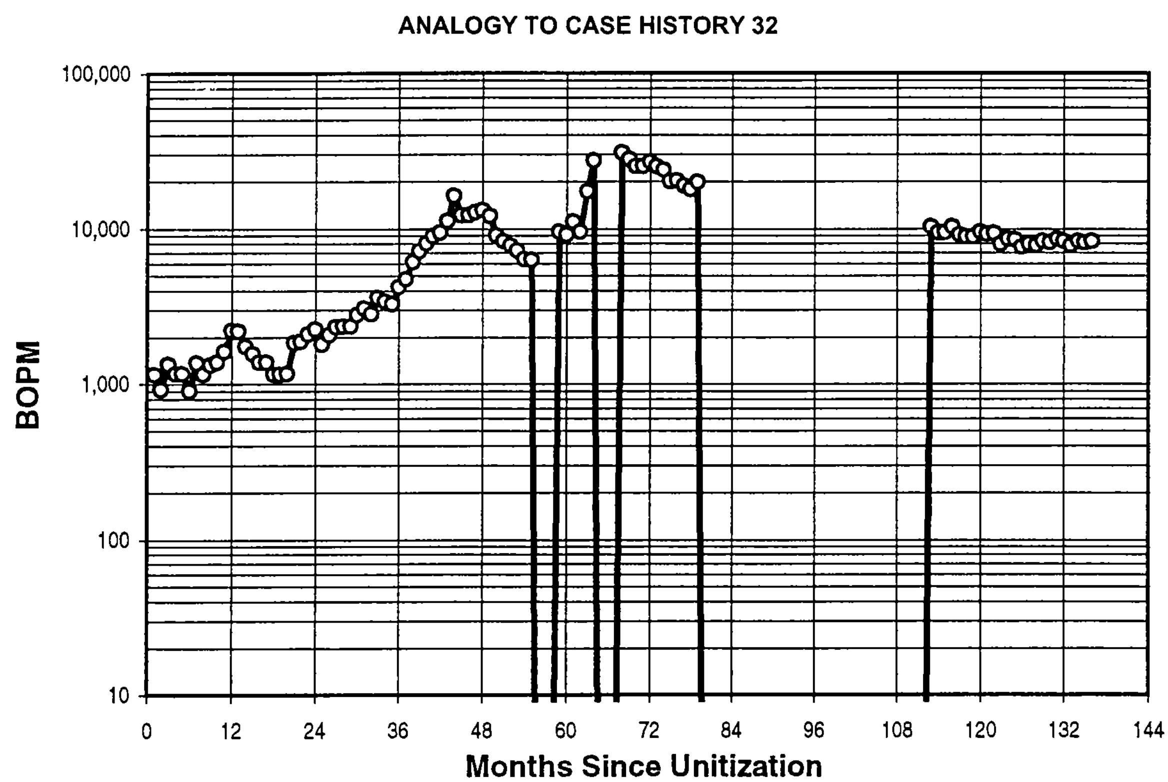


Figure 123. Production curve since unitization for the reservoir analogous to the waterflood candidate of case history 32. Cumulative production since unitization, 822,196 BO.

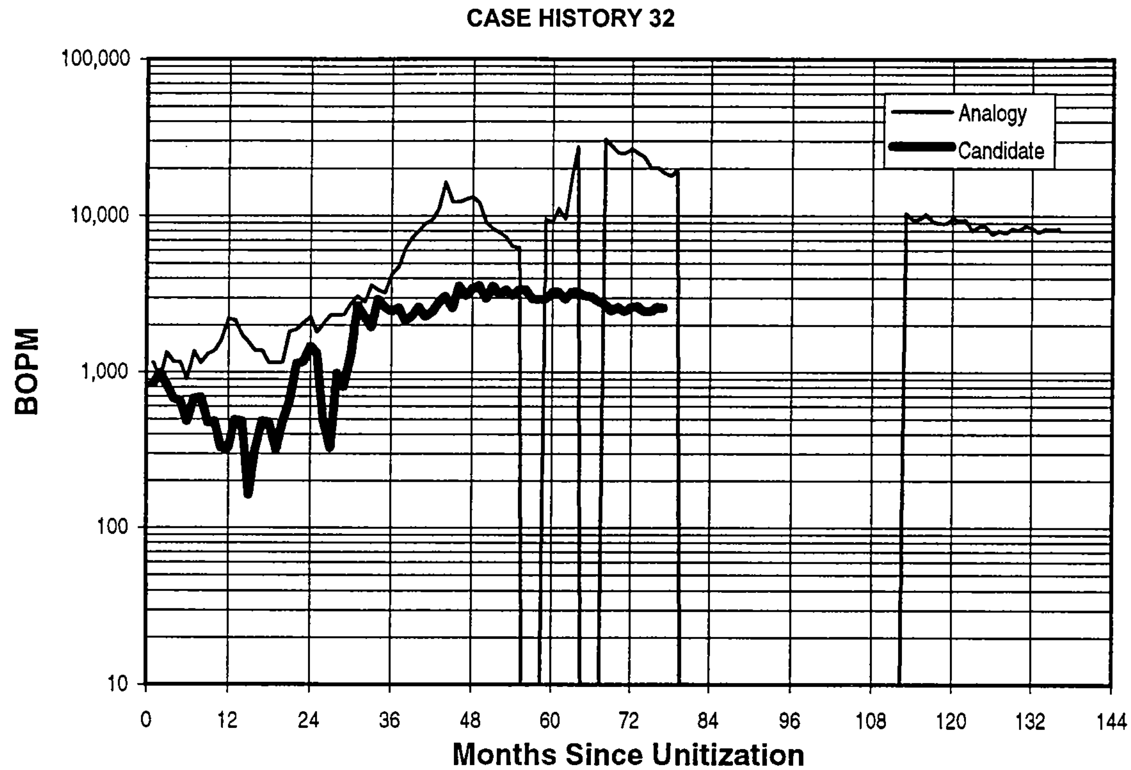


Figure 124. Superposition of production curves, since unitization, for the waterflood candidate (heavy line) and the analogous field (fine line) for case history 32.

nantly sandstone, whereas the wells that contained the conglomeratic facies produced predominantly water with a small oil cut.

The injected water in the candidate field naturally follows the path of least resistance toward the water-wet conglomeratic facies, which causes problems in building an oil bank in the oil-wet sandstone facies. Meanwhile, the injected water in the analogous field was confined to the sandstone facies, owing to the almost total absence of the conglomeratic facies, resulting in the classic waterflood response as seen in Figure 123. In this example, all reservoir characteristics were essentially equal, except facies. The variation in facies between the fields had been overlooked, resulting in different responses from otherwise similar fields producing from the same formation.

UNDERSTANDING ANALOGY FAILURES

An analogy does not have to be an economic success to provide insight for the viability of an evaluator's waterflood candidate. The following two case histories illustrate this point.

Case history 33, as seen in Figure 127, is the production curve for a reservoir under consideration as a waterflood candidate. An analogy was desired for this candidate because of the reservoir's unique facies distribution and composition. Figure 128 represents the reservoir parameters and model for case history 33. The reservoir was near depletion, and the recovery factor for primary production was 12.7%.

Figure 129 illustrates the production curve for a waterflood reservoir with almost identical facies characteristics as the reservoir of case history 33. The only difference between this field and the waterflood candidate is the volumetric differential. Figure 130 represents the reservoir parameters and model for the analogy. Point *A* in Figure 129 represents the time when the analogy was unitized and also the time when the reservoir model of the analogy was evaluated (see Fig. 130). At point *A*, the analogous field was producing approximately 1,000 BOPM. There were 20 producing wells in the field at this time, so the monthly production figure represents an average of 1.5 BOPD per well. As the drive mechanism for the candidate and the analogy is identical, the recovery factor of 11.4% suggests that the reservoir of the analogy was nearly energy-depleted. The unit was established, and injection commenced at point *A* in Figure 129. The reservoir has produced almost 100,000 BO since unitization. As the analogous reservoir was at or near depletion, this oil is truly secondary, because it was produced as a result of water injection. The question is, whether the amount of secondary oil produced is even economic when it was originally flooded; it is certainly not economic today. Thus, the analogy was a technical success but probably an economic failure.

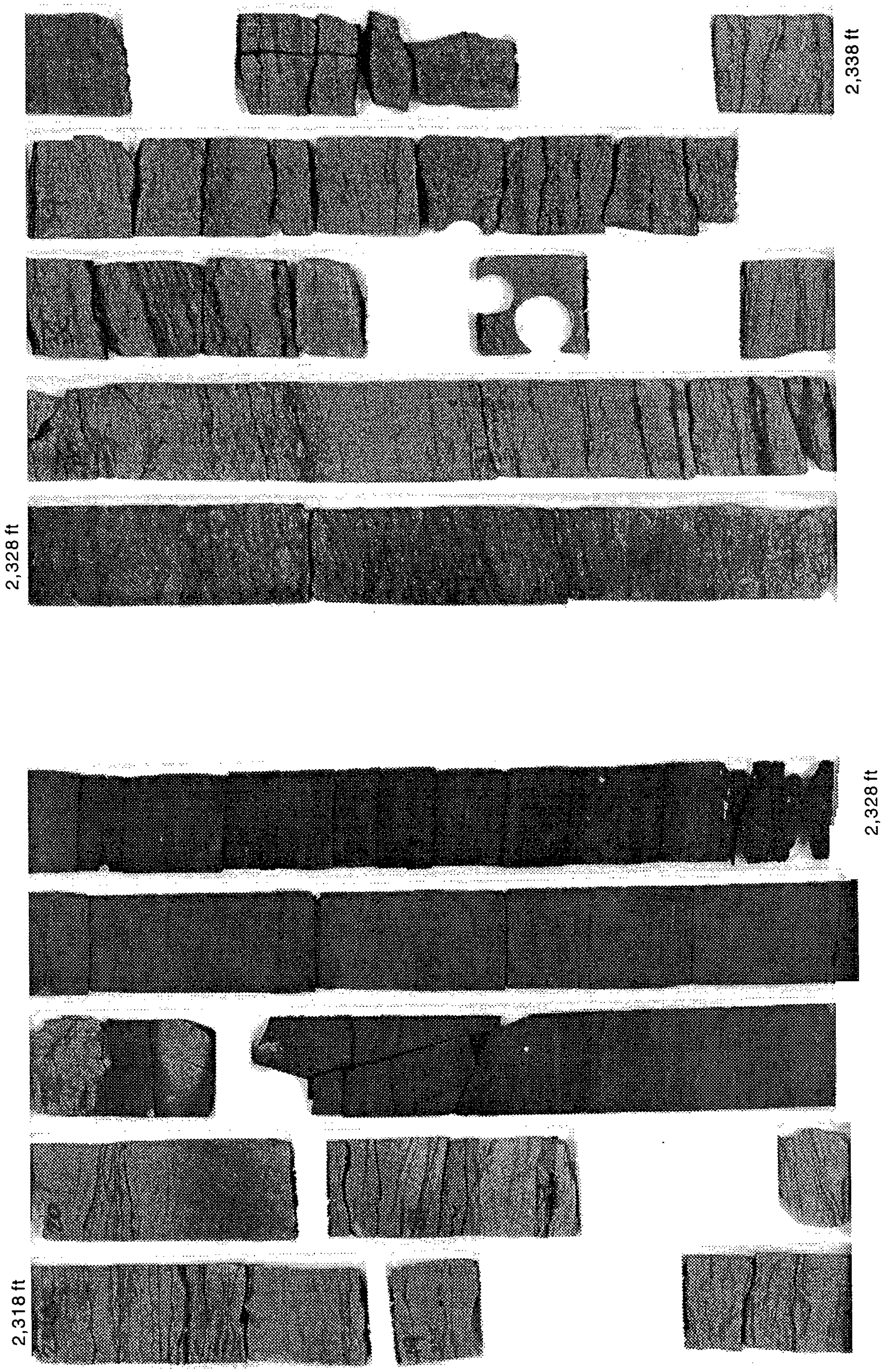


Figure 125 *(pages 107–109)*. Series of core photographs, under natural light, of the pay section of a well with lithofacies similar to the analogous reservoir represented by the production curve of Figure 123. Each column is 2 ft long.

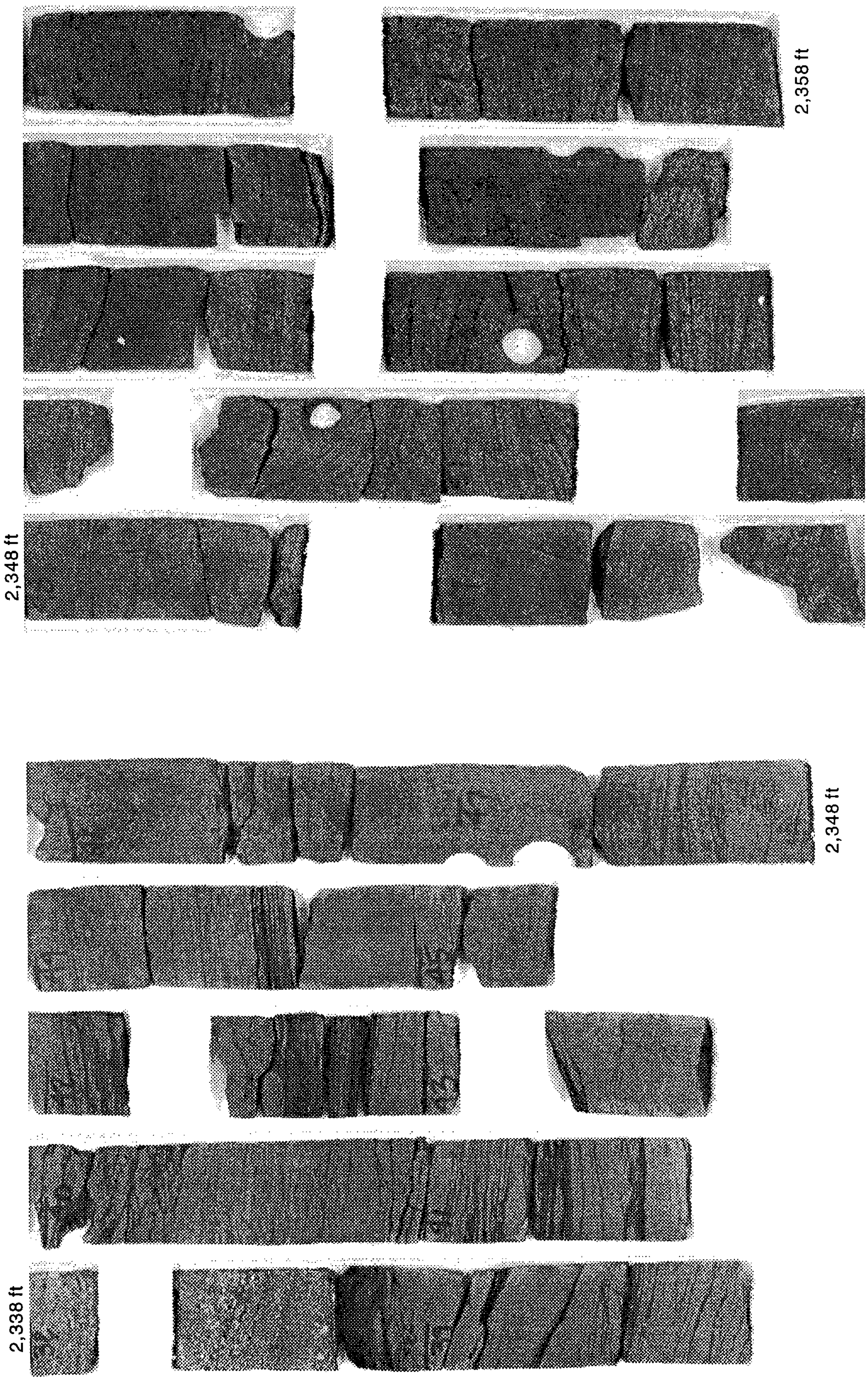


Figure 125 *(continued)*.

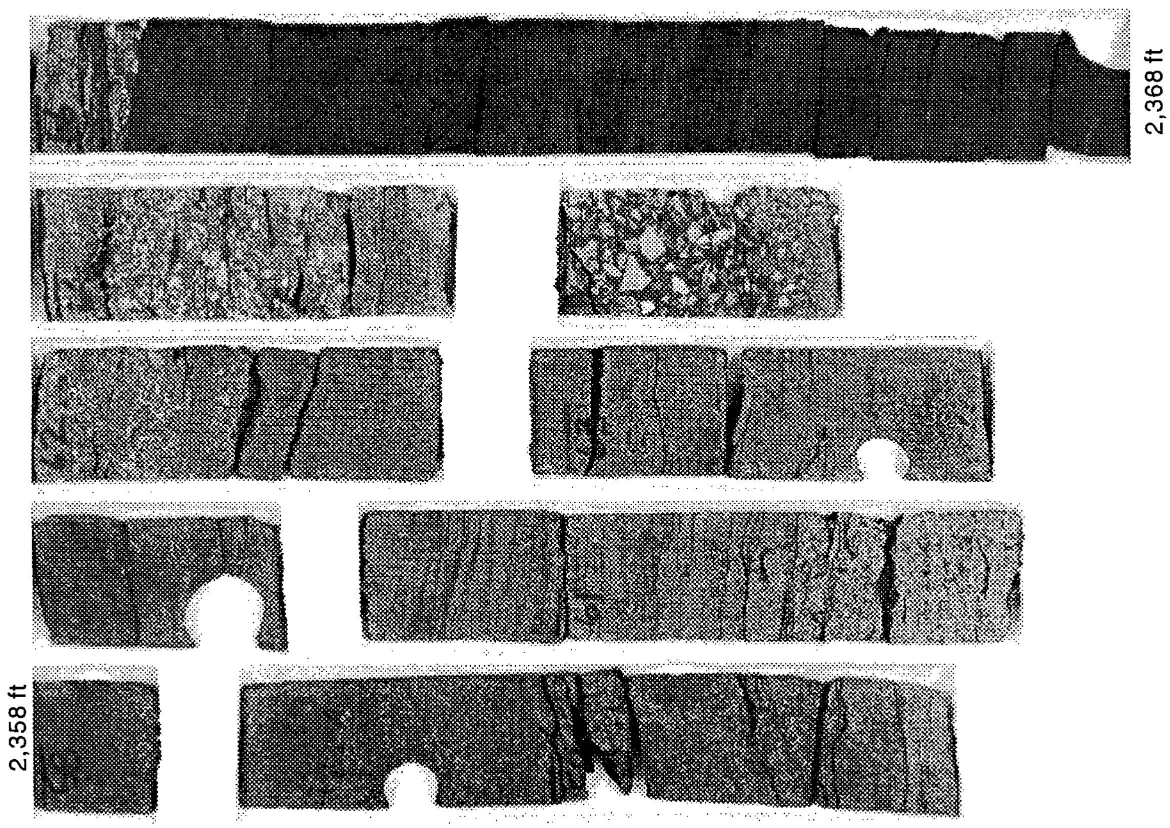


Figure 125 *(continued)*.

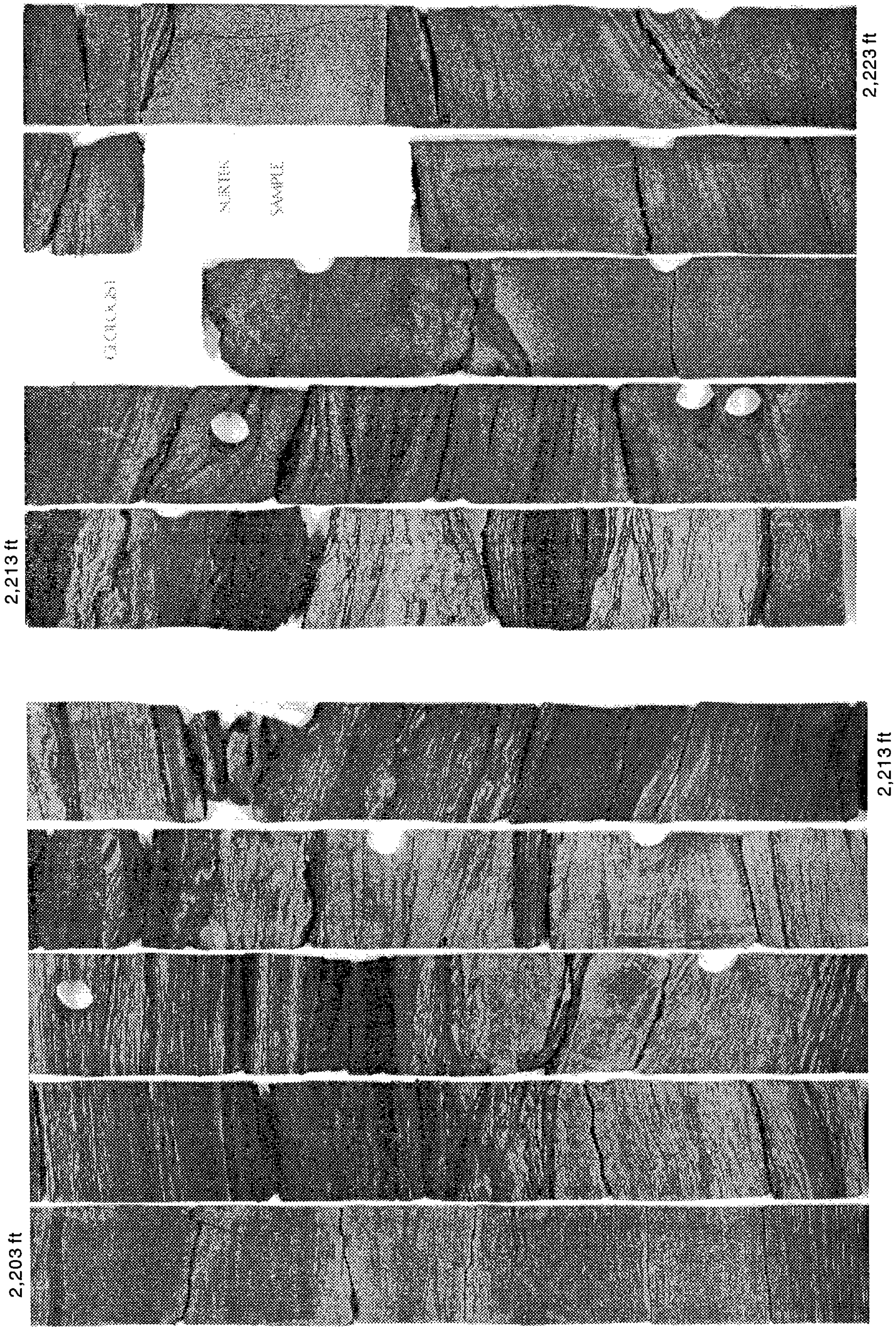


Figure 126 (*this page and facing page*). Series of core photographs, under natural light, of the pay section of a well drilled in the waterflood candidate. Each column is 2 ft long.

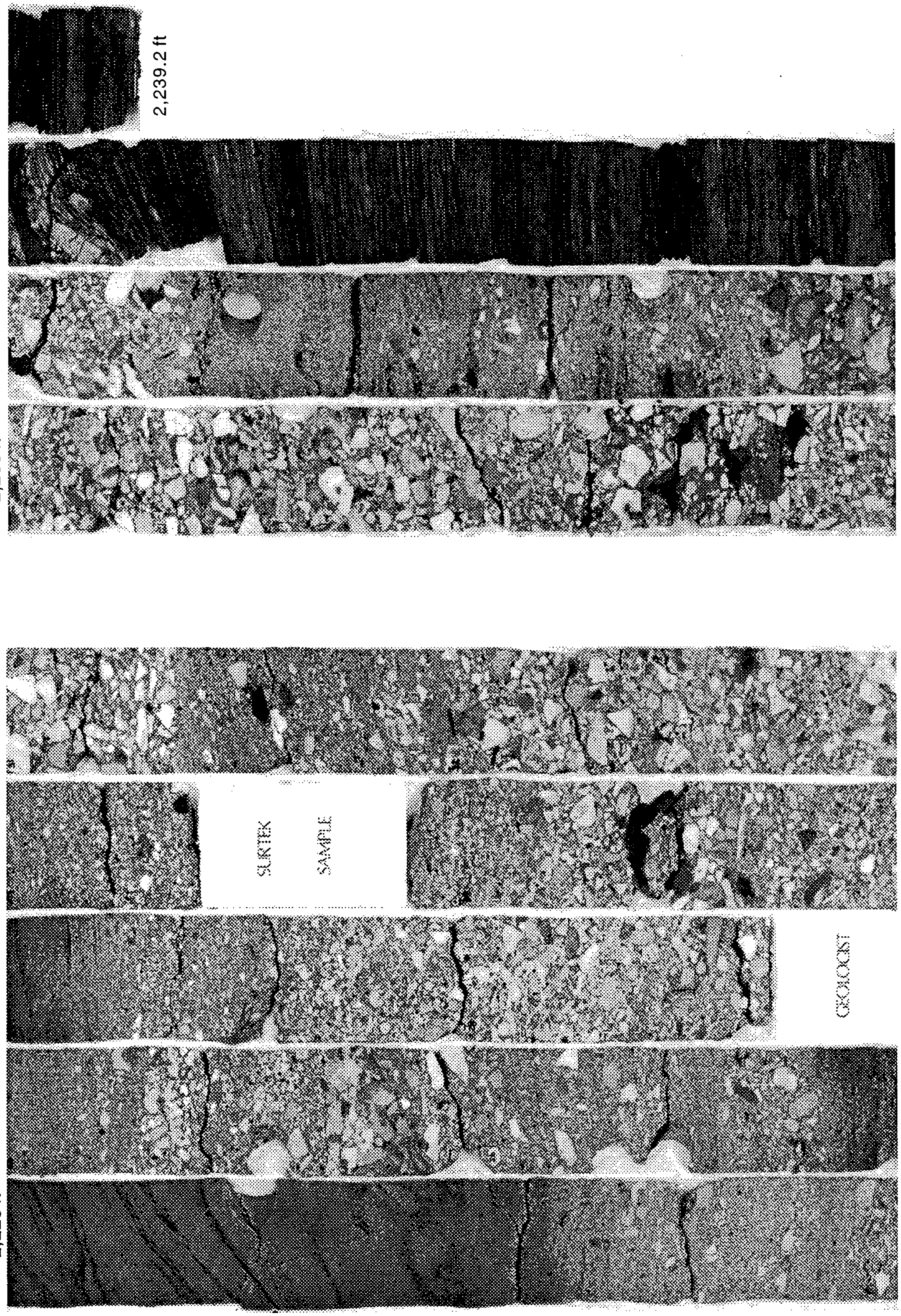


Figure 126 *(continued)*.

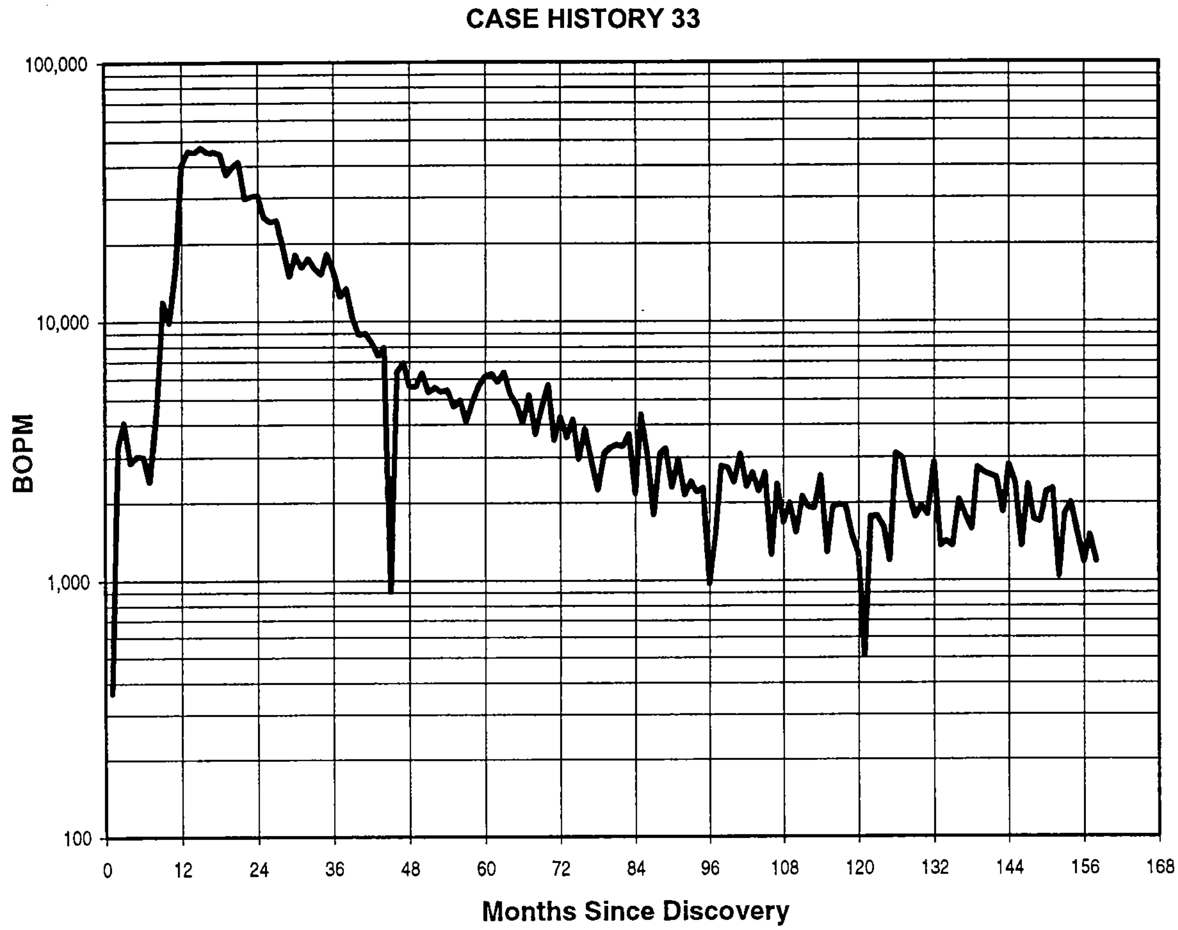


Figure 127. Production curve for a reservoir under consideration as a waterflood candidate (case history 33, central Oklahoma).

The pitfall arises when geologists and engineers focus only on the economic aspects of the analogy rather than on the physical response. It is easy to assume that since the analogy was an economic failure, then, by default, the candidate will also be an economic failure. Owing to the uneconomic condition of the analogy, injection ceased at point *B* in Figure 129. Of primary significance for the evaluation of this analogy is the ratio of production of secondary oil to primary oil. This is expressed as the N_{wf}/N_p parameter, whose calculated value was 0.65/1. The analogy's actual ratio of secondary oil to primary oil was 0.60/1 when injection ceased. A ratio of 0.65/1 would represent approximately 800,000 barrels of anticipated secondary oil for the candidate. This is the number that should be used to gauge whether costs for case history 33 are economic or not—not the economic outcome of the analogy.

Case history 34 (Fig. 131) is another analog to this topic. Figure 131 is an isopach map of one of the producing layers of a field in north Texas. Figure 132 shows the production curve for this field. The operator of the field decided to initiate a pilot waterflood. The first injection occurred 96 months after discovery of the field. Wells 1 and 2 (Figure 131) were converted to injectors. The analysis of the production data indicates that response occurred approximately 1 year after injection commenced, which is represented by the hatched area in Figure 132. At month 140, injection ceased, and the pilot project was abandoned. The field was allowed to deplete, and the wells were eventually plugged.

Years later, this field was considered as a potential waterflood candidate. The field was cautiously reviewed by several potential operators, who were leery of the project because of the apparent lack of secondary field development following the pilot project. They reasoned that the pilot was abandoned because it did not respond as anticipated.

The pitfall in this example is in not completely understanding the reason for the pilot project's abandonment. It is easy to assume that the pilot project was technically unsuccessful because of the lack of development afterward. In this case, however, water for injection was being purchased from the nearest municipality. Records indicate that the water contract was canceled, which was a major contributing factor to the operator's decision to abandon the project. This example illustrates the importance of understanding and examining all phases of the analogy for the purpose of comparing it to a waterflood candidate.

CASE HISTORY 33

Miscellaneous

Pi	1,876 psi
P	250 psi
Depth	4,600 ft
P-grad	0.408 psi/ft
T	115 °F
k	20 md
Oil Grav	37.0 °API
Gas Grav	0.75
NaCl %	10.0%

Material Balance

N	9,413,294 stbo	
G	1,177,481 mcf	
m	0.11	
Gas Cap %	10.2%	
SGDI	79.29%	951,454 stbo
GCDI	21.40%	256,733 stbo
WDI	-0.92%	-11,095 stbo
PVCI	0.24%	2,861 stbo

PVT Data

Condition	Initial	Current	BP
P (psi)	1,876	250	1,875
Rs (scf/stb)	478	44	478
Bt (cf/stb)	7.05	32.91	7.05
Bo (rb/stb)	1.2548	1.0504	1.2548
μo (cp)	1.0802	3.5701	1.0802
Co (1/psi)	1.341E-05	2.096E-03	1.342E-05
Bg (cf/scf)	0.0064	0.0622	0.0064
μg (cp)	0.0172	0.0116	0.0172
Cg (1/psi)	4.653E-04	3.822E-03	4.654E-04
Bw (rb/stb)	1.0098	1.0114	1.0098
μw (cp)	0.6808	0.6808	0.6808
Cw (1/psi)	2.601E-06	2.639E-06	2.601E-06

Volumetrics

N	9,414,011 stbo	A	1,721.80 ac
G	1,177,571 mcf	ø	12.5%
		Sw	25.0%

	Total	Oil	Gas
h (ft)	10.5	9.4	1.1
Vb (ac-ft)	18,091.60	16,241.54	1,850.06
Vp (ac-ft)	2,261.45	2,030.19	231.26
Vphc (ac-ft)	1,696.09	1,522.64	173.44

Reserves

	stbo	bpaf	Rf
Np	1,199,952	73.88	12.7%
Nwf	896,997	55.23	9.5%
Nult	2,096,949	129.11	22.3%
N	9,414,011	579.63	100.0%

Gp	4,875,422 mcf
G	1,177,571 mcf
Wp	500,000 bw
We	0 bw
Rp	4,063 scf/stb
Nwf/Np	0.75 to 1

Waterflood

Vb flood	9,280.00 ac-ft	Vb flood	57.1%
Inj Rate	4,000 bwpd	Ea	65.0%
V fillup	4,978,851 bw	Ev	65.0%
t fillup	3.41 yrs	Ed	45.2%
Sor	30.0%	Et	19.1%

Oil Column Conditions

	Initial	Current
Sw	25.0%	25.0%
So	75.0%	54.8%
Sg	0.0%	20.2%

Comments:

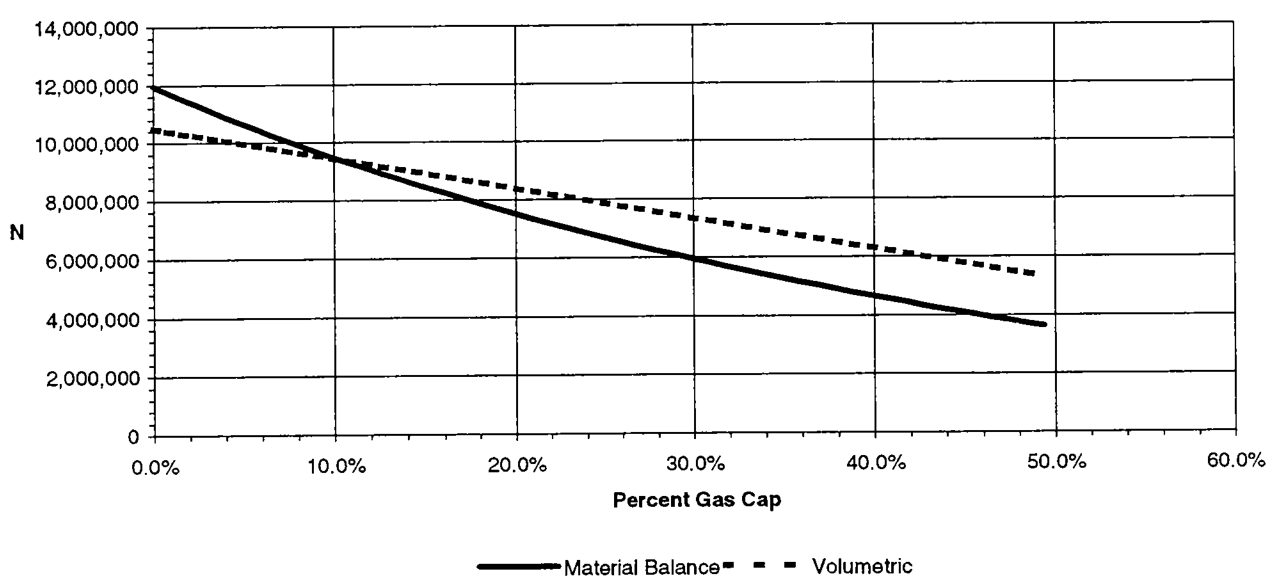


Figure 128. Reservoir model for the waterflood candidate of case history 33, illustrating various geologic and engineering variables at the time the reservoir was depleted. See Appendix 1 for explanation of abbreviations.

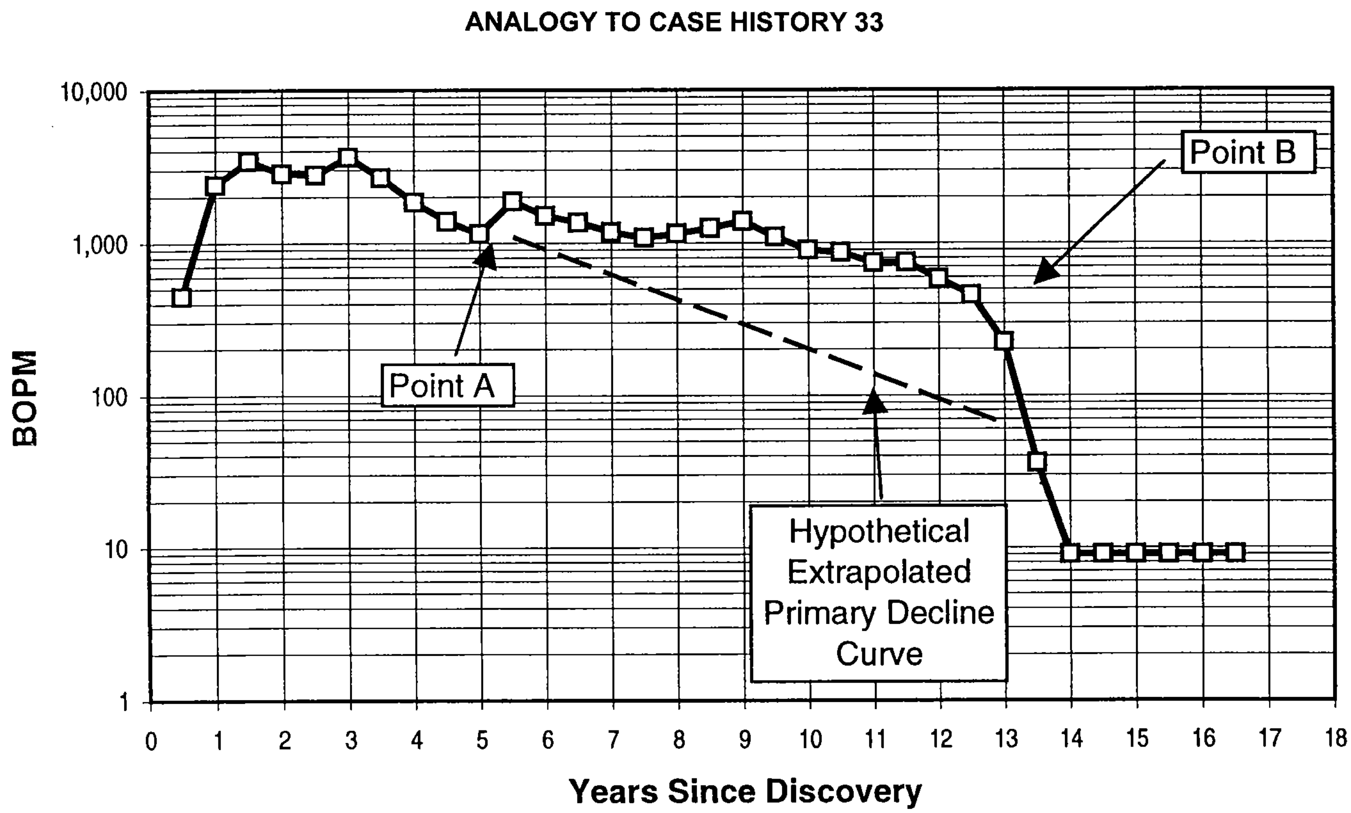


Figure 129. Production curve for the reservoir analogous to case history 33. Point *A* represents increase in production from water injection. Point *B* represents the time when water injection ceased.

ANALOGY TO CASE HISTORY 33

Miscellaneous

Pi	1,632	psi
P	300	psi
Depth	4,000	ft
P-grad	0.408	psi/ft
T	111	°F
k	30	md
Oil Grav	40.0	°API
Gas Grav	0.85	
NaCl %	14.0%	

Material Balance

N	1,423,762 stbo	
G	20,696 mcf	
m	0.01	
Gas Cap %	1.3%	
SGDI	96.87%	157,580 stbo
GCDI	2.84%	4,617 stbo
WDI	0.00%	0 stbo
PVCI	0.29%	468 stbo

PVT Data

Condition	Initial	Current	BP
P (psi)	1,632	300	1,628
Rs (scf/stb)	525	71	525
Bt (cf/stb)	7.15	28.75	7.15
Bo (rb/stb)	1.2732	1.0596	1.2733
μo (cp)	0.8964	2.5665	0.8961
Co (1/psi)	1.595E-05	2.229E-03	1.599E-05
Bg (cf/scf)	0.0066	0.0502	0.0067
μg (cp)	0.0175	0.0112	0.0175
Cg (1/psi)	4.427E-04	3.084E-03	4.433E-04
Bw (rb/stb)	1.0100	1.0111	1.0101
μw (cp)	0.7761	0.7761	0.7761
Cw (1/psi)	2.411E-06	2.473E-06	2.411E-06

Volumetrics

N	1,423,824 stbo	A	448.40 ac
G	20,697 mcf	ø	12.5%
		Sw	25.0%

	Total	Oil	Gas
h (ft)	5.6	5.6	0.1
Vb (ac-ft)	2,526.10	2,492.44	33.66
Vp (ac-ft)	315.76	311.56	4.21
Vphc (ac-ft)	236.82	233.67	3.16

Reserves

	stbo	bpaf	Rf
Np	162,664	65.26	11.4%
Nwf	105,133	42.18	7.4%
Nult	267,797	107.44	18.8%
N	1,423,824	571.26	100.0%

Gp	625,000 mcf
G	20,697 mcf
Wp	0 bw
We	0 bw
Rp	3,842 scf/stb
Nwf/Np	0.65 to 1

Waterflood

Vb flood	1,075.40 ac-ft	Vb flood	43.1%
Inj Rate	250 bwpd	Ea	65.0%
V fillup	495,566 bw	Ev	65.0%
t fillup	5.43 yrs	Ed	45.7%
Sor	30.0%	Et	19.3%

Oil Column Conditions

	Initial	Current
Sw	25.0%	25.0%
So	75.0%	55.3%
Sg	0.0%	19.7%

Comments:

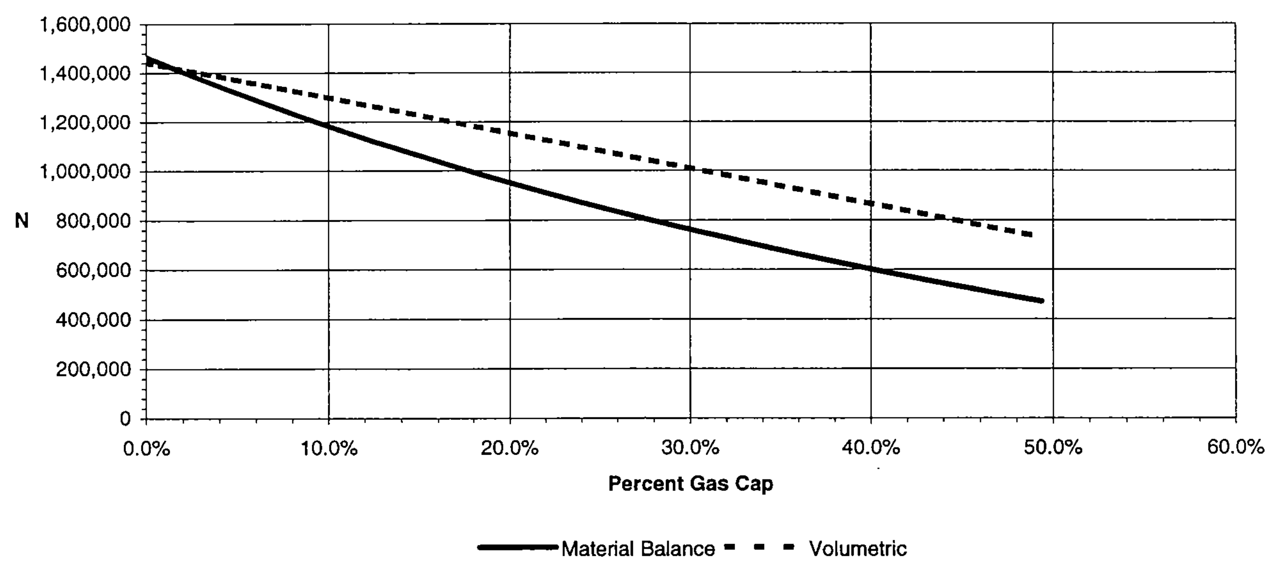


Figure 130. Reservoir model for the reservoir analogous to case history 33, illustrating various geologic and engineering variables at the time of pressure depletion of the reservoir. See Appendix 1 for explanation of abbreviations.

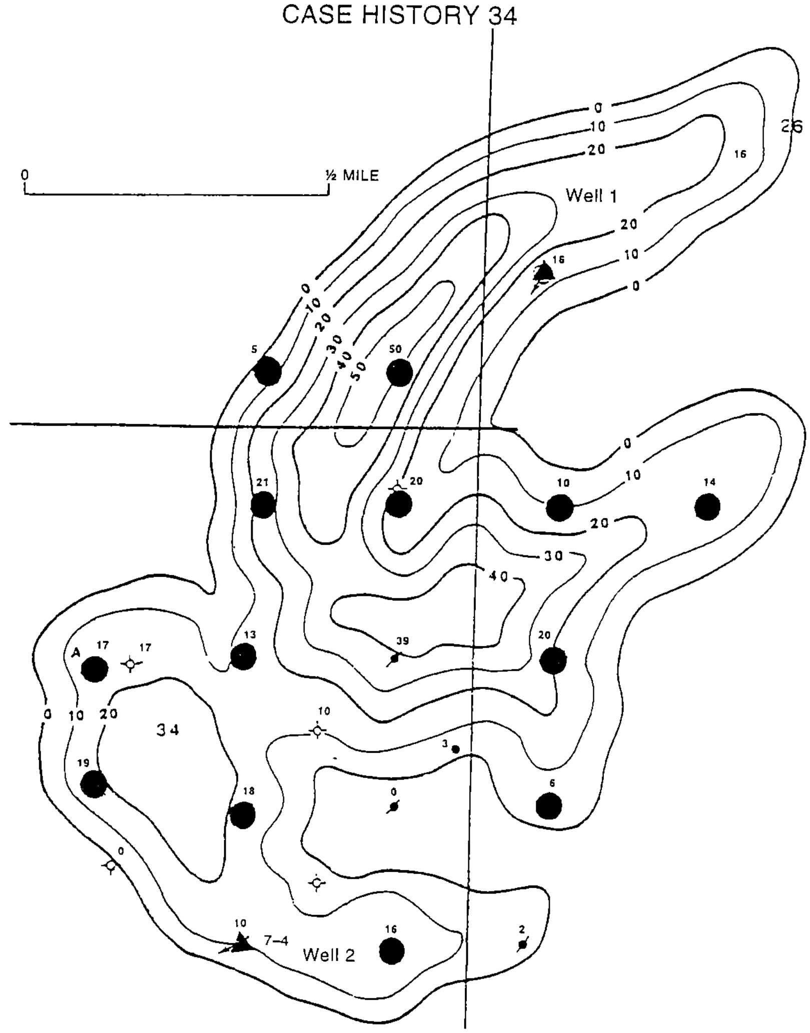


Figure 131. Net isopach map of a productive layer for the field of case history 34 (north Texas). Wells 1 and 2 were converted to injection in a pilot-waterflood attempt. Contour interval, 10 ft. See text for description.

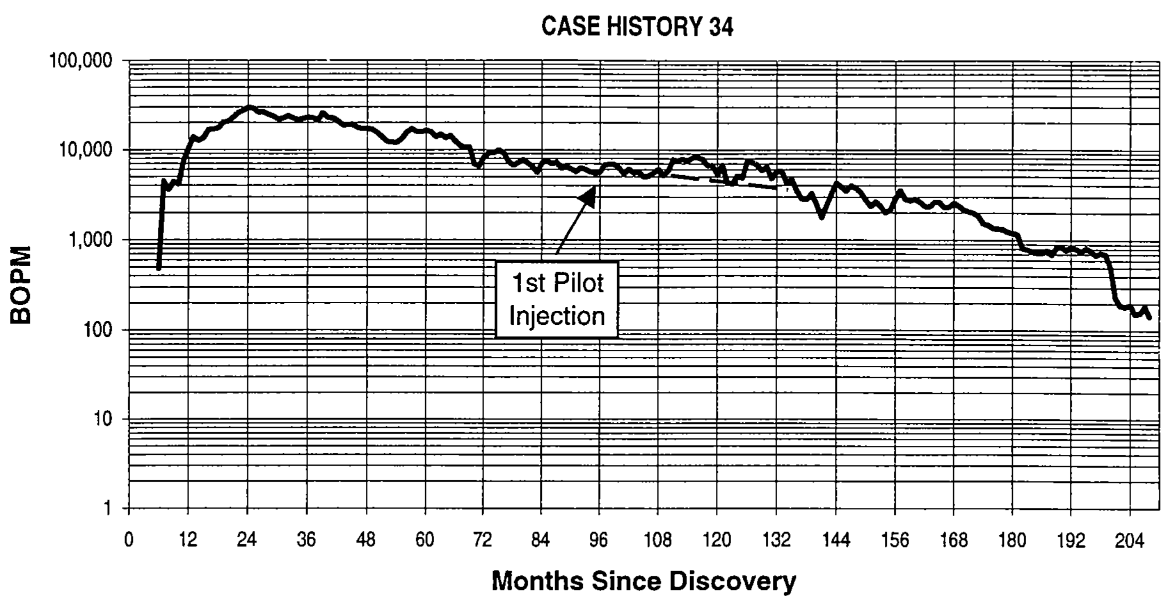


Figure 132. Production curve for the field of case history 34. Hatched area represents response to injection from the pilot waterflood (Fig. 131).

Coring and Core Results

8

CHAPTER 8

Core and Coring Results

INTRODUCTION

Cores are probably the best source for obtaining reservoir data for a waterflood candidate. This chapter does not deal with pitfalls of coring but presents material that suggests proper techniques for core analysis and evaluation to avoid pitfalls. For more detailed information concerning this subject, the reader should refer to the list of references.

CORING PROPERTIES AND OBJECTIVES

Table 16 lists the coring fluids necessary for obtaining specified objectives of core testing. When cores are needed for specific tests, selection of the correct coring fluid is essential to preserve the integrity of the tests.

SURFACE SATURATIONS OF CORED SECTION

When strata are cored, the coring fluid changes the fluid saturations in the reservoir. Physical changes also occur in a core's fluid saturations as the core approaches the surface. Table 17 lists various coring factors that might alter surface fluid saturations. Table 18 lists the effects on core saturations from various types of coring fluids.

A typical core analysis reports saturations for water and oil. The saturations reported are those observed at the surface and do not reflect actual saturations in the reservoir. Table 18 lists changes that can occur in core saturations from filtrates of various coring fluids; these changes can be dramatic. For instance, water-wet reservoirs typically have current oil saturations of 65%–75% at virgin-pressure conditions in the Midcontinent. However, analyses of cores from these reservoirs often report oil saturations in the range of 10%–20%. It is surprising that many geologists and engineers believe that the reported core saturations actually represent current reservoir saturations.

Figures 133–136 illustrate how reservoirs that contain various percentages of hydrocarbons and water are affected by filtrates and the recovery of the cored section. Notice that in all four scenarios, gas expansion

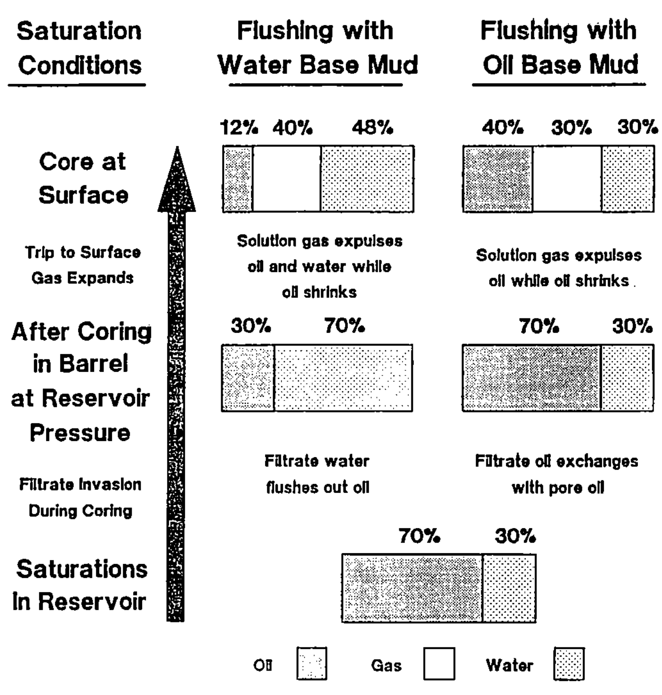


Figure 133. Typical fluid contents from reservoir to surface: oil-productive formation. (Core Laboratories, Inc., 1980.)

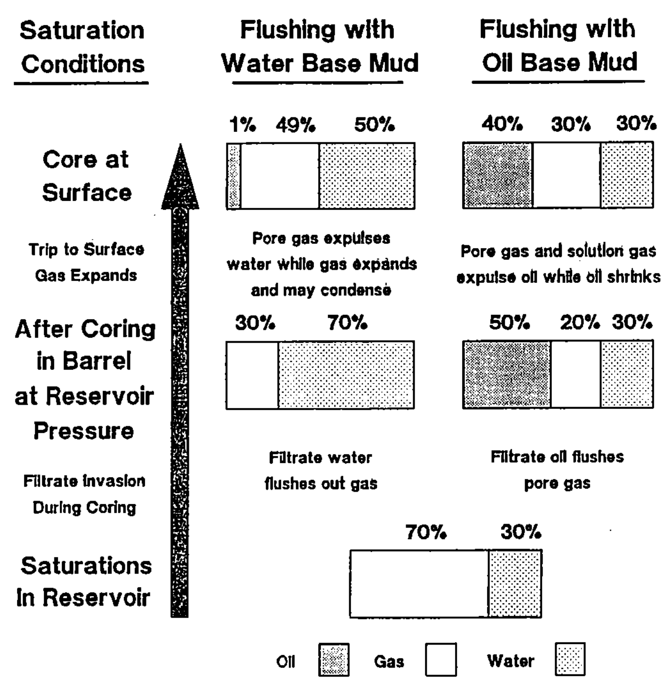


Figure 134. Typical fluid contents from reservoir to surface: gas-productive formation. (Core Laboratories, Inc., 1980.)

TABLE 16. – Coring Fluids Suitable for Obtaining Objectives

Objectives	Suitable coring fluids
Porosity, permeability, lithology, and productivity estimate from residual surface fluid saturations	Water-base mud Gas Oil emulsion
Porosity, permeability, and lithology	Any fluid
Interstitial water	Oil base Inverted oil emulsion (not suitable for high permeability) Gas (hydrocarbon) Non-oxidized (N-O) crude oil
Unaltered wettability	Fresh and salt water (no other additives) Bland drilling muds Non-oxidized (N-O) crude oil Gas (hydrocarbon)

If formation wettability is known, the following fluids are recommended for coring for special tests

	Water wet	Oil wet	Intermediate
Water–oil relative permeability	Water Gas N-O crude oil	N-O crude oil Oil base	N-O crude oil Gas (hydrocarbon)
Gas–oil relative permeability	Water base Gas N-O crude oil	N-O crude oil Oil base	N-O crude oil Gas (hydrocarbon)
Water–oil capillary pressure	Water base Gas N-O crude oil	N-O crude oil Oil base	N-O crude oil Gas (hydrocarbon)
Gas–water capillary pressure	Water base Gas N-O crude oil	*	**
Gas–oil capillary pressure	Any fluid	*	**
Mercury-injection capillary pressure	Any fluid	*	**

* Test data not applicable. ** Applicability of test data unknown. SOURCE: Core Laboratories, Inc., 1980.

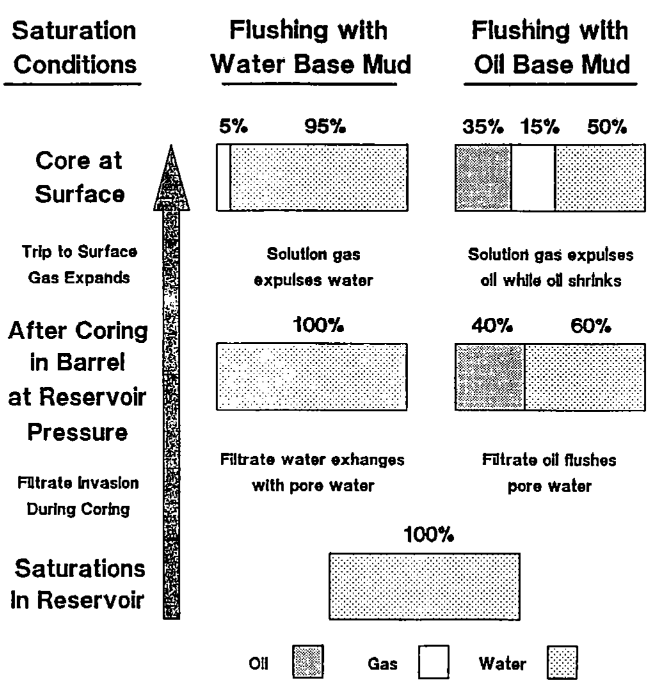


Figure 135. Typical fluid contents from reservoir to surface: water-productive formation. (Core Laboratories, Inc., 1980.)

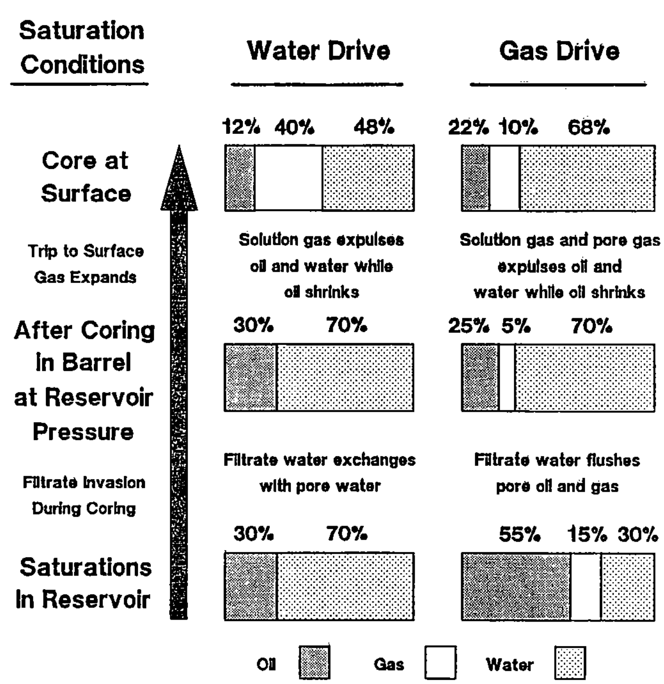


Figure 136. Typical fluid contents from reservoir to surface: depleted oil reservoir. (Core Laboratories, Inc., 1980.)

TABLE 17. – Coring Factors That Might Alter Surface Fluid Saturations

1. Overbalance pressure
2. Fluid/spurt/loss
3. Core diameter
4. Permeability/vertical permeability
5. Filtrate–reservoir oil interfacial tension
6. Viscosity contrast between resident and invading fluids
7. Rate of bit penetration
8. Rate of mud circulation
9. Coring fluid/additives
10. Relative permeability
11. Core handling/preservation
12. Gas/oil ratio

SOURCE: Core Laboratories, Inc., 1980.

occurs, which is a major factor in fluid-saturation changes from depth to surface.

PROPER TECHNIQUES AND PITFALLS OF CORE ANALYSIS

by Dan Wilson

Proper techniques for core analysis begin before the core has ever been drilled. Defining what your objectives are and what you want the core to tell you are important to delineate before taking the core. Core analysis is an important component of formation evaluation and is especially advantageous when complex reservoirs are to be developed. The fundamental objective of core analysis is to obtain data that are representative of the in-situ reservoir-rock properties.

Pore geometry controls or influences all rock properties. Pore geometry varies from reservoir to reservoir and changes with lithology, depositional environment, diagenesis, and rock type. Samples are required that reflect pore-geometry changes with depth and areal distribution, and with permeability and porosity. Core samples from the reservoir are therefore essential.

Basic core analysis defines porosity and permeability magnitude and distribution. Special core analysis complements these basic data and furnishes information that allows calculation of static fluid distribution as well as dynamic flow performance of a well or reservoir. Figure 137 is a flow chart that illustrates various tests for basic and special core analysis.

The Well Site

Reliable core analysis results begin at the well site:

Before the core is drilled:

- Rock type.—Different rock types may require additional precautions. The choice of the proper recovery method for unconsolidated or fractured reservoirs is essential in obtaining representative core data.
- Coring fluid—water based versus oil based.—The choice of coring fluid can have a significant impact on future studies.

After the core is drilled:

- Preservation, sample marking, and handling.—Attention to the following factors is essential to minimize the potential wettability alteration of the core:
  - Core exposure to the air, even for very short periods, is to be avoided.
  - Preservation of the core at the well site before it reaches the laboratory is critical if accurate core-analysis data are to be generated. A number of techniques for preservation can be employed, depending on the physical nature of the core, the types of tests to be performed, or the length of time necessary for the core to remain fresh. Some techniques include 3-ft plastic zip-lock bags, Saran wrap and aluminum foil, Seal-a-peal, cut-and-cap PVC or aluminum inner barrels, screw-top PVC tubes with or without reservoir fluids, and large boxes filled with dry ice.

TABLE 18. – Coring-Fluid Effects on Reservoir-Fluid Saturations

		Effects on core saturations	
Coring fluids	Filtrate	Water	Hydrocarbons
Water base	Water	Increased	Decreased
Oil base	Oil	No change[a]	Replaced[b]
Inverted oil emulsion	Oil	No change[a,c]	Replaced[b]
Oil emulsion	Water	Increased[d]	Decreased
Gas (hydrocarbon)	Gas	No change[a]	Replaced
Air	Uncertain	Uncertain[e]	Decreased
Foam	Nil	Nil	Nil

[a] If sample is at irreducible (immobile) water saturation prior to coring. Otherwise, filtrate will displace water and reduce its saturation if in a transition zone. Precautions to remove all extraneous water from system should be taken.

[b] This replacement sometimes causes gas sands to exhibit oil saturations at the surface indicative of oil- rather than gas-productive reservoirs.

[c] Inverted oil-emulsion muds contain water. A loss of whole mude to high-permeability formations will increase water saturations. The practical permeability limit for whole mud may be several hundred millidarcys.

[d] Improper mud control may cause filtrate loss to be oil rather than water.

[e] Data indicate that saturations may increase, decrease, or remain unchanged, depending on heat generated during coring, hole condition, and the agent mixed with air.

SOURCE: Core Laboratories, Inc., 1980.

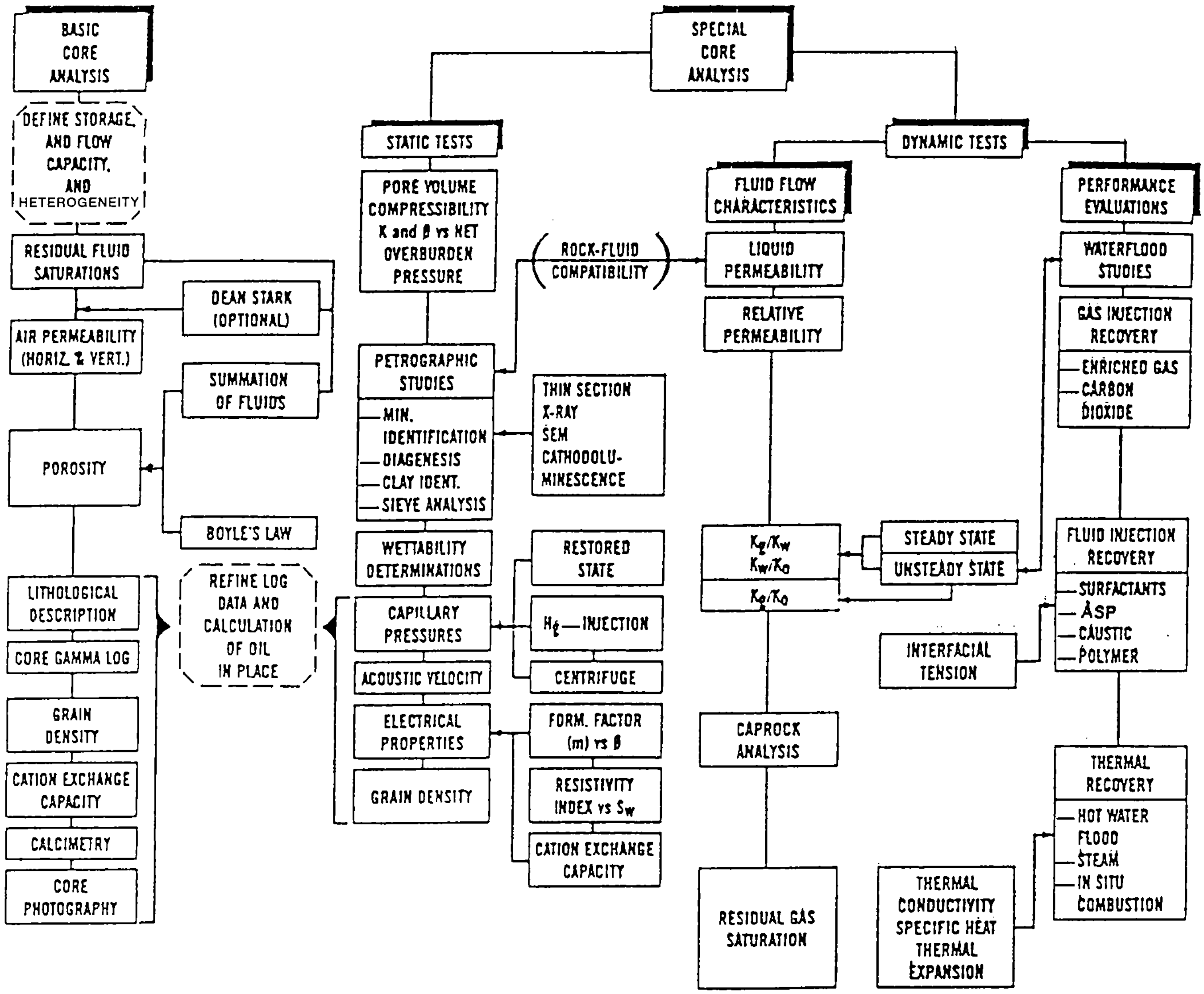


Figure 137. Diagrammatic flow chart of various basic and special core-analysis tests. (Courtesy of Surtek, Inc.)

The Laboratory

Reliable core-analysis results continue at the laboratory, provided standard procedures are followed:

Types of core samples:

- Fresh core.—Samples from core taken with either water- or oil-base muds and that are preserved and subsequently tested *without* cleaning and drying.
- Restored core.—Core samples cleaned and dried prior to testing. An advantage is that air permeability and porosity are available to assist in further sample selection. A disadvantage is that core wettability and spatial distribution of pore water may not match those in the reservoir. Weathered, dry cores containing low-API-gravity crude oils are difficult to clean. Weathered, clay-bearing rock may not be suitable for testing if humidity has resulted in rock deterioration.
- Native-state core.—Samples recovered with special fluids known to have minimal influence on core wettability and that are tested as fresh samples.

Basic Core Analysis: Whole-Core versus Plug Analysis

- Plug analyses are preferred in homogeneous sandstone and carbonate formations. Plug samples should be from the center of the core to minimize contamination by fine drilling-mud particles. Plugs should be cut parallel to any bedding features within the core so that the laminations are parallel to flow rather than cutting across the plug, restricting or blocking flow. Plugs are normally 1–1.5 in. in diameter and 1–3 in. long.
- Heterogeneous rocks require whole-core or full-diameter testing techniques. Whole-core testing

evaluates horizontal as well as vertical permeabilities. Laminated or stylolitic samples are not suitable for vertical permeability measurements.

- Samples that have been vacuum retorted are not normally suitable for water- or chemical-displacement tests, and special test samples must be selected prior to core analysis.
- Whole-core test samples are in the form of a right cylinder, and cores up to 10 in. long and up to 5 in. in diameter may be used. Selection of an unusual core diameter will result in laboratory delay and extra cost if the laboratory has to fabricate equipment.

Sample selection:

- Samples should be selected to cover each rock type present, as well as the porosity and permeability range within each rock type. Variables, such as formation factor and pore-volume compressibility, trend with porosity, whereas others, such as sandstone gas–oil relative permeability, trend with permeability. Crossplots can be made to yield data representative of desired porosity or permeability.
- In many reservoirs, a plot of core-analysis permeability versus porosity is a helpful tool in sample selection; histograms of porosity and permeability distribution also yield useful information.
- Individual samples that fall outside the normal permeability-versus-porosity trend bounds should normally be discarded as special test candidates. Widespread in-the-trend-line data indicate that a greater number of samples will be required to adequately cover the pore geometry.
- Study of basic core data, when related to the wells' structural position, can yield early insight into required special tests, as the presence or absence of a gas cap and water leg infers certain reservoir-drive mechanisms.
- Sufficient samples should be selected to provide statistical validity and to supply alternate samples if required.
- Visual examination of proposed samples is essential in the selection of homogeneous, nonlayered plugs for testing. One should not "high grade" the samples taken for analysis but keep to a standard 1-ft selection interval regardless of the rock type where that selection site lands; failure to do so will usually lead to inadequate, nonrepresentative data.

Complicating factors that extend testing times:

- Submission of incomplete data required to initiate the study will delay results.
- Shaly, clayey cores require low-temperature cleaning and humidity drying techniques that are slow.
- Friable cores require gentle cleaning (soxhlet) that is slow. Cores often must be coated with plastic or heat-shrinkable tubing that extends testing time. Rubber-sleeve cores often require that the core be frozen while in the rubber sleeve, and then that liquid nitrogen be used to drill the plugs. This process is time consuming and expensive.
- Low-permeability cores extend testing times.
- Cores containing vugs normally require that the vugs be filled or covered with fiberglass to prevent the elaster boot surrounding the core from extruding into the vug, thereby causing boot failure and test failure. This is of greatest concern at high overburden pressures.

Special Core Analysis: Static versus Dynamic Tests

Static tests:

- Capillary pressure.—Defines the magnitude and distribution of water saturation in the reservoir. It is one of the most important measurements that can be made, because it relates reservoir-rock and reservoir-fluid properties. Generated data can be used to define rock types by calculating pore-throat size, fluid distribution, relative permeability, and by determining the transition zone and the free-water level. Three generally accepted methods for determining capillary pressure are (1) porous plate cell, (2) mercury injection, and (3) centrifugal.
- Electrical properties.—These measurements define for a given formation (with its unique pore geometry) the variables a, n, and m in the equation used to calculate formation-water saturations from downhole-log response. Samples should be selected to cover the porosity range noted in the core. Gas, oil, and rock matrix are normally nonconductors of electricity. Their presence in an element of the reservoir or in a core sample will reduce the mean cross-sectional area of the flow path for an electric current and increase the length of the flow path, thereby increasing resistivity. Electrical-property measurements can be used to determine (1) *formation factor,* defined as the ratio of the resistivity of completely brine-saturated rock to the resistivity of the brine; and (2) *resistivity index,* defined as the ratio of rock resistivity at any condition of gas, oil, and water saturation to its resistivity when completely saturated with water.

Many other static tests are available that can also be performed on core samples, which include:

- Pore-volume compressibility.—Porosity and permeability changes versus net overburden pressure.
- Cation-exchange capacity.
- Petrographic studies.
- Wettability determinations.
- Acoustic-velocity measurements.
- Grain-density determinations.

Dynamic tests:

These types of tests exist in two separate categories, consisting of fluid-flow characteristics and performance evaluations.

- Fluid-flow characteristics:
  - Liquid permeability.—Liquid permeability of a rock is a constant and is independent of pressure differential imposed under conditions of laminar flow, no rock–fluid reaction, and 100% saturation by the flowing fluid. This is not true of gases, however. Liquid molecules do not flow at a uniform rate through small pores, because liquid molecules in the center of the pores move at a higher velocity than the nearly stationary molecules next to the pore walls. At low mean gas pressure, gas permeability exceeds liquid permeability. At high mean gas pressure, gas permeability equals liquid permeability. This difference in molecular movement results in a dependence of gas permeability on the mean pressure of the gas existing at the time of measurement. This gas-flow characteristic is termed *gas slippage*, or *Klinkenburg effect* after the man who observed it. Gas permeability corrected for Klinkenburg effect is termed *equivalent liquid permeability*. The reaction between reservoir rock and introduced fluids can increase or decrease permeability. For example, anhydrite dissolution increases permeability. Clay swelling or deflocculation, when contacted by water, reduces permeability. The fresher the water, the greater the swelling. Particle movement, rather than clay swelling, might be the mechanism causing the reduction in permeability. Permeability reduction is inversely proportional to permeability. The lower the permeability, the greater the reduction from clay reaction.
  - Relative permeability.—This is a dimensionless term reported as a fraction or percentage. The concept of relative permeability provides an extension of Darcy's Law to the presence and movement of more than a single fluid within the pore space. The shapes of the relative-permeability curves are a function of the fluid distribution within the porous medium. Fluid distribution in turn depends on the saturation history and on the wetting characteristic of the rock. Relative-permeability characteristics are important in the displacement of hydrocarbons by water, and in the displacement of oil and water by gas. These displacements occur during primary- and secondary-recovery operations, as well as during coring and core recovery. Water displacement of oil differs from gas displacement of oil. Water normally wets the rock, and gas does not. This wetting difference results in different relative-permeability curves for the two displacements. Pore geometry influences the quantity of residual oil and the shape of the relative-permeability curves. No set of general relative-permeability curves is applicable for all formations.
- Performance evaluations:
  - Enhanced-oil-recovery studies.—Three general categories under enhanced oil recovery are (1) *thermal*—in-situ combustion, injection of hot water or steam; (2) *chemical*—injection of a micellar, caustic, polymer, or a combination of alkali–surfactant–polymer; (3) *miscible*—injection of carbon dioxide, inert gas, a miscible hydrocarbon slug, enriched gas, or high-pressure lean gas.

Some important aspects to keep in mind if core analysis for enhanced oil recovery (EOR) is your main objective for taking a core:

- Most importantly, test the rock for flow characteristics and fluid compatibility in the laboratory to reduce any risk for a field application: if you cannot inject, you cannot produce the oil.
- Make sure the core is well preserved so that the rock is kept in as fresh a state as possible.
- Do not slab the core. EOR studies generally require full-diameter core.
- If EOR is the primary objective, allow the laboratory doing that evaluation to have the core first. Subsequent basic or special core analysis can be done later on unused, preserved sections of core.

Fractures

9

CHAPTER 9

Fractures

INTRODUCTION

This workshop addresses the issue of evaluating and determining fracture patterns. Producing oil from fractures and hydraulically fracturing a reservoir with injected water would need to be addressed in a workshop on engineering pitfalls of waterflooding.

Fractures, by definition, are cracks, joints, faults, or other breaks in rocks (Jackson, 1997). Fractures may be natural, occurring from stresses in the earth or artificially induced from well completions or some other mechanical process. *Fracture porosity,* by definition, is porosity resulting from the presence of openings produced by the breaking or shattering of an otherwise less pervious rock (Jackson, 1997). In some reservoirs, fracture porosity may even be the primary porosity source. Fractures may result from local stresses such as folding or faulting, or they may develop in response to regional or basinal stresses. However they are formed—whether natural or induced—fractures will affect the productive performance of a reservoir. Fractures can be a positive benefit for wells under primary production because of the increased permeability and accessibility to the additional rock matrix they afford. They can also be a detriment, because they may be the source of connectivity to bottom water or a downdip water leg.

Fractures generally have porosities and permeabilities higher than those of the surrounding rock matrix. Fractures filled with gouge are discussed later in this chapter. Of primary importance to the evaluator is the permeability associated with fractures. Fracture permeability can be several orders of magnitude higher than matrix permeability. Injected water will naturally take the path of least resistance. Therefore, if a fracture is present, injected water will immediately follow the fracture trend or plane. This can be a disastrous complication for a waterflood project if water is injected into a fracture plane that is in communication with a producer. The injected water will travel to the producer through the fracture, bypassing the rock matrix in the process. The only oil produced would be from moving oil in the fracture, imbibition processes in the rock matrix, or oil responding to the producer from other injectors not in the fracture pattern.

Distinguishing natural fractures from induced fractures is a basic subject of primary importance for geologists and engineers to master because of the influence of fractures on an injector–producer pattern. If a fracture trend connects an injector with a producer, sweep efficiency between the two wells can be greatly reduced by the channeling of water through fractures between the two wells. For this reason, it is important to determine if natural fractures exist in a reservoir, and if so, their orientation.

Induced fractures were not fully recognized or understood until the late 1970s. Up to this time, many induced fractures were arbitrarily termed "natural." This section will offer examples of natural and induced fractures only to help in distinguishing between them. Detailed descriptions of the origins and morphology of natural and induced fractures will not be addressed. Thus, this chapter will illustrate only those examples of natural and induced fractures for the purpose of demonstrating that fractures can indeed be induced and that induced fractures can be differentiated from natural fractures. For further information on this subject, the author recommends a book published by the American Association of Petroleum Geologists titled *Fractured Core Analysis: Interpretation, Logging, and Use of Natural and Induced Fractures in Core* by B. R. Kulander, S. L. Dean, and B. J. Ward, Jr. (1990).

NATURAL FRACTURES

The following (from Kulander and others, 1990) are some of the major characteristics for differentiating natural fractures in cores:

1. The presence of polished and slickenlined features on fracture faces; however, curved polished surfaces that are perpendicular to the core can be induced.
2. Marker-bed offsets can indicate a natural fracture, even though a fault surface is not visible.
3. Secondary mineral growth on a fracture face indicates natural origin.
4. Right-hand drilling-bit rotation plucks chips on natural fracture surfaces that are parallel or subparallel to the core axis. The chips are on the right-hand edge of the fracture face with the fracture face held toward the observer.
5. Pressure-solution features on a fracture surface from natural compressive forces.
6. Fracture-surface structures that are not symmetrical with the core geometry or that are oversize with respect to the core.

Figure 138 shows two examples of fractures that have been completely filled by secondary mineralization. Such fractures may or may not have porosities in the realm of those associated with the rock matrix. Commonly, fractures are only partially filled with secondary mineralization, in which case the associated porosity is a potential hydrocarbon reservoir. Sometimes, foreign material enters an induced fracture during drilling, coring, or core retrieval and adheres to the fracture surface, having the appearance of secondary mineralization.

Figure 139 illustrates a small fault observed in a section of core. What distinguishes faults from fractures is displacement parallel to the fracture zone. Movement may be the result of local extension or displacement. Larger faults are of interest to the evaluator of a waterflood project, and clues to their presence are important to observe. Figure 140 gives examples of slickensided natural fractures in core. *Slickensides* are defined as polished and striated rock surfaces that result from friction along a fault plane (Jackson, 1997). Kulander and others (1990) state that careful examination of slickensides is important, because they may be induced fractures from torque during coring operations.

Figure 141 illustrates two examples of cataclastic zones in sandstones termed *tabular compaction zones* (Kulander and others, 1990). These zones contain cataclastic material characterized by poorer sorting (Pittman, 1981; Harper and Moftah, 1985; Nelson, 1985) and grains smaller than the matrix (Aydin, 1978; Jamison and Stearns, 1982; Nelson, 1985). Of importance to geologists and engineers is that these zones are also characterized by lower porosity and permeability than the matrix (Aydin, 1978; Pittman, 1981; Jamison and Stearns, 1982; Harper and Moftah, 1985; Nelson, 1985; Underhill and Woodcock, 1987) and thus may have potential effects on reservoir flow properties. Figure 142 illustrates three sets of permeability measurements to support permeability reduction in a gouge zone. Figure 142A illustrates the effects that an oblique-angle horizontal and vertical gouge-filled fracture has on strictly horizontal and vertical permeability measurements. These measurements support the conclusion that permeability reductions occur when permeability is measured through a gouge zone. Figure 142B is a scatterplot of the percentage of granulated quartz versus permeability. The plot suggests that as granulated quartz in these zones increases, permeability decreases. Figure 142C compares the percentage reduction of permeability of plugs with and without gouge-filled fractures. In all these gouge-filled fractures, permeability was reduced.

Figure 143 are two photographs of stylolitic tension-gash fractures. Kulander and others (1990) point out that these fractures are minor on a reservoir scale but that their presence may cause porosity and permeability errors in whole-core and plug analysis.

Table 19 identifies and describes four types of contractional fractures (Nelson, 1985): desiccation or mudcrack, thermal-gradient, syneresis or chickenwire, and mineral-phase-change fractures.

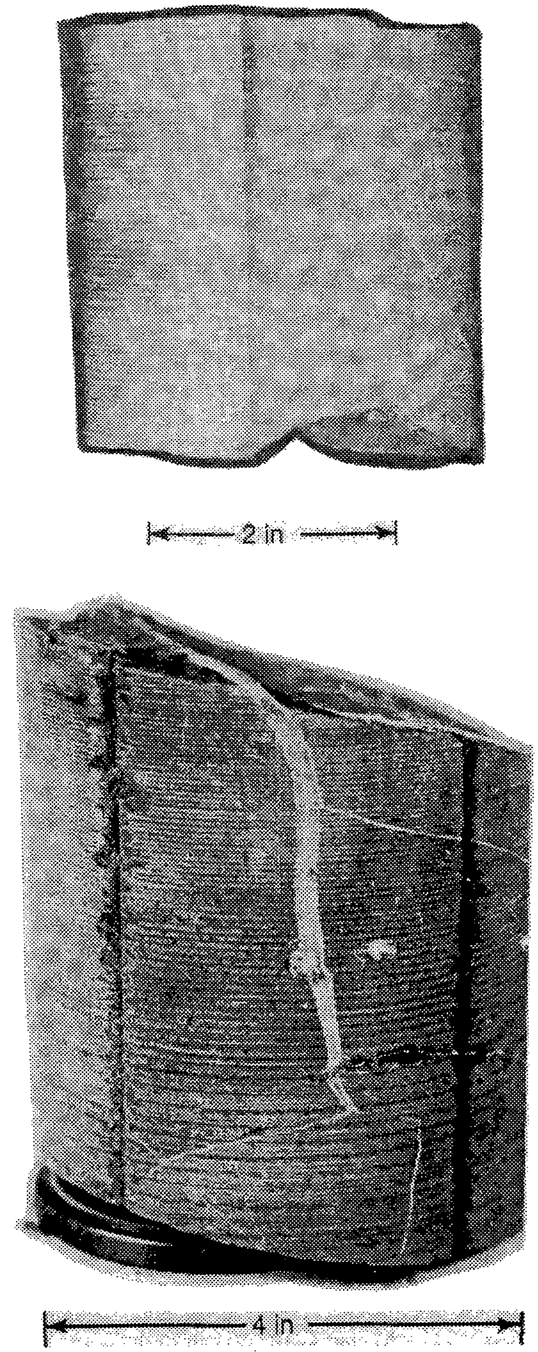


Figure 138. Two examples of secondary mineralization completely filling fractures. Lower photograph shows a core section of Devonian shale from the Appalachian basin, West Virginia. (Kulander and others, 1990, fig. 1; reprinted by permission of American Association of Petroleum Geologists.)

TABLE 19. — Four Types of Contractional Fractures

Desiccation fractures	Forms from mechanical drying of sediments, also known as mud cracks.
Thermal-gradient fractures	Forms in igneous rock from cooling and subsequent shrinkage.
Syneresis or chicken-wire fractures	Forms as a result of chemical changes that promote dewatering of the sediment.
Mineral-phase-change fractures	Forms from volumetric changes associated with mineralogical changes.

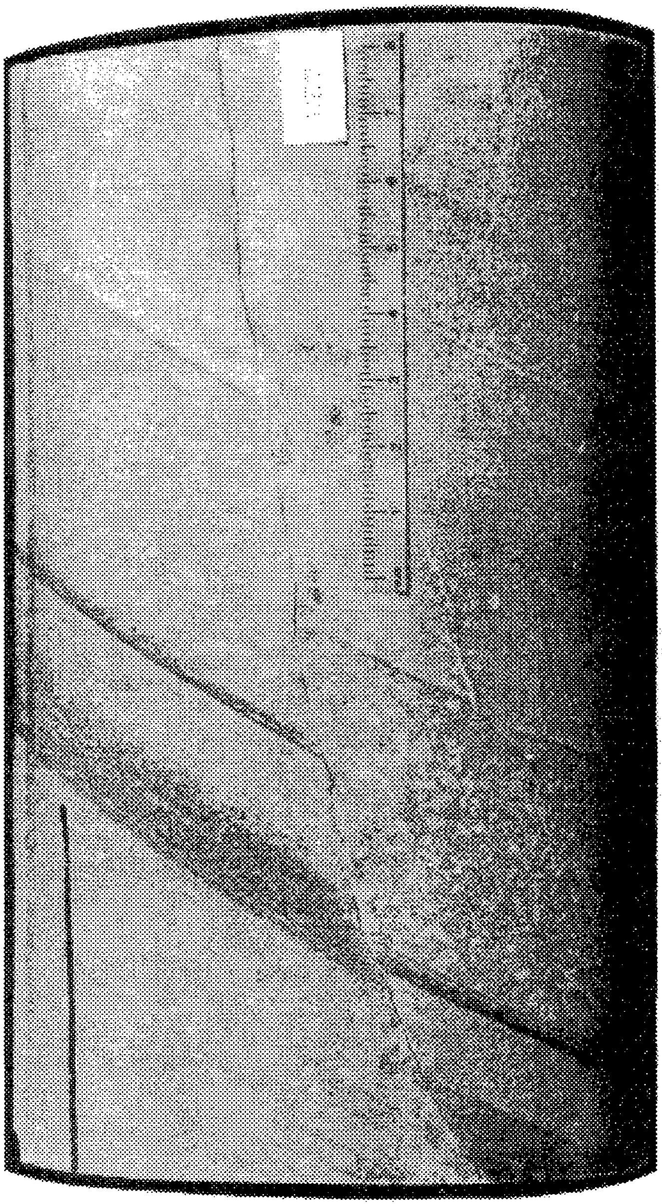


Figure 139. Example of a small fault in a section of core from a sandstone in the western United States. Scale is in millimeters. (Kulander and others, 1990, fig. 5; reprinted by permission of American Association of Petroleum Geologists.)

Kulander and others (1990) state that where normal natural-fracture characteristics—such as secondary mineralization, slickensides, or pressure solution features—are absent, natural fractures can be differentiated from induced fractures by the proper interpretation of hackle-plume components that can develop on the fracture face. Figure 144 shows photographs of actual plume components positioned on a hypothetical plume to emphasize the dissimilarity of the fracture structure of the core in relationship to the core boundary.

INDUCED FRACTURES

Induced fractures are derived and grouped into three distinct categories: (1) fractures that form in response to drilling; (2) fractures that form in response to coring; and (3) fractures that form in response to retrieving, handling, slabbing, and plugging the core. The following is a list of some of the major characteristics of induced fractures (Kulander and others, 1990).

Characteristics of drilling-induced fractures:

1. Drilling-induced fractures and surface structures show geometrical relationships with core parameters.
2. Closely spaced arrest lines in petal–centerline fractures are convex downcore.
3. Drilling-induced-fracture surfaces commonly show a unique orientation within a core.
4. Previously developed fractures will be chipped by the scribe knife.
5. The cored portion of a drilling-induced fracture generally does not indicate the origin of the fracture.

Characteristics of coring-induced fractures:

1. The fracture origin is always indicated in the core.
2. Hackle-plume structure curves until it becomes orthogonal to the core boundary.
3. Arrest lines curve and tend to tangentially meet the core boundary or a preexisting fracture surface.

Characteristics of handling-induced fractures:

1. The origin of handling-induced fractures is always indicated.
2. Hammer marks on the surface of a core strongly suggest the origin of fractures at or near the mark.
3. The lack of any drilling mud on a fracture suggests that the fracture occurred after coring.

The following are illustrations of the major types of induced fractures. For a more detailed description and overview of the origin and morphology of these types of fractures, see Kulander and others (1990).

Figure 145 is a schematic illustration of typical disc fractures. The direction of greatest in-situ stress is shown during fracture growth. The disc fracture in the center has not propagated to the core margin, but this hidden fracture would affect permeability, sonic, and

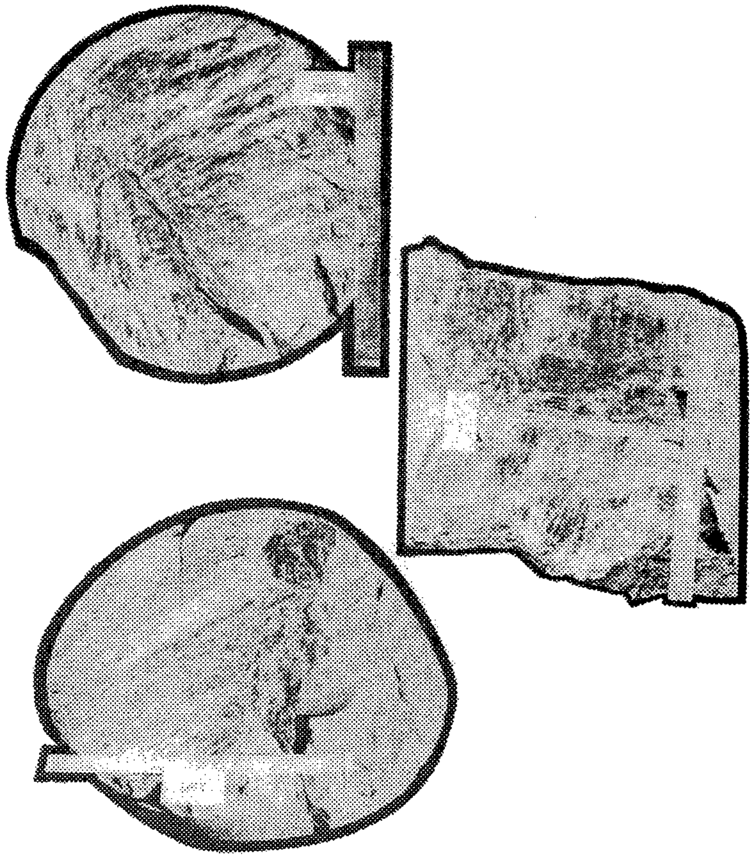


Figure 140. Examples of slickensided fracture surfaces. Scales are in millimeters. (Kulander and others, 1990, fig. 6a; reprinted by permission of American Association of Petroleum Geologists.)

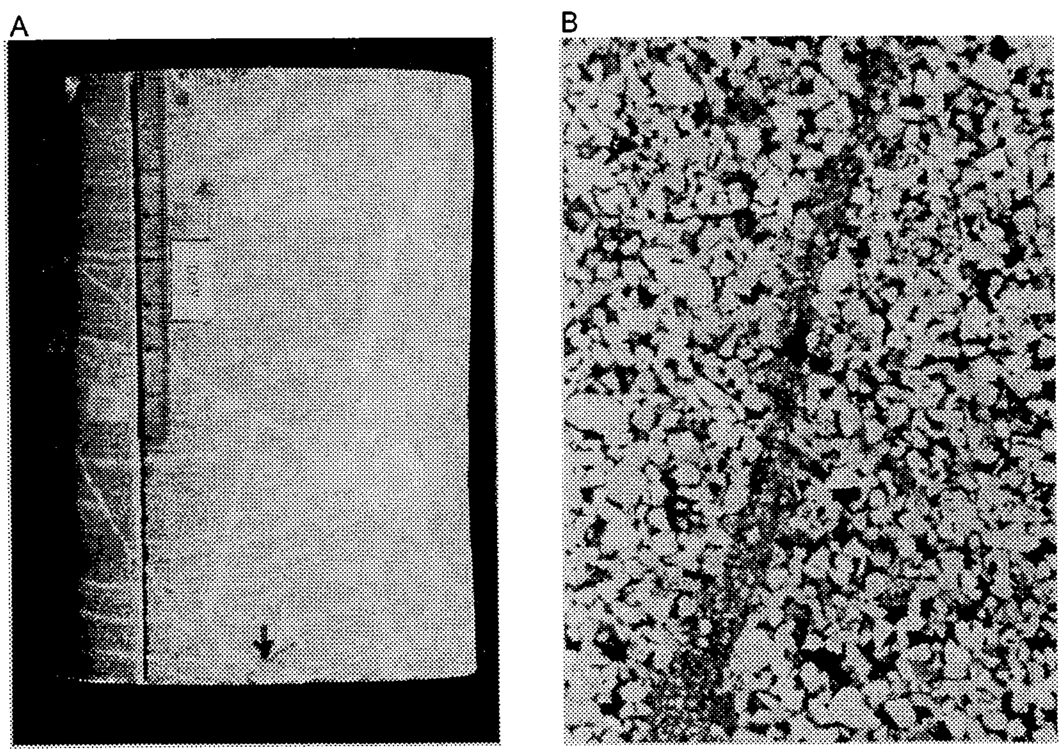
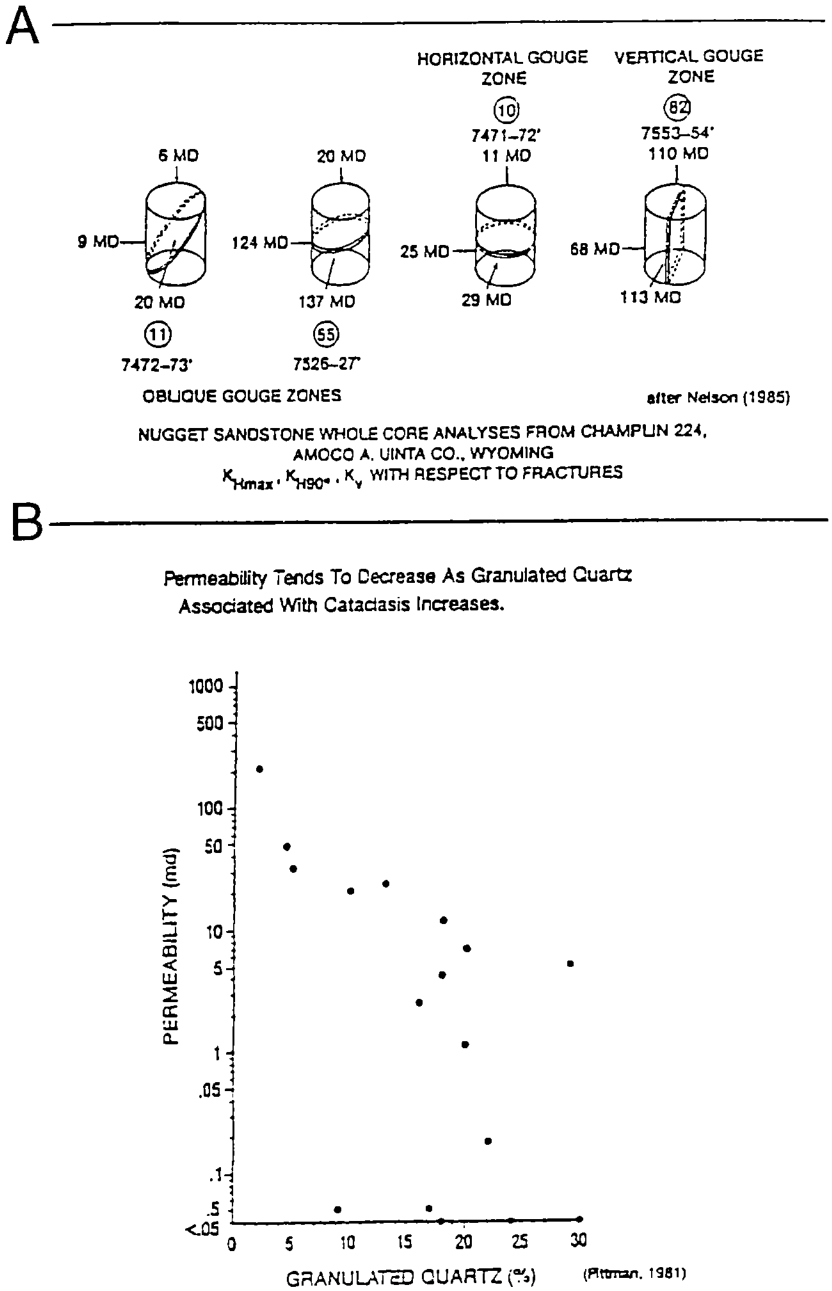


Figure 141. Two examples of cataclastic zones in sandstone cores. (A) Core from a sandstone in the western United States. (B) Plane-light thin section of a cataclastic zone; note reduction in grain size and sorting. (Kulander and others, 1990, fig. 7a; reprinted by permission of American Association of Petroleum Geologists.)



C

Plug Length cm	Permeability with Fracture	Permeability without Fracture	% Reduction in Permeability
2.1	0.8	12.1	93%
3.5	22.2	37.7	41%
>2.2	1.82	33.7	95%
>2.8	5.1	5.7	11%
>2.6	2.8	14.7	80%
>0.9	1.5	30.3	95%

After Harper and Moftah (1985)

Figure 142. Three sets of permeability measurements to support permeability reduction in a gouge zone. See text for explanation. (Kulander and others, 1990, fig. 8; reprinted by permission of American Association of Petroleum Geologists.)

strength tests performed on the core (Kulander and others, 1990). Disc fractures form in response to vertical tension and are generally horizontal in vertical or subvertical core. Disc fractures commonly have their beginning as clasts, fossils, or secondary minerals.

Figure 146 illustrates two examples of disc fractures in cores. Figure 146A is a disc fracture that has not completely propagated to the core margin. The hairline fracture postdates the disc fracture, because the plumes of the fracture are continuous across the hairline fracture. Figure 146B illustrates two disc fractures separated by a preexisting centerline fracture. Notice that the plume components curve in a tendency to meet the centerline fracture orthogonally.

Figure 147 is an example of a petal–centerline fracture. The fracture is composed of two parts, the petal fracture and the centerline fracture. Petal–centerline fractures initiate below the cutting edge of the bit, possibly by fluctuations in bit pressure. The petal section curves in a downdip direction generally between 30° and 75° at the edge of the core to 90° within the core (Kulander and others, 1990). The centerline fracture is usually only a few inches to a few feet long (Kulander and others, 1990). Figure 148 illustrates the stress trajectories that are thought to be responsible for the formation of petal–centerline fractures. Figure 149 illustrates three petal fractures in a section of core. Petal and petal–centerline fractures commonly have a similar strike in core. This implies that the fractures may have formed in response to in-situ stresses. These fractures commonly have preferred strike orientation parallel to trends of laboratory-induced fractures, such as those formed during engineering tests, maximum sonic-velocity direction, and the predominant strike direction of the axes of disc fractures (Kulander and others, 1990). This implies that the strike direction of petal and petal–centerline fractures may suggest natural stress directions in reservoirs. This information could be useful in estimating fracture-propagation directions for well completions and natural-fracture trends for water-injection wells of waterflood projects.

Figure 150 shows examples of torsion fractures in cores. These fractures are a direct response to torsion-related tensile stress (Kulander and others, 1990). The

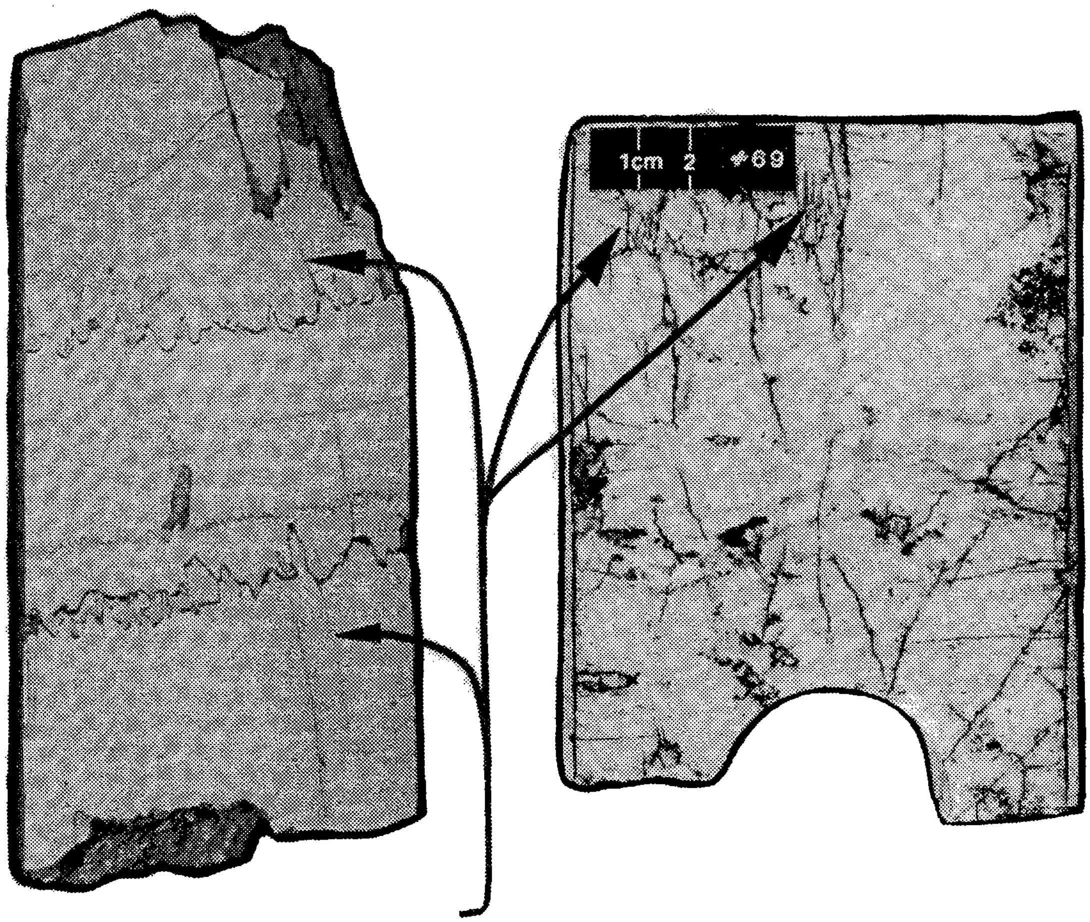


Figure 143. Two examples of tension-gash fractures in carbonates. Sample at left is from a North Sea carbonate; sample at right, from a Canadian carbonate. (Kulander and others, 1990, fig. 13; reprinted by permission of American Association of Petroleum Geologists.)

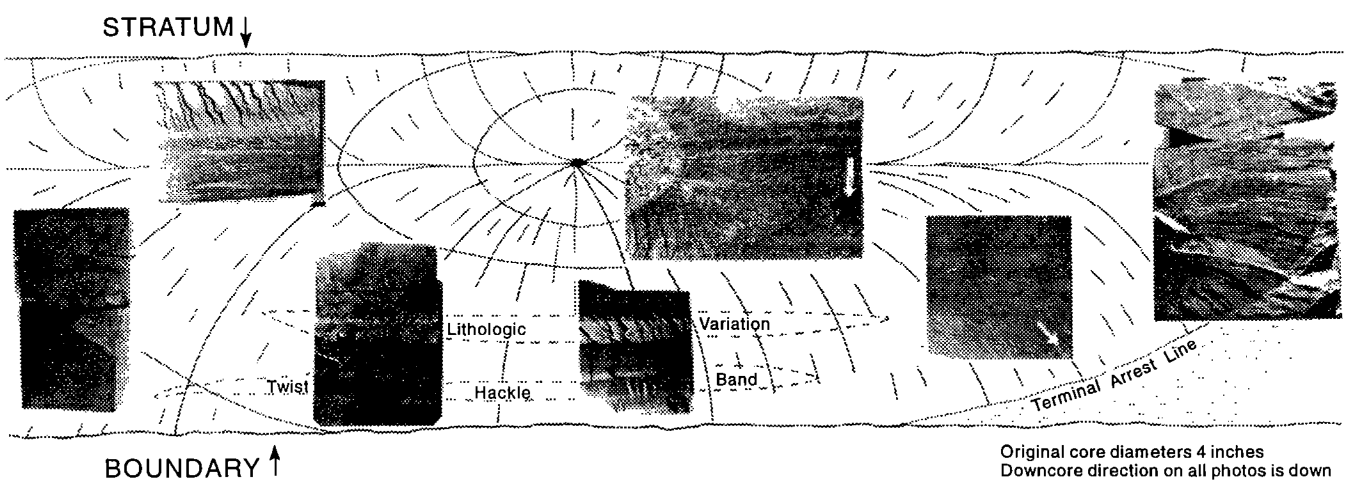


Figure 144. Schematic drawing of a fracture, with photographs of plume components on cored natural fractures. Photographs are placed at appropriate positions within the hypothetical plume. The complete dissimilarity between the geometries shown by fracture-surface structures and core boundaries is emphasized. Some photographs courtesy of M. A. Evans. All fractures cut Devonian shale from the Appalachian basin, West Virginia. (Kulander and others, 1990, fig. 17; reprinted by permission of American Association of Petroleum Geologists.)

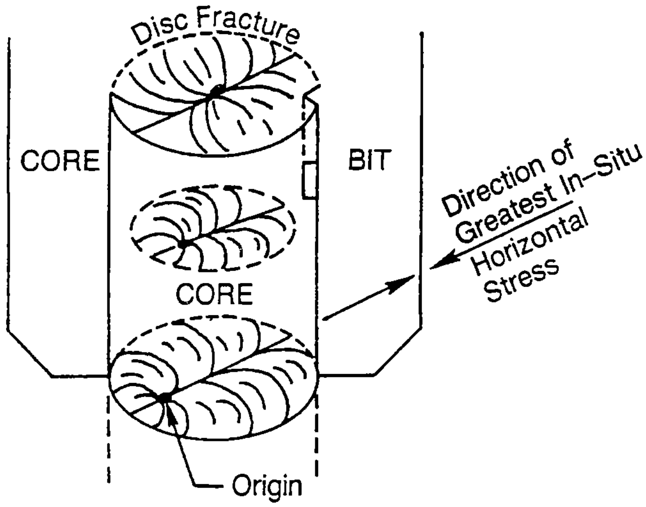
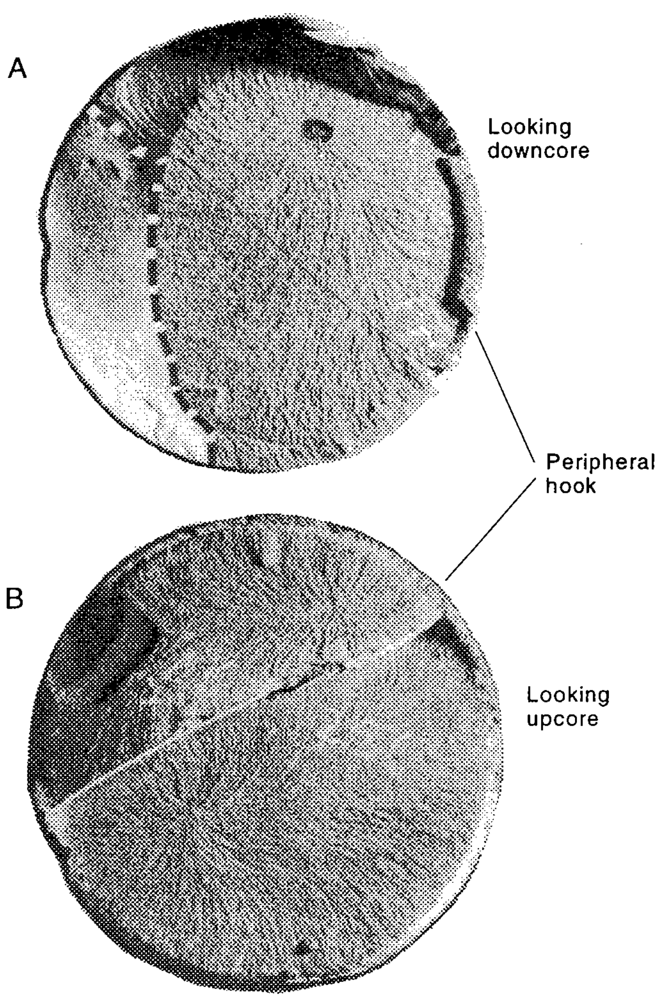


Figure 145. Schematic drawing of typical disc fractures showing direction of greatest in-situ horizontal stress during disc-fracture initiation and growth. Disc fracture in center has not propagated to core margin and is hidden within the core. (Kulander and others, 1990, fig. 19; reprinted by permission of American Association of Petroleum Geologists.)



fractures are described as having been caused by the transformation, in response to coring, of simple shear stresses to pure shear stresses by a 45° transformation of the reference axes.

Figure 151 illustrates single and paired scribe-knife fractures in cores. These fractures are directly related to the tensile stresses inflicted from scribe knives used to mark and orient the core (Lorenz and Finley, 1988). The fractures grow from a continuously advancing scribe groove and develop laterally and downward; they can terminate within the core or separate the core into pieces (Kulander and others, 1990).

Figure 152 is a photograph and line drawing illustrating knife-edge spalls. These fractures are small conchoidal chips that separate from the core in response to the tensile stresses produced by vertical compression at the advancing edge of the scribe knife (Kulander and others, 1990).

Table 20 lists four types of unconsolidated-sediment fractures: fluid-expansion, axial-cracking, cross-core-shear, and cone-in-cone-shear fractures (Dusseault and Van Domselaar, 1984).

HANDLING-RELATED FRACTURES

Kulander and others (1990) state that handling-related fractures in core can come from three sources: (1) extracting, boxing, preserving, and transporting core; (2) sampling core; and (3) plugging and slabbing core.

Most of the fractures incurred from handling core are breaks or cracks. These fractures usually have a fresh surface with no drilling mud on the fracture face. Fractures that develop in response to drying are desiccation fractures. Any fractures that develop when a core is sampled are characterized by hammer marks. Fractures caused by plugging or slabbing the core are usually geometrically related to the plug hole or the slab surface.

INTERPRETING FRACTURE PATTERNS IN RESERVOIRS

Determining natural-fracture patterns in reservoirs that are being considered for waterflood projects is an essential component of the overall project analysis. A fracture pattern can have a dramatic influence on an injector–producer pattern where the two are posi-

Figure 146. Disc fractures with pronounced arrest lines and ridges paralleling core perimeter. (A) Disc fracture failed to cut entire core. Complete separation from the arrest line delineating the well-developed plume (dashed line) occurred during handling. Hairline fracture through the core center postdates the disc fracture, as shown by the continuous plume. (B) Composite of two disc fractures that abut earlier formed centerline fracture. Here, plume components curve abruptly, showing a tendency to meet the centerline fracture orthogonally. Devonian shale core from the Appalachian basin, West Virginia. (Kulander and others, 1990, fig. 23; reprinted by permission of American Association of Petroleum Geologists.)

TABLE 20. – Four Types of Unconsolidated-Sediment Fractures

Fluid-expansion fractures	Forms in unconsolidated sediments with low to moderate mobility values.[a]
Axial-cracking fractures	May form from hydrostatic stress imposed by the mud column.
Cross-core shear fractures	May reflect a preexisting natural fracture. May form from subsequent offset in the core.
Cone-in-cone shear fractures	Forms by a sudden increase in vertical stresses—e.g., dropping the core on a hard surface.

[a]Ratio of rock permeability to fluid viscosity.

tioned in a common fracture trend. Readjusting or changing an injector–producer pattern after installation of the original pattern can have a serious economic impact on the profitability of marginal projects. The following examples demonstrate the impact fracture patterns have on waterflood projects.

Case history 35 (Fig. 153) is an isopach map of a reservoir in Oklahoma. The field was unitized, and shortly after injection commenced, it was determined that injectors and producers in an east-northeast–west-southwest pattern were in communication, possibly through a regional fracture pattern. This communication was suspected by an almost immediate increase of water production from the injectors to the producers. In fact, this occurrence is quite common in this part of the Anadarko basin. Often, an operator will install a waterflood project with no knowledge of any natural or induced fracture orientation. In this example, the operator changed the pattern to put injectors and producers in separate fracture planes, as illustrated in Figure 154. This allowed injected water to fill the fracture pattern first and then sweep the matrix, driving oil toward the producers. Fortunately, the secondary reserves were sufficient, even with the changes, to allow this project to be highly profitable.

The pitfall operators often encounter is not having included funds in the AFE in anticipation of changes in the injector–producer pattern when an unknown fracture orientation is anticipated. If the economic analysis does not meet the company objectives with these funds included, an alternative solution would be either to attempt to determine the fracture orientation through open-hole logs and cores or to establish a pilot project to determine the presence and orientation of a fracture pattern.

For many reservoirs, macroscopic evidence of natural fractures or fracture trends from cores may not be available, but completion techniques may enhance microscopic fracture orientations or increase stress fields on a field-wide basis. Consider case history 36 (Fig. 155), a series of core photographs from a well in a large reservoir. The core is described as a stacked series of small sand lenses separated by thinly laminated layers of carbonaceous shale. Physical examination of the core revealed a total lack of natural fractures, nor were natural fractures present in any other cores from the field. Some evidence of induced fracturing is apparent, predominantly petal fractures and handling-related fractures. A petal fracture can be observed at 4,553.5 ft, and an apparent handling-related fracture at 4,552.5 ft. All the wells were given a substantial fracture treatment on completion. No evidence of local or field fracture trends existed during primary production.

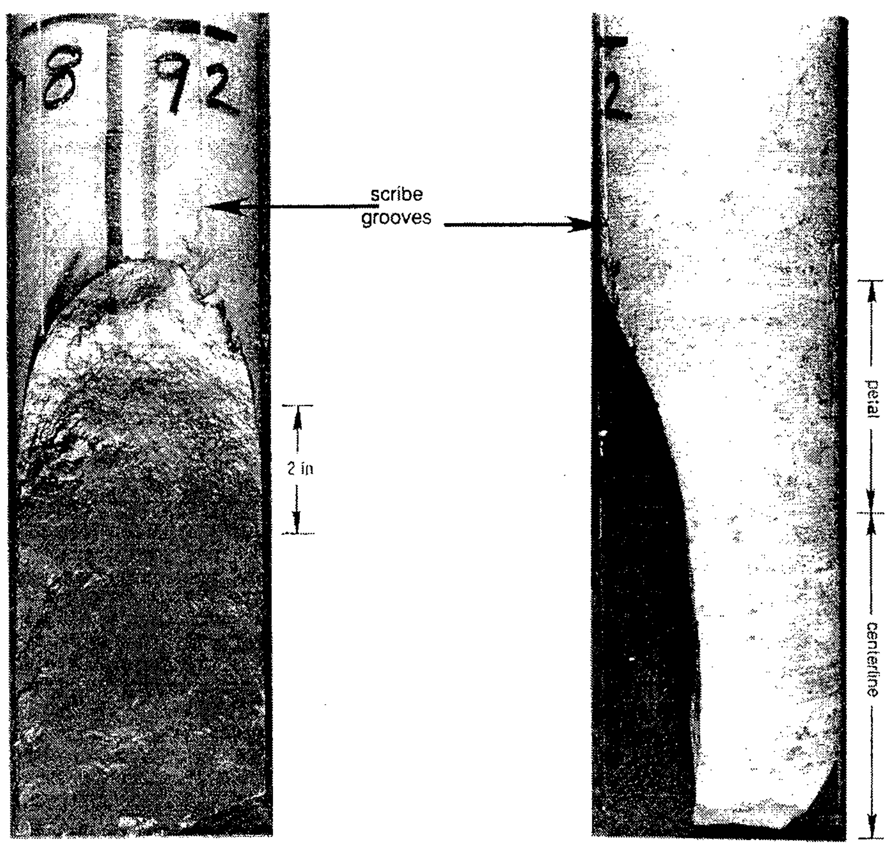


Figure 147. Plan view (left) and side view (right) of petal–centerline fracture. Surface structures are poorly developed on this particular fracture. In general, the megascopic definition of fracture-surface structures increases with decreasing grain size. Sample is from a carbonate in the western United States. (Kulander and others, 1990, fig. 26a; reprinted by permission of American Association of Petroleum Geologists.)

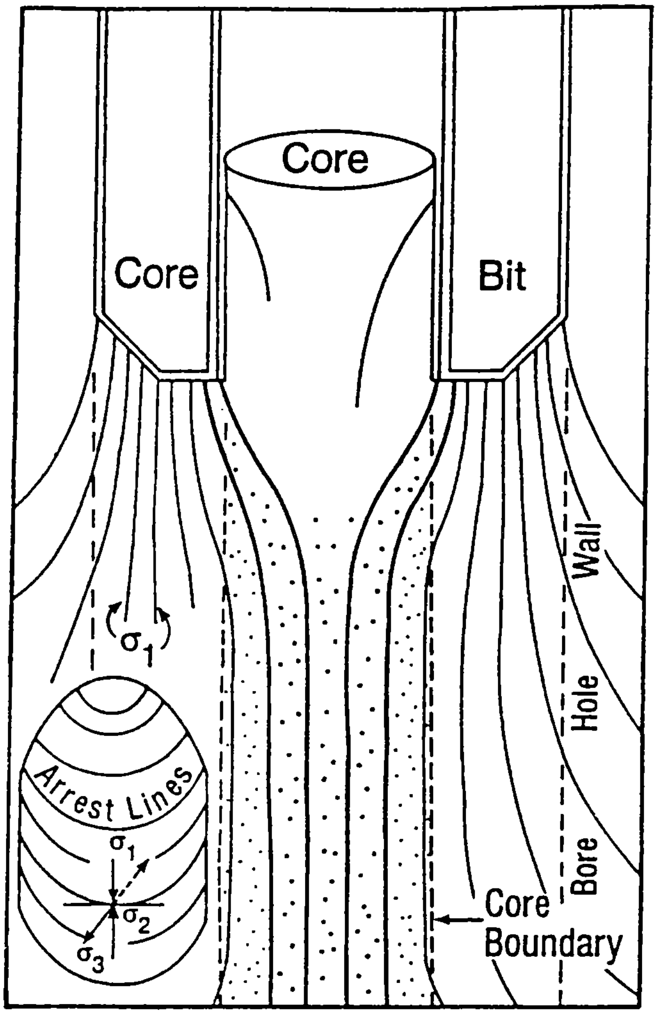


Figure 148. Example of stress trajectories emanating from core bit that are thought to be responsible for petal–centerline fractures (modified from Lorenz and Finley, 1988). Inset shows a plan-view sketch of petal–centerline fractures, with principal stress directions along core axis during fracture superposed. (Kulander and others, 1990, fig. 27; reprinted by permission of American Association of Petroleum Geologists.)

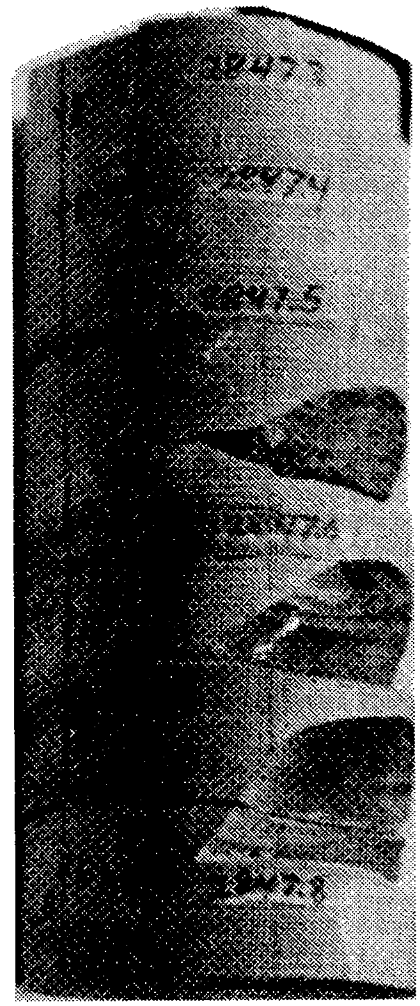
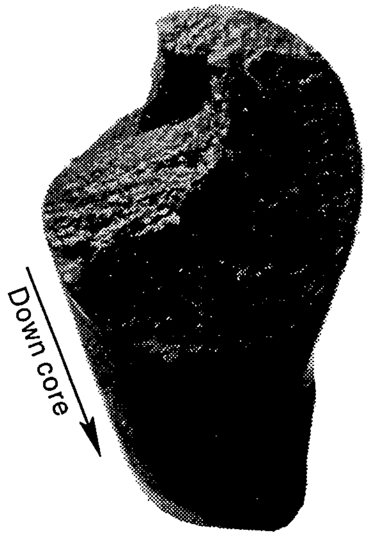


Figure 149. Three petal fractures that developed approximately 1 in. apart. Note the strike-parallelism of the coring-induced fractures. Arrest lines on petal surfaces are not symmetrically arranged around the fracture centerline, as is usually the case, but are convex downcore nevertheless. The top petal fracture curves into a bedding surface. Photograph courtesy of M. A. Evans. Devonian shale core, Appalachian basin, West Virginia. (Kulander and others, 1990, fig. 32; reprinted by permission of American Association of Petroleum Geologists.)

Figure 156 is the production curve for well 1, shown in Figure 157. The field was at depletion near month 156, when the decision was made to try a pilot waterflood. Wells 2–4 were converted to injectors. Response to injection was anticipated in wells 5–8 because of the geometry and natural-permeability orientations of the sand body. Point *A* (Fig. 156) represents the time when injection for the pilot waterflood commenced. Within a week after injection began, production from well 1 started to increase from 3 BOPD; it rose steadily to 25 BOPD 6 months later. The only explanation for this increase was a fracture pattern created in response to the fracture treatments given to each well at completion. In this case, the fracture orientation observed from the pilot project was incorporated into the design for the full-scale waterflood installation.

PRE-WATERFLOOD INDICATORS OF FRACTURE OR PERMEABILITY ORIENTATION

Determination of high-permeability trends, whether from fracture planes or naturally high-permeability orientations, should be a priority because of the tendency of such a trend to focus or concentrate injection water within the trend. An analysis of production trends, oriented cores, and visual open-hole logs should be undertaken to detect the slightest indication of either fracture or permeability trends. Nearby waterflood projects also should be evaluated for these trends. An analysis of the depositional environment of



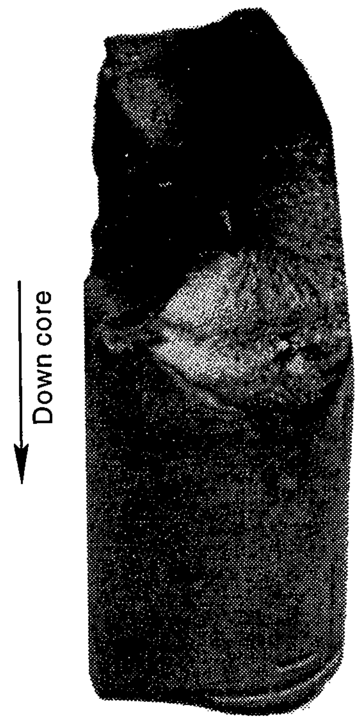


Figure 150. Two examples of torsion fractures in core. Devonian shale, Michigan basin. (Kulander and others, 1990, fig. 38b,c; reprinted by permission of American Association of Petroleum Geologists.)

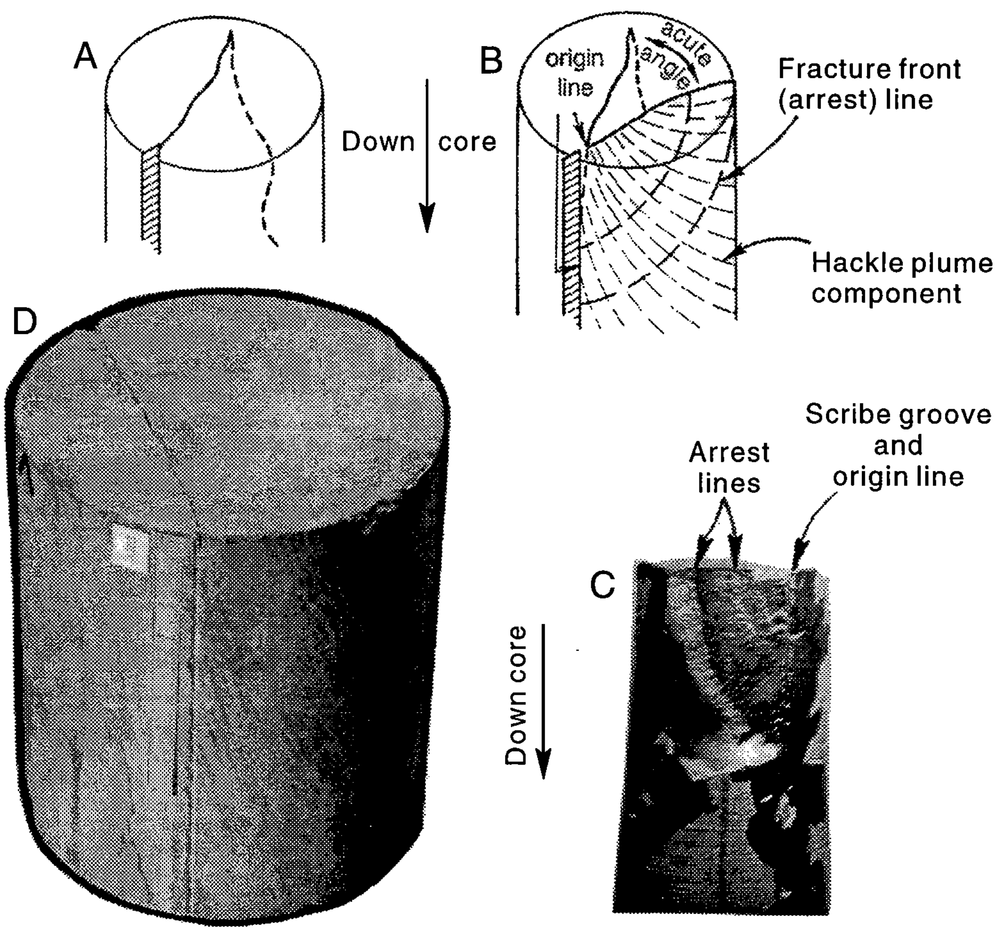


Figure 151. Single and paired scribe-knife fractures in core. (A) Single scribe-knife fracture that does not separate core. (B) Paired scribe-knife fractures, with one fracture face depicting typical fracture-surface structures. Fracture-front lines and hackle-plume components are perpendicular and tangential to the continuous origin line directly below and at base of scribe groove. (C) Photograph of the face of a single scribe-knife fracture that contains arrest lines and hackle-plume components. Devonian shale, Appalachian basin, West Virginia. (D) Photograph showing trace of what appears to be a single scribe-knife fracture that connects two scribe-knife grooves. (Kulander and others, 1990, fig. 39; reprinted by permission of American Association of Petroleum Geologists.)

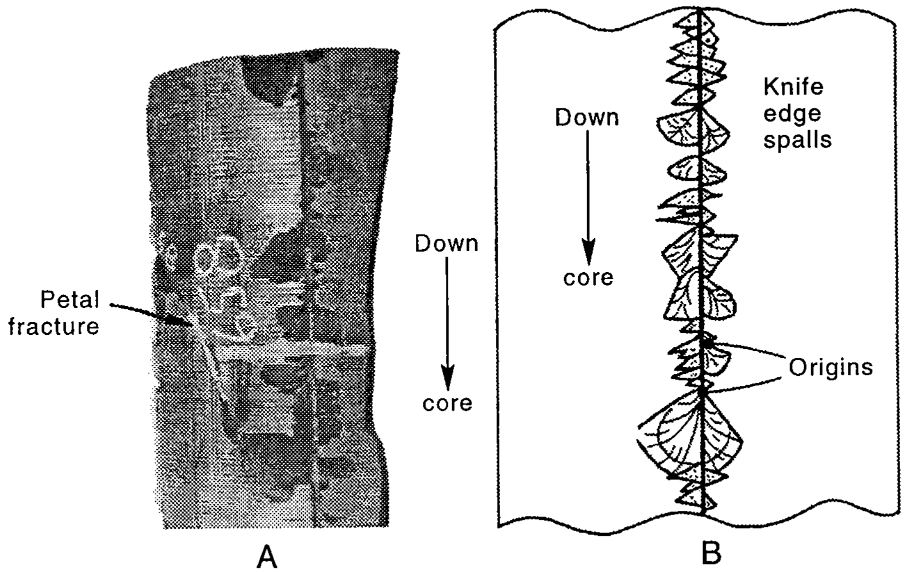


Figure 152. (A) Whole-core sample with knife-edge spalls. Note that arrest lines on spall surfaces are convex downcore. Downcore direction is also shown by trace geometry of a petal fracture. Devonian shale, Appalachian basin, Kentucky. (B) Sketch of knife-edge spalls, showing surface-structure morphology on selected chips. (Kulander and others, 1990, fig. 41a,b; reprinted by permission of American Association of Petroleum Geologists.)

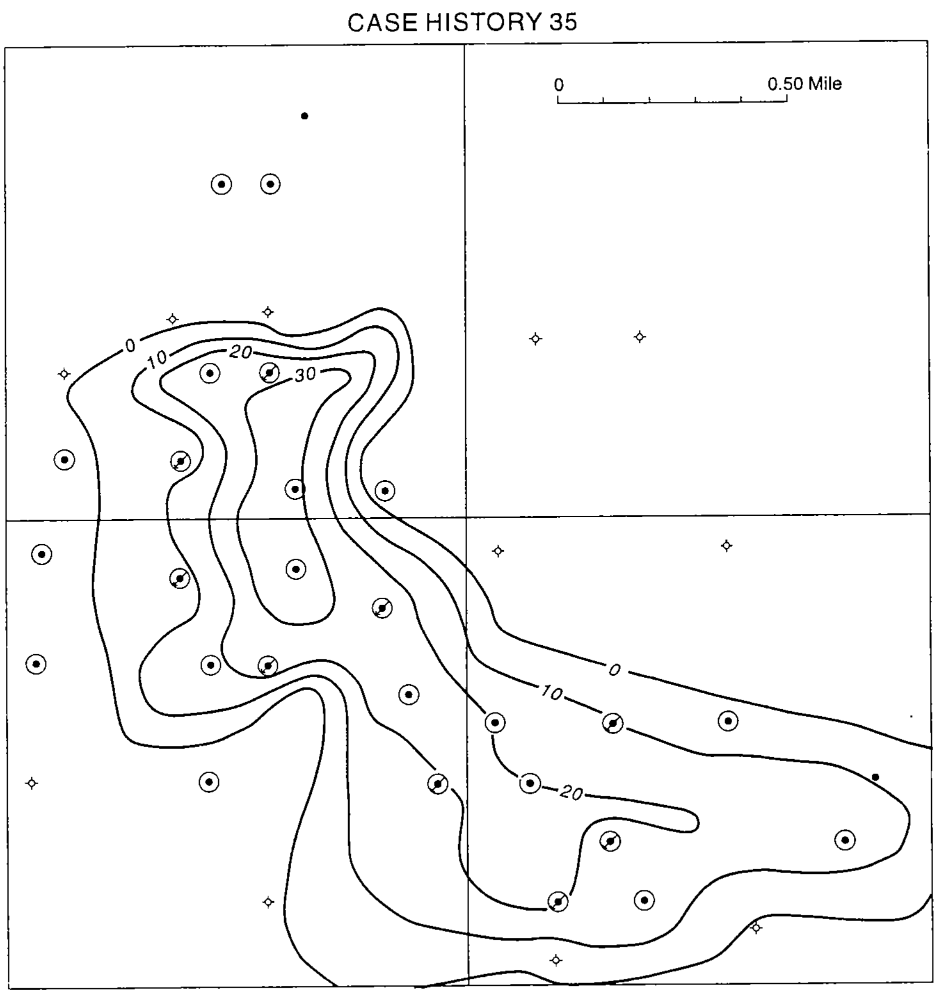


Figure 153. Gross-sand isopach map of the reservoir of case history 35 (north-central Oklahoma). Original injection pattern is shown. Contour interval, 10 ft.

CASE HISTORY 35

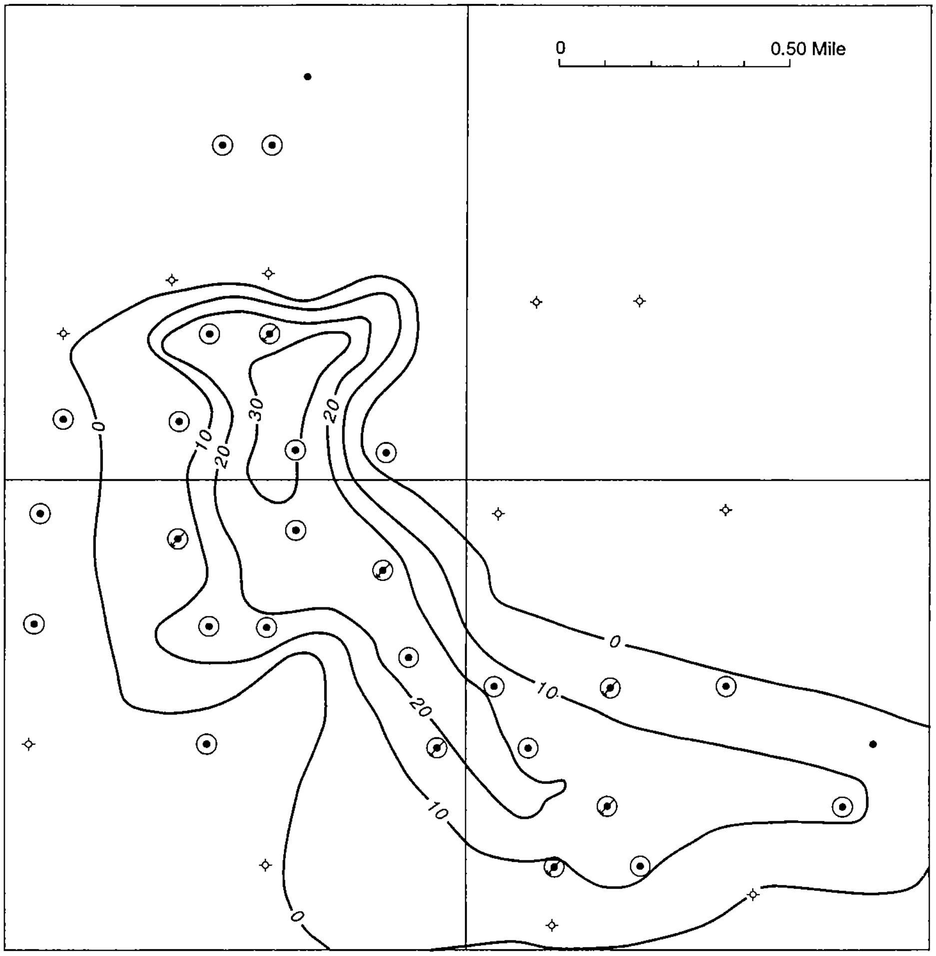


Figure 154. Net-sand isopach map of the reservoir of case history 35. Injection pattern has been modified in response to the fracture pattern interpreted from the rapid water production in an east-northeast–west-southwest direction. Contour interval, 10 ft.

the reservoir rock might discover naturally high-permeability orientations. The following are examples of the effect that fracture planes and high-permeability trends can have on injection.

Case history 37 (Fig. 158), a net-sand isopach map of a reservoir in Oklahoma, illustrates that production variations may offer clues for interpreting either fracture or permeability orientations. Well A was producing on primary production but eventually developed a casing leak. The well, which was almost depleted, was temporarily abandoned. Well B was an offset producer in a northeast direction. Figure 159 shows the production curves for both these wells. The casing leak developed in well A at approximately month 54 and is represented by the solid circles. Well B is interpreted to have responded to the water input from the casing leak at approximately month 72. This response is indicated by the flattening of the decline curve for well B and the eventual increase in production at month 96.

Two other casing-leak and offset-response patterns were observed in this mapped area, which are labeled *pattern B* and *pattern C* (see Fig. 158). The operator had initially considered that this orientation was attributed to a northeast–southwest fracture plane. However, a detailed geologic evaluation of the reservoir concluded that the orientation of the sand thicks and their corresponding primary or predominant permeability trend are also parallel to this direction.

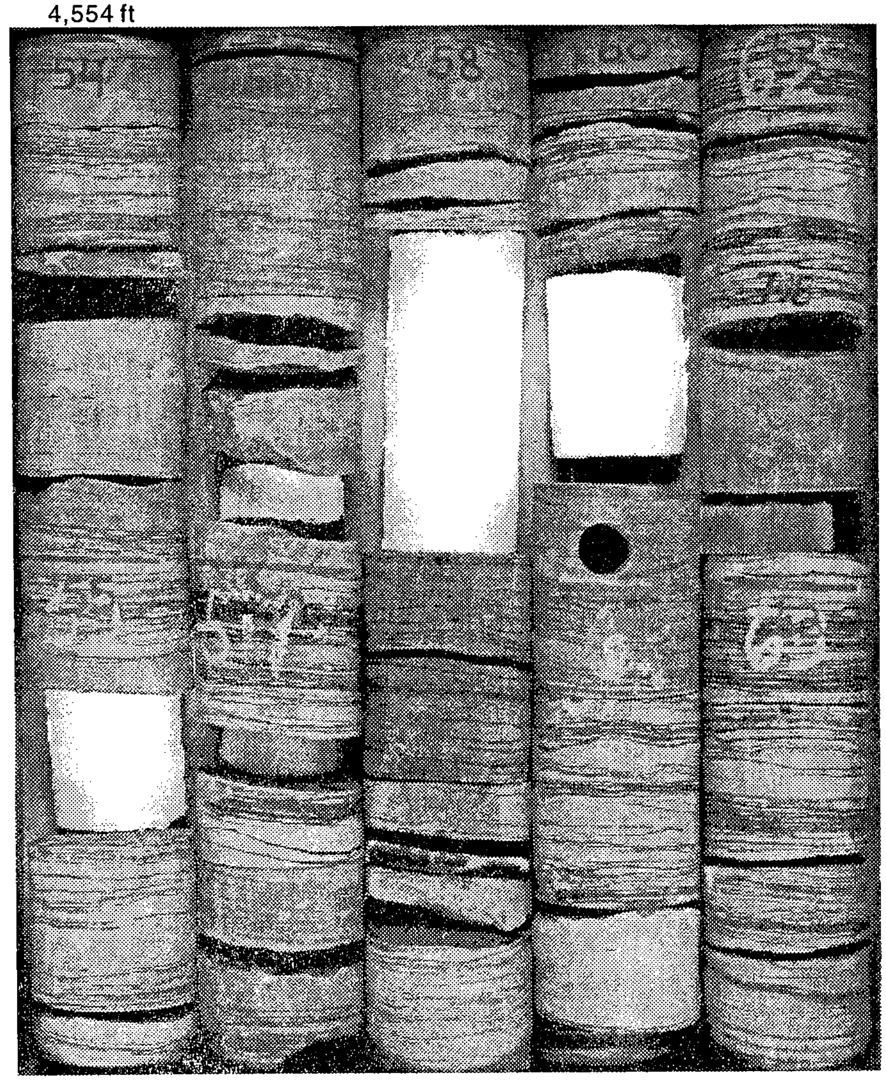
Figure 160 shows the injector–producer pattern established for this part of the reservoir. The pattern was designed to orient the injectors in a northeast–southwest direction. This orientation was intended to fill the high-permeability trend first, and then, with pressure buildup, to sweep the adjacent matrix toward the producers. However, after injection commenced, it became immediately apparent that injected water was moving in an east–west direction. Sources that were familiar with regional fracture orientations for this part

CASE HISTORY 36

4,544 ft

4,554 ft

4,554 ft



4,564 ft

Figure 155 *(pages 135–137)*. Core photograph, under natural light, for a section of core from the reservoir of case history 36 (eastern Oklahoma). Core is representative of the interpretation of the lack of megascopic evidence of natural fractures in cores of 21 additional wells in the reservoir. Each column is 2 ft long.

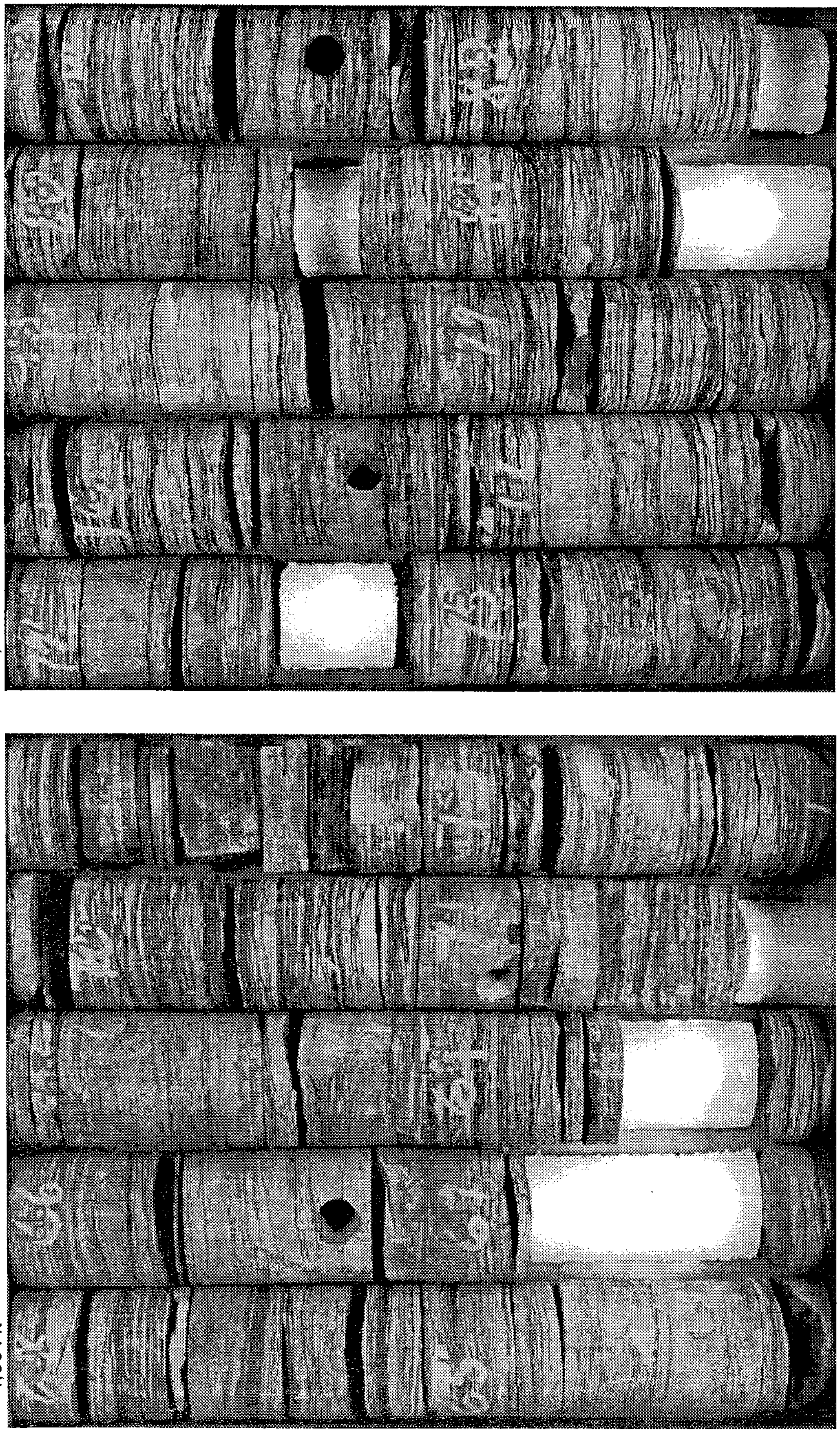


Figure 155 *(continued)*.

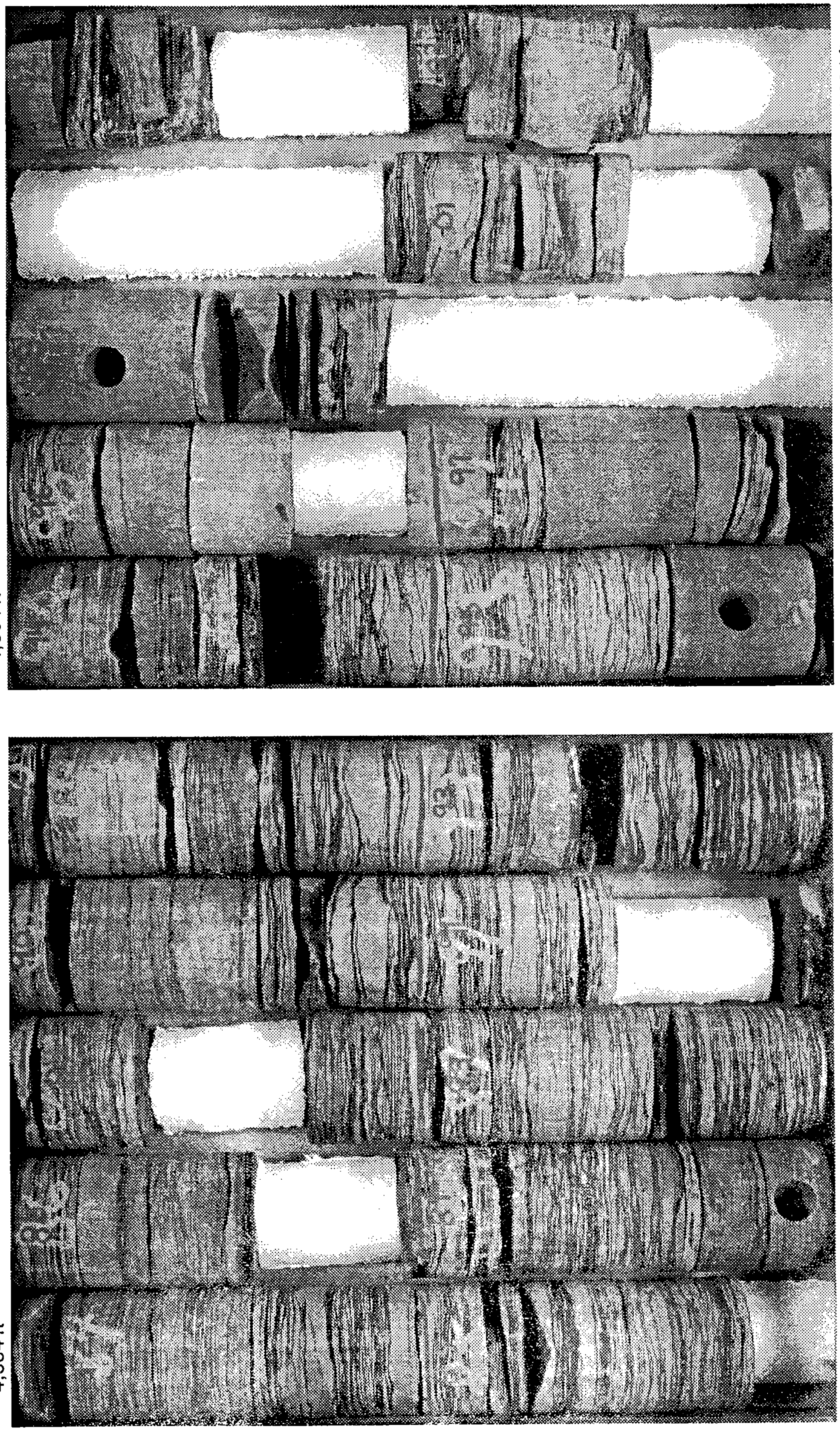


Figure 155 *(continued)*.

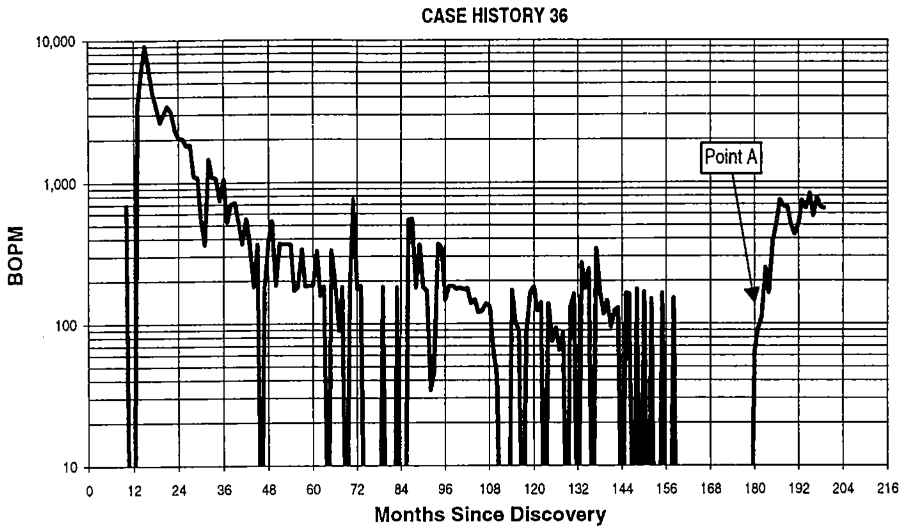


Figure 156. Production curve for a well in the reservoir of case history 36 (Fig. 155). Unitization and injection within the pilot waterflood occurred at point *A*. Notice the almost immediate response to injection.

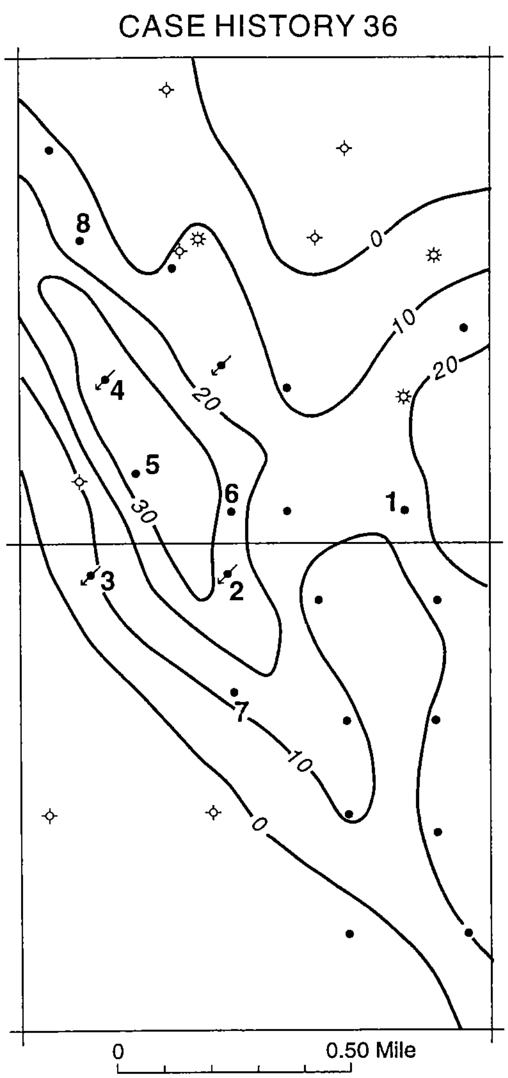


Figure 157. Net-sand isopach map for part of the reservoir of case history 36. Pilot waterflood was set up in wells 2 through 8. Response occurred almost immediately in well 1 (Fig. 156). Contour interval, 10 ft.

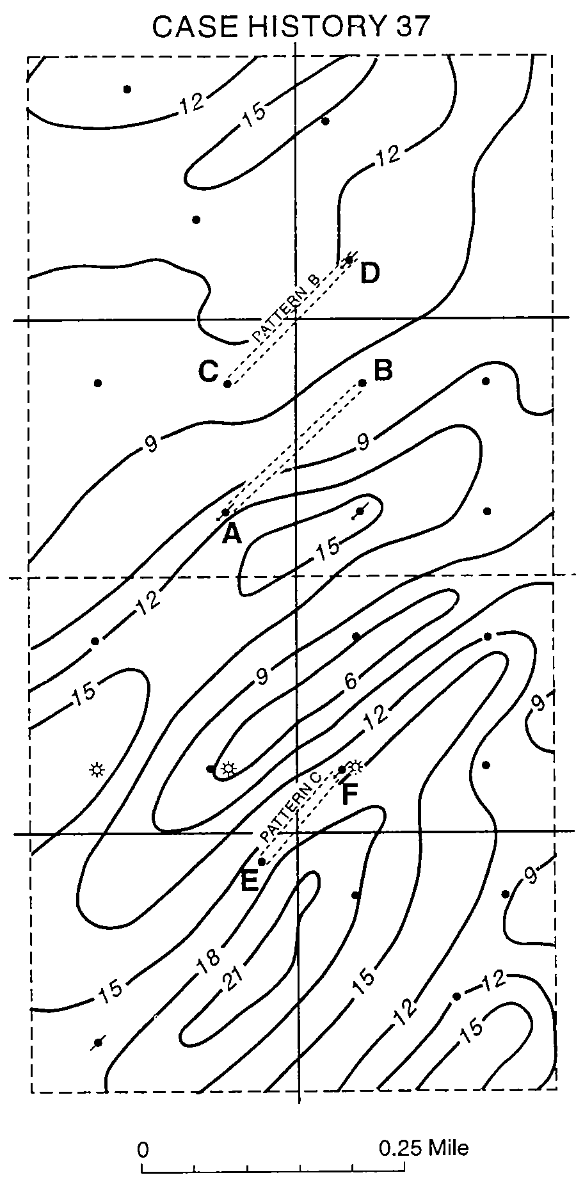


Figure 158 *(see caption on facing page).*

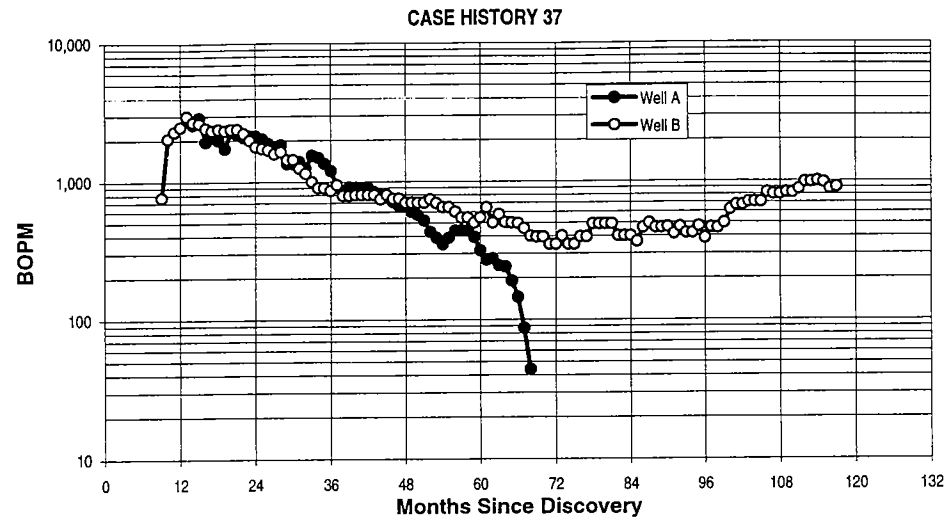
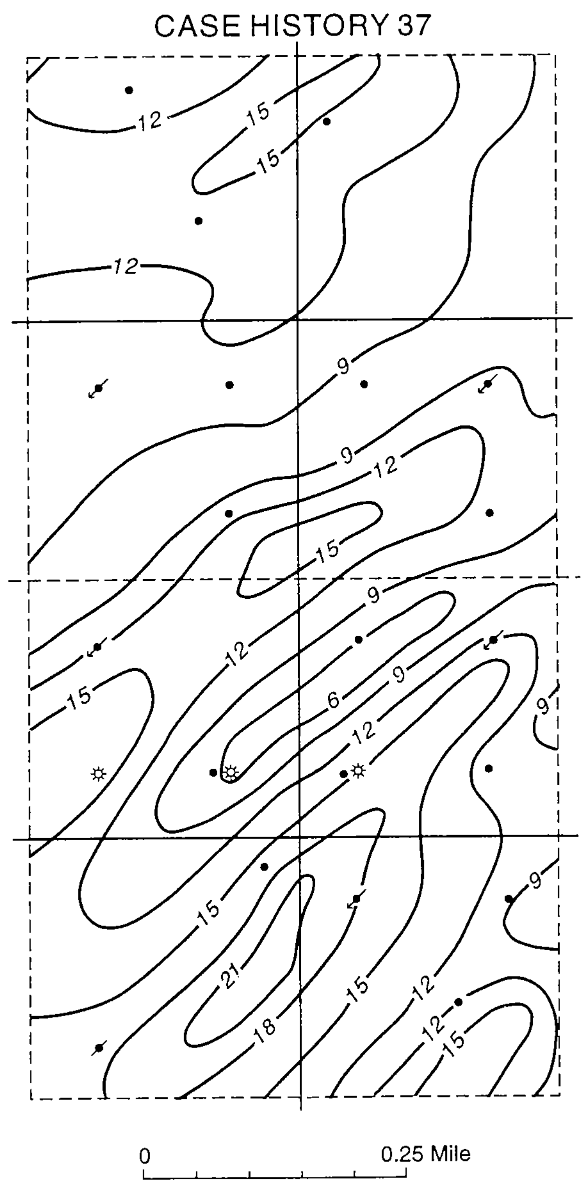


Figure 159. Production curves for wells A and B (Fig. 158). Well A developed a casing leak, and the corresponding response to the inadvertent injection occurred in well B, to the northeast. Patterns B and C (Fig. 158) had similar response orientations, which were attributed to the predominant permeability orientation of the sand geometry.

Figure 160 *(right)*. Net-sand isopach map for part of the reservoir of case history 37. Map illustrates the injector pattern installed, which was designed to take advantage of naturally high-permeability orientation (see text for explanation). Contour interval, 3 ft.



of the Anadarko basin suggested that this water-breakthrough trend was probably a result of these fracture orientations. The operator converted those wells that watered out prematurely to injectors. To date, the waterflood project has responded admirably.

Casing leaks and offset-production responses are rare, and because of this, geologists and engineers must rely on more common methods of fracture identification. One such method is the oriented core. This coring method attempts to maintain the core's physical position relative to the reservoir. Any natural fractures observed can be oriented as to strike and dip. Problems with oriented cores are that such coring is expensive, and the core itself is subject to fracturing and parting, thereby making the core useless. Two solutions may be practical, however: the first solution might be the taking of a normal core, followed by a visual-imaging tool. This method would allow the imaging tool to orient the core. If the waterflood project requires a new drill, a second solution would be to run the visual-imaging tool along with the open-hole logs.

Case history 38 illustrates this point. Figure 161 is a net-sand isopach map of a waterflood candidate in Oklahoma. As the project was being installed, however, the operator was concerned because of the lack of information about the reservoir's fracture orientation.

Figure 158 *(facing page)*. Net-sand isopach map for part of the reservoir of case history 37 (central Oklahoma). Wells A, D, and F developed casing leaks, and response occurred in wells B, C, and E, respectively. Contour interval, 3 ft.

Well A was a new drill, and the operator decided to run Schlumberger's formation micro-imaging (FMI) log through the pay interval. A natural fracture was observed striking N. 46° E. and dipping to the southeast at 57° (Fig. 162). This fracture-trend information was used to help design the injector–producer pattern for the project. Wells B and C were injectors installed in the gas cap to provide a water block for oil migrating northward. To date, over 3 MMBW has been injected into well B, and a lesser amount into well C, with no sign of water breakthrough in wells D and F. To date, water breakthrough has occurred in the producers as planned, and in accordance with the fracture orientation indicated by the FMI log.

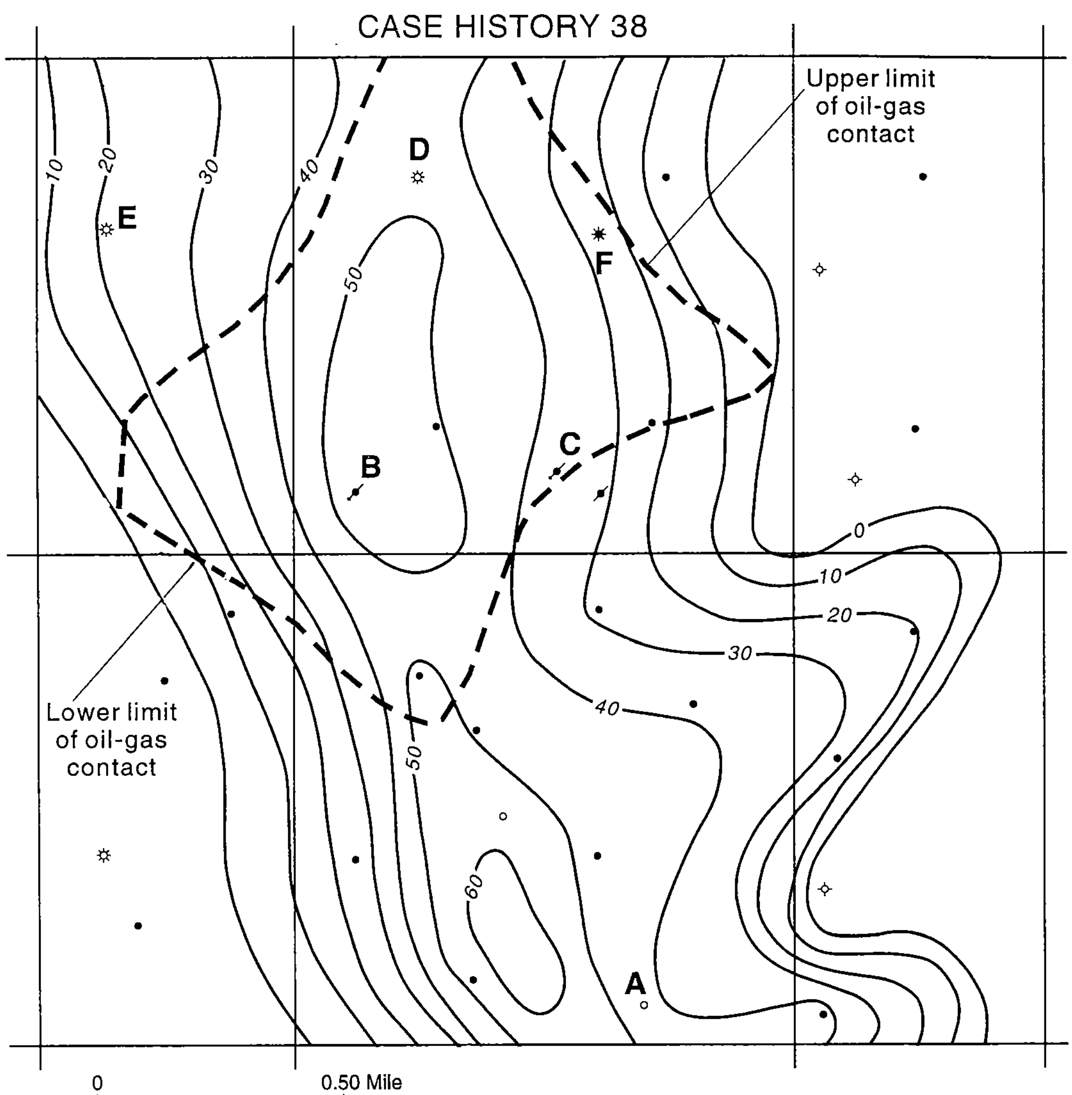


Figure 161. Net-sand isopach map for part of the reservoir of case history 38 (northwestern Oklahoma). Heavy dashed lines indicate lower and upper limits of the gas–oil contact. Wells B and C were converted to injectors on the basis of the regional fracture orientation as interpreted from an FMI log from well A. Contour interval, 10 ft.

CASE HISTORY 38

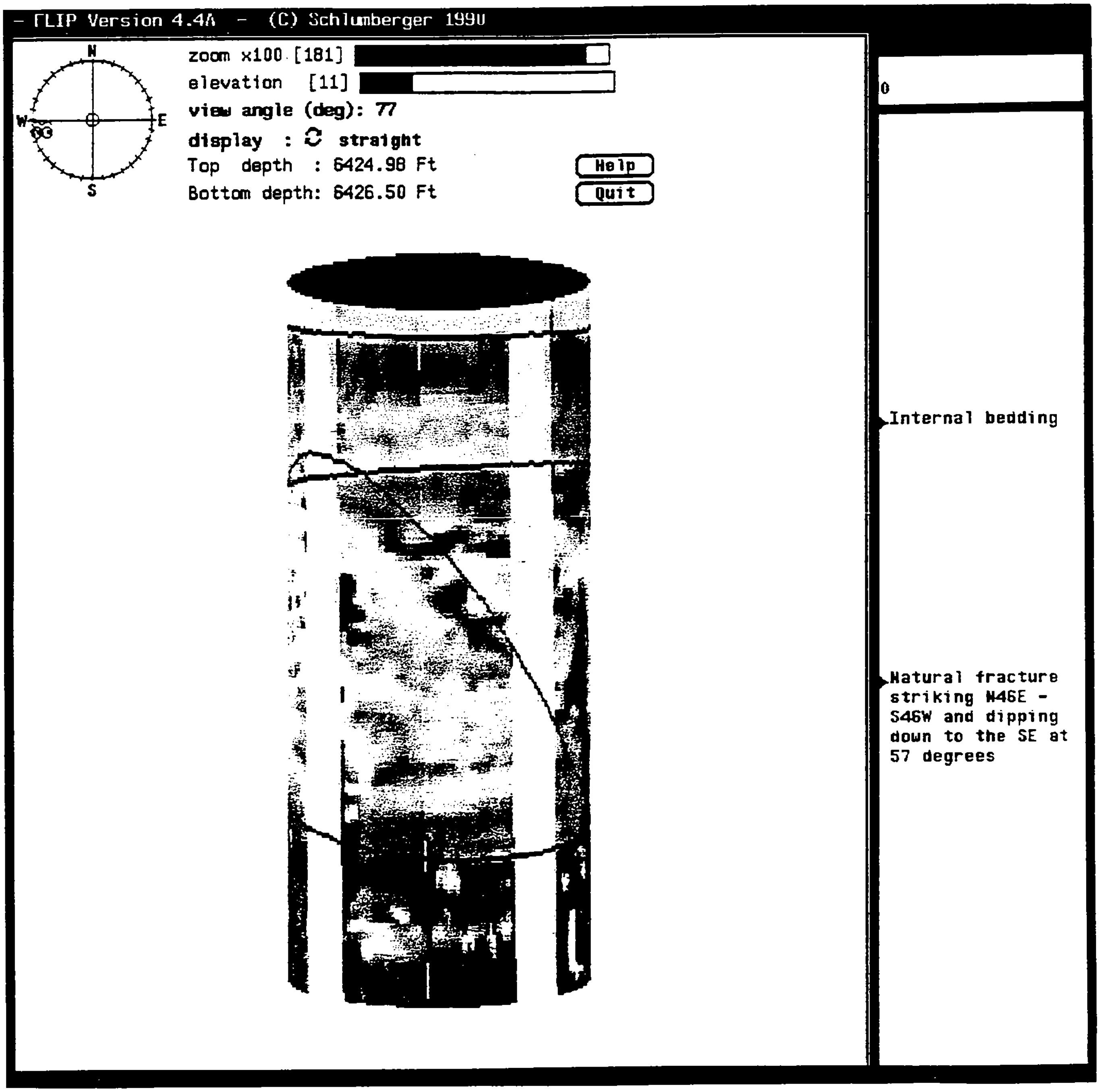


Figure 162. Part of an FMI log run in Well A (see Fig. 161). Convex curve is the interpreted trace of a natural fracture with an orientation striking N. 46° E. and dipping to the southeast at 57°.

Water Supply

10

CHAPTER 10

Water Supply

INTRODUCTION

Identifying a suitable water supply is an important facet of the waterflood evaluation, once the project has become a serious candidate. Water-supply evaluation consists of two parts: (1) identifying those zones capable of delivering adequate amounts of water for the duration of the waterflood project, and (2) determining possible compatibility problems between the supply water and the formation water.

Importance of an Adequate Water Supply

Once a waterflood project is under way, the lack of an adequate water supply can have dramatic negative economic ramifications, which could arise from excessive costs of drilling and completing a water-supply well or of having to purchase water. For marginal waterflood projects, the lack of a sufficient water supply is a factor that can be avoided ahead of time. For this reason, it is important to determine all available zones for water supply. It is also important to have an accurate isopach map of the reservoir for water-fill-up calculations.

Case history 39 (Fig. 163) illustrates problems that can occur when adequate water is not available. Figure 163 is a net-sand isopach map of a reservoir that produces in eastern Oklahoma. The lightly shaded area represents the gas cap, and the dark-shaded area, the oil–water contact. Figure 164 shows the production curve for this reservoir. The field was unitized, and injection commenced in year 6 at a rate of 1,000 BWPD in the six injectors illustrated in Figure 163. The purpose of starting injection early was to attempt to fill the depleted gas cap with water to prevent oil from migrating into it from the reservoir. The gas cap had a pore volume of approximately 1,500 acre-ft, which implies that approximately 2.12 MMBW would be needed to fill the gas cap. Also, only three of the six injectors were used for this purpose. At the rate at which the three injectors were putting water into the ground, it would have taken 11.6 years to fill the void in the gas cap. Whether or not the operator was aware of the amount of time necessary to fill the gas cap at this rate is unknown. A note in the operator's files 9 years after injection commenced read, "In order to try and force some kind of response on the 'field,' let's start injecting all of the fresh water produced by the Reda pump into #1 and #6. In other words we would be putting about 360 [barrels] a day in each of these wells." This note probably implies that the operator was looking for a response. It also implies that the operator may have underestimated the volume of water necessary to fill the gas cap and sweep the oil.

WATER-INCOMPATIBILITY REACTIONS

by Mark Sutherland

A water supply for injection, when introduced into the formation, can have harmful effects on the reservoir's flow properties if the injection water interacts with the formation water chemically. The following text defines potential chemical reactions between injection water and formation water commonly found in the Midcontinent. Remedies for treating these chemical reactions are also included.

Mineral Scales

Calcium Carbonate Mineral Scale

In waterflooding, calcium carbonate ($CaCO_3$) mineral-scale precipitation and deposition usually occurs when a saline water containing calcium (Ca^{2+}) ions is mixed with a fresher water containing moderate to high levels of bicarbonate (HCO_3^-) ions. The reaction that forms $CaCO_3$ precipitation is

$$Ca + 2HCO_3 \rightarrow CaCO_3 + H_2O + CO_2.$$

The following rules of thumb apply to calcium carbonate scaling tendencies:

1. Calcium carbonate scaling increases as temperature increases.
2. Scaling increases as pH increases.
3. Scaling increases, and the scale deposits become harder (more dense), as contact time increases.
4. Scaling decreases as the sodium chloride (NaCl) content of the water increases to a concentration of 120,000 milligrams per liter (mg/L). Further increases in NaCl concentration decrease $CaCO_3$ solubility, and scaling increases.
5. Scaling increases with increased turbulence and pressure drops.
6. Calcium carbonate is soluble in hydrochloric acid (HCl). To dissolve 1 ft^3 of calcium carbonate scale, 95 gallons of 15% HCl is required.

CASE HISTORY 39

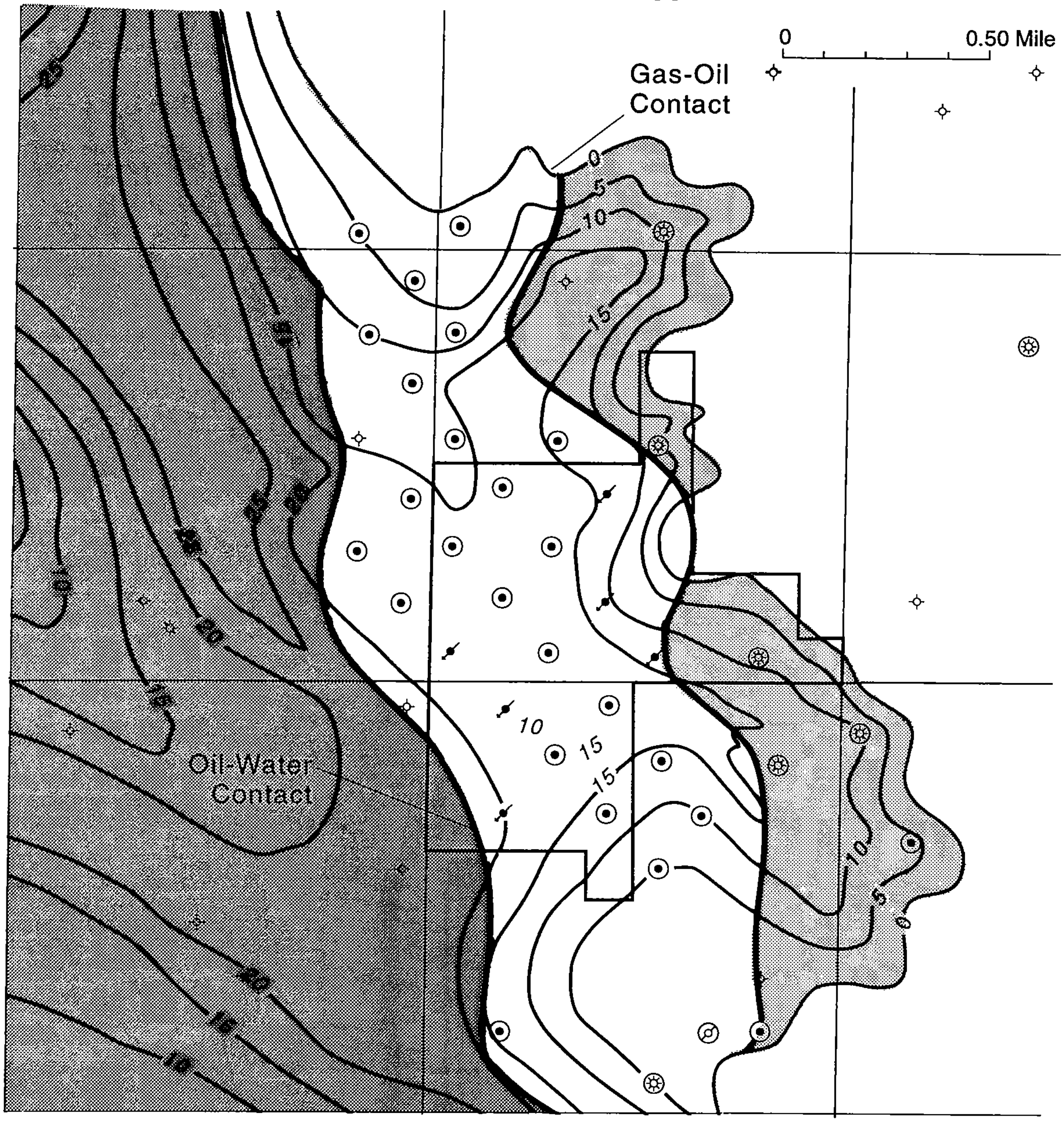


Figure 163. Net-sand isopach map of the reservoir of case history 39 (eastern Oklahoma). Lightly shaded area represents the gas cap, and dark-shaded area, the water leg. Contour interval, 5 ft.

Calcium Sulfate Mineral Scale

Although two forms of calcium sulfate mineral scale exist, the more common form that occurs in oil and gas production is $CaSO_4 \cdot 2H_2O$, or gypsum. The mixing of two waters, one containing calcium (Ca^{2+}) ions and the other containing high levels of sulfate (SO_4^{2-}) ions, is the typical cause of calcium sulfate precipitation in waterflooding. The reaction that forms calcium sulfate mineral scale is

$$Ca + SO_4 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O.$$

The following rules of thumb apply to calcium sulfate scaling tendencies:

1. Pressure drops and/or agitation decreases calcium sulfate solubility and increases scaling.
2. Increases in temperature increase scaling up to approximately 110°–115°F. Above this temperature range, calcium sulfate solubility increases, and scaling tends to decrease.
3. Calcium sulfate solubility increases and scaling decreases as the sodium chloride level of water increases.
4. A pH of 6–8 has little effect on calcium sulfate solubility and scaling.
5. Calcium sulfate is not soluble in HCl; however,

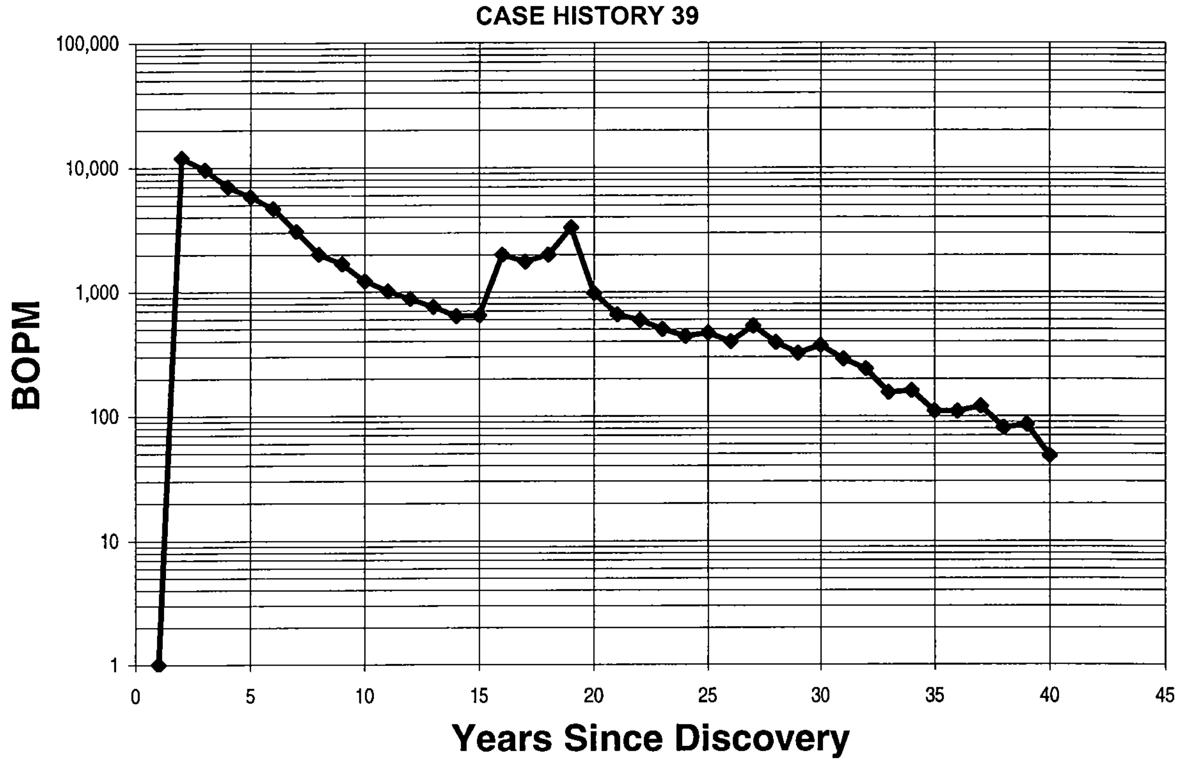


Figure 164. Production curve for the reservoir of case history 39. Unitization and injection occurred at year 6. Response to injection occurred at year 15.

the scale may be converted to an HCl form by treatment with certain chemical compounds.

Barium Sulfate Mineral Scale

As barium sulfate scale cannot be removed by conventional chemical treatments, the mention of this mineral scale in waterflooding gains immediate attention. Barium sulfate scale is almost always caused by the mixing of two incompatible waters, one containing barium (Ba^{2+}) ions and another containing sulfate (SO_4^{2-}) ions. Barium sulfate mineral scale is formed by the following reaction:

$$Ba + SO_4 \rightarrow BaSO_4.$$

Although barium sulfate has limited solubility in water, barium ions and sulfate ions can be soluble in the same water under certain conditions. The following are examples of barium sulfate solubility at various chloride levels and temperatures:

Chlorides (mg/L)	Temp. (°F)	$BaSO_4$ solubility (mg/L)
20,000	77	8
80,000	77	24
140,000	77	41
20,000	122	11
80,000	122	35
140,000	122	58

From the table above, it can be said that as the chloride level and/or temperature of a water increases, the barium sulfate solubility increases and scaling decreases.

1. Pressure drops may decrease barium sulfate solubility and increase scaling.
2. Barium sulfate scaling tendencies do not appear to be influenced by pH.
3. Barium sulfate scale is not soluble in HCl, and it cannot be dissolved by conventional chemical treatments.

Iron Precipitates

Typically, iron precipitates (1) can be the result of the mixing of two incompatible waters, (2) can be due to corrosion processes, or (3) can be due to both factors. For the scope of this discussion, we will consider those iron precipitates that result when two incompatible waters are commingled.

Iron Oxide

Iron oxide (orange to red) can result when one water containing appreciable concentrations of ferrous (Fe^{2+}) ions mixes with another water containing dissolved oxygen (O_2^{2-}), and the ferrous ions are oxidized to ferric ions. The resulting precipitate is called ferric oxide. Under certain circumstances, ferrous oxide (yellow) and ferric hydroxide can be observed, but this is the exception rather than the rule. Ferric oxide can be formed by the following reaction:

$$2Fe + O_2 + H_2O \rightarrow Fe_2O_3 + 2H.$$

The following factors regarding iron oxide may be of interest:

1. Iron oxide is soluble in HCl: 318 gallons of 15% HCl is required to dissolve 1 ft^3 of Fe_2O_3.
2. Iron oxide precipitation may be prevented by one or a combination of the following measures:
   - Treatment of the water containing the dissolved oxygen with an oxygen scavenging compound.
   - Treatment of the water containing the iron ions with the proper iron chelating agent.
   - Prevention of oxygen contamination of the waters.
3. The solubility of oxygen in water is a function of the dissolved-solids level of the water and the temperature of the water—i.e., as dissolved-solids levels and/or water temperatures increase, oxygen solubility decreases.
4. Iron oxide is cathodic to steel, meaning that corrosion of steel surfaces beneath iron oxide deposits is likely to occur.
5. Iron oxide can also be formed by iron-oxidizing bacteria.

Magnetite

Magnetite (Fe_3O_4), a lesser recognized form of iron oxide, might also be observed as a precipitate in waterflooding operations. Magnetite can be formed by the following reaction, which typically requires elevated temperatures and/or pressures:

$$3Fe + 4H_2O \rightarrow Fe_3O_4 + 4H_2.$$

The following can be said of magnetite:

1. Typically, magnetite is present in certain subsurface strata, and this is likely the source of much of the magnetite observed in production operations.
2. Magnetite is typically black, so the solid may be mistaken for iron sulfide.
3. Magnetite, unlike iron sulfide, is magnetic and will be attracted to a magnet and will attract iron filings.
4. Magnetite is slowly soluble in HCl.

Iron Sulfide

Iron sulfide arguably causes more problems in waterflooding operations than any other single scale. Iron sulfide (FeS) forms when iron (Fe) combines with sulfide (S) or hydrogen sulfide (H_2S). This reaction can occur in the same water or when two incompatible waters are mixed. The precipitate formed by these reactions, FeS, is insoluble in water and is often responsible for severe fouling and plugging of surface vessels, producing systems and wells, injection systems and wells, and even reservoirs. Iron sulfide can be formed by more than one reaction; however, the following reaction is exemplary:

$$Fe + H_2S + H_2O \rightarrow FeS_x + 2H.$$

Several statements can be made regarding iron sulfide:

1. Iron sulfide is soluble in HCl. **When iron sulfide is dissolved in HCl, dangerous H_2S gas will be generated.**
2. The sulfide and/or hydrogen sulfide contained in a water might be due to sulfate-reducing bacteria, or the H_2S might be naturally occurring.
3. Iron sulfide is cathodic to steel, and pitting and corrosion of steel surfaces will occur beneath such deposits.
4. Iron sulfide is preferentially oil-wet, meaning that iron sulfide solids will attract oil. The oil-wet state of iron sulfide worsens plugging and fouling.
5. Iron sulfide scale will often precipitate with other iron scales and/or mineral scales, giving the scales the appearance of black iron sulfide.
6. Iron sulfide is not magnetic.

OKLAHOMA AND KANSAS WATER SANDS AND COMPATIBILITY PROBLEMS

by Mark Sutherland

Most of the following water sands have contributed water-supply-incompatibility problems with injected water for units in Oklahoma and Kansas.

1. **County/State:** Seminole, OK
   Water Sand: Cromwell
   Compatibility Problems: The supply water precipitated significant levels of calcium carbonate mineral scale, both downhole in the water-supply well (WSW) and in the injection system. This problem required treatment with a scale-inhibitor compound. Additionally, when the supply water, which contained dissolved oxygen, was commingled with the produced water, which contained significant levels of both ferrous and ferric iron, iron oxide solids were precipitated in the injection system. This problem required treatment of the producing wells to minimize corrosion, and treatment of the produced water to chelate/sequester the iron, prior to commingling with the supply water.

2. **County/State:** Okfuskee, OK
   Water Sand: *Not known*
   Compatibility Problems: The supply water contained elevated levels of sulfate-reducing bacteria. These bacteria reduce sulfate ions in the water to sulfide and H_2S (hydrogen sulfide). When the supply water was commingled with the produced water which contained ferrous and ferric iron, iron sulfide solids were precipitated. This problem required treatment of the WSW to eliminate the bacteria, and treatment of the producing wells to minimize corrosion.

3. **County/State:** Creek, OK
Water Sand: *Not known*
Compatibility Problems: Same as no. 2 above.

4. **County/State:** Oklahoma, OK
Water Sand: Wellington Sand
Compatibility Problems: Few compatibility problems were encountered with this supply water; however, the water was highly corrosive, requiring corrosion-inhibition treatments for the WSWs.

5. **County/State:** Okmulgee, OK
Water Sand: Booch
Compatibility Problems: The Booch supply water contained barium ions, and the Dutcher produced water contained sulfate ions. This combination resulted in the precipitation of barium sulfate mineral scale unless the Booch water could be treated with the proper scale-inhibitor compound prior to commingling the waters.

6. **County/State:** Pottawatomie, OK
Water Sand: Layton Sand
Compatibility Problems: The supply water was actually of very good quality and injectability, but the water contained low levels of dissolved H_2S. When the "sour" supply water was commingled with the produced water, which contained very high levels of both ferrous and ferric iron, iron sulfide solids were precipitated. We recommended treatment of producing wells to minimize corrosion, treatment of the produced water to chelate/sequester the iron, and treatment of the supply water to lower/eliminate the H_2S.

7. **County/State:** Carter, OK
Water Sand: Pontotoc
Compatibility Problems: This supply well has presented some interesting problems. The chemical and physical characteristics of the supply water appear to exhibit variations from time to time. We have observed calcium carbonate mineral-scale problems, severe iron oxide and iron sulfide problems, both sulfate-reducing bacteria and aerobic bacteria, and severe corrosion problems. Obviously, the mineral-scale and iron-solids problems create problems in the injection system. We suspect that unidentified offset disposal well(s) are the primary contributor(s) to both the variations in the supply-water composition and the problems that have occurred. Treatment to alleviate each problem was initiated as the problem appeared.

8. **County/State:** Pottawatomie, OK
Water Sand: Layton
Compatibility Problems: This supply water was found to be of excellent quality and injectability. The operator stated that barium sulfate scale had been identified in the water-injection pump shortly after placing the first WSW on production. Although our testing did identify barium ions in the supply water, no sulfate ions were present in either the supply water or the produced water. We suspected that the sulfate ions, which apparently led to the barium sulfate scaling, were introduced into the WSW by the fluids used to complete this well. The operator insisted on treating the supply water with a barium sulfate scale inhibitor.

9. **County/State:** Cimarron, OK
Water Sand: Shawnee
Compatibility Problems: The two WSWs in this unit produced waters that precipitated high levels of calcium carbonate mineral scale. Originally, only the supply waters contained high levels of sulfate-reducing bacteria, resulting in high levels of dissolved H_2S in the supply water. By the time we were instructed to evaluate the waterflood, contamination of the Morrow sand with sulfate-reducing bacteria and H_2S had occurred. The calcium carbonate mineral scale and the iron sulfide, which resulted from the H_2S, caused significant plugging in the injection system, injection wells, and producing reservoir. We recommended treatment of the WSWs and the producing wells to prevent calcium carbonate precipitation and eliminate bacteria and H_2S.

10. **County/State:** Seminole, OK
Water Sand: Calvin
Compatibility Problems: Both the produced waters and the supply waters contained high levels of ferrous and ferric iron. Owing to the availability of oxygen in the surface vessels, significant levels of iron oxide were precipitated.

11. **County/State:** Okmulgee, OK
Water Sand: Wilcox
Compatibility Problems: The WSWs in this unit contained high levels of primarily ferric iron. Since oxygen could not be excluded from the surface system, iron oxide was precipitated. Treatment of the WSWs was initiated to minimize corrosion, thus reducing iron oxide in the injection water.

12. **County/State:** Seminole, OK
Water Sand: Lone Grove
Compatibility Problems: The supply water in this waterflood contained significant levels of barium ions, while the produced waters contained equally significant levels of sulfate ions. These factors, of course, resulted in the precipitation of barium sulfate mineral scale. Treatment of the supply water with the appropriate scale-inhibitor compound resolved the problem.

13. **County/State:** Seminole, Ok
Water Sand: Wilcox
Compatibility Problems: The supply water contained high levels of sulfate-reducing bacteria, which resulted in high levels of dissolved H_2S. The H_2S, as well as the inherent corrosivity of the supply water, resulted in high levels of iron and iron sulfide in the supply water. It was discovered that three offsetting disposal wells completed in the Wilcox were the sources of the bacteria, H_2S, and iron sulfide observed in the supply water. A certain degree of contamination of the producing reservoir resulted from the injection of the previously untreated supply water. The WSWs and the producing wells were treated to eliminate bacteria and minimize corrosion.

14. **County/State:** Okmulgee, OK
Water Sand: Bartlesville
Compatibility Problems: The supply water in this unit was found to contain both barium and sulfate ions, which is somewhat unusual. This was confirmed by the observance of barium sulfate mineral scale on the submersible pump pulled from the WSW. The supply water also contained a rather high level of corrosion iron from the corrosivity of the water. This iron resulted in the precipitation of iron oxide solids. The WSW was treated with a product containing both a barium sulfate scale inhibitor and a corrosion inhibitor, which resolved the problem. Finally, oil carry-over into the injection system also became a problem. The residual oil in the injection water was caused by overloading the free-water knockout with the supply-water volume, which contained a low percentage of oil.

15. **County/State:** Seminole, OK
Water Sand: Wilcox
Compatibility Problems: Much the same as no. 13 above.

16. **County/State:** Carter, OK
Water Sand: Pontotoc
Compatibility Problems: The supply water contains barium ions, and the produced water contains sulfate ions. Treatment of the supply water is required to prevent barium sulfate precipitation in the commingled water.

17. **County/State:** Carter, OK
Water Sand: Pontotoc
Compatibility Problems: None; excellent water quality and injectability.

18. **County/State:** Alfalfa, OK
Water Sand: Cottage Grove
Compatibility Problems: This water sand has presented some interesting situations. First, the supply water contains both barium and sulfate ions in significant levels, which is unusual. Treatment of the WSW with a specific barium sulfate scale inhibitor is required to prevent barium sulfate mineral scale downhole in the well. Also, the produced waters (from the Misener) contain high levels of sulfate ions; therefore, the barium sulfate treatment in the WSW also prevents barium sulfate precipitation in the commingled waters. Finally, this particular supply well periodically produces "slugs" of significant amounts of formation sand, resulting in filter plugging on an hourly basis. We suspect that the sand-slugging problem is due to completion problems in the well.

19. **County/State:** Alfalfa, OK
Water Sand: Cottage Grove
Compatibility Problems: As with no. 18 above, the Cottage Grove sand produces water that contains both barium and sulfate ions in significant concentrations. To combat the problem, the operator installed a chemical-injection system in the WSW that utilizes stainless-steel tubing to inject a barium sulfate scale inhibitor into the water below the motor of the submersible pump. Additionally, this water contains a high level of ferrous iron, which, when oxidized in the surface vessels, resulted in significant precipitation of iron oxide solids. To combat this problem, we formulated a combination product containing the barium sulfate scale inhibitor and a highly effective iron-chelating/sequestering agent. The iron-chelating agent reacts with the ferrous iron to maintain the iron in the ferrous state, even when oxidized, thus preventing iron-solids precipitation.

20. **County/State:** Oklahoma, OK
Water Sand: Cisco
Compatibility Problems: The supply water from the Cisco contains a significant level of barium ions, while the produced water from the Prue contains high levels of sulfate ions. Treatment of the supply water is required to prevent barium sulfate mineral-scale precipitation. Additionally, the Cisco water contains a relatively high level of ferrous iron. Treatment with the proper iron-chelating/sequestering agent is necessary to prevent the precipitation of iron oxide and/or iron sulfide.

21. **COUNTY/STATE:** Anderson, KS
WATER SAND: Arbuckle
COMPATIBILITY PROBLEMS: Arbuckle supply water is typically sour, with moderately high levels of dissolved H_2S. The precipitation of iron sulfide solids and contamination of the producing reservoir by H_2S usually occur in waterflooding projects that utilize supply water from the Arbuckle. Many times, the H_2S is due to sulfate-reducing bacteria. This operator has minimized problems by running fiberglass tubing in the WSW.

22. **COUNTY/STATE:** Allen, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Mississippi supply water is mildly corrosive and contains significant levels of dissolved H_2S. With most waterflood projects in southeastern Kansas, injection of the sour supply water into otherwise "sweet" reservoirs results in H_2S contamination of the reservoirs, with resulting corrosion and iron sulfide plugging problems. Often, the H_2S is due to sulfate-reducing bacteria.

23. **COUNTY/STATE:** Allen, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

24. **COUNTY/STATE:** Neosho, KS
WATER SAND: Tucker
COMPATIBILITY PROBLEMS: The Tucker sand contains relatively "clean" water, which is mildly corrosive and contributes to iron-solids precipitation.

25. **COUNTY/STATE:** Bourbon, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

26. **COUNTY/STATE:** Crawford, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

27. **COUNTY/STATE:** Woodson, KS
WATER SAND: Kansas City
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

28. **COUNTY/STATE:** Crawford, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

29. **COUNTY/STATE:** Woodson, KS
WATER SAND: Kansas City
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

30. **COUNTY/STATE:** Allen, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

31. **COUNTY/STATE:** Anderson, KS
WATER SAND: Mississippi
COMPATIBILITY PROBLEMS: Same as nos. 21 and 22 above.

Permitting

11

CHAPTER 11

Permitting

by
Saleem Nizami

INTRODUCTION

Prior to any detailed waterflood study, it is prudent, both from an economic and logistical point of view, to review the regulatory and environmental aspects of the proposed project. The regulatory authority for permitting injection wells in the State of Oklahoma is the Oklahoma Corporation Commission (OCC). Injection-well permitting is done administratively without a hearing unless the application is protested. Regulatory aspects include compliance of State and Federal rules prior to, during, and after the initiation of the waterflood. Environmental aspects include initial studies and continued monitoring to assure protection of the surface water, the subsurface water, and the soil to avoid environmental liability. The expenses associated with these aspects have to be considered and incorporated in the total cost of the project.

One of the most important components of the enhanced-recovery waterflood is the injection wells. We will deal with regulatory aspects governing these wells in some detail, especially the procedure for permitting, and probable solutions to potential problems in filing and obtaining injection-well permits. A brief overview of the unitization process is also included to make the discussion complete.

It should be noted how the Underground Injection Control Department (UICD) of the OCC's Oil and Gas Division differentiates between "injection" and "disposal" wells. Wells used for enhanced-recovery purposes by injecting fluids into the producing zones are termed *injection wells*, and wells used for getting rid of produced water by injecting it into another subsurface zone are termed *disposal wells*. The discussion here addresses injection wells. Most of the requirements and procedures for disposal wells are similar.

REGULATORY CONSIDERATIONS

Jurisdictional Agencies

The UICD is the authorized regulatory body mandated by the U.S. Environmental Protection Agency (EPA) to administer the Underground Injection Control Program, including the permitting and compliance of injection wells. In addition to the UICD, other departments of the OCC are responsible for the permitting of waterflood projects in Oklahoma. In some cases that include Federal or Indian lands or leases, the Bureau of Land Management (BLM), the Bureau of Indian Affairs (BIA), the Minerals Management Service (MMS), the EPA, and other Federal agencies are also directly involved.

Regulatory Filings: Unitization, Injection-Well Permits, Tests, and Reports

Unitization

Unitization, which is essentially similar to the creation of a large "spacing" unit, is an involved process requiring a hearing at the OCC and notification to all mineral-interest owners, landowners, and offset leaseholders. All technical data—including geological and engineering data, tract-participation formulas, and the plan of unitization spelling out the proposed procedure of operation—must be filed during the hearing. Most of this procedure is routine; however, the biggest stumbling block is the tract-participation formula. No clear-cut regulatory guidelines exist as to how this formula should be determined. If the project involves a number of technically competent working-interest owners, a technical committee is set up to oversee the project. The committee's most important function is to arrive at a fair and equitable tract-participation formula. This could involve a combination of such factors as OOIP, existing wells, and primary production. Generally speaking, OOIP is given the highest importance. It is prudent to work out the tract-participation formula prior to the hearing, rather than to run the risk of having a lengthy protested hearing.

Injection Wellbore

Once a decision has been made to go forward with the project, and the design phase of the waterflood is completed, selected wells within the unit must be permitted for conversion to injection wells. Three categories of wells are permitted for injection: (1) existing producers, (2) existing shut-in or plugged wells, and (3) new drills. Prescribed forms and paperwork to be filed with the regulatory agency to obtain a permit are basically the same for all the wells except for minor differences in the supporting documents required.

Injection-Well Permitting Requirements

For a well to qualify and be permitted as an injection well, the applicant has to prove to the OCC by means of documented evidence that the proposed injection well would not contaminate the "treatable" water or adversely affect any existing oil and gas reserves. (*Treatable water* is defined as "subsurface water in its natural state, useful or potentially useful for drinking water for municipal and recreational purposes and which will support aquatic life, and contains less than 10,000 mg/L total dissolved solids or less than 5,000 mg/L chlorides.") To achieve this end, the OCC has required the filing of certain prescribed application forms, notices, and ongoing testing and monitoring procedures. Some of the most important aspects of these requirements are described in the following paragraphs.

Cementing Requirements

The proposed injection well must have cemented casing from the surface to 50 ft below the base of treatable water (BTW) as established by the OCC, and also have a minimum of 250 ft of cement above injection perforations (Fig. 165). An exception for the cement requirements of 250 ft above the perforations can be filed and obtained administratively at the discretion of the UICD. However, exceptions to the cementing requirements of the BTW require a hearing.

Tubing and Packer Requirements

The proposed injection well needs to have a tubing and packer assembly for injection of fluids so that an annulus is available for performing a mechanical integrity test (MIT) in accord with the UICD guidelines. The tubing and packer should be set about 50 ft above the perforations (Fig. 165). Exceptions to tubing- and packer-setting depth are granted at the discretion of the UICD on reasonable explanation and on acceptance by the operator of additional stringent monitoring and testing requirements.

Pressure Requirements

The requested injection pressure, according to UICD guidelines, must be less than a 0.5 gradient of the injection depth. For example, if the injection perforations are at 1,800 ft, the maximum injection pressure permitted will be 900 psi or less. Exceptions to the pressure requirements are granted at the UICD's discretion on submission of fracture–pressure data to show a higher fracture gradient. If no fracture–pressure data are available, exceptions are granted if the applicant agrees to perform a radioactive tracer survey (RTS) at the permitted pressures to prove that the injection zone is the only zone conducting water.

Volume Requirements

The requested daily rate-of-injection volume cannot be more than 1,000 BW if the intervening interval (the distance between the BTW and the top injection perforation) is less than 500 ft.

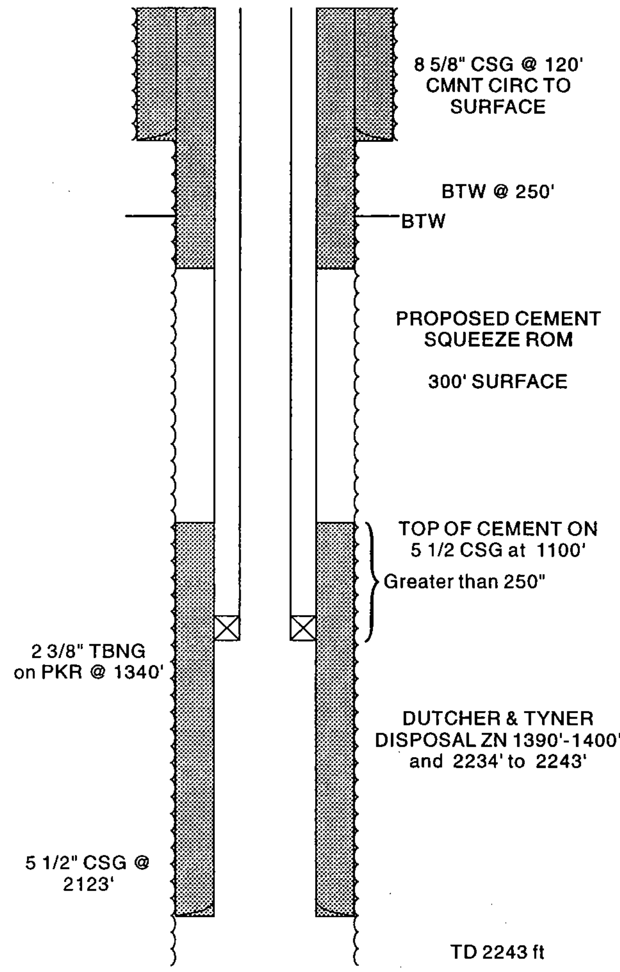


Figure 165. Proposed injection-well–disposal-well schematic illustration for wells with inadequate cement. *BTW* = base of treatable water.

Exceptions to the volume requirements are granted at the discretion of the UICD if the applicant agrees to further testing and monitoring procedures in addition to other required tests, such as more frequent MITs and RTSs, to show that the fluids are being injected into the permitted zone only.

Area of Review (AOR) Requirements

A quarter-mile radius around the proposed injection well is reviewed by the UICD to verify if there are any "problem wells" that might be affected by the proposed injection well. A *problem well* is defined as any well within 0.25 mi of the injection well that is theoretically capable of conducting injected fluids and that does not have adequate protection of the treatable-water zone. This is one of the most frequent stumbling blocks that operators encounter in trying to permit injection wells. A number of older wells, especially in the mature oil-producing areas of Oklahoma, do not have adequate surface casing to meet current standards.

The ideal solution for addressing the problem wells is to replug them to protect the treatable water. Replugging, however, is not only expensive but also impractical, because reentry and washdown, especially of an old well, is risky.

A number of other methods are available for addressing problem wells (Fig. 166). One method uses the "intercept" concept in which a well producing from the same zone as that of the proposed injection well is drilled between the injector and the problem well to intercept injected fluids. An alternative method involves calculation of theoretical areas of influence to show that the extent of the injected fluid (at the requested rates and pressures for the given porosity and permeability) is sufficiently limited so as not to affect the problem well (Fig. 167). For cases in which problem wells are plugged with mud, it can be shown, by calculating the pressure exerted by the mud column, that these wells are not capable of conducting injected fluids (Fig. 168). This usually requires permitting at a low injection pressure. Another UICD-accepted method for addressing a problem well is to demonstrate geological constraints, such as shale-out of the reservoir in the problem well (Fig. 169). This option is especially applicable for injection wells on the edge of waterfloods, with the problem well just outside the unit.

It is critical to remember that whatever method is used to explain problem wells must be backed up by means of substantiated supporting evidence, such as isopach maps of the reservoir, cross sections, logs, porosity and permeability data, mud weights, and fracture–pressure data.

Notice Requirements

The surface landowner on whose property the proposed injection well is being permitted, and all operators of producing leaseholds within 0.5 mi, are to be notified of the proposed injection-well filing by sending them copies of the application. A notice listing the details given in the application must be published in a newspaper of general circulation in Oklahoma County and in the county in which the well is located.

Water-Analysis Requirements

A water analysis for total dissolved solids, sodium, and chlorides of the water to be injected, and a minimum of two samples of fresh water from wells within 1 mi of the proposed injection well, need to be filed. If

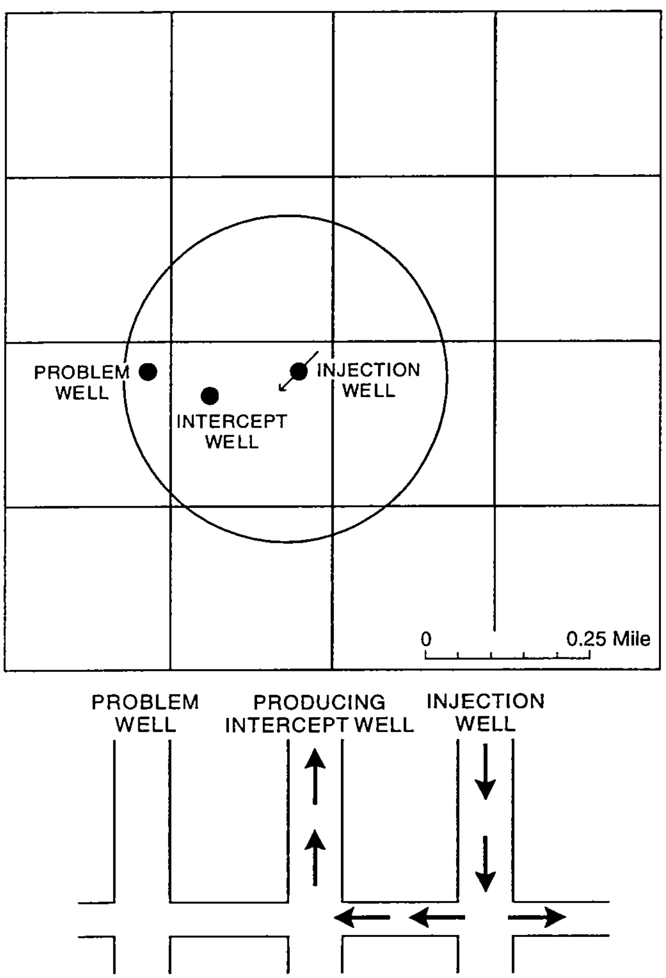


Figure 166. Example of the concept of using an intercept well to demonstrate that injection will not affect a plugged problem well.

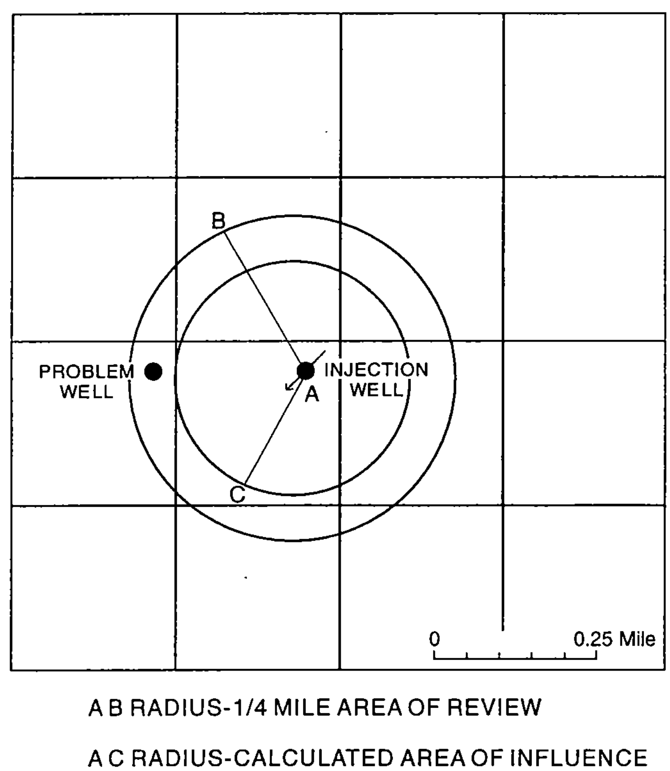


Figure 167. Example showing reduction of the radius of endangering influence from the standard 0.25-mi rule used by the UICD.

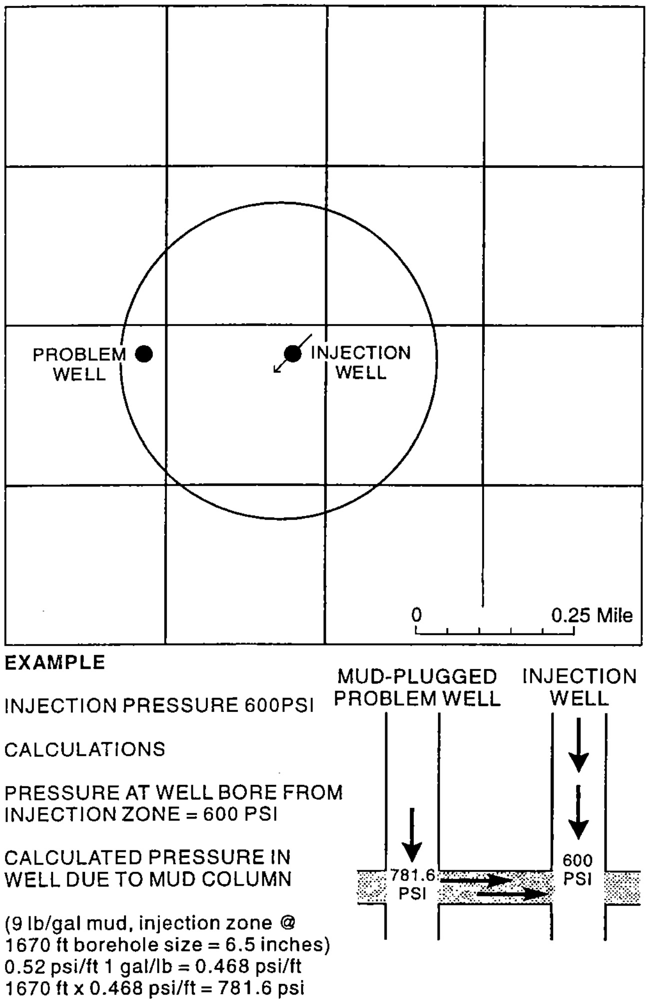


Figure 168. Example showing pressure differential between mud-plugged problem well and proposed injection well.

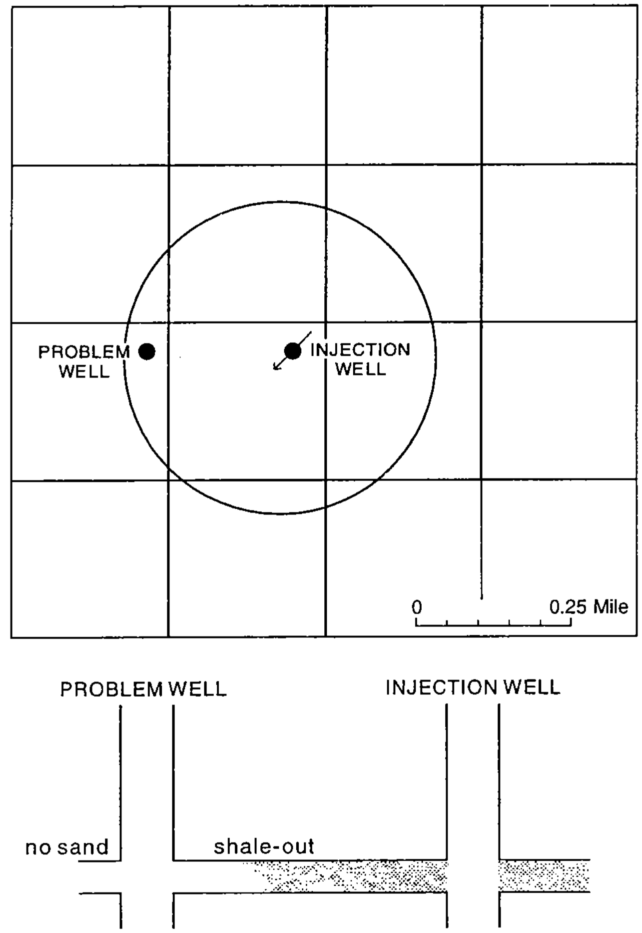


Figure 169. Example showing a geological constraint (shale-out) of the reservoir to address the concern of a possible problem well.

only one freshwater well is available (or none), a notarized affidavit to this effect is accepted by the UICD.

In addition to these requirements, depending on the specificity of the injection-well filing, it may be necessary to file such information as a cement-bond log, core-analysis data, permeability data, and fracture–pressure data.

Personal Experiences in the Permitting Process

From experience, both as the permitting coordinator for the UICD and as an industry consultant, I have established the following sequence for gathering information for the permitting process.

Gather, Review, and Analyze Data

Meet with the project geologist and engineer, obtain maximum-injection-pressure and volume requirements for the proposed well, completion reports, logs, BTW depth as established by the OCC, surface-owner information, and offset-operator information. Plot all the wells within 0.25 mi of the subject well and mark the total depth and the formations that are open in the borehole. Obtain necessary information about the surface owner and offset operators.

Application Form 1015

Fill out this OCC application form for an injection-well permit, using the data gathered.

Supporting documents and attachments needed:

- *Schematic diagram.*—How the proposed injection well will be completed (Fig. 165).
- *Completion report.*—Existing completion report (OCC form 1002A) of the proposed injection well. If the injection well is to be drilled and not converted, or if for some other reason form 1002A is not available, furnish a notarized affidavit stating that the completion report will be filed on completion of the well. A copy of OCC form 1073 (transfer of well operatorship) also needs to be filed if the completion report does not show the applicant for the injection permit as the operator.

- *Logs.*—Copies of open-hole logs with the injection interval marked. If logs for the proposed well are not available, logs of a direct offset well showing the proposed injection zone are acceptable at UICD's discretion.
- *Plat.*—A quarter-mile radius on a plat around the proposed injection well, showing all the wells currently producing, shut in, and plugged and abandoned, and their total depths.
- *Water analysis.*—A signed and dated water analysis, not less than 1 year old, of the water to be injected, and a minimum of two freshwater samples from wells within 1 mi of the injection well. If there are no such freshwater wells, a notarized affidavit stating that fact should be filed.
- *Affidavit of mailing.*—A notarized affidavit of mailing, listing the names and addresses of the persons to whom a copy of the application was mailed. The mailing should be done within 5 days of filing the application.
- *Notices.*—Prepare and publish notices in Oklahoma County and in the county where the well is located.
- *Proposed order (permit).*—A proposed completed order (permit) in UICD-accepted format should also be submitted along with the application. Blank order forms are available at the UICD.

On submission of the application, supporting documents, and notices, the UICD reviews the application. If it meets all the requirements, an order will be issued authorizing the applicant the use of the well as an injection well. If there are any deficiencies, the UICD will inform the applicant in a tolling letter and ask that the deficiencies be addressed before a permit can be issued.

If the application is protested by any entity, the UICD sends a letter informing the applicant and stating that permit approval or denial will be rendered after a hearing before an administrative-law judge of the OCC. If the applicant has met all the requirements of administrative approval, the UICD will issue a letter to this effect; this letter can and should be used as an exhibit at the time of the hearing to show that the well meets all the criteria for the permit.

Most protests are from people who are concerned that their water or land may be polluted because of the injection activities. Some protesters are genuinely concerned with the potential for pollution; some are ill informed as to the stringent requirements the UICD imposes to assure that no pollution occurs; some feel that they have not been adequately compensated; some protest just for the sake of protesting. Before going through with the hearing, it is advisable to get in touch with the protester and allay any concerns. Then, if the protester is satisfied and withdraws the protest, the permit is issued administratively without a hearing.

Testing, Monitoring, and Following Through

Once an injection permit is issued, the operator has 18 months to complete the injection well.

Mechanical-Integrity Test (MIT)

On completion of the well, and prior to its use as an injection well, a mechanical-integrity test (MIT) needs to be performed in the presence of an OCC representative. The annulus between the long string and the tubing above the packer is tested either to the maximum requested pressure or to 1,000 psig, whichever is lower. The minimum testing period is 30 min, with a 10% bleed-off allowed. After the MIT has been successfully completed, OCC form 1075 must be completed and filed with the UICD within 30 days. MITs are to be performed every 5 years or at any time the packer is unseated.

Injection-Commencement Notice

The operator is required to file OCC form 1072 on commencement of injection operations.

Annual Reports

The operator is required to file OCC form 1012, reporting the annual injection and production information for the unit as a whole and for each individual injection well, by April 1 of each calendar year.

ENVIRONMENTAL CONSIDERATIONS

Projects involving waterfloods inherently involve handling a substantial amount of salt water. Prior to initiation of a waterflood, therefore, it is wise to have a plan of action to protect the environment and also to minimize any potential environmental liability. Current OCC rules do not require an environmental report, but it is prudent to have a certified environmental audit report on file so that any potential environmental liabilities can be eliminated or minimized.

A phase I type of review of the lands on which the project is to be initiated should be done. Such a review should include a general assessment of the area, a complete listing of all drilled wells including completion and plugging reports, any previous documented environmental problems, and remediations on file with the OCC. All the water wells, surface-water ponds, streams, and soils within and directly adjacent to the waterflood area need to be analyzed, and the results recorded. These analyses serve two purposes: they will indicate any existing spills or contamination, and establish a baseline for future comparisons in case of frivolous environmental lawsuits. These reports should be certified and preferably be done by outside consultants.

A spill-prevention-control and countermeasure (SPCC) plan should be in place to avoid or minimize the impact of potential spills.

CASE HISTORIES

Case History 1: Surface Casing and BTW Conflict

Background information: About 19 wells in the unit were to be permitted for injection. We reviewed and analyzed the information. Most of the wells were of late 1970s or early 1980s vintage. Most of the requirements to obtain injection permits were satisfied. According to OCC maps, however, the BTW depth ranged from 800 to 950 ft. The existing surface-casing-setting depth on most of the wells ranged from 300 to 500 ft. This would have required a cement squeeze from 50 ft below (the current requirements call for 100 ft below) the BTW to the surface on the long string to meet the permit requirements. Perforating the production string is not only risky but is also expensive. We looked for other options within the framework of OCC rules, and resolved the problem.

Problem: Inadequate surface casing in the proposed injection wells.

OCC's suggestion: Perforate long string below the BTW, and squeeze cement to surface.

Solution: Look into other ways to address the problem.

The following were three options for solving the problem:

1 Squeeze cement as suggested; approximate cost, $120,000.
2. Obtain an exception to the rule; approximate cost, $15,000.
3. Analyze logs to verify the BTW; approximate cost, $2,000.

On review of the logs, using OCC criteria for the definition of the BTW, we found that there was no treatable water below the surface-casing depth in all the wells. We met with the appropriate OCC staff and obtained certification to show the correct BTW depth, and filed and obtained injection permits. The unit prior to commencement of injection was making about 5,000 BO per month; on initiation of the flood, the unit peaked at 80,000 BO per month.

Case History 2: Many Problem Wells Within Area of Review

Background information: This was an old waterflood in an old oil-producing province in southern Oklahoma. The operator needed to add about 17 new injection wells within the unit. Most of the wells are of 1930 vintage, and it is a densely drilled area with a number of wells either mud plugged or having inadequate surface casing for treatable-water protection per current OCC definition.

Problem: A large number of inadequately cemented and/or old mud-plugged wells (problem wells) within the area of review of the proposed injection wells.

OCC's suggestion: Replug old plugged wells; squeeze cement on current wells with inadequate (by current OCC rules) surface casing.

Solution: Show, by means of various OCC-acceptable options, that the injected fluids would not be conducted to the problem wells.

The following were the four methods considered for solving the problem:

1. Replug old mud-plugged wells, and squeeze cement on the current wells with inadequate cement on production as well as surface casing. These options, aside from being expensive and risky, are also impossible in some cases because of the age of the wells and should be tried only as a last resort.
2. Thoroughly review old records to determine if all the wells in question are located as referenced by OCC (some of the old records have typographical errors, giving incorrect locations), and also to determine if there had been any workovers, recompletions, or replugging. This resolved permitting processes for eight of the wells and eliminated 60% of the problem wells.
3. Use the concept of "intercept" wells to show that the injected fluids would not affect the problem wells. This resulted in approval for four more injection wells and elimination of another 30% of the problem wells.
4. Propose, negotiate, and put together an agreement with the UICD of the OCC to utilize strategically located existing wells within the unit as monitoring wells to assure that the problem wells would not be affected by the injection operations. Incorporate the terms of agreement within the order (permit). This step eliminated all the remaining problem wells and gained the approval for the remaining five injection wells.

Case History 3: Many Problem Wells Within Area of Review

Background information: This was an old waterflood in an old oil-producing province of southern Oklahoma. The operator needed to add about 11 additional injection wells within the unit. Most of the wells are of 1930 vintage, and it is a densely drilled area with a number of wells either mud plugged or having inadequate surface casing for treatable-water protection per current OCC standards.

Problem: A large number of inadequately cemented and/or old mud-plugged wells (problem wells) within the area of review of the proposed injection wells.

OCC's suggestion: Replug old plugged wells; squeeze cement on current wells with inadequate (by current OCC rules) surface casing.

Solution: Show, by means of various OCC-acceptable options, that the injected fluids would not be conducted to the problem wells.

We came up with the following options and solutions:

1. Replug old mud-plugged wells, and squeeze cement on the current wells with inadequate cement on production as well as surface casing. These options, aside from being expensive and risky, are also impossible in some cases because of the age of the wells and should be tried only as a last resort.
2. Thoroughly review old records to determine if all the wells in question are located as referenced by OCC (some of the old records have typographical errors, giving incorrect locations), and also to determine if there had been any workovers, recompletions, or replugging. This resolved permitting processes for five of the wells and eliminated 50% of the problem wells for the other proposed injection wells.
3. Use the concept of "intercept" wells to show that the injected fluids would not affect the problem wells. This resulted in approval for four more injection wells and elimination of another 40% of the problem wells.
4. Physically search for wells that do not show up on company files but are shown in OCC records. This discrepancy could be due to typographical errors on the old completion reports. If the wells do not exist at the locations given, prepare an affidavit to that effect. (Please note that the search must be performed in the presence of the OCC field inspector.) This procedure resulted in the approval of one more injection well.

Note: The last remaining proposed injection well had an offset problem well with theoretical access to the injected fluids. To obtain the injection permit, the problem well needed to be replugged.

Case History 4: Protection from Potential Environmental Liability

Background information: The operator was planning a secondary-recovery waterflood unit on parts of its producing leases. As part of its pre-unitization due-diligence effort, it became apparent that there was a surface owner who was known to cause problems for the operator.

Problem: Future or potential environmental liability for the operator.

OCC's suggestion: None. OCC rules do not require an environmental study.

Solution: Perform an environmental audit to establish baseline data.

We reviewed the data and the plans and suggested that a pre-unitization environmental audit be done and that a report be prepared for in-house use and for establishment of baseline data for the soil and water within the unit.

We sampled and analyzed soil, surface water, and water wells within and directly offsetting the proposed unit boundary and prepared a certified report. The environmental review will help in identifying any polluted areas, and the establishment of baseline values will protect the operator from any future illegitimate claims by either the surface owner or the regulatory bodies. On completion of the unitization process, we permitted the injection wells. The operator is in the process of initiating injection.

SUMMARY AND CONCLUSIONS

Regulatory and environmental compliance are important aspects of waterflood projects, with the injection wells being the most important part. Permitting and operating an injection well is easy if the requirements are understood and the regulatory-agency guidelines are followed. Dealing with problem wells and meeting cementing requirements are the two most important factors that need to be addressed. It should be remembered that if a well does not meet current UICD criteria, the applicant can always propose, in the application, that the required necessary changes could be made prior to using the well as an injection well. If this proposal is accepted, a conditional permit will be issued. As an example, if a well has surface casing above the depth of the BTW, a conditional permit can be issued. The use of the well as an injection well will be contingent on squeezing cement from below the BTW to the surface and providing documentary proof to the UICD. Similarly, if the packer-setting depth is greater than the UICD guidelines, if the pressure being requested is greater than the 0.5 gradient, or if the intervening thickness is more than 500 ft, a conditional order will be issued with specific additional requirements to be met. The rules are flexible enough so that if the wells to be permitted do not meet the standard requirements, alternate options are available to satisfy the rules and protect the environment.

Economic Feasibility

12

CHAPTER 12

Economic Feasibility

The economic feasibility of a waterflood project is literally what the title of this chapter means. What is the likely economic outcome of the project? The evaluations given in the various subjects presented are simply pieces of a puzzle, which, when fit together, culminate in the number of barrels of oil likely to be produced from the waterflood. As mentioned previously, the geologist or engineer is not responsible for the successful outcome of the waterflood project. The economic analysis, with all the incorporated data, predicts the success of the project. In this publication, we have dealt with less than half the parameters calculated for the economic feasibility of the prospect—chiefly those parameters that are geologically oriented. The engineering and geological-engineering aspects will be dealt with in the next workshop. However, a major subject that should be addressed now concerns the price structure for the economic evaluation of a submitted waterflood prospect.

Figure 170 is a plot of the current dollar price of oil and the constant dollar price adjusted to 1982 dollars for the period 1947–95. The oil-price boom of the early 1980s is quite apparent, but of particular interest is the current and adjusted price of oil since 1990. In 1990, the current and adjusted prices of oil were $20.03 and $17.22, respectively. In 1995, however, the current and adjusted prices had fallen to $14.62 and $11.72, respectively. There has been a general decline in oil prices since 1981. This price trend is important to keep in mind when evaluating a waterflood prospect, because the future value of the prospect is based on an extrapolated price of oil through the potential life of the prospect.

Consider case history 40 (Fig. 171). These data represent part of an economic analysis for a waterflood prospect submitted in 1992. The shaded areas, from left to right and top to bottom, give the projected price of oil, the projected price of gas, and the projected net

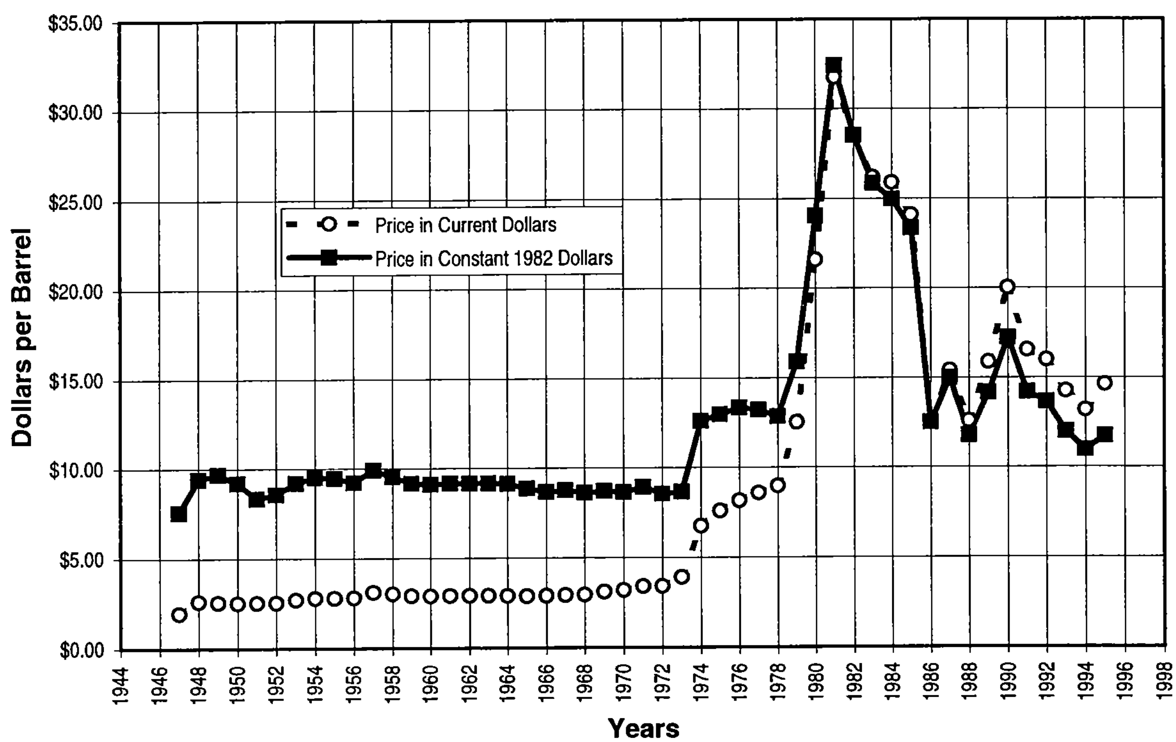


Figure 170. Plot of current dollar price of oil and constant dollar price of oil (adjusted to 1982 dollars) for 1947–95.

CASE HISTORY 40

Year	Gross Oil (Barrels)	Revenue Interest Oil	Net Oil (Barrels)	Oil Price ($/BBL)	Net Oil Revenue	Gross Gas (MCF)	Revenue Interest Gas	Net Gas (MCF)	Gas Price ($/MCF)	Net Gas Revenue	Total Net Revenue
0	0	75.91000	0	0.00	0	0	75.91000	0	0.00	0	0
8/92	1955	75.91000	1484	21.25	31536	0	75.91000	0	1.50	0	31536
1993	4489	75.91000	3408	22.31	76024	0	75.91000	0	1.57	0	76024
1994	4219	75.91000	3203	23.43	75038	0	75.91000	0	1.65	0	75038
1995	3964	75.91000	3009	24.60	74023	0	75.91000	0	1.74	0	74023
1996	3725	75.91000	2828	25.83	73038	0	75.91000	0	1.82	0	73038
1997	3498	75.91000	2655	27.12	72013	0	75.91000	0	1.91	0	72013
1998	3288	75.91000	2496	28.48	71084	0	75.91000	0	2.01	0	71084
1999	3089	75.91000	2345	29.90	70111	0	75.91000	0	2.11	0	70111
2000	2903	75.91000	2204	31.40	69195	0	75.91000	0	2.22	0	69195
2001	2727	75.91000	2070	32.97	68250	0	75.91000	0	2.33	0	68250
Subtotal	33857		25701		680312	0		0		0	680312
Remaining	7231		5489		199231	0		0		0	199231
Total	41088		31190		879543	0		0		0	879543

Year	Net Oper. Expense ($/Year)	Net Oper. Expense ($/BBL)	Net Oper. Expense ($/MCF)	Net Oper. Expense (% Oil Rv)	Net Oper. Expense (% Gas Rv)	Net Oper Expense ($/Well)	Total Net Sev. Tax	Total Net Misc. Tax	Total Net Fin Ovhd.	Net Sink. Fund Cont	Total Net Expenses
0	0	0	0	0	0	0	0	0	0	0	0
8/92	13702	0	0	0	0	0	2237	0	0	0	15939
1993	34529	0	0	0	0	0	5394	0	0	0	39923
1994	36255	0	0	0	0	0	5324	0	0	0	41579
1995	38069	0	0	0	0	0	5252	0	0	0	43321
1996	39972	0	0	0	0	0	5182	0	0	0	45154
1997	41971	0	0	0	0	0	5109	0	0	0	47080
1998	44069	0	0	0	0	0	5043	0	0	0	49113
1999	46272	0	0	0	0	0	4974	0	0	0	51246
2000	48586	0	0	0	0	0	4909	0	0	0	53495
2001	51015	0	0	0	0	0	4842	0	0	0	55857
Subtotal	394439	0	0	0	0	0	48268	0	0	0	442707
Remaining	168867	0	0	0	0	0	14135	0	0	0	183002
Total	563306	0	0	0	0	0	62404	0	0	0	625710

Figure 171. Part of an economic analysis of a prospect in northern Oklahoma (case history 40). Boxed areas represent price of oil, gas, and net operating expenses, respectively.

operating expenses for the project through the year 2001. Note that the price of oil in 1992 starts at $21.25 and increases by 5% increments until 2001, when the price is expected to be $32.97. However, in Figure 170, the average price for 1992 was $15.99, and it decreased until 1995. The price for 1996 and a part of 1997 is not available as of this writing, but it probably is lower than $20.00. This illustrates that the economics of the project were based on inflated oil prices and that, to date, the actual price has not met expectations. Furthermore, the adjusted price, which takes the rate of inflation into account and represents the actual worth of the oil, is even lower. The net operating expenses are also increased by 5% increments, which probably is a realistic trend.

The pitfall of this example was the use of unrealistic oil-price projections to evaluate a potential prospect. No one knows what the future holds, or its effect on oil prices. Because of this, projects should incorporate a conservative price structure. If a prospect does not meet the company's standard for profitability at conservative prices, the prospect is probably too sensitive to bear unknown price fluctuations or variations in performance.

Reservoir Model

CHAPTER 13

Reservoir Model

The reservoir model is the evaluator's interpretation of the various geologic and engineering parameters of a waterflood prospect. Figure 172 is an example of the input and output spreadsheet that contains these geologic and engineering parameters.

The result or summation of all the data that go into the reservoir model is aimed at determining the amount of secondary oil that can be produced. If any of the parameters for the reservoir model are miscalculated or misinterpreted, these miscalculations will affect the economic analysis of the prospect, and possibly its financial viability.

RESERVOIR MODEL
MID-CONTINENT

Miscellaneous

Pi	2,156 psi
P	265 psi
Depth	4,950 ft
P-grad	0.436 psi/ft
T	117 °F
k	30 md
Oil Grav	40.0 °API
Gas Grav	0.75
NaCl %	0.0%

Material Balance

N	1,263,225 stbo	
G	2,706 mcf	
m	0.00	
Gas Cap %	0.2%	
SGDI	99.14%	217,703 stbo
GCDI	0.48%	1,046 stbo
WDI	0.00%	0 stbo
PVCI	0.39%	851 stbo

PVT Data

Condition	Initial	Current	BP
P (psi)	2,156	265	1,687
Rs (scf/stb)	475	53	475
Bt (cf/stb)	7.02	30.75	7.06
Bo (rb/stb)	1.2502	1.0583	1.2572
μo (cp)	0.9306	2.5215	0.8873
Co (1/psi)	1.194E-05	2.232E-03	1.525E-05
Bg (cf/scf)	0.0056	0.0588	0.0073
μg (cp)	0.0189	0.0116	0.0162
Cg (1/psi)	4.407E-04	3.597E-03	4.967E-04
Bw (rb/stb)	1.0071	1.0098	1.0078
μw (cp)	0.5724	0.5724	0.5724
Cw (1/psi)	3.326E-06	3.242E-06	3.318E-06

Volumetrics

N	1,263,313 stbo	A	252.90 ac
G	2,706 mcf	ø	12.5%
		Sw	25.0%

	Total	Oil	Gas
h (ft)	8.6	8.6	0.0
Vb (ac-ft)	2,175.20	2,171.52	3.68
Vp (ac-ft)	271.90	271.44	0.46
Vphc (ac-ft)	203.93	203.58	0.35

Reserves

	stbo	bpaf	Rf
Np	219,600	101.13	17.4%
Nwf	157,066	72.33	12.4%
Nult	376,666	173.46	29.8%
N	1,263,313	581.76	100.0%

Gp	504,036 mcf
G	2,706 mcf
Wp	0 bw
We	0 bw
Rp	2,295 scf/stb
Nwf/Np	0.72 to 1

Waterflood

Vb flood	1,492.10 ac-ft	Vb flood	68.7%
Inj Rate	1,000 bwpd	Ea	72.0%
V fillup	478,967 bw	Ev	72.0%
t fillup	1.31 yrs	Ed	42.5%
Sor	30.0%	Et	22.0%

Oil Column Conditions

	Initial	Current
Sw	25.0%	25.0%
So	75.0%	52.2%
Sg	0.0%	22.8%

Comments:

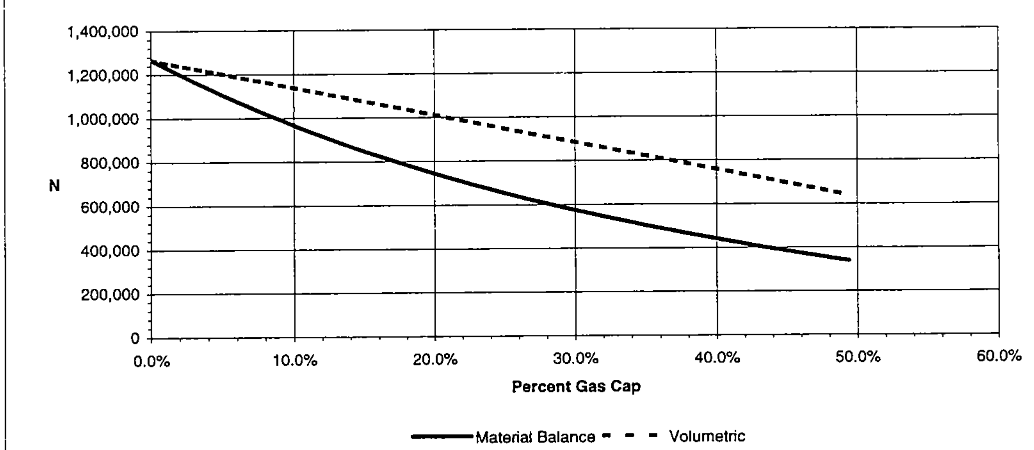


Figure 172. Reservoir model used to analyze waterflood prospects. See Appendix 1 for explanation of abbreviations.

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Appendixes

APPENDIX 1
Abbreviations Used in This Volume

A	production area
ac	acre
ac-ft, acre-ft	acre-foot, acre-feet
AFE	authorization for expenditures
AOR	area of review
API	American Petroleum Institute
avg	average
BCF	billion cubic feet (of gas)
BCFG	billion cubic feet of gas
B_g	gas formation volume factor
BIA	U.S. Bureau of Indian Affairs
BLM	U.S. Bureau of Land Management
BO	barrels of oil
B_o	oil formation volume factor
B_{oi}	initial oil formation volume factor
BOPD	barrels of oil per day
BOPM	barrels of oil per month
BOPY	barrels of oil per year
BP	bubble point
bpaf	barrels per acre-foot
B_t	two-phase formation volume factor
BTW	base of treatable water
BW, bw	barrels of water
B_w	water formation volume factor
BWPD	barrels of water per day
CAL	caliper
CDP	conductivity-derived porosity
CF	cubic feet
C_g	gas compressibility
C_o	oil compressibility
COND	conductivity
cp	centipoise (a standard unit of viscosity)
C_w	water compressibility
D_e	effective decline rate
DEN	density
Depth	formation depth
DST	drillstem test
E_a	areal sweep efficiency
E_d	displacement sweep efficiency
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
E_t	total sweep efficiency ($E_a \cdot E_v \cdot E_d$)
E_v	vertical sweep efficiency
F	Fahrenheit
FMI log	formation micro-imaging log (a Schlumberger tool)
ft	foot, feet
FVF	formation volume factor
G	original-gas-cap to total-volume ratio
Gas Cap %	gas-cap to total-volume ratio
Gas Grav	gas gravity
GCDI	N_p due to gas-cap expansion
GOC	gas–oil contact
GOR	gas/oil ratio
GOR_{avg}	average gas/oil ratio
G_p	cumulative gas production
GR	gamma ray
H, h	thickness of formation
Inj Rate	waterflooding water-injection rate
IP	initial potential, initial production
k	absolute permeability
k_o	relative permeability for oil at irreducible water saturation
L	liter
m	ratio of gas-cap to oil-column volume
MBO	thousand barrels of oil
MCF	thousand cubic feet (of gas)
mcf	million cubic feet (of gas)
md	millidarcies, or 0.001 darcy
mg	milligrams

MIT	mechanical integrity test
ML	microlog
MMBO	million barrels of oil
MMCF	million cubic feet (of gas)
MMCFG	million cubic feet of gas
MMS	U.S. Minerals Management Service
N	original oil in place
NaCl %	water salinity
NEU	neutron
N_p	cumulative production
N_{pp}	primary oil production between bubble-point pressure and current reservoir pressure, in stock tank barrels of oil
N_{ult}	ultimate primary and secondary oil production
N_{wf}	remaining primary and secondary oil production
N_{wf}/N_p	waterflood- to cumulative-production ratio
OCC	Oklahoma Corporation Commission
Oil Grav	oil gravity
OOIP	original oil in place
OWC	oil–water contact
P	current pressure
P_{bp}	bubble-point pressure
P-grad	initial pressure gradient
pH	a measure of hydrogen-ion concentration in solution
P_i	initial pressure
psi	pounds per square inch
psig	pounds per square inch, gauge
PV	pore volume
PVCI	N_p due to pore-volume contraction
PVT	pressure, volume, temperature
Q	total daily production for individual wells
q_i	initial production rate
q_t	production rate at time, t
rb	reservoir barrels
RES	resistivity
RF, rf	recovery factor, or recovery efficiency
R_p	average producing gas/oil ratio
R_s	solution-gas ratio
R_{si}	initial solution-gas ratio
R_t	resistivity of uninvaded zone (true resistivity)
RTS	radioactive tracer survey
R_w	resistivity of formation water
R_{xo}	resistivity of flushed zone
scf	standard cubic feet
S_g	gas saturation
SGDI	N_p due to solution-gas drive
S_o	oil saturation
S_{or}	residual oil saturation
SP	spontaneous potential
SPCC	spill-prevention control and countermeasures
stbo	stock tank barrels of oil
S_w	water saturation
S_{wc}	connate-water saturation at time of discovery
S_{wir}	irreducible water saturation
T	formation temperature
t fillup	time required to reach fill-up
UICD	Underground Injection Control Department (of Oklahoma Corporation Commission)
V_b	bulk volume of formation
$V_{b\,flood}$	floodable volume
V fillup	water volume required to fill up gas space
V_p	pore volume
V_{phc}	V_p hydrocarbons
WDI	N_p due to water influx
W_e	water encroachment
W_p	water produced
WSW	water-supply well
μ_g	gas viscosity
μ_o	oil viscosity
μ_w	water viscosity
ϕ	porosity

APPENDIX 2
Glossary of Terms
(as used in this volume)

Definitions modified from Jackson (1997), Sheriff (1984), and Van Wagoner and others (1990).

absolute permeability—The ability of a rock to conduct a fluid; e.g., gas, at 100% saturation with that fluid.

acre-foot—The volume of liquid or solid required to cover 1 acre to a depth of 1 foot, or 43,560 cubic feet. It is commonly used in measuring volumes of water, reservoir storage space, or reservoir rock.

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.

API gravity—A standard adopted by the American Petroleum Institute for expressing the specific weight of oils. API gravity = (141.5/specific gravity at 60°F) – 131.5. This arbitrary scale simplifies the construction of hydrometers because it enables the stems to be calibrated linearly. The lower the specific gravity, the higher the API gravity.

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.

bubble point—A state of fluids characterized by the coexistence of a liquid phase with an infinitesimal quantity of gas phase in equilibrium.

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 in which 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.

connate water—Water entrapped in the interstices of a sedimentary rock at the time the rock was deposited. The term is commonly misused by reservoir engineers and well-log analysts to mean any water in the voids of rock; i.e., *formation water.*

crevasse-splay deposit—See: *splay.*

darcy—A standard unit of permeability, equivalent to the passage of 1 cubic centimeter of fluid of 1 centipoise viscosity flowing in 1 second under a pressure differential of 1 atmosphere through a porous medium having an area of cross section of 1 square centimeter and a length of 1 centimeter.

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.

dissolved-gas drive—Energy within an oil pool, resulting from the expansion of gas liberated from solution in the oil. Cf: *solution-gas drive.*

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.

effective permeability—The ability of a rock to conduct one fluid, e.g., gas, in the presence of other fluids, e.g., oil or water.

effective porosity—The percentage of the total volume of a given mass of soil or rock that consists of interconnecting voids.

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.

fault—A fracture or fracture zone along which there has been displacement of the sides relative to one another parallel to the fracture.

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.*

fracture—(a) A crack, joint, fault, or other break in rocks. (b) Deformation due to a momentary loss of cohesion or of resistance to differential stress and a release of stored elastic energy.

gas cap—Free gas occurring above oil in a reservoir, and present whenever more gas is available than will dissolve in the associated oil under existing pressure and temperature.

gas-cap drive—Energy within an oil pool, supplied by expansion of an overlying volume of compressed free gas as well as by expansion of gas dissolved in the oil.

gas/oil ratio—(a) The quantity of gas produced with the oil from an oil well, usually expressed as the number of cubic feet of gas per barrel of oil. Abbr.: GOR. (b) *reservoir gas/oil ratio.*

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.

imbibition—The tendency of granular rock or any porous medium to absorb a fluid, usually water, under the force of capillary attraction, and in the absence of any pressure.

impermeable—Said of a rock, sediment, or soil that is incapable of transmitting fluids under pressure.

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.

initial production—The volume or quantity of gas or oil initially produced by a well in a certain interval of time, usually 24 hours.

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

isopleth—(a) A general term for a line on a map or chart that connects points of equal value, e.g., of elevation, or of any quantity that can be numerically measured and plotted on a map; a *contour.*

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.

oil–water contact—The boundary surface between an accumulation of oil and the underlying "bottom water." Syn.: *oil–water interface.*

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

permeability—The capacity of a porous rock, sediment, or soil for transmitting a fluid; it is a measure of the relative ease of fluid flow under unequal pressure. The customary unit of measure is the *millidarcy.* Cf: *absolute permeability; effective permeability; relative permeability.* Adj.: *permeable.*

point bar—One of a series of low, arcuate ridges of sand or 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.

porosity—The ratio of the aggregate volume of interstices in a rock or soil to its total volume. It is usually stated as a percentage. Cf: *effective porosity.* Syn.: *total porosity.*

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).

relative permeability—The ratio between the *effective permeability* to a given fluid at a partial saturation and the permeability at 100% saturation (the *absolute permeability*). It ranges from zero at a low saturation to 1.0 at a saturation of 100%.

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.

secondary recovery—Production of oil or gas as a result of artificially augmenting the reservoir energy, as by injection of water or other fluid. Secondary-recovery techniques are generally applied after substantial depletion of the reservoir. See: *waterflooding.*

shoestring sand—A narrow linear deposit 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.*

solution-gas drive—Energy within an oil accumulation supplied by expansion of gas dissolved in the oil.

specific gravity—The ratio of the weight of a given volume of a substance to the weight of an equal volume of water.

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 connecting 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.

unitization—Consolidation of 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.

upper delta plain—Depositional environment in a *delta* that extends from the downflow 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.

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

water drive—Energy within an oil or gas pool that results from hydrostatic or hydrodynamic pressure transmitted from the surrounding aquifer. Cf: *dissolved-gas drive; solution-gas drive; gas-cap drive.*

waterflooding—A *secondary-recovery* operation in which water is injected into a petroleum reservoir to force additional oil out of the reservoir rock and into producing wells.

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

APPENDIX 3
Well Symbols Used in Figures

•	Oil well
☼	Gas well
✷	Oil & gas well
⌖	Dry hole
○	Water-supply well
	Water-injection well
	Oil well, plugged & abandoned
⊙	Oil zone producer
⊛	Gas zone producer
⊡	Tracer survey producer
NL	No log
NDE	Not deep enough
ND	No data