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PETROLEUM-ENGINEERING STUDY OF K. M. A. RESERVOIR,  
SOUTHWESTERN PART K. M. A. OIL FIELD,  
WICHITA AND ARCHER COUNTIES, TEX.

BY ROLLIE P. DOBYNS, MARION L. AYERS, AND ROGER E. LEWIS

United States Department of the Interior—June 1952

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**UNITED STATES DEPARTMENT OF THE INTERIOR**

Oscar L. Chapman, Secretary

BUREAU OF MINES

J. J. Forbes, Director

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**June 1952**



## PETROLEUM-ENGINEERING STUDY OF K.M.A. RESERVOIR, SOUTHWESTERN PART

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by

Rollie P. Dobyns,1/ Marion L. Ayers,1/ and Roger E. Lewis2/

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## SUMMARY

The K.M.A. reservoir was discovered to be oil bearing at a depth of 3,719 feet on March 11, 1931. Extensive development, however, was not begun immediately, because the discovery well had a low initial daily oil production, and market conditions for oil were unfavorable. Development of the field progressed slowly for the next  $6\frac{1}{2}$  years. In the latter part of 1937, a wildcat well approximately 2 miles southwest of the discovery well was drilled on a magnetometer high and completed with an initial flowing production of 2,018 barrels of  $43^{\circ}$  A.P.I.-gravity oil in 12 hours. Rapid development of the southwestern part of the K.M.A. field was begun immediately and continued until over 700 wells were drilled and approximately 12,500 acres proved oil productive.

Because of the large size of the entire K.M.A. field, this report is limited in scope to the southwestern part only, and the discussion that follows pertains to this area only. The closing date for production statistics is August 1, 1949.

The K.M.A. structure is a complex anticline having a maximum closure of 250 feet, and the K.M.A. formation is composed of sediments that grade from limestone through sandy lime and limy sand to sandstone with thin streaks of shale. Two distinct members of the K.M.A. formation, zone I and zone II, are oil productive. Core analyses indicate the average porosity to be 16.5 percent for zone I and 16.1 percent for zone II. A relationship was established from core data, which showed the correlative permeabilities to be 42.1 millidarcys for zone I and 39.5 millidarcys for zone II, whereas the arithmetical averages of the permeabilities were 84 millidarcys for zone I and 216 millidarcys for zone II. Connate-water saturations were 17.5 percent for zone I and 20.0 percent for zone II. The porosity-saturation method, using a thickness-correction factor, was employed to calculate the volume of 168.1 million barrels of stock-tank oil initially in place in the reservoir. Analyses of the reservoir oil indicate that, although the initial reservoir pressure was 1,750 p.s.i., the original reservoir oil was saturated to only 1,300 p.s.i., at which pressure 1 barrel of stock-tank oil contained 525 cubic feet of gas in solution.

A serious decline in reservoir pressure during the 2 years of rapid development alarmed the operators and caused them to consider a cooperative pressure-maintenance program. In the latter part of 1939, the K.M.A. Pressure Maintenance Association was organized, and the gasoline plants in the field agreed to process the wet gas and return the dry gas to leases having gas-injection wells. Approximately 27 percent of the cumulative volume of produced gas had been returned to the reservoir by August 1, 1949.

The increased oil recovery as a result of the pressure-maintenance program was evaluated by calculating the theoretical oil recovery without gas injection. These calculations indicate a theoretical cumulative primary oil recovery of 41,000,000 barrels to August 1, 1949, whereas the actual recovery to the same date was 46,107,738 barrels. The difference in these recoveries is approximately 5,000,000 barrels of oil, an increase of 12.2 percent over the volume of oil theoretically recovered by primary production. As the estimated initial volume of stock-tank oil in the reservoir was 168.1 million barrels, the oil recovery to August 1, 1949, was 27.4 percent of the initial stock-tank oil in place.

Even though the reservoir pressure was not maintained by the gas-injection program, it made valuable contributions toward conserving natural resources and reservoir energy. Benefits derived from the gas-injection program include longer flowing life for the wells, greater ultimate oil recovery, increased recovery of natural gasoline, and conservation of natural gas.

The ultimate recovery by present methods of production is estimated to be 53 million barrels of stock-tank oil (31.5 percent of the initial stock-tank oil in place) at an assumed economic limit of production of 2 barrels per well per day.

The theoretical performance of one 20-acre, five-spot-pattern water flood for the K.M.A. reservoir was calculated, using the method proposed by Suder and Calhoun. The results of these calculations indicate that, with certain limitations, approximately as much additional oil could be recovered by water flooding as has been recovered to August 1, 1949. The engineering and operating aspects of injecting water into the reservoir are discussed in the report.

Recovery of the oil remaining in the K.M.A. reservoir challenges the ingenuity and initiative of the operators.

#### INTRODUCTION

The K.M.A. field, in Wichita and Archer Counties, Tex., is an example of a large oil field controlled by many independent operators who voluntarily initiated a pressure-maintenance program soon after the field was developed. The Production Committee of the North Texas Oil and Gas Association requested that the Bureau of Mines prepare a report on the K.M.A. field with the twin objectives of evaluating the pressure-maintenance program and investigating the possibilities of water flooding. Because of the size of the K.M.A. field (approximately 30,000 acres), the Production Committee decided that the engineering study should be confined to the southwestern part of the field. The oil recovery has been greater and more beneficial results have been obtained from pressure maintenance in the southwestern than in the northern part of the field.

All data gathered from the many operators in the southwestern part of the K.M.A. field have been compiled and are presented, with calculations and interpretations by the writers. In addition to the development history and the production records concerning the field, sample material-balance calculations and theoretical water-flood calculations are presented.

The writers have used all available records, including electric logs, radioactive logs, core analyses, driller's logs, completion and remedial work records, production statistics, and pressure data, in developing this petroleum-engineering report. Production statistics were obtained from the files of the K.M.A. Pressure Maintenance Association, Wichita Falls, Tex. Cores from three wells were analyzed in the Bureau of Mines Petroleum Experiment Station, Bartlesville, Okla. All other data were obtained directly from the oil companies or operators.

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#### GEOLOGY OF SOUTHWESTERN PART, K.M.A. FIELD

The K.M.A. field, Wichita and Archer Counties, Tex., is in the North Texas area approximately 20 miles west of Wichita Falls, Tex. (see fig. 1). The main body of the field, which has an areal extent of approximately 30,000 acres, is in Wichita County, but a small part of the southwestern edge extends into Archer County. The area discussed in this report is the part of the field shown in solid black in figure 1; it is over 8 miles long (west to east) and nearly 4 miles wide (north to south) and covers an area of approximately 12,500 acres.

The main structural features controlling the occurrence of oil in the North Texas area are the Bend arch and the Red River uplift. According to Cable,<sup>3/</sup>:

The Bend arch is a broad anticlinal feature dipping to the northwest, and extending from the Llano-Burnett uplift in Central Texas to about the center of Archer County in North Central Texas. It separates the West Texas Permian Basin, to the west, from the Fort Worth syncline, to the east.

The Red River uplift is a buried ridge, trending generally east-west and extending from eastern Cooke County to at least as far as western Foard County. It probably is not one continuous ridge but more likely is composed of an "en-echelon" arrangement of northwest-southeast trending anticlinal features, such as the Muenster arch and the Electra arch.

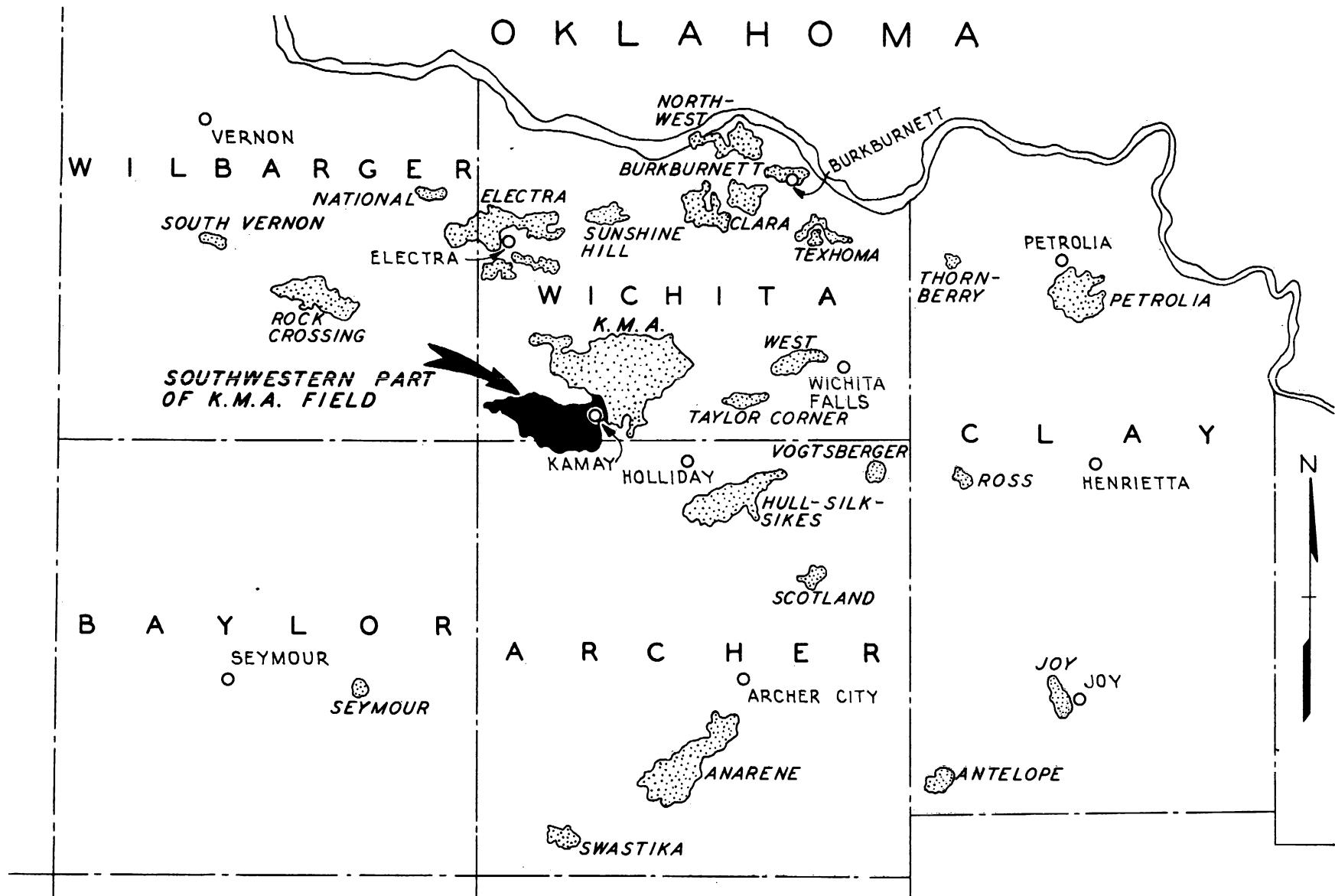
Cheney<sup>4/</sup> reported:

The several hundred million barrels of oil accumulated in the K.M.A. field of southwest Wichita County is no doubt the result of the coincidence of particularly favorable conditions, such as of updip termination of an extensive sedimentary wedge of Strawn beds which included several reservoir members. The main accumulation has taken place where pronounced local folding intersected one of the more prominent "en-echelon," southeast-trending elements of the Electra arch.

In discussing the K.M.A. field Rouzer<sup>5/</sup> stated:

The surface rocks in the vicinity are of Permian age. The general attitude of the beds down to the older depositions of the Red River uplift is a northeast strike with a northwest dip. Drilling in the K.M.A. field has encountered a number of saturated zones. Oil has been produced since 1912 from the Cisco formation at depths above 1,850, but it was not until 1927 that deeper drilling found oil at approximately 3,650 feet in the Strawn section. Development has covered an area 1½ miles long and 8 miles wide. The accumulation is on the south side of the district's main structural feature known as the Red River arch. It would appear that the last active disturbance was in middle Strawn time when the uplift existed as a chain of islands stretching east and west in a shallow sea. In what is now the western part of Wichita County and now the location of the K.M.A. field, a promontory extended south from a high point on the uplift, the present Electra field. Around this promontory, sands, oolites, reef building material, and limestone gathered. This mass-like deposit is now described as the K.M.A. lime, although it is made up of the utmost variety of porous rocks. The whole structure is a complex anticline having a dense seal on the north with no indications of active water drive. This description is given to transmit a picture of oil accumulation in a section that grades from oolite lime through sandstone and sandy limes into sandstone and shales, far from the ideal picture of a reservoir adaptable to secondary recovery methods.

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- <sup>3/</sup> Cable, Jo H., Gas Repressuring in the State of Texas: A.P.I. Secondary Recovery of Oil in the United States, 1st ed., 1942, p. 216.  
<sup>4/</sup> Cheney, M. G., Geology of North-Central Texas: Bull. Am. Assoc. Petrol. Geol., vol. 24, No. 1, January 1940, p. 118.  
<sup>5/</sup> Rouzer, W. H., Jr., Pressure Maintenance in the K.M.A. Field: Oil Weekly, vol. 105, Apr. 6, 1942, p. 22.



Prepared from map furnished by courtesy  
of North Texas Oil Scouts Association.  
Original map compiled and drawn by Wayne Ferguson.

Figure 1.-Map of selected oil and gas fields in North Texas area.



Although the entire K.M.A. field may be considered one reservoir, the K.M.A. formation in the southwestern part is different in lithology from the K.M.A. formation in the northern part. A generalized geologic column accompanied with an electric log from the southwestern part of the K.M.A. field is shown in figure 2.

For purposes of this report, the following terminology is used to designate the rocks between the top of the K.M.A. limestone and the top of the main shale break.

K.M.A. limestone - That part of the rocks between the top of the K.M.A. limestone and the top of zone I.

K.M.A. formation - The rocks between the top of zone I and the top of the main shale break. The oil-productive parts of the K.M.A. formation are designated zones I and II.

K.M.A. reservoir - The oil productive parts of the K.M.A. formation, which are zones I and II.

In the southwestern part of the field, oil is produced mainly from the K.M.A. formation, a member of the Strawn group of Pennsylvanian age. The K.M.A. formation has two distinct oil-producing members, which are locally named zone I and zone II. The K.M.A. limestone overlies the K.M.A. formation and is used as a marker bed when drilling into the K.M.A. formation. The first zone of production is found at varying depths below the top of this marker bed and is identified easily by electric logs. Zone I usually lies immediately below a distinctive shale break, and zone II is separated from zone I by a dense limestone stringer. A thin but distinctive shale break is present directly above and below this limestone stringer separating zone I from zone II. Throughout the entire area, the base of zone II lies above a thick bed of shale, which is locally called the "main shale break." In some small areas, oil has been produced from thin sand lenses and oolitic limestone stringers immediately underlying the top of the K.M.A. limestone.

Other horizons productive of oil in some localities within the southwestern part of the K.M.A. field are the shallow Gunsight sand, the Goen limestone, and the Ellenburger limestone. Wells completed in the 1,800-foot Gunsight sandstone are not located on the development map (fig. 3). The Goen limestone is encountered approximately 20 to 50 feet below the main shale break. The K.M.A. and Ellenburger wells that were recompleted to produce from the Goen limestone are shown in figure 3 (most of these recompletions were made subsequent to the closing date of this report, August 1, 1949).

The Ellenburger limestone of Ordovician age, which underlies the K.M.A. formation approximately 500 feet, was nonproductive of oil in the K.M.A. discovery well drilled in 1931. Later, Fain-McGaha Oil Corp. drilled a deep test on its Griffin "B" lease (now owned by Shell Oil Co., Inc.). This well, which was completed in April 1940, found the Ellenburger limestone oil productive. Subsequent deep drilling defined the productive area of the Ellenburger limestone as covering a large part of units 5 and 6. The performance of the Ellenburger reservoir is not included in this report; however, the location of the Ellenburger wells is shown on the map in figure 3.

A structure map contoured on top of the K.M.A. limestone is shown in figure 4. The contours in this illustration depict a complex anticline with a maximum closure of 250 feet. Although the structural contours depict a complex anticline, core-analysis data indicate that permeability pinch-outs probably assisted in forming the trap necessary for accumulating oil.

One longitudinal and five transverse correlative cross sections prepared from electric, radioactive, and drilling logs (see figs. 5-10) depict the structural configuration of the area and the relative positions of the tops of the K.M.A. limestone, zone I, and zone II. Cross sections 2-2' through 5-5' disclose a displacement ranging from 112

to 154 feet along the north side of the area, indicating the possibility of faulting. This displacement, however, does not appear in cross sections 1-1' or A-A'. The facies changes in zones I and II are apparent from examination of the cross sections.

The entire K.M.A. formation undoubtedly was deposited under conditions of very erratic sedimentation, causing the two producing zones to have different lithological characteristics across the field. The K.M.A. formation grades from limestone to sandstone, with interspersions of shale. Part of the limestone is oolitic, and vugs occasionally are evident. The matrix of the sandstone is usually calcareous, with varying degrees of cementation.

An X-ray analysis of the insoluble residue left after acid-solubility tests showed the presence of illite, in addition to other minerals, such as quartz. Illite is a clay mineral that is next in base exchange to montmorillonite.<sup>6/</sup>

The illite, when contacted by water having a different salt concentration than the connate water, may disperse to such an extent that the fine dispersed particles of clay will plug the pore openings and reduce the permeability of the formation.

#### DEVELOPMENT OF SOUTHWESTERN PART, K.M.A. FIELD

##### Discovery

The K.M.A. formation was found to be oil bearing when the Deep Oil Development Co. completed its Munger "A" well No. 1 on March 11, 1931. (The Munger lease is now owned by W. A. Moncrief & Sons.) This well was a dry hole at 5,430 feet in the Ellenburger limestone and was plugged back to the K.M.A. formation at 3,977 feet. After being shot with 500 quarts of nitroglycerin, placed between 3,675 and 3,942 feet, the well flowed, by heads, 125 barrels of oil and 18 barrels of water per day. The depression period, an unfavorable market condition, and the discovery of the East Texas field discouraged development in the K.M.A. field, and only 12 more wells were drilled during the next 5 years.

In 1937 a magnetometer survey was made of the area southwest of the discovery well. This survey indicated a magnetometer high and resulted in the Kadane-Griffith Oil Co. drilling and completing on November 14, 1937, the Mangold "A" well No. 1 (see fig. 3) in the K.M.A. formation. The well was completed in open hole between 3,688 and 3,752 feet and had an initial flowing production of 2,018 barrels of 43.8° A.P.I. gravity oil during a 12-hour test. This wildcat opened a large area southwest of the discovery well for development, which was begun immediately.

##### Drilling Methods

Most wells in the K.M.A. field were drilled with standard rotary rigs to the top of the K.M.A. limestone. Casing was set and cemented at this point or slightly below the top of the K.M.A. limestone before drilling into the oil-productive section. Most of the early wells were completed with cable-tool spudders; but, in some of the later wells, rotary rigs were used entirely. Generally the wells were drilled the full distance with rock bits; however, fishtail bits were used by some of the drillers to a depth of 1,400 to 1,800 feet. Natural gas, gasoline, and fuel oil were the fuels commonly used for power. Commercial admixtures were used in the drilling fluid, and the

<sup>6/</sup> Hughes, Richard V., and Pfister, Rudolf J., Advantages of Brines in Secondary Recovery of Petroleum by Water-Flooding: Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 170, 1947, pp. 187-201.

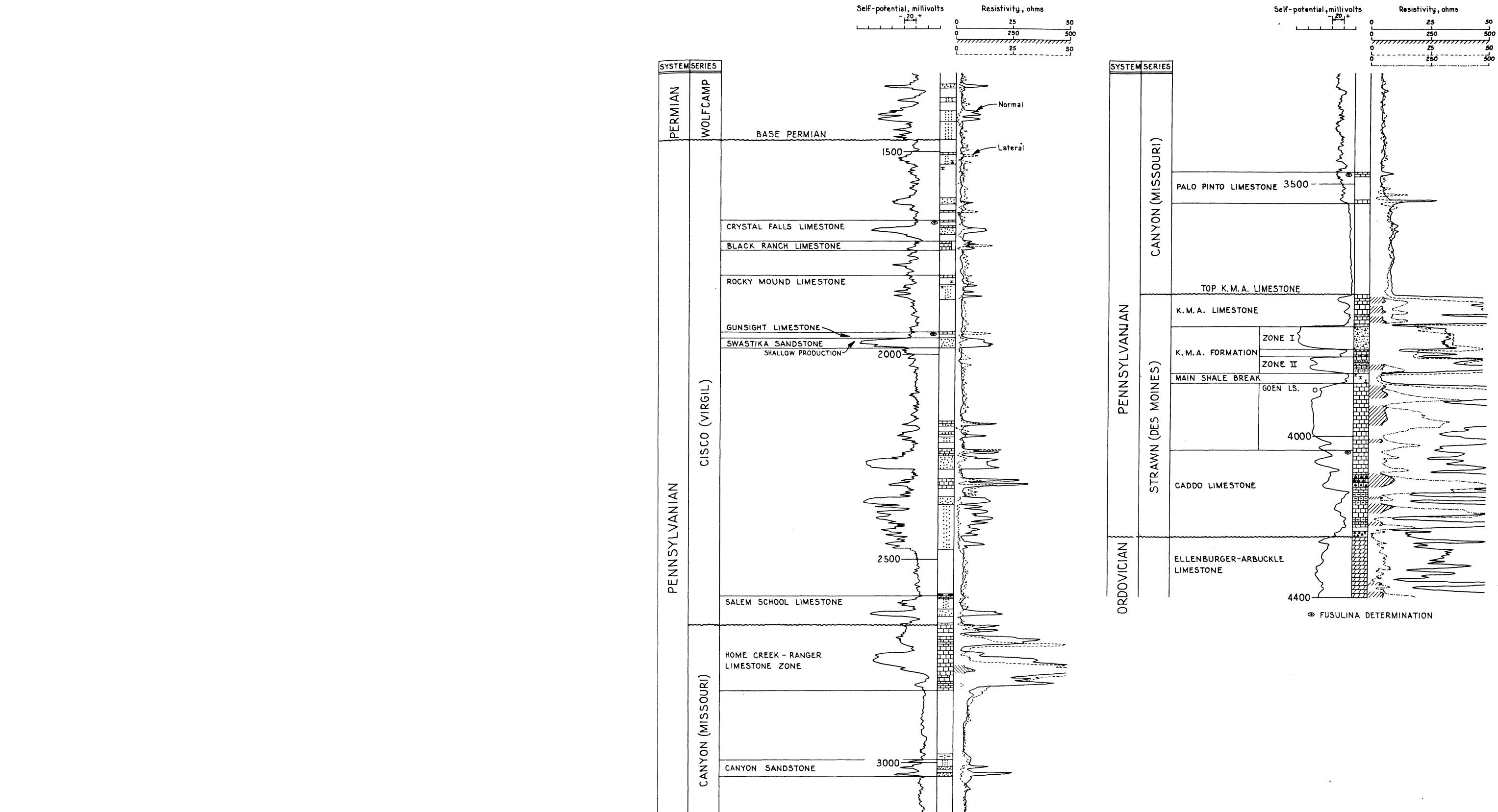


Figure 2.- Correlation of generalized geologic column and electric log, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



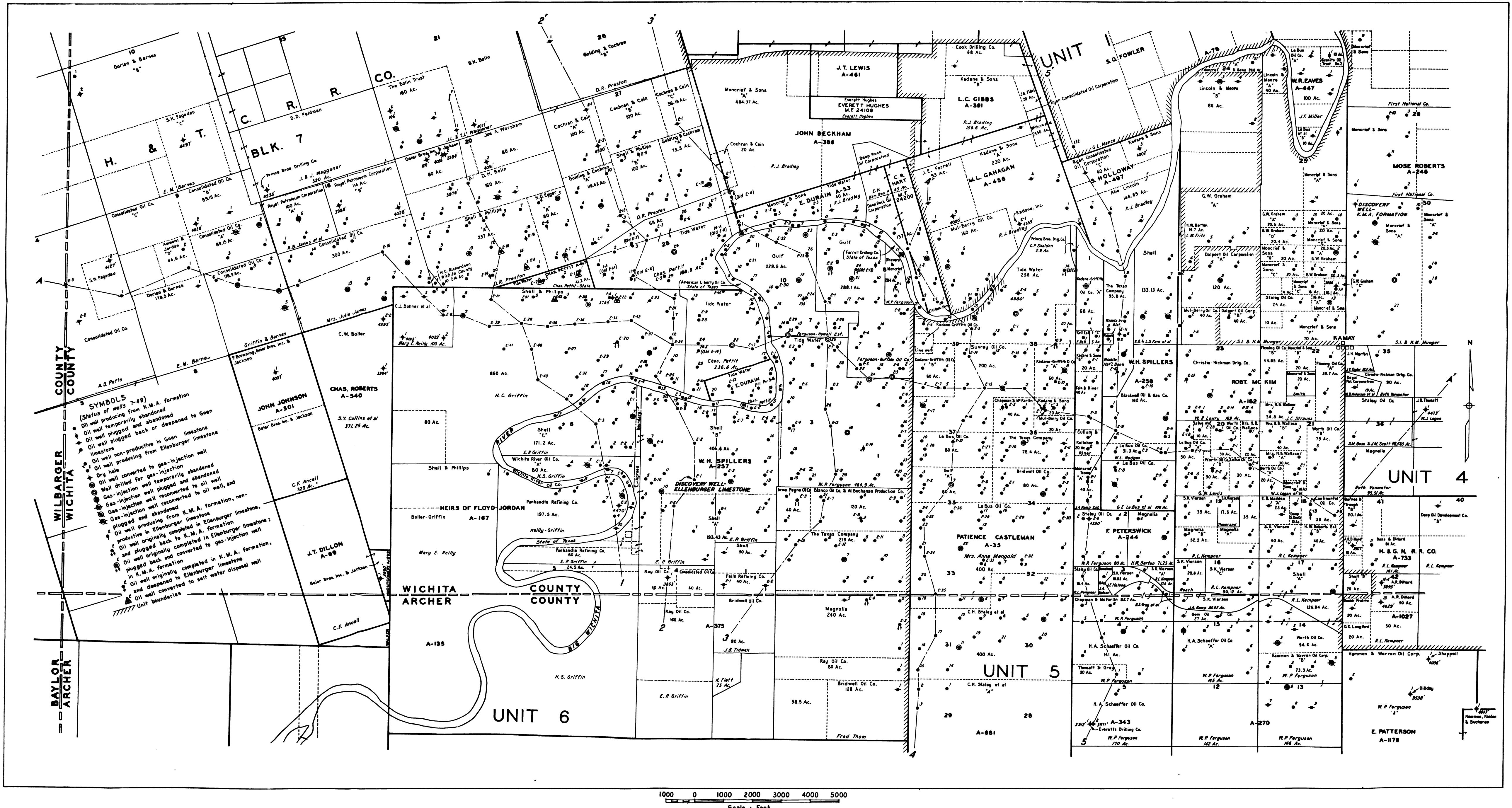


Figure 3.-Development map, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



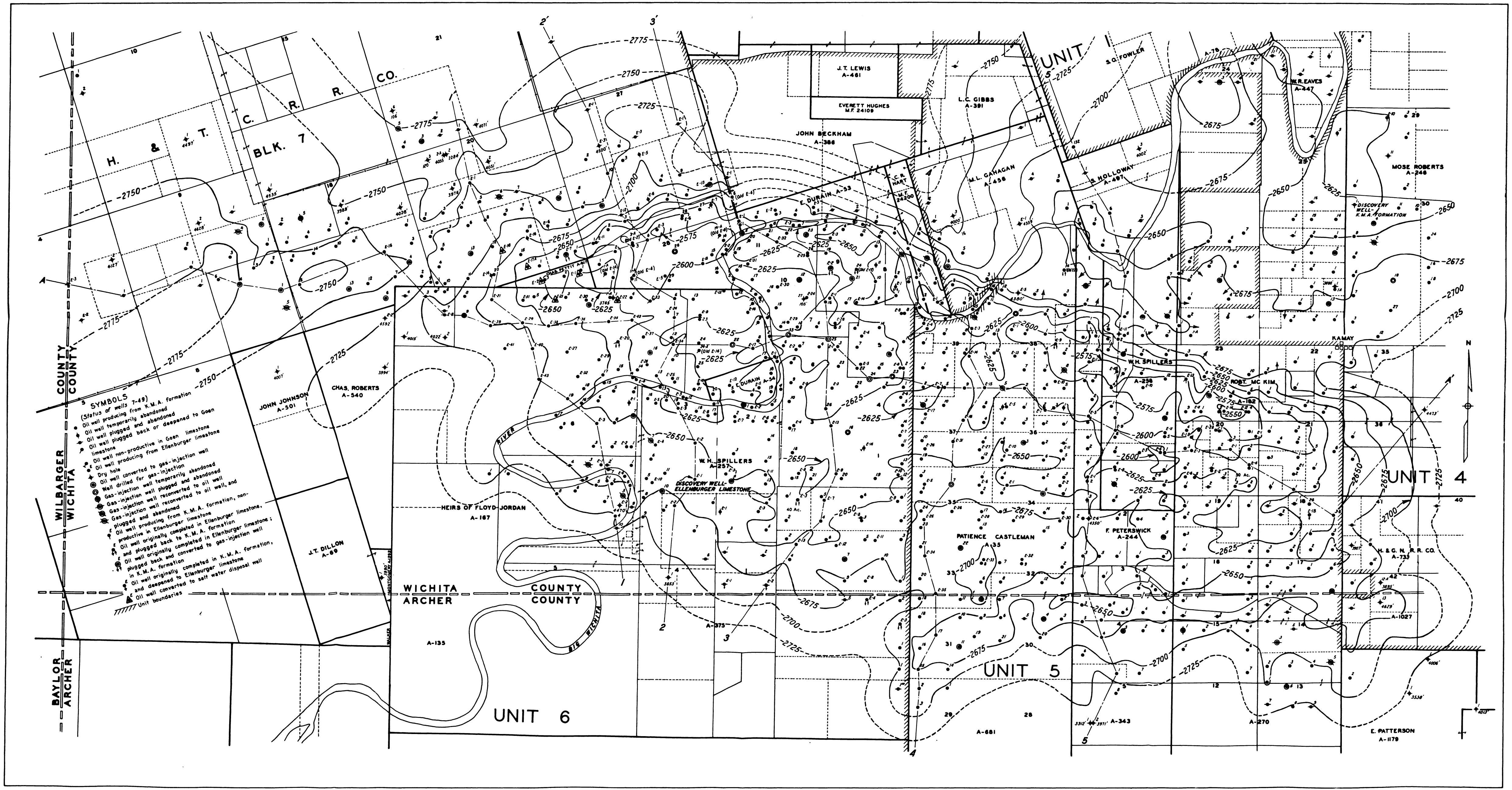


Figure 4.-Structure map, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



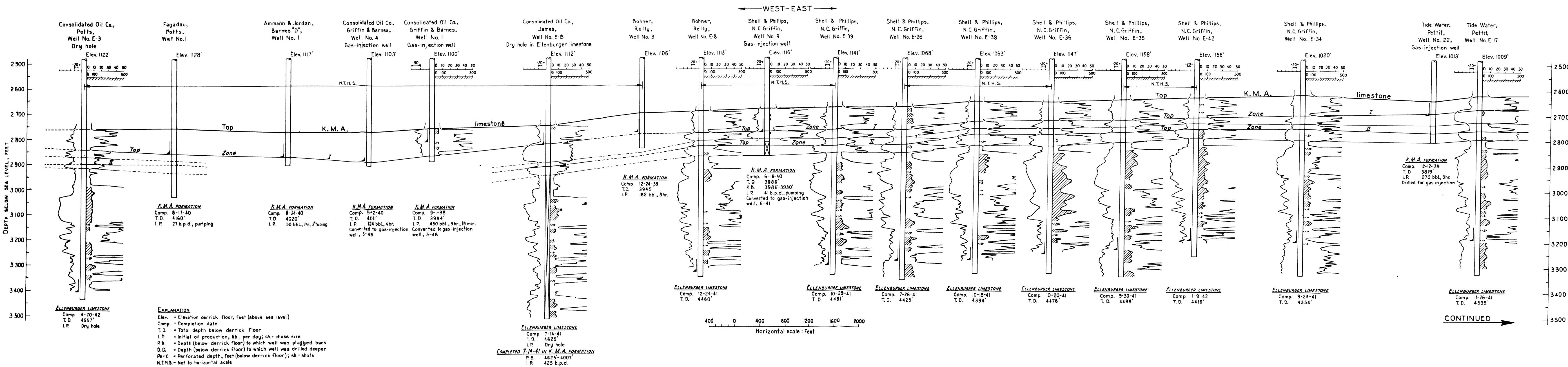


Figure 5.-Longitudinal correlative cross section A-A', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



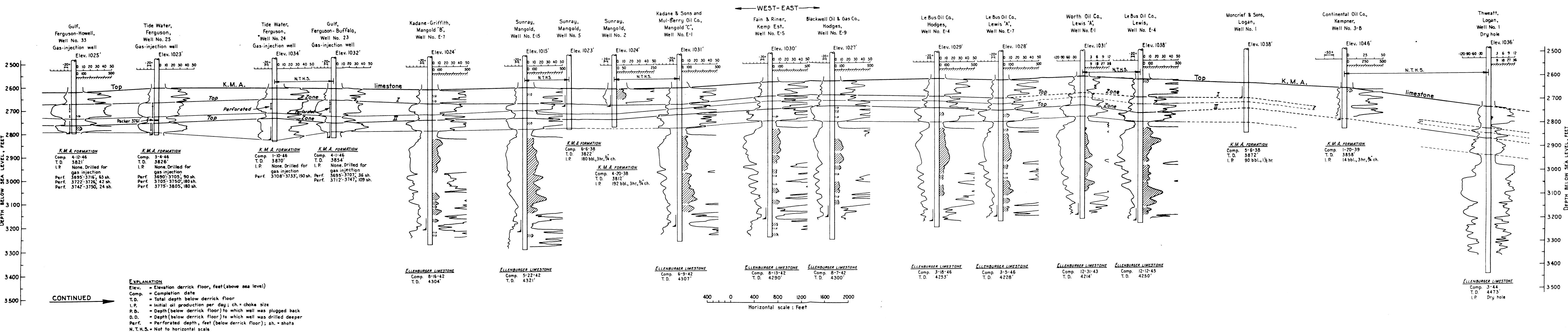


Figure 5.-Longitudinal correlative cross section A-A', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



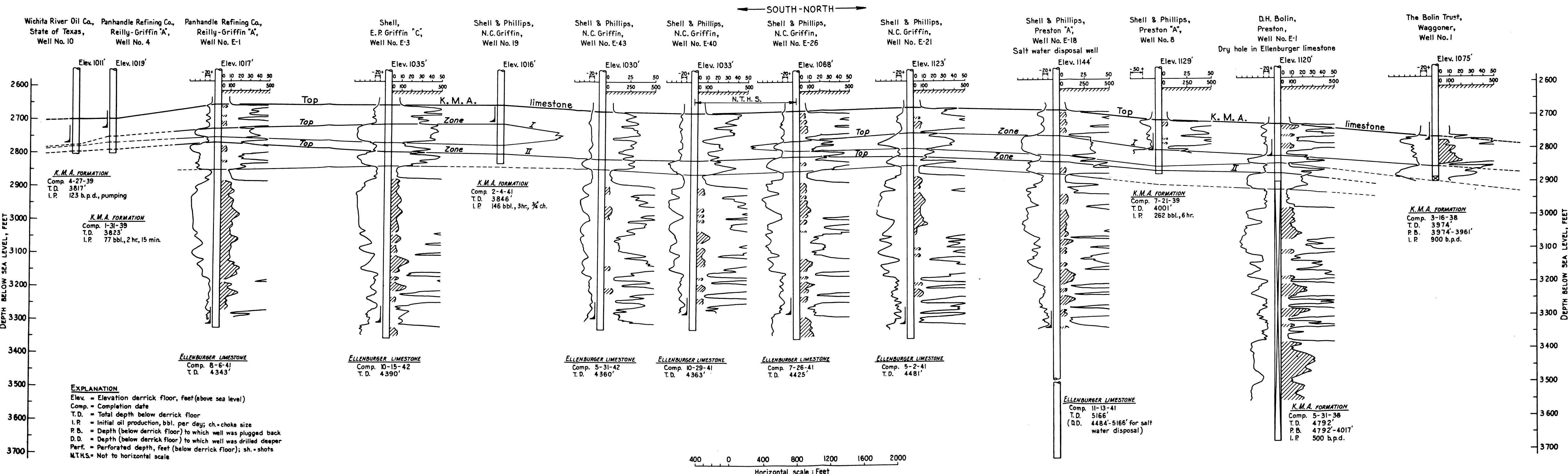


Figure 6.- Transverse correlative cross section I-I', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



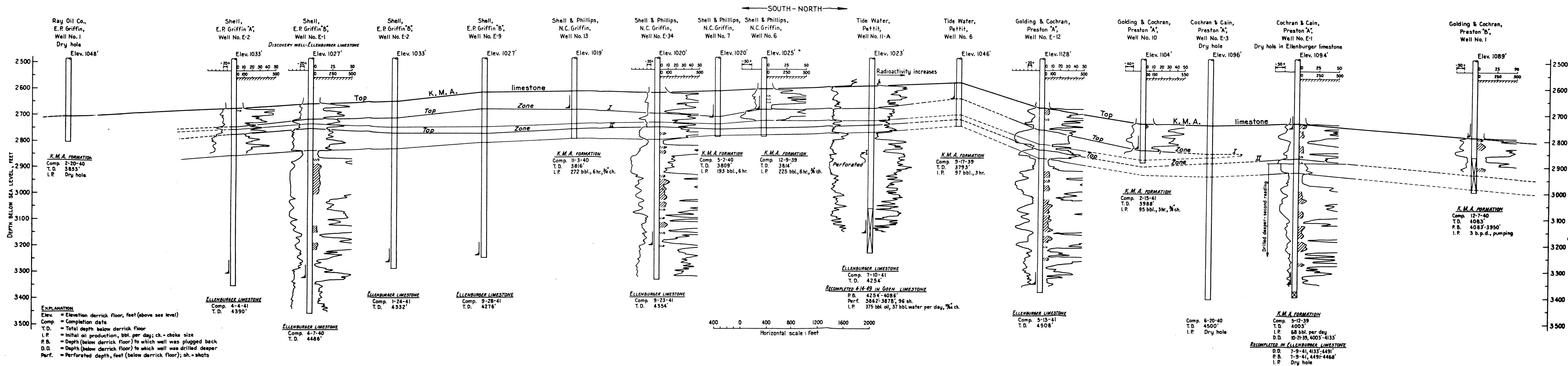


Figure 7.-Transverse correlative cross section 2-2, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



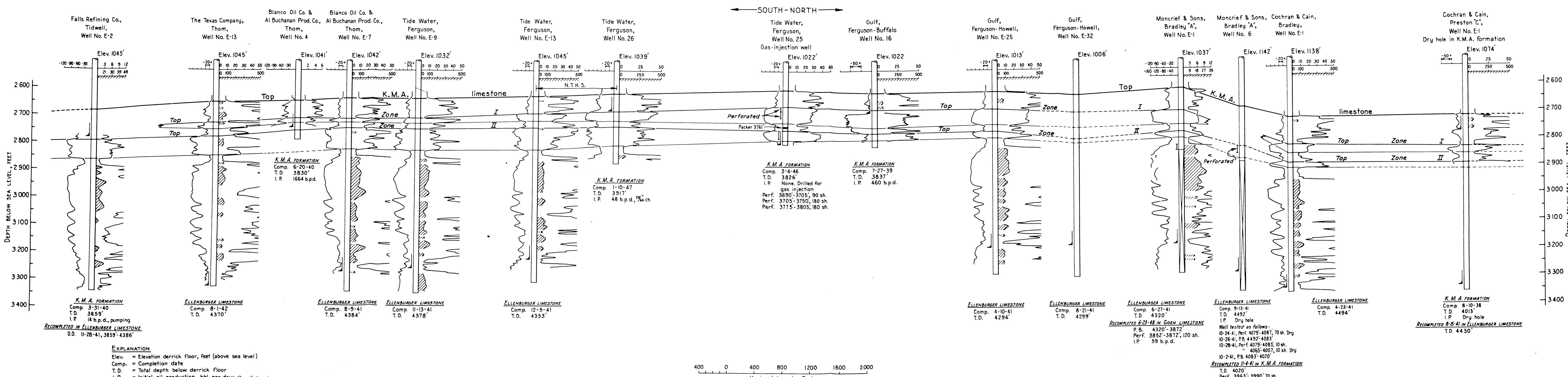


Figure 8.-Transverse correlative cross section 3-3', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

**EXPLANATION**

Elev. = Elevation derrick floor, feet (above sea level)  
 Comp. = Completion date  
 T.D. = Total depth below derrick floor  
 I.P. = Initial oil production, bbl. per day; ch. = choke size  
 P.B. = Depth (below derrick floor) to which well was plugged back  
 D.D. = Depth (below derrick floor) to which well was drilled deeper  
 Perf. = Perforated depth, feet (below derrick floor); sh. = shots  
 N.T.H.S. = Not to horizontal scale



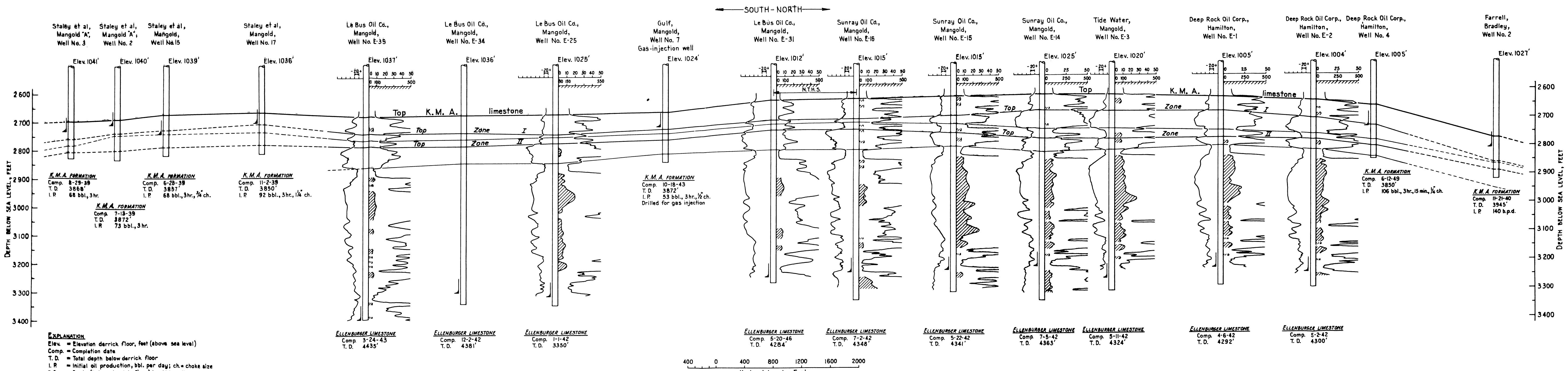
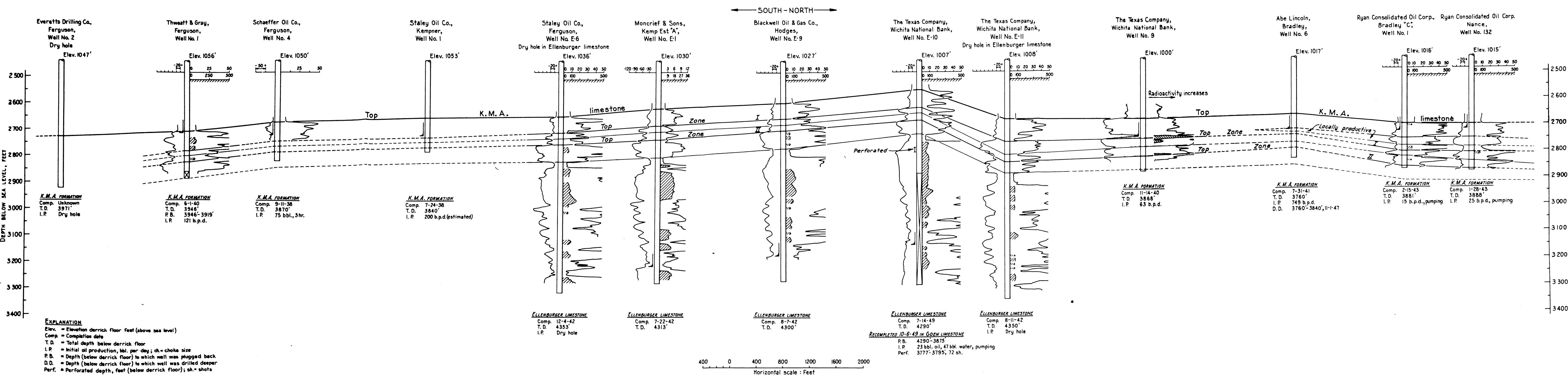


Figure 9.-Transverse correlative cross section 4-4', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.





verse correlative cross section 5-5', southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



weight of the fluid was maintained between 9.5 and 10.0 pounds per gallon.

Only a few wells penetrated the entire K.M.A. formation, because the operators either feared drilling into water or were willing to stop drilling if a good flowing well could be completed in zone I. Consequently, the completion depths were not uniform, and zone II was not penetrated in many of the K.M.A. wells. Even the wells that were drilled into zone II frequently did not penetrate the entire zone. The impervious limestone stringer separating zone I from zone II prevented vertical movement of the oil between the zones. Smaller impervious layers of shale and limestone within zones I and II probably prevented vertical movement of the oil. Hence, the writers believe that much oil was left in the reservoir because entire sections of zones I and II were not open to the well bore in all wells.

#### Drilling Time

The time required by the rotary rigs to drill to the top of the K.M.A. limestone was 15 to 22 days. The time required to drill from the top of the K.M.A. limestone to total depth ranged from a minimum of 4 days to a maximum of about 2 weeks.

#### Casing Program

Rule 2 of the Railroad Commission of Texas Special Order 9-185 states that the casing program for the field should include two strings set in accordance with the following program:

- (a) A minimum of 100 feet of surface casing shall be used with enough cement to fill the annular space behind the surface casing shoe to the surface of the ground.
- (b) The oil string shall be new or second-hand pipe that has been tested to 1,500 p.s.i., and a minimum of 100 sacks of cement shall be used.

Most of the wells in the K.M.A. field were completed with 10-inch surface casing and 7-inch oil string; however, a few wells were equipped with  $5\frac{1}{2}$ -inch pipe for the oil string.

#### Drilling Costs

The estimated cost of drilling and completing a 3,987-foot well in the K.M.A. formation in 1939 is shown in table 1. This cost estimate is believed to be typical of wells in the southwestern part of the K.M.A. field; however, other operators reported costs as high as \$25,000 per well.

#### Well Spacing

Rule 1 of the Railroad Commission of Texas Special Order 9-185 stipulates that no well should be drilled for oil or gas at any point less than 660 feet from another well or less than 330 feet from any property or division line. Although drilling thus was permitted on 10-acre spacing, the commission encouraged 20-acre spacing; and the field was divided into tracts of approximately 20 acres, with each tract designated as a proration unit.

The well spacing pattern for the K.M.A. formation was irregular, and the well density ranged from 10 to 20 acres per well. The following tabulation gives statistical data, by units, for the southwestern part of the K.M.A. field regarding operators, leases, wells, and spacing.

TABLE 1.—Estimated cost of drilling and completing 3,987-foot well  
in K.M.A. reservoir, southwestern part of K.M.A. field,  
Wichita and Archer Counties, Tex.

Labor:		
Drilling contract:		
Derrick erection, labor, repairs, shop work, fuel and water, trucking, miscellaneous . . . . .	\$ 9,500.00	
Drilling-in-spudder . . . . .	1,011.00	
Company account:		
Labor - day work . . . . .	40.00	
Schlumberger . . . . .	275.00	
Cementing:		
Contract oil string . . . . .	175.00	
Contract surface string . . . . .	50.00	
Well shooting . . . . .	487.00	
Miscellaneous . . . . .	120.00	
Material:		
Cost of cement:		
Oil string . . . . .	100.00	
Surface string . . . . .	50.00	
Miscellaneous supplies . . . . .	169.00	
Pipe and appurtenances:		
Pipe:		
100 feet 10-3/4-inch O.D. casing at \$1.55 . . . . .	155.00	
3,967 feet 7-inch O.D. casing at \$105.96 . . . . .	4,203.43	
3,799 feet 2-3/8-inch O.D. tubing at \$29.28 . . . . .	1,112.35	
Appurtenances:		
Clamps - casing . . . . .	10.50	
Casing head . . . . .	145.00	
Christmas-tree assembly . . . . .	186.20	
Lead lines to tanks:		
1,000 feet 2-inch at \$0.13 . . . . .	130.00	
Total . . . . .	\$17,919.48	

Well completed . . . . . February 1939

	Unit 4 (subdivided)	Unit 5	Unit 6	Units 4 (subdivided), 5, and 6 combined
Number of operators .....	10	42	28	62
Number of leases .....	21	83	44	148
Maximum number of wells completed in K.M.A. formation .....	65	345	341	751
Productive area, acres .....	1,334	5,503	5,663	12,500
Average well density, acres per well .....	20.5	16.0	16.6	16.7

An examination of the development map (fig. 3) shows that the well locations on some leases followed a competitive or offset obligation pattern rather than uniform spacing. Locating most of the wells on the large leases near the lease boundary lines may have resulted in poor drainage from the center of these leases.

#### Well Completions and Equipment

Wells in the K.M.A. formation generally were completed by cementing the casing above zone I and leaving the hole open to the oil-bearing strata. Liners were seldom used during the initial completion; however, sloughing of the formation caused many operators to recomplete the wells with liners later. Flowing wells ordinarily were equipped with 2-inch tubing through which the rate of flow was regulated by surface chokes.

The flow lines from individual wells usually were joined to a central gathering line. At the tank battery, the oil passed through a low-pressure gas-oil separator before being stored in the stock tanks. The gas from the separators was delivered to the gasoline plants for processing. On leases equipped with central gathering lines for the oil, portable field testing units generally were used to measure the gas:oil ratios of individual wells. Some operators were successful in reducing high gas:oil ratios by installing bottom-hole chokes.

Although some paraffin was associated with the oil produced from the K.M.A. formation, it resulted in only minor production problems.

No wells were dually completed to produce oil from the Ellenburger limestone and the K.M.A. formation.

When it became necessary to produce wells by artificial lift, either conventional pumping equipment or subsurface hydraulic units were installed. The conventional pumping jacks were individually powered by electric motors or gas engines.

#### Shooting and Acidizing

Many oil wells completed in the K.M.A. formation have been shot with liquid or solidified nitroglycerin. Available records indicate that 572 wells (approximately 80 percent of all the wells) were shot at completion or later as a remedial measure. The

size of the nitroglycerin charges ranged from less than 1 quart per foot to more than 8 quarts per foot, and the average charge was 3 quarts per foot.

Acidizing was used as a treatment in about  $5\frac{1}{2}$  percent of the total number of wells. An average of 2,500 gallons of acid was used per well, and usually the wells that were treated had been shot previously.

The results of the shootings generally were regarded as favorable, as the initial production of most K.M.A. wells shot at completion usually was increased materially. Figure 11 compares flow tests taken before and after a nitroglycerin shot in Tide Water Associated Oil Co. Mangold well No. 8.

#### SUBSURFACE INTERPRETATION OF SOUTHWESTERN PART, K.M.A. RESERVOIR

##### Electric and Radioactive Well Logging

Approximately 17 percent of the wells completed in the K.M.A. formation were logged electrically. The general practice before setting the casing was to drill only deep enough into the K.M.A. formation to obtain oil saturation. After the hole was surveyed by an electric logging device to the existing total depth, the casing was set and cemented at or near the top of the K.M.A. limestone. Normally the hole was not resurveyed after the well was completed. As most of the K.M.A. wells that were logged electrically showed, at best, only a small part of the K.M.A. formation, these electric logs were of little value in analyzing the reservoir. A total of 125 K.M.A. wells were logged electrically; however, these wells were not uniformly dispersed over the southwestern part of the field; and, in many areas of the field, especially the eastern part of unit 5, electric logs were lacking entirely. As most of the wells were logged during 1938 and 1939, these electric logs do not have many of the improvements of present-day electric logging devices. The interpretation of these logs was extremely difficult and occasionally impossible.

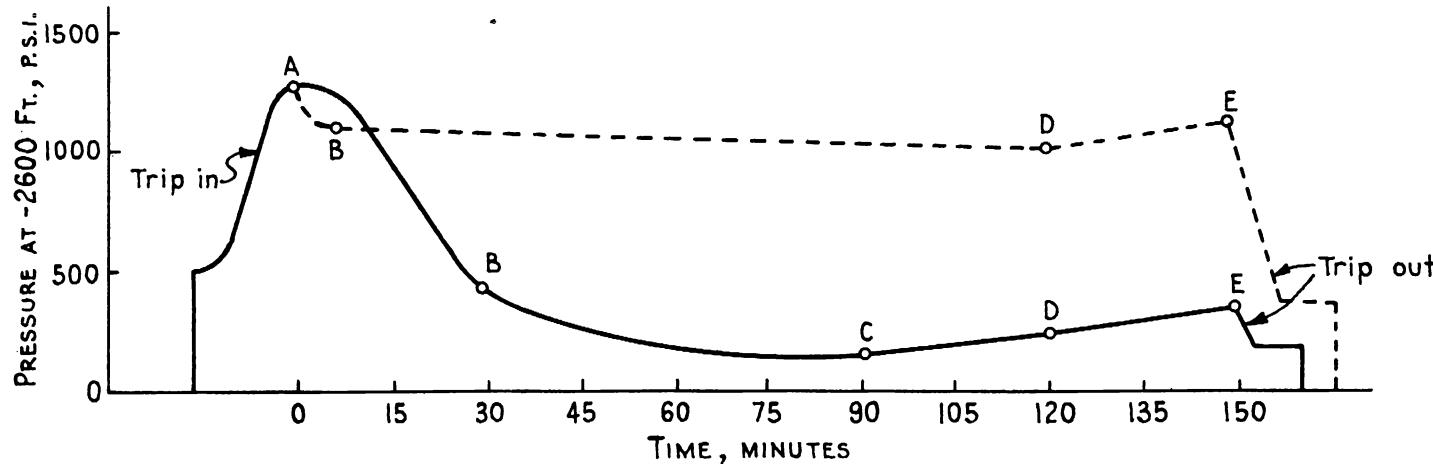
In all, 91 Ellenburger wells were logged electrically during development of the Ellenburger reservoir. These logs were very useful in interpreting and correlating the K.M.A. formation, as most operators surveyed the entire depth of the hole.

In the K.M.A. field, the radioactive well-logging device was used first during 1943; since that time, 26 wells have been logged by this method. The principal use of the radioactive well log in the southwestern part of the K.M.A. field has been to locate the porous sections in the Goen limestone, and many Ellenburger wells have been successfully plugged back and recompleted in this formation.

Correlative cross sections (figs. 5-10) were prepared, using the available electric and radioactive logs. The identification and correlation of zones I and II is readily apparent by examining these cross sections. Because of the changing lithological characteristics of zones I and II, the writers were unable to interpret the electric logs quantitatively for porosity, permeability, connate water, and net thickness or to correlate them with core analyses. Electric and radioactive logs, however, were indispensable in determining the tops of the K.M.A. limestone and the gross thicknesses of zones I and II.

##### Coring and Core Analyses

Parts of the K.M.A. formation were cored in a substantial number of wells; however, only a small part of the cores from these wells were either analyzed or described lithologically. Because zones I and II have different lithological characteristics and, apparently, are not in communication with each other except through the well bores, the core analyses from the two zones were grouped separately.

NOMENCLATURE

— FLOW TEST RUN ON 9-23-39  
BEFORE SHOT

- - - FLOW TEST RUN ON 2-21-40  
AFTER SHOT

A WELL OPENED  
B FLUID HIT CASING HEAD  
C WELL DEAD  
D WELL SHUT IN  
E STARTED OUT OF HOLE

WELL DATA

STATIC BOTTOM HOLE PRESS. @ -2600'	1,270 p.s.i.	1,244 p.s.i. <sup>1/</sup>
MINIMUM BOTTOM HOLE PRESS. @ -2600'	140 p.s.i.	1,015 p.s.i.
TIME FOR FLUID TO REACH SURFACE	28 min.	5 min.
TOTAL PRODUCTION <sup>2/</sup>	29.87 bbl. <sup>3/</sup>	107.08 bbl. <sup>4/</sup>

Before Shot	After Shot <sup>1/</sup>
1,270 p.s.i.	1,244 p.s.i.
140 p.s.i.	1,015 p.s.i.
28 min.	5 min.
29.87 bbl. <sup>3/</sup>	107.08 bbl. <sup>4/</sup>

- 1/ Well shot with 240 qts. nitro-glycerin from 3736'-3819'; total depth of well was 3823'.
- 2/ Initial potential at completion was 70 bbl. flowing in 2 hours.
- 3/ Well open through casing for 2 hours.
- 4/ Well pinched through casing for 2 hours.

FIGURE 11.- COMPARISON OF FLOW TESTS TAKEN BEFORE AND AFTER A NITRO-GLYCERIN SHOT, TIDE WATER ASSOCIATED OIL COMPANY, MANGOLD LEASE, WELL NO. 8, K.M.A. RESERVOIR, SOUTHWESTERN PART OF K.M.A. FIELD, WICHITA AND ARCHER COUNTIES, TEX.



Analyses of cores made by oil companies and commercial laboratories from 82 K.M.A. wells were obtained from the operators. In all, 1,011 individual samples were analyzed from 65 wells that cored zone I, and 808 individual samples were analyzed from 47 wells that cored zone II. Although the complete cores were analyzed from only four wells penetrating the entire K.M.A. formation, the remaining wells were distributed over the area in such a way that the analyses of the cores from these wells should give representative values for the physical characteristics of the K.M.A. formation.

Most of the wells were cored with rotary equipment and water-base drilling fluid; however, oil was used as the drilling fluid in four wells. Coring time varied 2 to 30 minutes per foot, depending upon the texture of the formation being cut.

The core-analysis data could not be correlated with the self-potential and resistance curves of electric logs, and calculations to determine quantitatively the porosity and connate-water saturation from electric logs were unsuccessful. These calculations and correlations probably were unsatisfactory because the erratic sedimentation caused vertical changes in the lithological characteristics of the formation to such an extent that the quantitative interpretation of electrical logs was virtually impossible.

Tables 2-10 show core analyses for nine wells in different areas in the southwestern part of the K.M.A. field. These tabulations include analyses of cores from zones I and II, wells cored with oil and with water as the drilling fluid, and one well cored with a Carter pressure-core barrel. Tables 2, 5, 6, 7, and 10 show core analyses from wells in widely separated parts of the field. Table 3 shows the analyses of cores taken with the Carter pressure core barrel. Tables 4 and 8 show the analyses of cores from two wells cored with oil as the drilling fluid. The analytical data in table 9 include connate-water determinations by the restored-state method in addition to permeability, porosity, and acid-solubility measurements. An interesting feature of the core analyses is that the acid solubility of the permeable beds is considerably lower in zone I than in zone II (see tables 2, 7, and 9). Another interesting relationship was the low water saturation of the permeable cores taken with oil as the drilling fluid (see tables 4 and 8).

Figure 12 is a graphic presentation of core analyses for wells in widely separated parts of the field. This figure illustrates a lack of uniformity in the permeability between wells, which would virtually eliminate the possibility of having gravity segregation of the oil.

#### Interpretation of Core Analyses

To analyze the K.M.A. reservoir, it was necessary to determine the net void space in the reservoir rock and the percentage of the net void space occupied by oil, gas, and connate water. As the K.M.A. reservoir oil was undersaturated with gas, the void space initially contained no free gas, because all the gas was dissolved in the reservoir oil. Free gas did not appear in the reservoir until the pressure had declined below the saturation point.

Because of the incompleteness of any one type of reliable information, all available core data; electric, radioactive, driller's, and drilling-time logs; and drill-cutting analyses were used to determine the net void space and fluid content of the K.M.A. reservoir. Normally, to calculate the net void space in the reservoir, it is desirable to determine the net productive thickness of the reservoir rock in each well. Because of inadequate data, however, this thickness could not be determined in most of the K.M.A. wells; and, as an alternate procedure, the gross thickness of zones I and II in individual wells was determined.

TABLE 2.—Analyses of core samples from first and second producing zones, K.M.A. formation, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex., Shell Oil Co., Inc., Kempner "A" well No. 6.

Elevation, 1,047 feet

Interval from which core was taken, feet below derrick floor	From -	To -	Permeability, millidarcys	Porosity, percent	Saturation, percent		Acid solubility, percent
					Oil	Water	
		3,784		Top of first producing zone			
3,789	3,790	694		19.5	14.6	63.5	2.2
3,790	3,791	1,570		21.9	13.2	56.5	2.4
3,791	3,792	850		18.3	14.2	61.2	4.5
3,792	3,793	419		18.7	13.8	50.3	.8
3,793	3,794	666		20.5	9.8	42.6	1.1
3,794	3,795	1.1		9.6	0	35.0	29.4
		3,795		Base of first producing zone			
		3,818		Top of second producing zone			
3,818	3,819	587		19.6	10.3	28.1	6.8
3,819	3,820	.6		6.4	4.6	42.2	26.3
3,820	3,821	< .1		6.4	2.5	34.9	52.9
3,821	3,822	109		18.0	13.0	21.4	2.7
3,823	3,824	< .1		2.7	0	47.2	57.9
3,824	3,825	1.8		11.5	11.0	43.1	12.1
3,825	3,826	.7		8.8	5.0	24.0	52.3
3,826	3,827	.2		9.5	8.9	20.6	44.2
3,827	3,828	< .1		2.4	0	63.0	64.4
3,828	3,829	1.0		9.4	9.4	22.9	30.5
3,829	3,830	.5		10.3	10.0	18.6	68.6
3,831	3,832	7.6		15.0	2.6	51.8	12.5
3,832	3,833	17		14.2	8.6	24.3	27.9
3,833	3,835	< .1		4.0	0	24.3	51.8
3,835	3,836	.1		6.6	28.2	59.5	14.3
3,836	3,837	45		18.6	12.4	28.9	18.2
3,837	3,838	.3		8.5	14.2	25.6	23.5
3,838	3,839	< .1		4.1	0	57.3	41.6
3,839	3,840	3.7		12.2	13.6	22.4	39.3
3,840	3,841	1.6		11.9	18.5	23.9	30.3
3,841	3,842	8.4		15.4	10.3	18.7	41.7
3,842	3,843	.2		7.7	7.9	32.9	53.8
3,843	3,844	.5		8.6	13.2	14.7	60.2
3,844	3,845	.4		7.4	12.2	15.6	61.1
3,845	3,846	< .1		4.7	3.4	16.9	56.1
3,846	3,847	< .1		4.6	2.8	18.4	72.9
3,847	3,848	.3		11.0	7.3	12.6	56.0
3,848	3,849	1.7		8.3	9.7	11.6	69.0
3,849	3,850	< .1		19.7	.8	3.6	56.4
3,850	3,851	< .1		3.3	6.1	30.6	55.1
3,851	3,852	.2		8.7	3.6	9.0	62.7
3,852	3,853	.3		9.5	6.2	11.6	66.6
3,853	3,854	< .1		2.6	4.5	34.4	70.2
3,863.5	3,864.5	< .1		2.8	0	41.7	67.7
3,864.5	3,865.5	< .1		4.5	5.3	63.6	64.5
3,865.5	3,866.5	< .1		7.4	7.9	24.9	90.6
		3,866.5		Base of second producing zone			

TABLE 3.—Analyses of core samples from first producing zone, K.M.A. formation, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex., Shell Oil Co. and Phillips Petroleum Co., N. C. Griffin well No. E-32, Floyd Jordan Survey.

Cored with Carter pressure core barrel

(Analyses by Bureau of Mines)

Depth, feet	Porosity, percent	Permeability, millidarcys	Chloride content, mg. per cc core	Sump density, gm. per cc core	Saturation, percent					Elevation, 1,024 feet D.F.
					Total water	Interstitial water	Drilling water	Residual oil	Total liquid saturation	
3,769'-6" -3,769'-9"	18.6	-	0.49	2.16	54.9	2.9	52.0	11.1	66.0	
3,770'-3" -3,770'-8"	18.9	-	.39	2.21	53.4	2.3	51.1	17.4	70.8	
3,770'-10" -3,771'-2"	16.6	-	.60	2.20	73.0	4.0	69.0	14.9	87.9	
3,771'-7" -3,771'-11"	22.2	-	.57	2.12	52.1	2.9	49.2	12.3	39.8	
3,772'-3" -3,772'-7"	17.0	-	.53	2.24	42.7	3.7	39.0	10.7	53.4	
3,772'-11" -3,773'-4"	13.5	0.1	.55	2.32	59.8	3.6	56.2	17.5	77.3	
3,773'-9" -3,774'	19.3	-	.56	2.18	57.2	4.7	52.5	17.4	64.1	
3,774'-7" -3,774'-10"	18.9	-	.62	2.18	58.1	3.7	54.4	12.2	70.3	
3,775'-6" -3,775'-10"	18.0	-	.54	2.20	47.1	3.4	43.7	14.1	61.2	
3,775'-3" -3,776'-5"	16.4	-	.97	2.29	40.0	6.7	33.3	11.4	51.4	
3,776'-6" -3,776'-9"	13.9	.6	3.08	2.36	20.0	25.0	-	5.8	25.8	
3,779'-2" -3,779'-6"	7.0	.3	2.38	2.50	64.7	38.5	26.2	26.8	91.5	
3,779'-10" -3,780'-1"	9.6	.4	3.34	2.46	38.7	39.3	-	14.1	52.8	
3,780'-4" -3,780'-7"	19.4	-	.68	2.18	52.1	4.0	48.1	12.2	64.3	
3,781'-6" -3,781'-10"	8.1	.8	2.86	2.47	43.0	39.8	3.2	14.8	57.8	
3,782'-8" -3,782'-11"	11.9	.2	3.05	2.40	34.4	28.9	5.5	12.0	46.4	
3,783'-7" -3,783'-11"	13.5	2.1	3.85	2.36	38.3	32.2	6.1	11.1	49.4	
3,784'-5" -3,784'-9"	19.2	-	.71	2.16	53.3	4.2	49.1	13.4	66.7	
3,785'-5" -3,785'-8"	18.8	45	.67	2.20	42.5	4.0	38.5	12.8	55.3	
3,786'-3" -3,786'-3"	18.7	-	.77	2.23	41.3	4.6	36.7	13.3	54.6	
3,786'-8" -3,787'	19.8	213	.70	2.18	45.0	4.0	41.0	12.1	57.1	
Average	16.2	-	1.33	2.27	48.2	12.5	35.9	13.7	61.9	

TABLE 4.—Analyses of core samples from first and second producing zones, K.M.A. formation, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex., Shell-Phillips, Preston "A" well No. 12, sec. 20, blk. 7, H.&T.C. RR Survey.

Cored with oil as drilling fluid

Elevation, 1,147 feet

Interval from which core was taken, feet below derrick floor		Permeability, millidarcys	Porosity, percent	Saturation, percent	
				Oil	Water
From -	To -				
	3,919		Top of first producing zone		
3,925	3,926	< 1	7.7	14.8	36.0
3,926	3,927	< 1	7.1	6.7	45.9
3,927	3,928	< 1	7.4	17.2	33.6
3,928	3,929	< 1	6.6	8.6	35.2
3,929	3,930	< 1	5.8	5.7	52.3
3,930	3,931	< 1	6.2	8.3	38.3
3,931	3,932	< 1	6.8	9.8	41.0
3,932	3,933	< 1	6.3	45.5	47.3
3,933	3,934	3.6	13.3	16.2	20.3
3,934	3,935	< 1	7.6	21.4	35.5
3,935	3,936	26.6	15.9	23.2	16.9
3,936	3,937	< 1	9.2	71.7	22.9
3,937	3,938	20	15.3	7.6	17.6
3,938	3,939	40.3	16.3	50.6	18.0
3,939	3,940	9.8	14.4	14.0	17.7
3,940	3,941	127	18.3	38.4	15.6
3,941	3,942	< 1	6.6	64.9	31.6
3,942	3,943	2.9	12.2	11.7	30.5
3,945	3,946	11.8	15.0	61.4	20.8
3,946	3,947	117	18.7	55.0	16.3
3,947	3,948	32.8	15.0	51.6	19.2
3,954	3,955	48.7	16.8	16.0	14.5
3,956	3,957	97.5	18.6	6.9	12.5
3,957	3,958	< 1	7.5	< 2	44.0
	3,984		Base of first producing zone		
	4,001		Top of second producing zone		
4,005	4,006	< 1	3.6	5.5	44.9
4,006	4,007	1.2	17.9	20.6	9.4
4,007	4,008	< 1	4.4	4.4	50.0

TABLE 5.—Analyses of core samples from second producing zone, K.M.A. formation,  
southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.,  
Dalport Oil Corp., Munger "B" well No. 2.

Depth from which core was taken, feet below derrick floor	Permeability, millidarcys	Porosity, percent	Elevation, 1,024 feet	
			Saturation, percent	
			Oil	Water
3,833		Top of second producing zone		
3,846.3	6	16.6	18.7	45.7
3,847.0	7	15.5	25.2	40.0
3,847.8	7	16.5	20.0	47.8
3,849.3	14	17.9	22.4	40.1
3,864.5	0	12.8	18.8	33.6
3,865.2	19	16.5	29.1	31.5
3,866.0	33	17.2	33.1	29.6
3,866.7	45	17.0	31.8	30.0
3,867.5	60	16.6	29.5	28.9
3,868.1	56	15.6	41.7	32.7
3,868.9	59	16.9	39.0	28.4
3,869.6	47	16.7	29.4	36.0
3,870.3	55	17.0	41.8	28.9
3,871.1	45	17.4	34.5	28.8
3,871.9	45	16.9	33.7	31.4
3,873.5	18	18.3	25.1	43.7
3,874.4	5	17.2	31.4	39.5
3,875.3	27	17.5	28.0	36.6
3,876.1	14	15.9	30.8	37.7
3,876.9	5	16.0	26.2	41.2
3,877.6	4	17.9	22.4	36.9
3,878.5	5	16.7	25.8	41.3
3,879.5	10	17.0	23.0	43.0
3,880.5	7	17.8	23.6	42.2
3,881.3	6	16.0	18.1	41.8
3,882		Base of second producing zone		

TABLE 6.—Analyses of core samples from first and second producing zones, K.M.A. formation, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex., Texas Co., Fred Thom well No. 1, W.H. Spillers Survey, A-257.

Elevation, 1,040 feet						
Interval from which core was taken, feet below derrick floor		Permeability, millidarcys		Porosity, percent	Saturation, percent	
From -	To -	Vertical	Horizontal		Oil	Water
Top of first producing zone						
3,795	3,795	0	0	7.5	42	61
3,796	3,796	0	0	6.65	21	75
3,796	3,797	0	0	8.69	18	60
3,797	3,798	654	260	7.65	6	63
3,798	3,799	0	0	7.65	0	67
3,799	3,800	0	0	7.65	13	73
3,800	3,801	0	0	7.21	4	142
3,801	3,802	0	0	5.37		
3,802	3,803	95.6	107	14.0	15	59
3,803	3,804	353	341	17.5	29	45
3,804	3,805	120	153	15.2	41	47
Base of first producing zone						
3,822	3,822	Top of second producing zone				
3,822	3,824	0	0	4.84	34	38
3,825	3,826	0	0	4.85	18	53
3,831	3,832	0	0	4.35	45	187
3,832	3,833	0	0	4.58	0	79
3,836.5	3,837.5	0	2.73	12.9	20	63
3,838	3,839	.335	5.84	13.3	21	56
3,839.5	3,840.5	.470	.302	8.45	9	26
3,841	3,842	0	0	5.49	9	22
3,842	3,843	0	0	6.48	4	47
3,843	3,844	0	0	4.37	-	165
3,844	3,845	2.49	18.5	10.3	32	27
3,845	3,846	0	18	16.3	2	38
3,846	3,847	.427	1.33	9.00	58	45
3,847	3,848	13.1	9.30	15.9	23	11
3,848	3,849	4.35	19.6	16.6	12	38
3,849.5	3,850.5	0	0	4.65	0	41
3,851	3,852	0	0	6.31	0	35
3,854	3,855	2.51	5.65	14.2	21	46

TABLE 7.—Analyses of core samples from first and second producing zones, K.M.A. formation, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex., Sam K. Viersen, Kempner well No. B-3, KWVFL Subdivision, sec. 18.

Elevation, 1,042 feet

Interval from which core was taken, feet below derrick floor		Permeability, millidarcys	Porosity, percent	Saturation, percent		Acid solubility, percent
From -	To -			Oil	Water	
Top of first producing zone						
3,785	3,786	70.6	16.1	9.7	11.0	1.6
3,786	3,787	126.0	17.6	9.2	15.6	2.7
3,787	3,788	148.0	17.8	8.8	15.3	1.5
3,788	3,789	2.8	15.0	7.2	19.8	6.0
Base of first producing zone						
Top of second producing zone						
3,812	3,813	.3	7.5	4.1	63.1	18.5
3,813	3,814	.3	7.1	3.3	49.6	30.0
3,814	3,815	<.1	2.7	12.1	55.1	35.6
3,815	3,816	<.1	6.2	1.7	32.7	43.1
3,816	3,817	<.1	3.5	14.2	39.4	59.0
3,817	3,818	.3	8.5	7.9	40.3	13.9
3,818	3,819	50.9	15.3	8.0	21.1	7.3
3,819	3,820	<.1	3.6	2.6	36.8	47.4
3,820	3,821	.5	8.0	38.4	35.4	7.4

TABLE 8.—Analyses of core samples from second producing zone, K.M.A. formation,  
southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.,  
Gulf Oil Corp., Anna Mangold well No. 7.

Cored with oil as drilling fluid

Elevation, 1,024 feet

Interval from which core was taken, feet below derrick floor	Permeability, millidarcys	Porosity, percent	Saturation, percent						
			From —	To —	Vertical	Horizontal	Oil	Water	Total
3,793	3,793	0.00	Top of second producing zone						
3,793	3,794	0.00			0.00	7.26	-	-	-
3,794	3,795	Trace			Trace	12.62	-	-	-
3,795	3,796	.00			.00	11.91	8.66	52.10	60.76
3,796	3,797	.00			.00	5.16	-	-	-
3,797	3,798	.00			.00	4.82	-	-	-
3,798	3,799	-			6.21	13.70	4.31	46.50	50.81
3,799	3,800	.00			.00	5.83	-	-	-
3,800	3,801	31.20			31.30	17.62	32.10	26.20	58.30
3,801	3,802	.00			2.42	16.06	27.60	30.20	57.80
3,802	3,802.25	634.00			746.00	22.20	-	-	-
3,802.25	3,802.5	738.00			1,012.00	21.64	53.20	13.90	67.10
3,802.5	3,803	335.00			374.00	21.70	47.80	16.20	64.00
3,803	3,803.25	312.00			558.00	20.60	-	-	-
3,803.25	3,803.5	521.00			430.00	21.46	52.40	12.70	65.10
3,803.5	3,803.75	192.00			483.00	21.50	-	-	-
3,803.75	3,804	352.00			489.00	20.52	51.90	15.40	67.30
3,814	3,815	.00			.00	4.83	.00	53.30	53.30
3,815	3,816.5	-			-	5.71	10.60	53.20	63.80
3,816.5	3,817	.00			.00	4.21	-	-	-
3,817	3,817.5	.00			.00	4.69	-	-	-
3,817.5	3,818	.00			.14	7.97	38.30	31.20	69.50
3,818	3,818.5	.00			.00	5.16	-	-	-
3,818.5	3,819	3.63			23.39	15.67	36.80	20.70	57.50
3,819	3,819.5	29.65			6.53	14.48	37.20	25.20	62.40
3,819.5	3,820.5	.00			.00	5.38	2.90	49.40	52.30
3,820.5	3,821	.214			8.56	12.71	40.0	23.8	63.8
3,821	3,821.5	.21			2.78	14.63	26.5	17.7	44.2
3,821.5	3,822	.617			31.70	12.06	20.0	21.0	52.0
3,822	3,822.5	.00			.00	5.26	3.10	.35.6	38.7
3,822.5	3,823	.00			143.1	11.97	36.7	23.8	60.5
3,823	3,824	.00			.00	4.62	6.5	57.2	63.7
3,824	3,825	.00			.00	4.78	10.9	45.4	56.3
3,825	3,826	.349			20.55	16.11	36.5	29.0	65.5
3,826	3,826.5	.00			.00	5.95	29.2	47.7	76.9
3,826.5	3,827.5	97.5			298.0	22.30	26.8	16.3	43.1
3,827.5	3,828	.00			.00	6.02	20.9	55.0	75.9
3,828	3,829.5	.00			.00	6.01	12.1	51.6	63.7
3,829.5	3,830	-			1.93	8.77	21.3	29.8	51.1
3,830	3,830.5	.00			.00	3.91	15.0	56.2	71.2
3,830.5	3,831	14.9			36.9	16.53	53.4	20.7	74.1
3,831	3,832	.00			.00	10.86	43.6	39.0	82.8
3,832	3,832.5	.438			20.35	17.30	31.0	34.8	65.8
3,832.5	3,833	Trace			21.70	14.69	42.4	31.2	73.6
3,833	3,833.5	.00			.00	4.88	6.5	73.1	79.6
3,833.5	3,834	2.165			.00	9.78	14.5	33.3	47.8
3,834	3,835	.00			.00	3.94	.0	59.6	59.6
3,835	3,836	.00			Trace	11.76	15.5	53.1	68.6
3,836	3,837	.00			24.40	8.98	11.7	46.6	61.3
3,837	3,838	15.5			45.2	14.00	27.6	37.5	65.1
3,838	3,838.5	5.63			26.25	13.89	25.2	38.1	63.3
3,838.5	3,839.5	.00			.00	4.74	.0	57.2	57.2
3,839.5	3,841	.00			.00	10.13	15.1	47.7	62.8
3,841	3,841.5	.00			.00	12.98	20.8	29.8	50.6
3,841.5	3,842	.00			.00	3.08	10.5	65.4	75.9
3,842	3,843	.00			.00	4.75	.0	42.3	42.3
3,843	3,844	.00			.00	7.09	.0	68.7	68.7
3,844	3,846	.00			.00	9.66	.0	84.4	84.4
3,846	3,849	.00			.024	10.42	.0	72.2	72.2
3,849	3,851	.00			.00	11.98	.0	78.4	78.4
3,851	3,854	.00			.00	13.56	.0	62.5	62.5
3,854	3,856	.00			.00	12.52	.0	70.4	70.4
3,856	3,858	.00			.00	10.51	.0	48.5	48.5
3,858	3,860	.00			.00	12.48	.0	80.2	80.2
3,860	3,861	Trace			.00	15.68	.0	77.2	77.2
3,861	3,862.5	.00			.00	6.71	.0	89.1	89.1
3,862.5	3,863.5	-			.00	13.63	.0	81.8	81.8
3,863.5	3,864	.00			.00	11.89	.0	80.2	80.2
3,864	3,865	.00			.00	11.00	.0	66.7	66.7
3,865	3,866	.00			.00	3.98	-	-	-
	3,866								
					Base of second producing zone				

TABLE 9.—Analyses of core samples from first and second producing zones, K.M.A. formation, southwestern part, K.M.A. Field, Wichita and Archer Counties, Tex., Tide Water Associated Oil Co., Ferguson well No. 25, W. H. Spillers Survey A-251.

(Analyses by Bureau of Mines)

Elevation, 1,023 feet D.F.

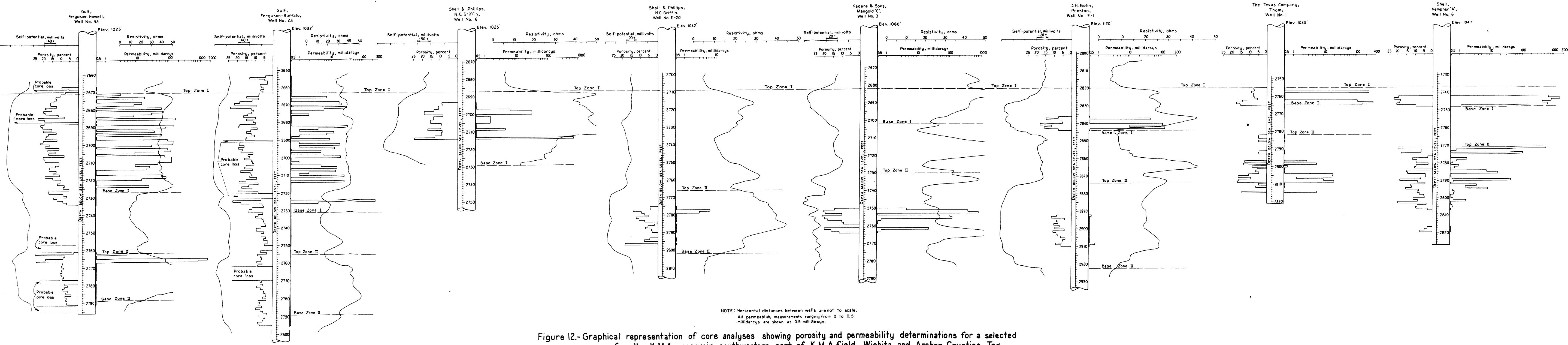
Depth from which core was taken, feet below derrick floor	Permeability, millidarcys		Porosity, percent		Connate water, <sup>3/</sup> percent		Acid Solubility, <sup>4/</sup> percent
	Horizontal <sup>2/</sup>	Vertical <sup>2/</sup>	Horizontal <sup>2/</sup>	Vertical <sup>2/</sup>	Horizontal <sup>2/</sup>	Vertical <sup>2/</sup>	
Top of the first producing zone							
3,692.5	2.0	1.1	12.4	12.8	18.6	17.3	13.2
3,694.5	32	1.0	16.1	12.6	17.5	20.1	2.8
3,695.5	.58	.60	10.0	9.8	26.6	20.5	37.2
3,696.5	35	14	16.2	15.8	18.4	17.7	3.2
3,697.5	1.1	.23	9.4	8.4	22.6	41.8	30.0
3,698.5	.10	.21	4.6	9.6	48.8	33.9	32.0
3,699.5	.29	.63	9.2	12.4	46.9	18.4	32.4
3,700.5	.3	1.7	12.8	13.8	18.2	15.1	28.4
3,701.5	.60	.18	8.0	8.9	33.0	24.0	40.8
3,702.5	.13	8.9	5.5	4.0	42.3	19.5	.4
3,703.5	60	6.7	17.3	16.5	17.8	19.5	3.6
3,704.5	.24	.28	7.4	7.9	53.1	38.2	34.8
3,705.5	120	31	19.0	18.3	11.9	19.1	4.8
3,706.5	31	4.6	13.9	16.1	25.5	22.2	29.2
3,707.5	88	.55	18.5	11.6	15.7	23.4	9.2
3,708.5	99	42	17.1	17.9	16.3	16.9	6.4
3,709.5	40	11	15.0	15.8	24.6	17.9	.4
3,710.5	52	28	17.3	16.8	16.2	16.1	4.0
3,712.5	.21	.14	6.1	5.2	48.2	56.9	19.2
3,713.5	.49	.39	10.2	9.9	36.8	36.5	40.0
3,714.5	.41	.37	5.3	9.4	31.3	35.5	34.8
3,715.5	.17	.13	6.5	4.7	46.8	55.7	25.2
3,716.5	90	35	17.4	16.7	16.1	16.1	9.6
3,730.5	18	12	12.5	11.2	18.4	18.9	10.4
3,731.5	69	13	16.7	16.8	21.0	19.2	4.0
3,732.5	149	150	16.9	18.9	16.1	16.8	12.4
3,733.5	3.5	.42	12.0	9.2	25.1	30.6	18.4
3,734.5	112	123	16.5	19.6	19.2	16.0	6.0
3,735.5	.20	<.1	6.9	4.5	40.6	51.2	35.2
3,736.5	1.6	.45	8.8	10.6	29.7	23.9	22.4
3,737.5	.17	.13	5.4	4.5	50.4	49.0	30.4
3,738.5	54	50	18.2	17.7	13.4	16.4	6.4
3,739.5	.17	.17	4.3	5.1	57.8	44.6	32.8
3,740.5	<.1	<.1	2.7	2.8	—	—	33.6
3,741.5	<.1	<.1	3.5	4.8	—	—	45.2
3,742.51/	<.1	.1	5.3	2.6	—	—	46.4
3,742.55/	11	170	15.6	19.9	32.5	14.6	4.8
3,743.5	<.1	.11	2.7	12.7	72.3	—	35.2
3,744.5	100	143	12.7	17.8	15.9	13.3	2.8
Base of first producing zone							
3,745.5	<.1	<.1	2.3	2.3	—	65.5	27.2
3,749.5	<.1	.1	2.0	1.5	—	—	39.6
3,775.5	<.1	.1	2.9	4.1	—	—	78.4
3,776.5	<.1	.19	5.1	3.9	70.5	70.9	60.0
Top of second producing zone							
3,777.5	3.0	15	12.2	15.0	25.6	16.5	39.2
3,778.5/	1.8	1.1	—	9.0	53.6	39.1	42.8
3,779.5/	<.1	<.1	4.4	—	—	—	36.4
3,780.5/	8.2	.21	11.2	—	31.6	—	20.0
3,781.5/	1.9	.82	8.5	—	23.0	—	22.4
3,782.5/	<.1	<.1	6.7	—	47.4	—	76.0
3,783.5	<.1	<.1	5.9	4.9	59.8	—	57.6
3,784.5/	<.1	.1	5.0	—	62.5	—	68.8
3,785.5	10	7.1	11.9	9.8	19.3	28.7	44.8
3,786.5	.17	.28	6.6	5.2	43.7	46.4	57.2
3,787.5	2.0	.87	8.9	5.7	24.1	24.3	19.6
3,788.5	<.1	<.1	3.8	3.5	50.6	56.8	68.4
3,793.5	<.1	<.1	7.4	—	—	—	51.6
3,794.5	<.1	<.1	4.5	3.2	63.7	—	67.2
3,795.5	<.1	<.1	3.3	5.5	—	—	62.4
3,796.5	<.1	<.1	2.3	3.6	—	—	54.0
3,797.5	<.1	<.1	4.8	5.3	—	—	67.2
3,798.5	<.1	<.1	1.9	3.7	—	—	65.2
3,799.5	<.1	<.1	3.3	2.3	—	—	66.0
3,800.5	51	10	17.4	15.6	15.5	17.1	21.6
3,801.5	<.1	<.1	3.3	2.9	—	—	53.6
3,802.5	.17	.1	1.9	3.8	68.5	—	54.0
3,803.5	<.1	<.1	3.3	3.3	—	—	59.2
3,804.5	<.1	<.1	6.0	7.7	29.0	23.2	80.0
Base of second producing zone							

Note:—In most instances connate water was not run on cores with permeability less than 0.1 millidarcy.

<sup>1/</sup> This core was half limestone and half sandstone, hence the L for the limestone section and the S for the sandstone section. <sup>2/</sup> The core sample plugs that were used for permeability determinations also were used for porosity and connate water determinations. <sup>3/</sup> Connate water was determined by the capillary pressure method of analysis. <sup>4/</sup> Percent of core sample soluble in 15-percent solution of cold hydrochloric acid. <sup>5/</sup> Horizontal permeability plug was square - too large for porosity apparatus. <sup>6/</sup> Plug cut in cube form - both horizontal and vertical permeability from same plug and connate water determined in one direction only.

TABLE 10.—Analyses of core samples from first producing zone, K.M.A. formation,  
southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.,  
Sunray Oil Corp., Mangold well No. 1

		Elevation, 1,010 feet		
Interval from which core was taken, feet below derrick floor		Permeability, millidarcys	Porosity, percent	Oil saturation, percent
From —	To —			
	3,691		Top of first producing zone	
3,691	3,692	0	11	22.0
3,692	3,693	0	7	18.0
3,693	3,694	.26	8.5	37.0
3,694	3,695	37.0	7.7	38.0
3,695	3,696	.4	9.3	32.0
3,696	3,697	9.9	13.0	27.0
3,697	3,698	8.2	14.7	27.0
3,698	3,699	3.4	8.6	27.0
3,699	3,700	.8	9.5	18.0
3,700	3,701	2.3	8.1	7.0
3,701	3,702	.4	7.6	18.0
3,702	3,703	.6	9.2	39.0
3,703	3,704	3.3	10.4	38.0
3,704	3,705	2.0	16.3	34.0
3,705	3,706	.2	12.8	25.0
3,706	3,707	.3	15.8	27.0
3,707	3,708	41.0	10.5	39.0
3,708	3,709	22.0	12.2	44.0
3,709	3,710	.8	10.7	52.0
3,710	3,711	45.0	16.3	27.0
3,711	3,712	.2	9.7	10.0
3,712	3,713	0	7.4	30.0
3,713	3,714	.9	8.2	40.0
3,714	3,715	1.7	10.8	40.0
3,715	3,716	0	8.8	46.0
3,716	3,717	0	15.5	25.0
3,717	3,718	.3	8.5	12.0
3,718	3,719	22.0	14.7	19.0
3,719	3,720	0	7.5	24.0
3,720	3,721	9.9	10.4	30.0
3,721	3,722	18.0	12.3	40.0
3,722	3,723	45.0	13.7	38.0
3,723	3,724	62.0	8.3	25.0
3,724	3,725	87.0	16.8	14.0
3,725	3,726	20.0	7.1	14.0
3,726	3,727	450.0	18.8	34.0
3,727	3,728	340.0	18.7	38.0
3,728	3,729	320.0	20.5	49.0
3,729	3,730	430.0	19.2	57.0
3,730	3,731	330.0	8.3	26.0
3,731	3,732	.1	10.8	.0
3,732	3,733	0	3.0	.0
3,733	3,734	0	4.6	.5
3,734	3,735	.2	8.8	.5
3,735	3,736	0	3.5	.0
3,736	3,737	0	2.5	.5
3,737	3,738	0	7.5	1.0
3,738	3,739	0	5.8	1.0
3,739	3,740	0	2.6	20.0
3,740	3,741	0	7.7	40.0
3,741	3,742	0	4.5	21.0
3,742	3,743	0	5.6	1.0
3,743	3,744	0	5.7	22.0
3,744	3,745	0	7.0	21.5
3,745	3,746	0	6.4	.0
	3,745		Base of first producing zone	



esentation of core analyses showing porosity and permeability determinations for a selected  
, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

wells are not to scale.  
ranging from 0 to 0.5  
millidarcys.



The interpretation of core analyses and electric, radioactive, and selected driller's logs made it possible to estimate the gross thickness of the producing formation in enough representative wells throughout the field to construct isopachous maps of zones I and II (figs. 18 and 19). The gross volume obtained from each isopachous map was multiplied by a thickness correction factor to give the net volumes of the zones. A systematic statistical analysis was made to determine the thickness correction factors from permeability data. As the thickness-correction factors were calculated from field-wide core analyses (to be discussed later), the factors cannot be used to determine the net reservoir volume of each zone under individual leases.

The method of interpreting core analyses discussed is a modified form of the statistical treatment discussed by Jan Law,<sup>7/</sup> Bulnes,<sup>8/</sup> Bulnes and Fitting,<sup>9/</sup> and Calhoun.<sup>10/</sup> Although enough core analyses were not available for application of the complete statistical treatment suggested by the above authors, a modified form of their method was followed to arrive at the factors used in this report to convert the gross to the net reservoir volumes. The mechanics involved in making the modified statistical analysis are presented in the following subsections, using zone I as the example.

The available core analyses were studied individually, by wells, and, by correlation, the tops and bottoms of zones I and II were marked. A graphical cross section, representing 82 cored wells, was made, showing the tops and bases of zones I and II and the vertical positions of the interval cored and analyzed from each zone. This graphical representation indicated that the intervals cored and analyzed occupied different vertical positions from well to well throughout each zone. Although the two zones were analyzed completely from the top to the base in only a very few wells, the cross section showed that the remaining analyses varied vertically to such an extent that consolidation of all cores analyzed from each zone would be representative of the total thickness of that zone throughout the field. This consolidation of core data for each zone was interpreted to obtain representative field-wide average values for porosity, permeability, connate water saturation, and a thickness correction factor, which is used to reduce the gross volume to the net volume.

#### Permeability

To be commercially productive, a formation must have permeability greater than a certain limiting value.<sup>11/</sup> This limiting value is obtained from calculations shown graphically in figure 13 for zone I and figure 14 for zone II. These illustrations were

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- <sup>7/</sup> Law, Jan, A Statistical Approach to the Interstitial Characteristics of Sand Reservoirs: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vols. 155 and 160, 1944 and 1945, pp. 200-220.
  - <sup>8/</sup> Bulnes, A. C., An Application of Statistical Methods to Core Analysis Data of Dolomitic Limestone: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 165, 1946, pp. 223-240.
  - <sup>9/</sup> Bulnes, A. C. and Fitting, R. U., Jr., An Introductory Discussion on the Reservoir Performance of Limestone Formations: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vols. 155 and 160, 1944 and 1945, pp. 428-450.
  - <sup>10/</sup> Calhoun, John C., Engineering Fundamentals No. 403. Permeability, Porosity Variations, Oil and Gas Jour., vol. 48, No. 52, May 4, 1950, p. 155; No. 404. Histograms of Permeability, vol. 59, No. 1, May 11, 1950, p. 105; Permeability Distribution, vol. 49, No. 3, May 25, 1950, p. 163; Comparing Permeability Distributions, vol. 49, No. 4, June 1, 1950, p. 85; Permeability Capacity Distribution, vol. 49, No. 5, June 8, 1950, p. 87; Porosity Variations, vol. 49, No. 6, June 15, 1950, p. 123; Core Data, vol. 49, No. 8, June 29, 1950, p. 91.
  - <sup>11/</sup> See footnote 10.

made by arranging the permeability values from the consolidated core analyses for each zone in order of decreasing values. As each sample was taken to represent 1 foot, the capacity value (permeability multiplied by thickness) is the same as the permeability value. The capacity values were added cumulatively from the highest value downward, and each cumulative capacity value was divided by the total cumulative capacity and multiplied by 100 to obtain the cumulative capacity in percent. Figures 13 and 14 were constructed by plotting the cumulative capacity in percent versus the individual values of permeability. The above calculations showed that 98.99 percent of the total capacity for zone I and 99.35 percent of the total capacity for zone II was accounted for by those samples having permeabilities of 5 millidarcys or greater. The lower limit of permeability for commercial production thus was selected as 5 millidarcys in each zone. The arithmetical average of all permeability values of 5 millidarcys or over was 84 millidarcys for zone I and 216 millidarcys for zone II. By comparison, the arithmetical averages of all samples having permeabilities of 1 millidarcy or over were 66 millidarcys for zone I and 166 millidarcys for zone II.

The validity of arithmetical averages of the permeabilities is questionable because a few extremely high permeabilities overshadow those of moderate values. An attempt was made to apply a statistical analysis to permeability, but it was found that the large number of very low permeabilities, as compared with the few very high permeabilities, gave a distribution curve that was left open on the low-permeability end, which prevented statistical treatment of permeability. A value believed more representative than the arithmetical average of the permeability for each zone was obtained from the porosity-permeability relationship curve, which is discussed later.

#### Porosity

The porosity data were examined and analyzed statistically. As the limiting productive permeability for each zone was chosen at 5 millidarcys, the corresponding porosity values of all core samples having a permeability of 5 millidarcys or over were selected for the statistical analysis. Within each zone, all the samples having a permeability of 5 millidarcys or greater had a porosity of at least 6 percent. All porosities of 6 percent and greater were arranged in order of increasing values, and a histogram was constructed for each zone by plotting porosity versus the number of times each porosity occurred. A line drawn through the average values of the points forming the histograms resulted in normal, or bell-shaped, curves for both zones I and II. A normal curve is symmetrical about its vertical axis, and the magnitude of the intersection of this axis with the abscissa is the mean value of the curve; this value also equals the arithmetical average of the points plotted. The arithmetical averages of the porosities were 16.5 percent for zone I and 16.1 percent for zone II. The average porosities are believed representative of the reservoir because the histograms formed normal curves.<sup>12/</sup>

#### Porosity-Permeability Relationship

The difficulties experienced in reaching an average permeability value that would reflect the producing ability of the two zones led to an investigation of the porosity-permeability relations of the core data.

A general relationship is believed to exist between porosity and permeability within each oil-productive zone in the K.M.A. formation. Other petroleum technologists

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<sup>12/</sup> See footnote 7.

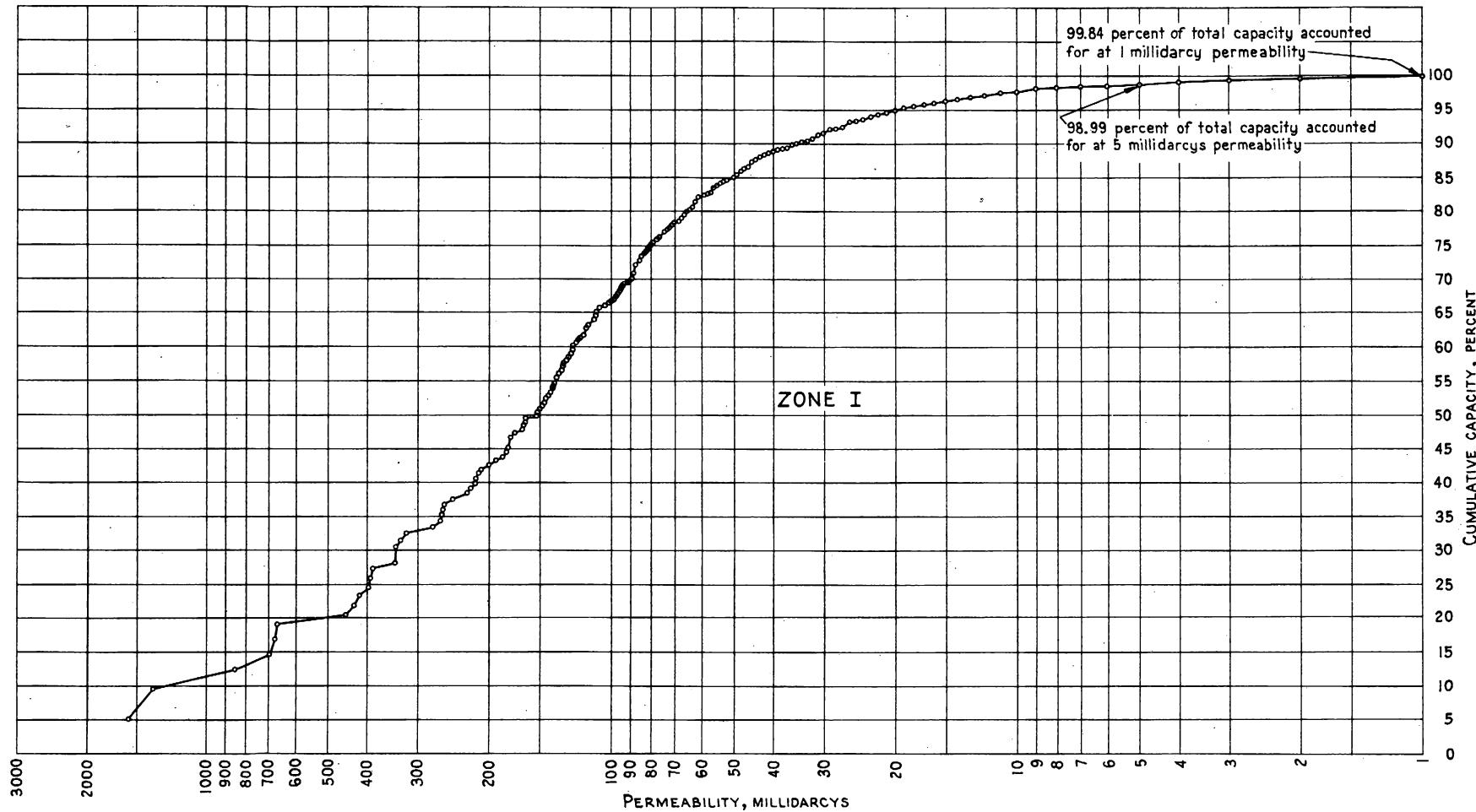


Figure 13.-Curve showing relationship between permeability and cumulative capacity, Zone I, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

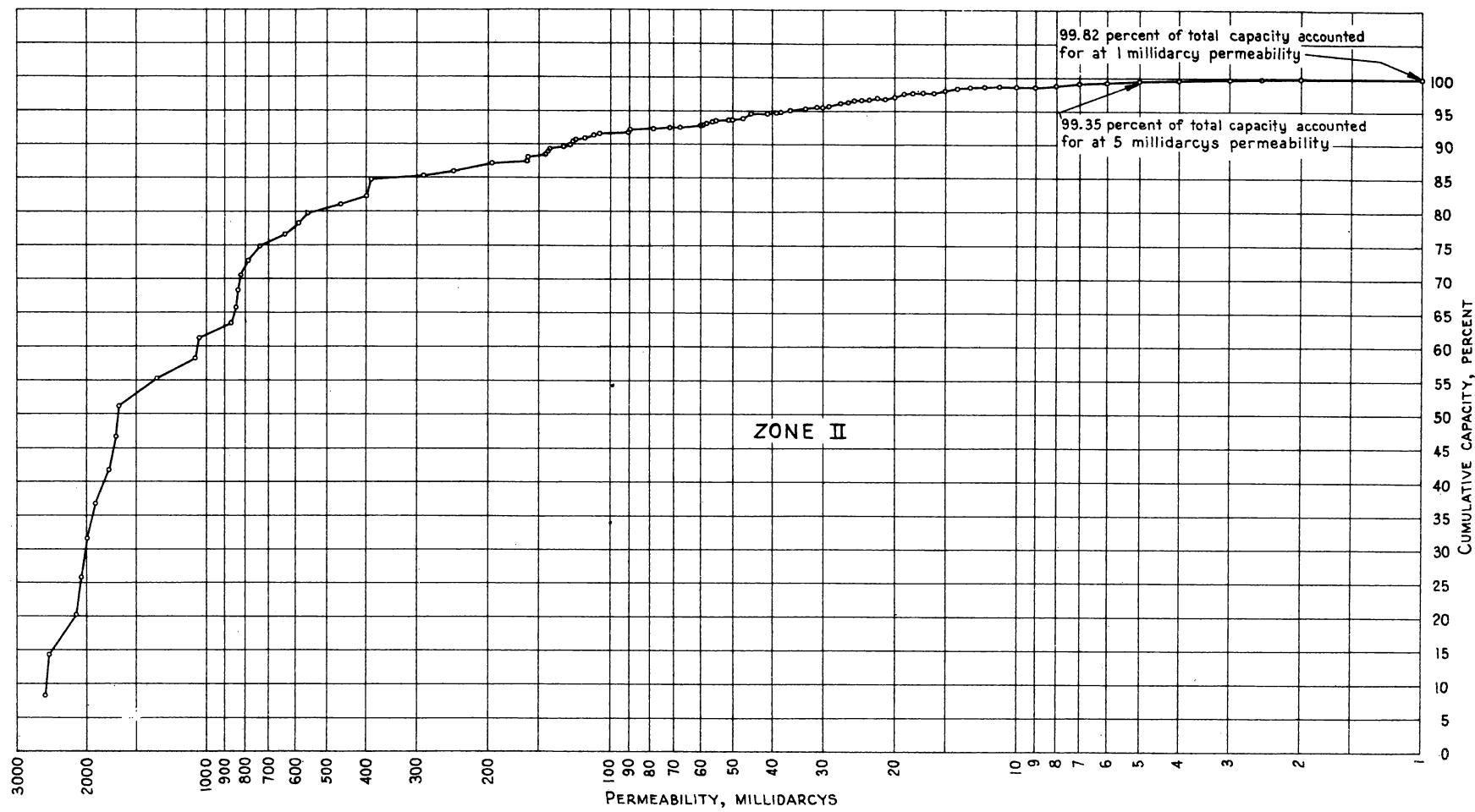


Figure 14.-Curve showing relationship between permeability and cumulative capacity, Zone II,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

have expressed their views concerning porosity and permeability relationship. In 1930, Barb<sup>13</sup>/ stated, " \* \* \* it seems that there is a relationship between porosity and permeability which can be expressed in a manner accurate enough for control of secondary recovery in Eastern fields." Fettke and Copeland<sup>14</sup>/ discussed this relationship in 1931, and they maintained that, in most instances, porosity is a more-important factor than grain size in determining relative permeability, but grain size together with grain distribution, shape of grains, manner of packing, and degree of cementation must be taken into consideration. Fettke and Copeland explained, "As the latter factors (distribution, size and shape of grains, manner of packing, and degree of cementation) also have an important bearing on the porosity, they are to a considerable extent reflected in it. In using the porosity-permeability graphs, therefore, it should be kept in mind that, in general, sands with coarser grains than those along the median line will have higher permeabilities and those with finer grains will have lower permeabilities than the points with corresponding porosities on the median line."

The porosities of all core samples having a permeability of 1 millidarcy or over were plotted against their permeabilities on logarithmic paper, with permeability as the abscissa and porosity as the ordinate (fig. 15 for zone I and fig. 16 for zone II). Although the points showed considerable scattering, a definite trend is indicated for each zone. A few widely scattered points, which are shown circled on the plot, are believed erroneous and were discarded. The remaining points were then grouped, and the equation for the line of best fit was calculated by the method of least squares. The calculated equations are shown for each zone on the respective figures.

Considering the fact that the accuracy of the arithmetical average of the porosities was confirmed by the normal shape of the histograms, the permeability corresponding to the average porosity of each zone should be the most-representative value for use in reservoir calculations. These permeability values were derived by solving the equation for each zone after the substitution was made for the corresponding average porosity. In this report, the permeability determined by this method is designated correlative permeability.

The calculation for the correlative permeability of zone I is illustrated below:

Equation of porosity-permeability line:

$$Y = 11.34 (X)^{0.1003};$$

where: Y = porosity, percent;

X = permeability, millidarcys.

<sup>13</sup>/ Barb, C. F., Porosity-Permeability Relations in Appalachian Oil Sands: Pennsylvania State Coll., Min. Ind. Exper. Sta., Bull. 9, Oct. 24-25, 1930, pp. 47-59.

<sup>14</sup>/ Fettke, Charles R., and Copeland, W. A., Permeability Studies of Pennsylvania Oil Sands: Trans. Am. Inst. Min. and Met. Eng., Petrol. Div., 1931, pp. 329-339.

Substituting 16.5 percent for Y in the above equation gives:

$$16.5 = 11.34 (X)^{0.1003},$$

$$\log 16.5 = \log 11.34 + 0.1003 (\log X),$$

$$\log X = \frac{\log 16.5 - \log 11.34}{0.1003} = 1.62383;$$

hence:  $X = 42.1$  millidarcys for zone I.

The correlative permeabilities were 42.1 millidarcys for zone I and 39.5 millidarcys for zone II.

According to Cardwell and Parsons<sup>15</sup>/ the equivalent permeability of a reservoir, in which the measured permeability varies in an irregular manner, is the permeability of a homogeneous reservoir of the same dimensions that would pass the same flux under the same pressure drop. They also showed, by mathematical calculations, that the equivalent permeability of a block of porous medium involving any number of different permeabilities and any type of directional variation lies between a harmonic and an arithmetic average of the actual permeabilities.

The correlative permeability values derived by use of the porosity-permeability relationship curves are considered to reflect the true flow characteristics of the producing formation better than a straight weighted arithmetical average permeability. What relation the correlative permeability bears to the equivalent permeability is problematical. These correlative values of permeability, however, are much lower than the arithmetical averages; and the use of correlative permeability values to determine connate-water saturations and flow capacities is believed justifiable.

#### Connate-Water Saturation

The average connate-water saturation in each zone was obtained from a curve showing the relationship between permeability and the percentage of connate-water saturation as determined by the restored-state method and the percentage of water saturation of samples that were cored using oil as the drilling fluid. The average curve for these plotted points for zone I is shown in figure 17. The equation for the portion of the connate water versus permeability curve for zone I that is a straight line was calculated by the method of least squares and found to be  $Y = 18.317 - (0.02176) (X)$ , where Y is the connate-water saturation and X is the permeability. The correlative permeability for zone I, as determined from the porosity-permeability relationship curve, was substituted for X in the above equation. The solution of the equation for Y gave 17.4 percent as the average connate-water saturation in zone I. The calculation for zone I is shown below:

The equation of that portion of the connate water-permeability curve that is a straight line is:

$$Y = 18.317 - (0.02176) (X);$$

<sup>15</sup>/ Cardwell, W. T., and Parsons, R. L., Average Permeabilities of Heterogeneous Oil Sands: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 155 and 160, 1944 and 1945, pp. 283-291.

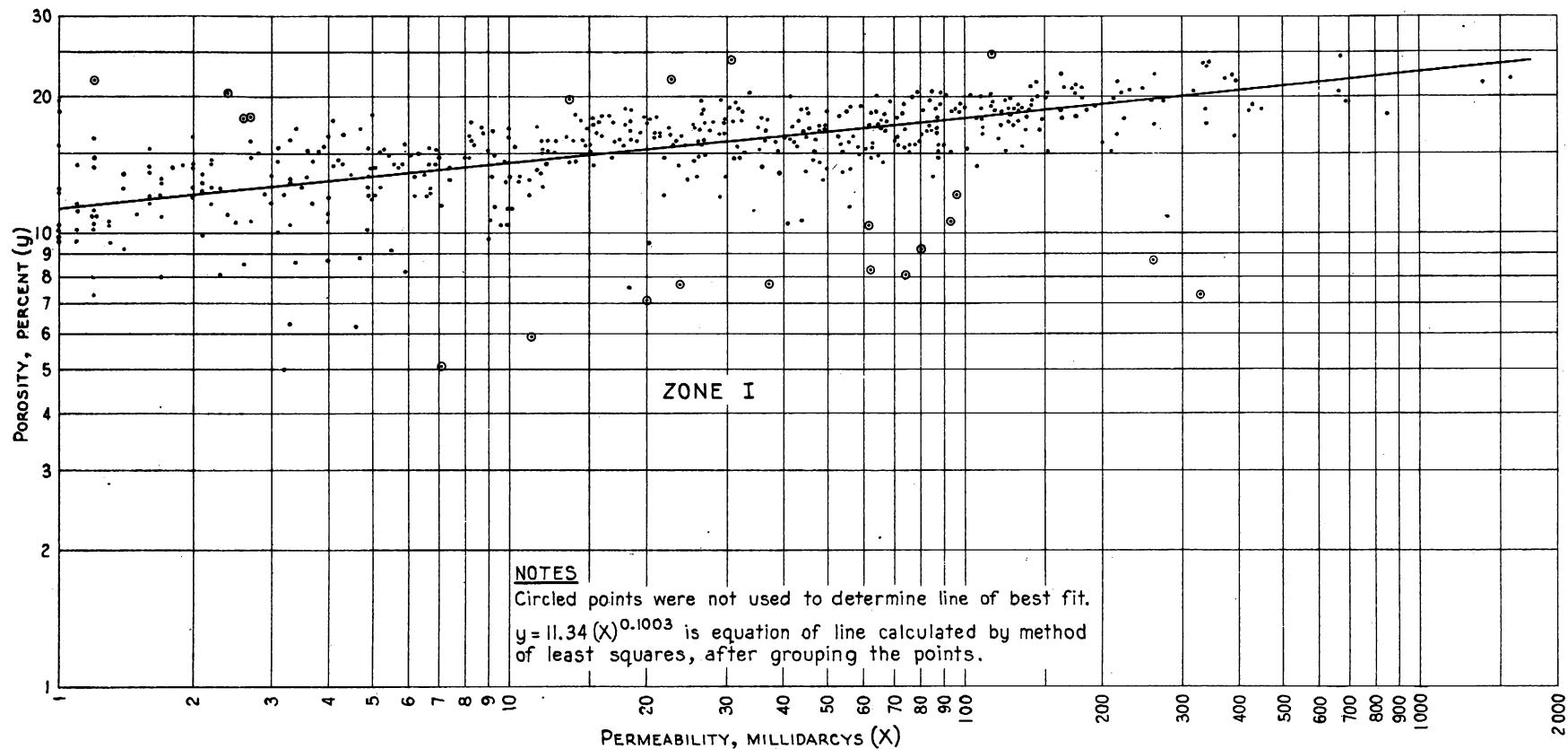


Figure 15.- Logarithmic relationship between permeability and porosity, Zone I, K.M.A. reservoir,  
southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

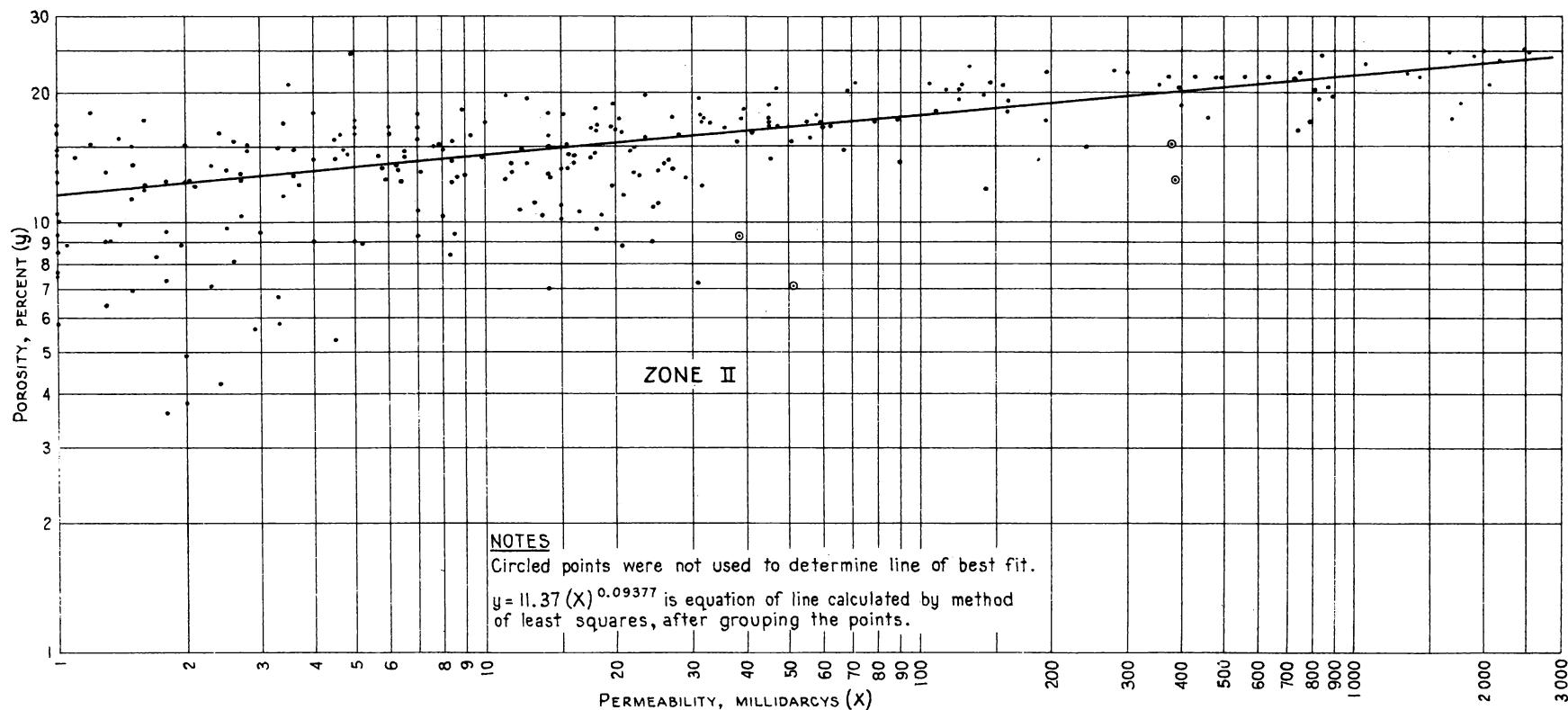


Figure 16.- Logarithmic relationship between permeability and porosity, Zone II, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

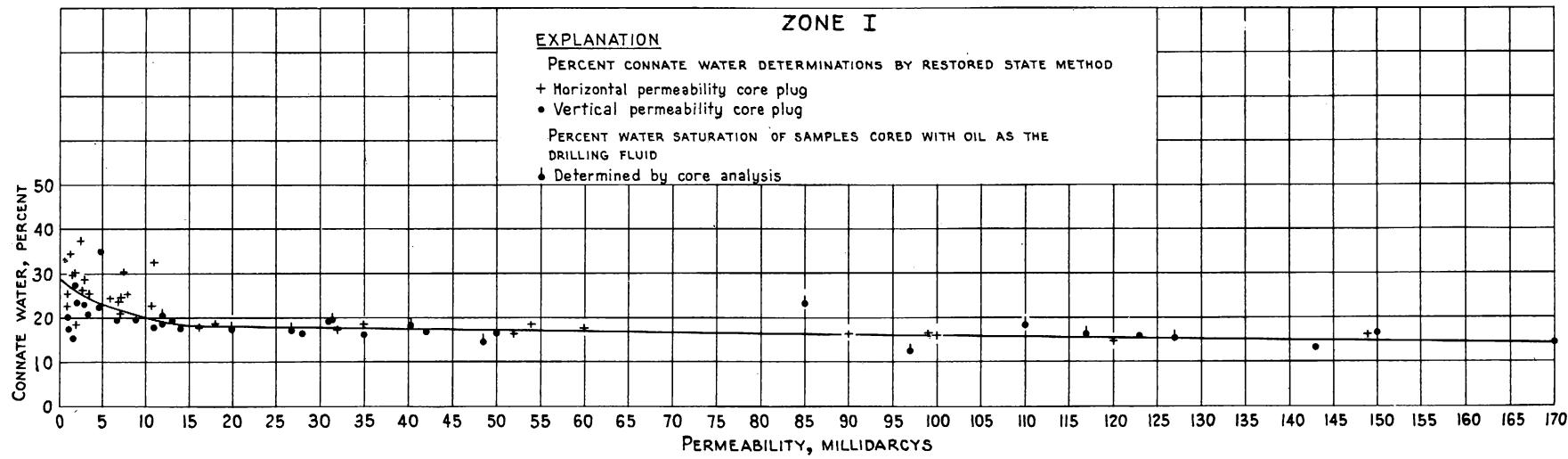


Figure 17.- Curve showing relationship between permeability and connate water saturation, Zone I,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



where:

Y is the connate-water saturation, in percent;

X is the permeability, in millidarcys.

Substituting 42.1 for X in the above equation gives:

$$Y = 18.317 - (0.02176) (42.1),$$

$$Y = 18.317 - 0.916,$$

$$Y = 17.4 \text{ percent.}$$

Because of the inherent limitations on accuracy, the connate water saturation is expressed to the nearest  $\frac{1}{2}$  percent, so 17.5 percent is taken as the connate water saturation for zone I.

The above procedure was repeated for zone II, and the average connate-water saturation was computed to be 20.0 percent. A summary of the interpretation of core analyses for zones I and II is shown in table 11.

#### Thickness Correction Factor

Out of 1,011 core samples from zone I (which represents a total of 1,011 feet of core), 360 core samples had a permeability equal to or greater than the limiting productive permeability of 5 millidarcys. The ratio of 360:1,011 gives a factor of 0.356 or 35.6 percent, which is the percentage of the formation considered commercially productive in zone I. As the core analyses are believed representative of the entire zone, the net thickness is believed to be 35.6 percent of the gross thickness for zone I. Likewise, it was determined from the core analyses of zone II that 163 samples in the total of 808 samples had permeabilities equal to or greater than 5 millidarcys. Similarly, the ratio of 163:808 gives a factor of 0.202 or 20.2 percent; consequently, the net thickness would be 20.2 percent of the gross thickness of zone II. These factors and other data are shown in table 11.

These thickness correction factors are used in this report to calculate the net volumes for each zone from the gross volumes obtained from gross-thickness isopachous maps.

Because cores from all areas in the southwestern part of the field were used in calculating the above thickness correction factors, application of the factors is limited to computations pertaining to the entire reservoir and should not be used to reduce gross volumes under individual leases to net volumes.

#### Gross and Net Volume of Reservoir

All available electric logs, radioactive logs, drillers' logs, and core analyses were used in determining the gross thickness of zones I and II. These gross thicknesses were used in constructing isopachous maps, which are illustrated in figures 18 and 19. The gross thickness for zones I and II was considered to be the total thickness from the top to the base of each zone, after deductions were made for shale beds. No deductions were made, however, for dense limestone stringers, as they were accounted for in the thickness correction factor used to correct the gross to the net reservoir volume.

The reservoir oil originally was undersaturated with gas, and no gas cap was present. The original oil-water contact was 2,850 feet below sea level for the

southern and eastern edges of the field, and this datum limited the oil-productive thickness of zone II in these areas. However, no oil-water contact on the northern and western edges of the field could be established. The gross volumes of zones I and II, which are shown in table 12, were computed by summing the products of the areas and the corresponding mean thickness between the isopachs.

The net volumes for zones I and II were obtained by multiplying the gross volumes by the thickness correction factors that were determined from the interpretation of the core analyses. (See discussion on thickness correction factor.) These volumes are given in table 12.

TABLE 11.—Summary of interpretation of core analyses, K.M.A. reservoir,  
southwestern part, K.M.A. field, Wichita  
and Archer Counties, Tex.

	Zone I	Zone II
Number of wells cored .....	65	47
(Total, 82 different wells for both zones)		
Number of core samples .....	1,011	808
Average porosity of all core samples having a permeability of 5 md. or greater ..... percent..	16.5	16.1
Average permeability of all core samples having a permeability of 5 md. or greater ..... md..	84	216
Average permeability of all core samples having a permeability of 1 md. or greater ..... do..	66	166
Minimum "productive" permeability determined from permeability-cumulative capacity curve ..... do..	5	5
Number of core samples having a permeability of 5 md. or greater .....	360	163
Thickness correction factor ..... percent..	35.6	20.2
Correlative permeability from porosity- permeability curve using average porosities given above ..... md..	42.1	39.5
Average connate water saturation from connate water-permeability curve using correlative permeabilities of 42.1 and 39.5 md. ..... percent..	17.5	20.0
Average minimum residual oil saturation of all core samples having a porosity of 6 percent or greater ..... percent pore volume..	15.5	14.1

TABLE 12.—Computed volume of K.M.A. reservoir,  
southwestern part, K.M.A. field,  
Wichita and Archer Counties, Tex.

	Zone I	Zone II	Zones I and II combined
Oil productive area as delimited by isopachous maps ..... acres..	10,851	11,642	12,500
Gross volume of reservoir from iso- pachous maps ..... acre-feet..	300,893	525,808	-
Thickness correction factor .....	0.356	0.202	-
Net productive volume ..... acre-feet..	107,119	106,214	213,333
Average net thickness ..... feet..	9.9	9.1	17.1

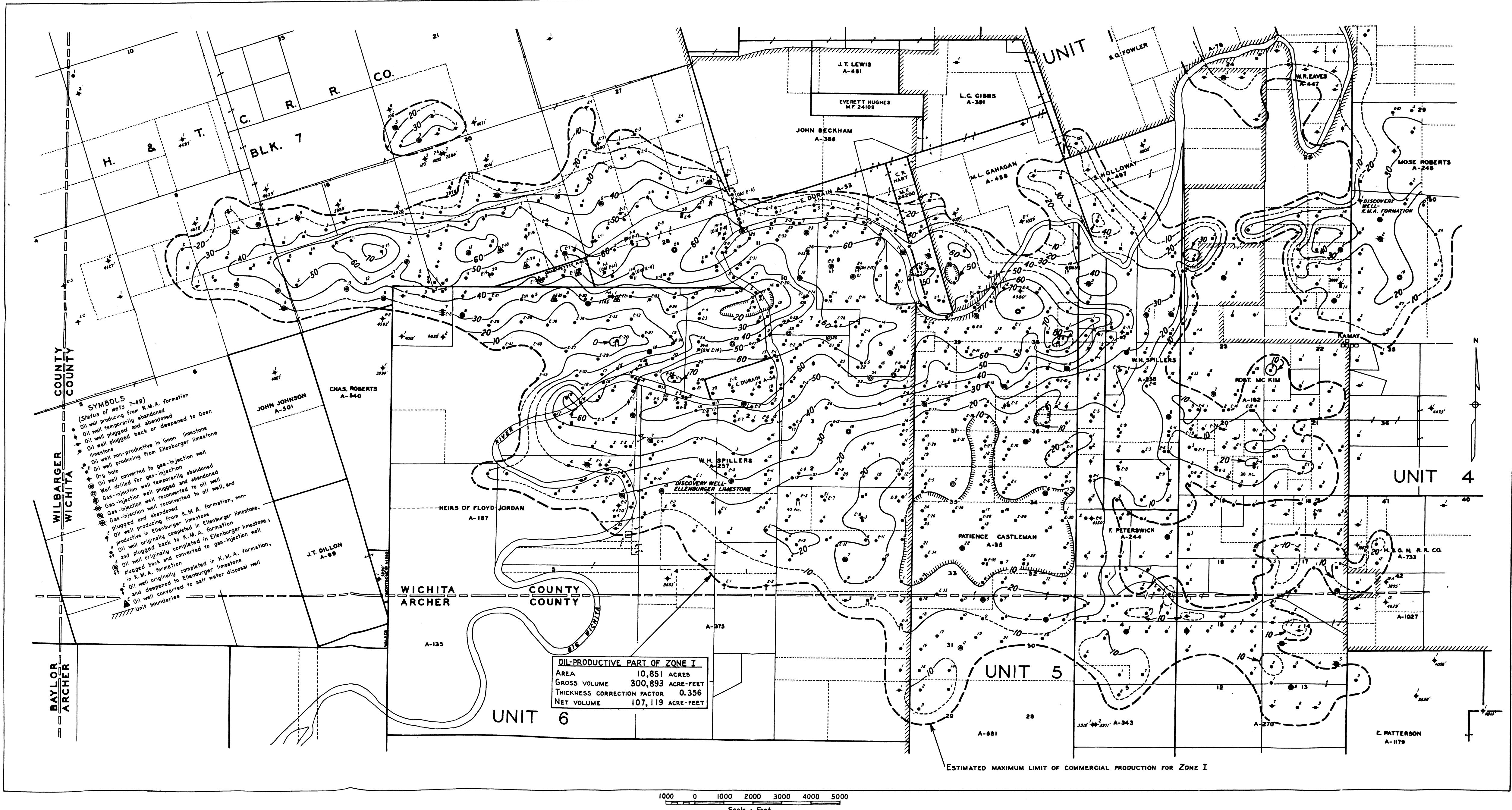


Figure 18.- Isopachous map showing gross thickness of Zone I, K.M.A. reservoir,  
southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



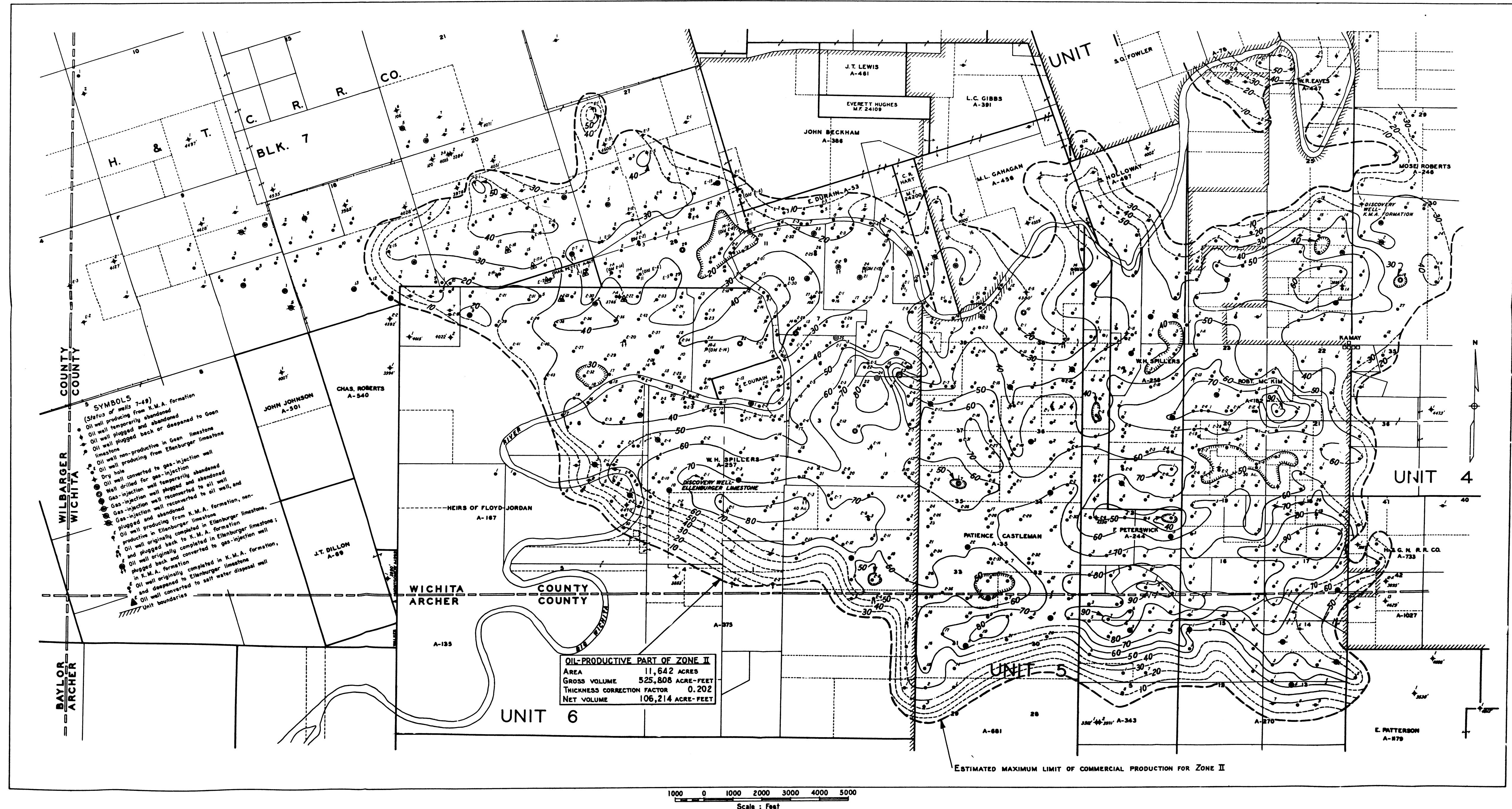


Figure 19.-Isopachous map showing gross thickness of Zone II, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



Wherever possible, the lines delimiting the area of commercial production shown on the isopachous maps were determined from dry holes, water tables, core analyses, formation thickness, initial oil production, and lease-production information. Where none of these data could be applied, the maximum limit of commercial production was assumed to be approximately one location away from the edge oil wells. No attempt was made to control the contouring, so that the line delimiting commercial production would coincide with the zero isopach; consequently, in many areas the line representing the limit of commercial production is intersected by isopachs of different thicknesses. In other areas, the line delimiting the maximum limit of commercial production corresponds or coincides with the zero isopach.

#### Physical Characteristics of Reservoir Fluids

Three K.M.A. reservoir-fluid analyses were made available for this report. The observed and calculated data in tables 13-17 and in figures 20 and 21 are the results of laboratory work by the companies supplying the reservoir-fluid analyses. A summary of pertinent statements made by the company personnel performing the work follows.

One subsurface sample of K.M.A. reservoir fluid was taken from each of the three following wells on the dates indicated: (1) Tide Water Associated Oil Co. Mangold well No. 1, March 3, 1938; (2) Shell-Phillips Griffin well No. 1, December 14, 1938; (3) Shell-Phillips Preston "A" well No. 12, January 23, 1941.

A subsurface-fluid sample taken from the Tide Water Associated Oil Co. Mangold well No. 1 had a saturation pressure of 570 p.s.i. at a static reservoir pressure of 1,475 p.s.i., a flowing pressure of 1,361 p.s.i. at the sampling point, and a reservoir temperature of 126°F. The average fractional analysis of this subsurface sample is shown in table 13.

A subsurface sample taken from Shell-Phillips Griffin well No. 1 had a saturation pressure of 1,255 p.s.i. at a static reservoir pressure of 1,599 p.s.i., a flowing pressure of 1,255 p.s.i. at the sampling point, and a reservoir temperature of 124°F. The fractional analysis of this subsurface sample is shown in table 13.

A subsurface sample of reservoir fluid, which contained some free gas, was taken from Shell-Phillips Preston "A" well No. 12 at a static reservoir pressure of 1,243 p.s.i., a flowing pressure of 1,165 p.s.i. at the sampling point, and a reservoir temperature of 124°F. and had a saturation pressure of 1,210 p.s.i. The fractional analysis of the subsurface sample from this well is shown in table 14. For purposes of comparison, the fractional analysis of the subsurface sample from Griffin well No. 1 is also shown in table 14.

Examination of the fractional analyses of the subsurface samples from Griffin well No. 1 and Mangold well No. 1 (table 13) indicated that the saturation pressure and the composition of the reservoir fluid in the K.M.A. reservoir were not the same throughout. The composition of the subsurface sample from the Griffin well No. 1 calculated to the saturation pressure of the subsurface sample from the Mangold well No. 1 (table 13) indicated that the reservoir fluid was similar in composition but differed in saturation pressure. To obtain more information about the saturation pressure and the reservoir-fluid composition, a subsurface sample was taken from the Preston "A" well No. 12. A comparison of the fractional analysis of this sample with that of the sample from the Griffin well No. 1 (table 14) indicated that the two samples were identical in composition. By using the observed analysis of the separator sample and the gas:oil ratio from the Mangold well No. 1 (data not shown) and the Griffin well No. 1 (table 15), the composition of the composite fluid produced from each well was calculated; and the results of these calculations, which are shown in table 16, established

TABLE 13.—Comparison of analyses of subsurface fluid samples from Shell-Phillips,  
 Griffin well No. 1 and Tide Water Associated Oil Co., Mangold  
 well No. 1, K.M.A. reservoir, southwestern part, K.M.A.  
 field, Wichita and Archer Counties, Tex.

Component	Griffin well No. 1, subsurface-fluid sample, mole percent	Griffin well No. 1, calculated to Mangold well No. 1 saturation pres- sure, mole percent	Mangold well No. 1, average composition of subsurface-fluid samples, mole percent
Nitrogen . . . . .	2.02) ) 21.57	11.38	11.74
Methane . . . . .	19.55)		
Ethane . . . . .	6.68	6.22	7.23
Propane . . . . .	11.13	11.88	11.58
Isobutane . . . . .	1.64) ) 8.05	9.07	9.44
Normal butane . . . . .	6.41)		
Pentane . . . . .	5.77	6.66	6.90
Hexane . . . . .	5.38	6.26	6.83
Residue heptanes plus .	41.42	48.53	46.28
Total . . . . .	100.00	100.00	100.00

Molecular weight of residue	197	200
Gravity of residue at 60°F.	0.8404	0.8383
Formation temper- ature, °F.	124	126
Compressibility (percent per 100 pounds)	0.125	0.111
Saturation pressure, p.s.i.	1,255	570

the fact that the reservoir fluid from the two wells was identical in composition. The data and calculations established that the reservoir fluid throughout the entire K.M.A. reservoir was identical, and that the original saturation pressure of the Mangold well No. 1 sample was in error (table 13).

TABLE 14.—Comparison of analyses of subsurface-fluid samples from Shell-Phillips, Griffin well No. 1 and Preston "A" well No. 12, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

Component	Mole percent	
	Preston well No. A-12	Griffin well No. 1
Carbon dioxide .....	0.10 )	-
Nitrogen .....	1.10 ) 21.54	2.02 ) 21.57
Methane .....	20.34 )	19.55 )
Ethane .....	6.77	6.68
Propane .....	10.39	11.13
Isobutane .....	1.53 ) 8.08	1.64 ) 8.05
Normal butane .....	6.55 )	6.41 )
Pentane .....	5.41	5.77
Hexane .....	5.97	5.38
Residue heptanes plus .....	40.84	41.42
Gravity of residue at 60°F. ....	0.8391	0.8404
Molecular weight of residue .....	198	197
Saturation pressure at 124°F., p.s.i. ....	1,210	1,255

TABLE 15.—Comparison of analyses of observed and calculated separator samples, Shell-Phillips, Griffin well No. 1, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

Component	Gas, mole percent		Liquid, mole percent	
	Observed	Calculated <sup>1/</sup>	Observed	Calculated <sup>1/</sup>
Carbon dioxide .....	0.21 )			
Nitrogen .....	4.21 )	51.40	0.44	0.38
Methane .....	46.03 )			
Ethane .....	15.77	14.82	.97	.90
Propane .....	19.18	20.01	4.14	4.82
Isobutane .....	2.46 )	9.31	7.58	7.16
Normal butane .....	7.41 )			
Pentane .....	3.14	2.83	7.74	7.86
Hexane .....	1.09	1.06	8.24	8.44
Residue heptanes plus .....	.50	.57	70.89	70.44
Total .....	100.00	100.00	100.00	100.00

Butanes plus = 5.03 g.p.m.  
 Pentanes plus = 1.89 g.p.m.  
 $26/70 = 2.68$  g.p.m.

Separator pressure = 10 p.s.i.  
 Separator temperature = 58°F.  
 Atmospheric temperature = 53°F.  
 Flow rate = 15.78 bbl. per hour

<sup>1/</sup> Calculated from analysis of Griffin well No. 1 subsurface-fluid sample, shown in table 14.

TABLE 16.—Comparison of calculated composite analyses of subsurface fluids from Shell-Phillips, Griffin well No. 1, and Tide Water Associated Oil Co., Mangold well No. 1, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Component	Mole percent	
	Griffin well No. 1 <sup>1/</sup>	Mangold well No. 1 <sup>2/</sup>
Methane .....	23.07	23.51
Ethane .....	7.67	6.80
Propane .....	10.95	10.67
Butane .....	8.62	8.24
Pentane .....	5.66	5.97
Hexane .....	5.00	5.36
Residue heptanes plus .....	39.03	39.44

1/ Calculated from separator-sample analyses, using observed ratio of 423 cubic feet per barrel.

2/ Calculated from separator-sample analyses, using observed ratio of 437 cubic feet per barrel.

Because the reservoir-fluid samples obtained from the Shell-Phillips Griffin well No. 1 and the Preston "A" well No. 12 were saturated with gas at the sampling pressure, the original saturation pressure had to be estimated. The calculated composition of the composite analyses shown in table 16 and the subsurface-sample fractional analyses shown in table 14 when compared indicates that the calculated composite analyses had more gas in solution (a higher methane content) than the subsurface samples, indicating that the observed saturation pressure of the subsurface samples was too low. It was estimated from the additional methane present in the calculated composite analyses that the original saturation pressure in the K.M.A. reservoir was 1,300 p.s.i.

Table 17 shows a separator-gas analysis from the Tide Water Associated Oil Co. Mangold well No. 1.

The differential gas-liberation data obtained from analysis of the subsurface sample from the Shell-Phillips Preston "A" well No. 12 is considered the most accurate of the several analyses examined. These data are plotted in figure 20. As this sample had a saturation pressure of only 1,210 p.s.i., the curves were extrapolated to the estimated initial saturation pressure of 1,300 p.s.i. At 1,300 p.s.i., the volume of gas in solution becomes constant at 525 cubic feet per barrel, and the relative oil-volume curve reverses its trend with an increase in pressure. The extrapolated part of the relative oil-volume curve was calculated from liquid-compressibility data listed at the bottom of table 13. The calculated relative oil volume was 1.304 at the initial reservoir pressure of 1,750 p.s.i. and 1.310 at the saturation pressure of 1,300 p.s.i. No flash gas-liberation data were available.

The volume to which 1 cubic foot of gas at reservoir temperature and different reservoir pressures will expand when brought to base conditions of 14.4 p.s.i.a. and 60°F. is shown in figure 21. This factor, f, is used in the section of this report discussing material balance and pressure maintenance.

The  $U_0:U_g$  curve (fig. 21) is the ratio of the viscosity of reservoir oil to that of reservoir gas at different pressures and was used in calculating instantaneous gas:oil ratios in the pressure-maintenance section of this report.

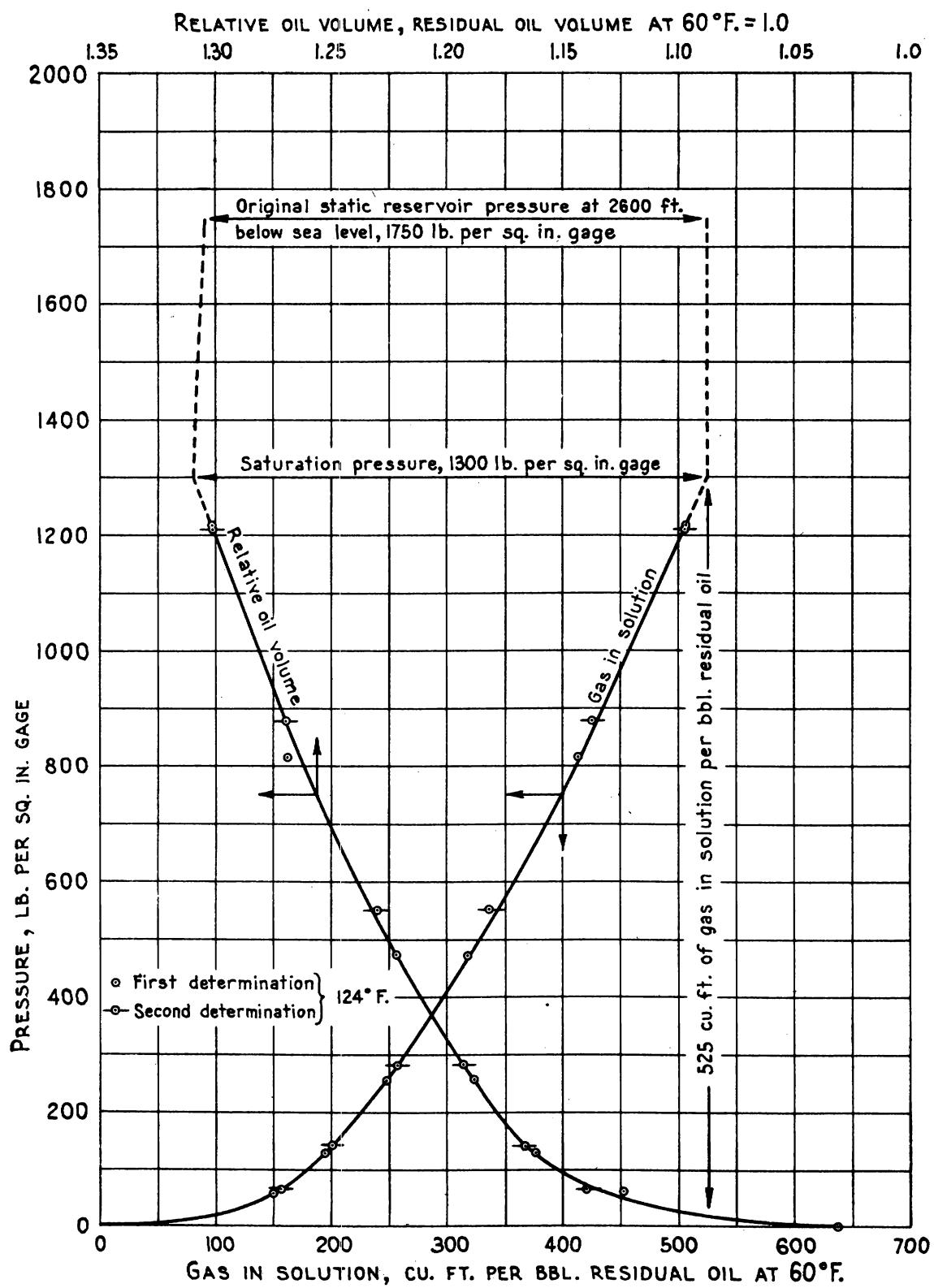


Figure 20.- Solution gas and shrinkage curves for subsurface oil sample, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

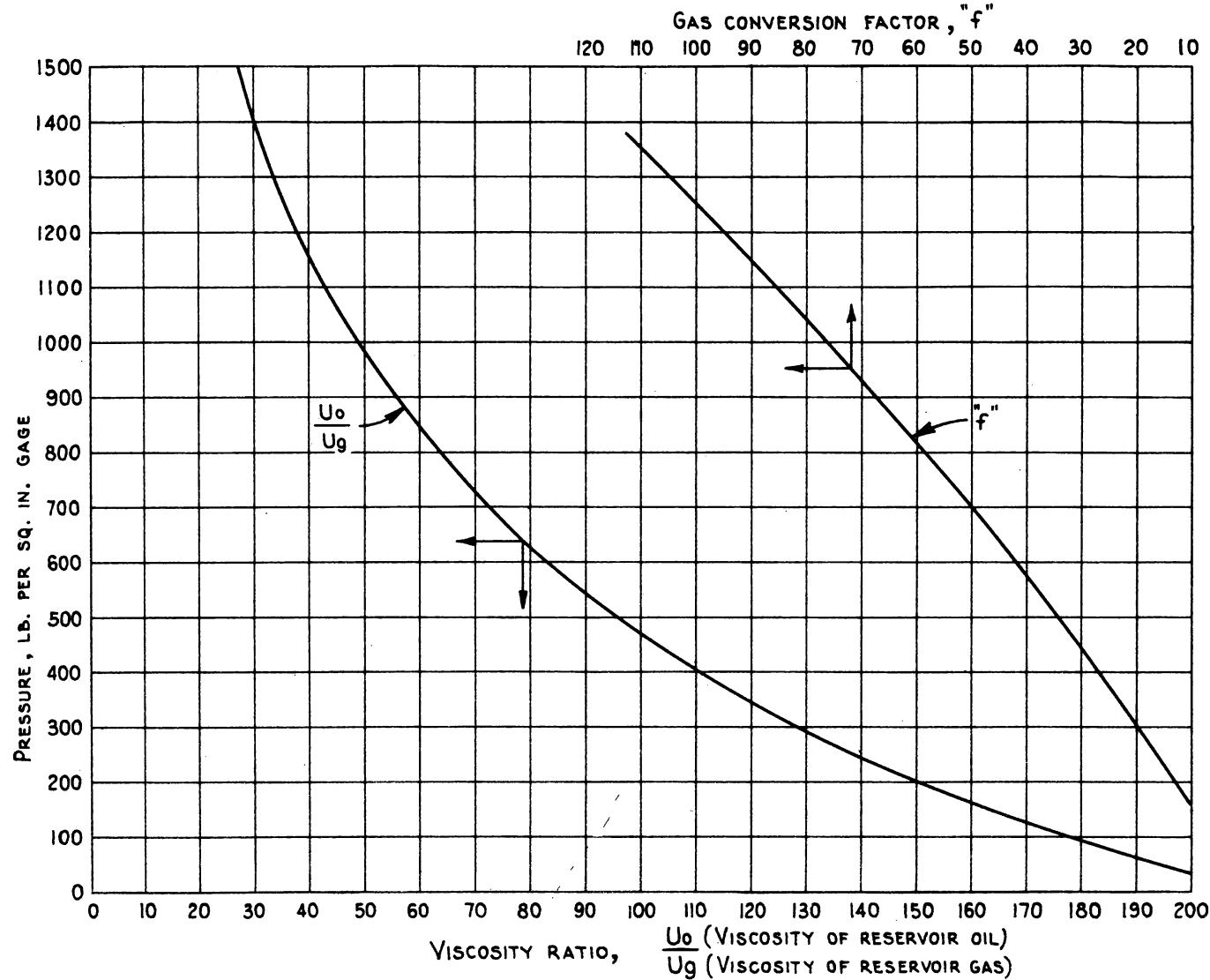


Figure 21.-Curves showing variation of viscosity ratio,  $\frac{U_o}{U_g}$ , and gas conversion factor, "f", with pressure, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

TABLE 17.—Separator-gas analysis, Tide Water Associated Oil Co., Mangold well No. 1, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Component	Mole or volume percent
Nitrogen . . . . .	5.62
Carbon dioxide . . . . .	.75
Methane . . . . .	45.51
Ethane . . . . .	15.55
Propane . . . . .	18.66
Isobutane . . . . .	2.21
Normal butane . . . . .	7.23
Pentane . . . . .	2.93
Hexane . . . . .	.93
Residue heptanes plus . .	.60

Calculated specific gravity (air = 1.00) = 1.07

<u>Component</u>	<u>G.p.m.</u>
Butanes plus	= 4.79
Pentanes plus	= 1.78
26/70	= 2.53
Separator pressure	= 8.5 pounds per square inch
Separator temperature	= 59°F.
Atmospheric temperature	= 76°F.
Flow rate	= 30 barrels per hour

## Initial Volume of Stock-Tank Oil and Solution Gas in Reservoir

### Porosity-Saturation Method

The initial volume of stock-tank oil in the K.M.A. reservoir was calculated by the porosity-saturation method. By this method of calculation, the product of the net volume of the reservoir (as determined from the isopachous maps), the average porosity, and the oil saturation gave the initial volume of reservoir oil. This volume of reservoir oil divided by the relative oil volume at initial conditions gave the volume of stock-tank oil initially in place.

The following procedure was used to compute the initial volume of stock-tank oil in zones I and II and the K.M.A. reservoir:

$$V_0 = \frac{7,758 p s R}{F_1};$$

where:

$V_0$  = volume of stock-tank oil initially in reservoir, barrels;

7,758 = volume of 1 acre-foot, (expressed in barrels);

$p$  = effective porosity of reservoir rocks (expressed as a decimal);

$s$  = oil saturation of effective pore space or 100 percent minus percent of volume occupied by connate water (expressed as a decimal);

$F_1$  = relative oil volume at initial reservoir pressure and temperature, residual oil volume at 60°F. = 1.0 (dimensionless);

$R$  = volume of reservoir, acre-feet.

Zone I:

$V_{01}$  = volume of stock-tank oil initially in place, barrels;

$$V_{01} = \frac{7,758 \times 0.165 \times 0.825 \times 107,119}{1.304};$$

$V_{01}$  = 86,700,000 barrels.

Zone II:

$V_{02}$  = volume of stock-tank oil initially in place, barrels;

$$V_{02} = \frac{7,758 \times 0.161 \times 0.800 \times 106,214}{1.304};$$

$V_{02}$  = 81,400,000 barrels.

Southwestern part, K.M.A. reservoir:

$$V_0 = V_{01} + V_{02} = \text{volume of stock-tank oil initially in place, barrels};$$

$$V_0 = 86,700,000 + 81,400,000;$$

$$V_0 = 168,100,000 \text{ barrels.}$$

As the K.M.A. reservoir did not have a gas cap and the reservoir oil was initially undersaturated with gas, all the gas contained originally was dissolved in the oil. Therefore, the initial volume of solution gas in the reservoir was calculated by multiplying the initial volume of stock-tank oil by the original solution gas:oil ratio of 525 cubic feet per barrel.

The following procedure was used to compute the initial volume of gas in the K.M.A. reservoir:

$$V_g = V_0 S;$$

where:

$V_g$  = volume of solution gas initially in reservoir, cubic feet;

$V_0$  = volume of stock-tank oil initially in reservoir, barrels;

$S$  = solution gas:oil ratio, cubic feet per barrel.

Therefore:

$$V_g = 168,100,000 \times 525;$$

$$V_g = 88.25 \text{ billion cubic feet.}$$

The calculated volumes of oil and solution gas initially in place are summarized in table 18.

#### Material-Balance Method

Petroleum technologists<sup>16</sup> generally agree that material-balance calculations do not provide as accurate a means of determining the volume of initial reservoir oil as does the porosity-saturation method. As the porosity-saturation method of estimating the initial volume of oil in the K.M.A. reservoir required use of a thickness-correction factor, the writers decided that an independent method of determining the initial volume of reservoir oil was needed to substantiate the volume obtained by the porosity-saturation method. Material balance was chosen as the independent method to be used.

Material-balance calculations solving for the initial volume of oil in place in the K.M.A. field at reservoir pressures above the saturation pressure were not attempted. Such calculations generally are unreliable when the reservoir is producing only by liquid expansion because the pressure-volume-temperature data are very critical. The calculations made at reservoir pressures below the saturation pressure, however, are considered well-justified. Reference dates were chosen throughout 6 years, and the corresponding reservoir pressures ranged from 1,129 to 200 p.s.i. These calculations

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<sup>16</sup>/ Muskat, Morris, Physical Principles of Oil Production: McGraw-Hill Book Co., Inc., New York, N. Y., 1st ed., 1949, pp. 387-391.

TABLE 18.—Initial volume of oil and solution gas in place by porosity-saturation method, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

	Zone I	Zone II	Zones I and II combined
Net productive volume, ... acre-feet..	107,119	106,214	213,333
Effective porosity, ..... percent..	16.5	16.1	-
Connate-water saturation,.....do....	17.5	20.0	-
Relative oil volume at original conditions of temperature and pressure .....	1.304	1.304	-
Pore volume:			
..... acre-feet..	17,675	17,100	34,775
..... barrels..	137,200,000	132,600,000	269,800,000
Volume of connate water .....do....	24,100,000	26,500,000	50,600,000
Initial volume reservoir oil in place .....do....	113,100,000	106,100,000	219,200,000
Initial volume of stock-tank oil in place:			
.....do....	86,700,000	81,400,000	168,100,000
..... barrels per acre-foot	811	779	790
Initial volume gas in solution ...cu. ft. per bbl. stock-tank oil..	-	-	525
Initial volume solution gas in reservoir ..... billion cu. ft...	-	-	88.25

gave very consistent initial volumes of oil (see table 19) from which a weighted average volume of 171.5 million stock-tank barrels (223.7 million reservoir barrels) was computed (see Appendix A for sample calculation). The initial volume of 171.5 million stock-tank barrels of oil obtained by material balance is considered to be in excellent agreement with the volume of 168.1 million barrels obtained by the porosity-saturation method.

In making material-balance calculations, flash gas-liberation data should be used in determining the volume of gas produced above the solution gas:oil ratio. As flash gas-liberation data were not available for K.M.A. subsurface-oil samples, differential gas-liberation data were utilized. This substitution is believed to introduce only negligible error because differential gas-liberation data determined at approximately 120°F. approximates flash gas-liberation data determined at atmospheric temperature, and the initial temperature of the K.M.A. reservoir was 124°F.

Material-balance principles are applied most logically to a reservoir as a whole. Such principles, however, may be applied to a part of a reservoir provided there is no regional drainage, no effective water drive, and the reservoir as a whole has a solution-gas drive.<sup>17/18/</sup> In preparing this report, material-balance principles were applied to the southwestern part of the K.M.A. field only. Regional drainage is thought to be negligible because the part of the field studied is connected to the northern part only by a narrow producing area. This narrow connecting area was the first part of the field to be developed, and the wells in the area were completed with lower than average initial well production. This is evidence of low permeability and conditions generally unfavorable for regional drainage. The rapid decline of bottom-hole pressure, the general absence of water production, and the initial undersaturated condition of the crude oil substantiate the theory that the reservoir mechanism was solely solution-gas drive.

Some evidence of water influx on the Panhandle Refining Co., Reilly-Griffin lease and Shell Oil Co., Inc., Griffin "A" lease can be seen from localized highs on the isobaric maps. Also, an above average recovery on the Panhandle lease is evident from figure 36. This is a small area, however, and the assumption that the effect of the water influx on the whole area studied was considered to be negligible for purposes of material-balance calculations is supported by the failure of the calculated volumes of initial reservoir oil to increase at successive reference dates.

#### Properties of Crude Oil

The oil produced from the K.M.A. reservoir is a relatively high gravity, intermediate-base, sweet crude that has a total gasoline and naphtha content of about 40 percent. Initially, the A.P.I. gravity of K.M.A. crude oil was approximately 43°, but later in the life of the field the gravity decreased to about 40°. The sulfur content is slightly greater than 0.2 percent. Distillation analyses by the Bureau of Mines Hempel method of crude-oil samples from the Mangold and Ferguson leases are shown in table 20.

<sup>17/</sup> Pirson, Sylvain J., Elements of Oil-Reservoir Engineering: McGraw-Hill Book Co., Inc., New York, N. Y., 1950.  
<sup>18/</sup> Schilthuis, Ralph J., Active Oil and Reservoir Energy: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 118, 1936, pp. 31-50.

TABLE 19.—Summary of results of material-balance calculations to determine initial volume of oil in place, K.M.A. reservoir, south-western part, K.M.A. field, Wichita and Archer Counties, Tex.

Date	Reservoir pressure, p.s.i.	Calculated initial volume, reservoir oil, million bbl.
3-1-40	1,129	214
8-1-40	1,078	223
2-1-41	1,040	230
8-1-41	1,000	233
2-1-42	956	230
8-1-42	907	231
3-1-43	841	226
8-1-43	789	220
2-1-44	713	216
8-1-44	635	223
6-1-47	200	220
Weighted average		223.7

223.7 million reservoir barrels =  $\frac{223.7}{1.304}$  = 171,500,000 stock-tank barrels.

TABLE 20.—Crude-oil analyses, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Sample 38071

Kadane, Inc.  
Mangold well No. 1-A  
3,630-3,752 feet

K.M.A. field  
K.M.A. formation

Texas  
Wichita County  
Sample taken  
4-6-38

GENERAL CHARACTERISTICS

Specific gravity, 0.807  
Sulfur, percent, 0.21  
Saybolt Universal viscosity at 100°F., 35 sec.

A.P.I. gravity, 43.8°  
Color, brownish green

DISTILLATION, BUREAU OF MINES HEMPEL METHOD

Distillation at atmospheric pressure, 741 mm. Hg. First drop, 30°C. (86°F.)

Fraction No.	Cut °C.	at- °F.	Per cent	Sum, per-cent	Sp. gr. 60/60°F	°A.P.I., 60°F.	C.I.	S.U. visc., 100°F.	Cloud test, °F.
1	50	122	4.0	4.0	0.641	89.3	-	-	-
2	75	167	4.2	8.2	.661	82.6	3.2	-	-
3	100	212	7.4	15.6	.708	68.4	16	-	-
4	125	257	7.5	23.1	.736	60.8	20	-	-
5	150	302	6.9	30.0	.756	55.7	22	-	-
6	175	347	5.8	35.8	.776	50.9	24	-	-
7	200	392	5.0	40.8	.791	47.4	25	-	-
8	225	437	5.2	46.0	.805	44.3	26	-	-
9	250	482	5.5	51.5	.820	41.1	28	-	-
10	275	527	5.5	57.0	.838	37.4	32	-	-
Distillation continued at 40 mm. Hg.									
11	200	392	3.6	60.6	0.852	34.6	35	41	10
12	225	437	5.9	66.5	.859	33.2	34	47	30
13	250	482	4.8	71.3	.874	30.4	38	60	50
14	275	527	3.8	75.1	.882	28.9	39	89	65
15	300	572	4.8	79.9	.892	27.1	40	160	80
Residuum			15.8	95.7	.946	18.1			
Carbon residue of residuum, 6.7 percent; carbon residue of crude, 1.1 percent.									

APPROXIMATE SUMMARY

Light gasoline	Percent	Sp. Gr.	°A.P.I.	Viscosity
	15.6	0.678	77.2	
Total gasoline and naphtha	40.8	0.730	62.3	
Kerosine distillate	10.7	.813	42.6	
Gas oil	13.4	.849	35.2	
Nonviscous lubricating distillate	9.0	.863-.884	32.5-28.6	50-100
Medium lubricating distillate	6.0	.884-.898	28.6-26.1	100-200
Viscous lubricating distillate	-	-	-	Above 200
Residuum	15.8	.946	18.1	
Distillate loss	4.3			

TABLE 20.—Crude-oil analyses, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex. - Continued

Sample 43146

Tide Water Associated Oil Co.  
Ferguson Lease

K.M.A. field  
K.M.A. formation

Texas  
Wichita County  
Sample taken  
10-11-43

GENERAL CHARACTERISTICS

Specific gravity, 0.825

A.P.I. gravity, 40.0°

Sulfur, percent, 0.23

Color, brownish green

Saybolt Universal viscosity at 100°F., 36 sec.

DISTILLATION, BUREAU OF MINES HEMPEL METHOD

Distillation at atmospheric pressure, 746 mm. Hg. First drop, 26°C. (79°F.)

Fraction No.	Cut °C.	at °F.	Per-cent	Sum, per-cent	Sp. gr. 60/60°F	°A.P.I., 60°F.	C.I.	S.U. visc., 100°F.	Cloud test, °F.
1	50	122	2.2	2.2	0.636	91.0	-	-	-
2	75	167	3.3	5.5	.676	77.8	10	-	-
3	100	212	7.1	12.6	.718	65.6	20	-	-
4	125	257	8.2	20.8	.742	59.2	23	-	-
5	150	302	6.7	27.5	.763	54.0	25	-	-
6	175	347	6.5	34.0	.782	49.5	27	-	-
7	200	392	5.6	39.6	.798	45.8	29	-	-
8	225	437	5.5	45.1	.812	42.8	30	-	-
9	250	482	5.8	50.9	.826	39.4	31	-	-
10	275	527	6.6	57.5	.839	37.2	32	-	-
Distillation continued at 40 mm. Hg.									
11	200	392	3.1	60.6	0.851	34.8	34	40	10
12	225	437	6.3	66.9	.858	33.4	34	46	25
13	250	482	5.3	72.2	.872	30.8	37	58	45
14	275	527	4.9	77.1	.884	28.6	40	89	65
15	300	572	5.0	82.1	.896	26.4	42	150	85
Residuum		17.7	99.8		.946	18.1			
Carbon residue of residuum, 7.2 percent; carbon residue of crude, 1.3 percent.									

APPROXIMATE SUMMARY

	Percent	Sp. gr.	°A.P.I.	Viscosity
Light gasoline	12.6	0.693	72.7	
Total gasoline and naphtha	39.6	0.744	58.7	
Kerosine distillate	5.5	.812	42.8	
Gas oil	20.6	.842	36.6	
Nonviscous lubricating distillate	9.8	.862-.886	32.7-28.2	50-100
Medium lubricating distillate	6.6	.886-.902	28.2-25.4	100-200
Viscous lubricating distillate	-	-	-	Above 200
Residuum	17.7	.946	18.1	
Distillation loss	0.2			

## PRODUCTION

### Initial Well Production

The initial production tests on wells in the southwestern part of the K.M.A. field are difficult to compare because of the inconsistencies of the producing conditions during the tests. Some of the wells were tested through open casing or open tubing, some through a choke, and some while artificial lift was in use. In addition to these variations, some of the wells were tested before and some after shooting with nitroglycerin.

In view of the inconsistencies of the test conditions, no attempt was made to correlate initial well production with sand thickness, recovery, or flowing life of the well. Initial well production, however, ranged from a few barrels per day by pumping to a maximum of 7,200 barrels per day by flowing. The arithmetical average of all initial production tests was 916 barrels per day, whereas the median initial production was 720 barrels per day.

### Productivity-Index Tests

The productivity index of a well is a measure of its ability to produce oil and is defined as the barrels of stock-tank oil produced per day per pound difference between the static and the flowing bottom-hole pressures. Only a very few productivity index tests were available for this report. Tables 21 and 22 show the results of productivity index tests on four wells at different rates of flow. The productivity indexes shown in these tables change in magnitude with different flow rates and assume minimum values at intermediate flow rates. Table 23 shows the rapid increase in bottom-hole pressure after the well reported in table 22 was shut-in.

The most-important formation characteristics reflected by the magnitude of productivity index tests are permeability and net formation thickness. The average permeability in the southwestern part of the K.M.A. field is approximately 40 millidarcys, and the average net thickness (zones I and II combined) is 17.1 feet. Owing to the low average permeability and net thickness of only 17.1 feet, K.M.A. productivity-index tests should be low.

### Proration of Oil Production

Rule 6 of the Railroad Commission of Texas Special Order 9-185 stipulates that the total daily oil allowable for each well should be proportioned 50 percent on acreage and 50 percent on the field allowable. The commission later amended rule 6 by a special order effective May 24, 1940, that fixed the total daily oil allowable on a basis of 50 percent on acreage, 20 percent on the field allowable, and 30 percent allocated on a bottom-hole-pressure survey. When pressure maintenance by gas was started in the K.M.A. field, the commission issued a special order, effective August 12, 1940, stating that the allowable granted to gas-injection wells could be distributed to and produced by other wells on the lease ratably. Because of the high gas:oil ratios, the commission adopted rule 7, which established a penalty "net gas:oil ratio" of 2,000 cubic feet per barrel. Rule 7 was amended by the commission on August 31, 1943, to permit the operators to close in as many as half of the high-gas:oil ratio wells on a lease and to transfer the allowables of the closed-in wells to other wells on the lease. Rule 6 was again amended by the commission on May 10, 1948, to authorize the daily oil allowable for the field after deductions for marginal wells, high-gas:oil ratio wells, and wells incapable of producing their allowable, to be distributed on the basis of 50 percent on acreage and 50 percent on the remaining field allowable.

TABLE 21.—Pressure and production data, K.M.A. reservoir, southwestern part,  
K.M.A. field, Wichita and Archer Counties, Tex.

Well	Date	Depth, feet below tubing gate	Pressure, p.s.i.	Reservoir temp., °F.	Tubing press., p.s.i.	Flow, bbl. per hour	Gas:oil ratio, cu. ft. per bbl.	Productivity index
Shell- Phillips Preston A-12	1-20-41	0 3,205 3,955	841 995 1,243		841	0	-	-
do	1-21-41	0 3,200 3,955	275 947 1,170	124	275	3.67	1,240	1.035
do	1-22-41	0 3,520 3,955	365 884 974	124	365	10.0	898	.893
do	1-22-41	0 3,210 3,955	282 608 721	124	282	21.0	912	.965
Shell- Phillips Griffin No. 11	1-20-41	0 2,000 3,000	557 691 1,015		557	0	-	-
do	1-21-41	0 3,050 3,756	222 905 1,254	124	222	6.0	453	1.108
do	1-22-41	0 3,002 3,756	251 691 885	124	251	15.0	559	.882
do	1-22-41	0 3,756	175 592	124	175	28.0	728	1.002
Shell- Phillips Griffin No. 7	1-20-41	0 3,620 3,750	424 1,160 1,202	124	424	0	-	-
do	1-23-41	0 2,518 3,751	187 582 911		187	6.0	1,069	.494
do	1-23-41	0 2,550 3,750	148 490 767	124	148	10.5	520	.579

TABLE 22.—Flow data for Shell-Phillips, Griffin well No. 1,  
K.M.A. reservoir, southwestern part, K.M.A.  
field, Wichita and Archer Counties, Tex.

Depth	Pressure, p.s.i.	Rate of flow, bbl. per hr.	Tubing pressure p.s.i.	Productivity index	Gas:oil ratio, cu. ft. per bbl.	Length of test, hr.
3,680	1,599	0	680	-	-	-
3,680	1,248	4.50	300	0.31	552	12.0
3,680	741	15.78	112	.44	423	2.5

TABLE 23.—Pressure build-up data for Shell-Phillips, Griffin well No. 1, K.M.A.  
reservoir, southwestern part, K.M.A. field,  
Wichita and Archer Counties, Tex.

Elapsed time, minutes	Pressure, p.s.i.
0	741
10	758
30	807
70	869

Note:-Build-up test taken after well was shut in after being flowed at the rate of 15.78 barrels per hour.

### Oil- and Gas-Production Statistics

On August 1, 1949, the average daily oil production per well in barrels was 4.0 for unit 4 (subdivided), 7.3 for unit 5, 9.5 for unit 6, and 8.0 for the combined units. The oil produced from the K.M.A. and Ellenburger wells recompleted in the Goen limestone was not segregated from the oil produced from the K.M.A. formation. Because of the many recompletions in this reservoir during the last half of 1949, the volumes of oil and gas produced from the Goen limestone after August 1, 1949, were believed enough to affect materially the calculations pertaining to the K.M.A. reservoir; consequently, the compilations of the K.M.A.-reservoir production statistics were stopped as of that date. These data are tabulated, by months, for unit 4 (subdivided) in table 24, for unit 5 in table 25, for unit 6 in table 26, and for the combined units in table 27.

The cumulative oil production from the southwestern part of the K.M.A. field to August 1, 1949, was 46,107,738 barrels. Reservoir performance curves showing the oil-production history and related data are illustrated in figure 22 for unit 4 (subdivided), in figure 23 for unit 5, in figure 24 for unit 6, and in figure 25 for the combined units.

On June 4, 1940, the Railroad Commission of Texas issued Special Order 9-1610 requiring semiannual gas:oil ratio surveys of all producing wells in the K.M.A. field; however, these individual well tests were not used to determine the field-wide gas:oil ratios. The gas produced from leases with connections to gasoline plants was metered by the gasoline plants. The gas produced from leases without gasoline-plant connections was calculated by multiplying the oil produced from these leases by the average gas:oil ratio of the leases with gasoline-plant connections. The sum of these two volumes of gas gave the gross gas production for each unit; the net gas production was obtained by subtracting from this gross volume the total volume of gas injected. The estimated cumulative gross volume of gas produced for the southwestern part of the K.M.A. field to August 1, 1949, was 91,186,594 M cubic feet, of which 24,367,249 M cubic feet was returned to the reservoir, leaving a cumulative net produced volume of 66,819,345 M cubic feet. Reservoir-performance curves showing gas-production history and related data are illustrated in figure 26 for unit 4 (subdivided), in figure 27 for unit 5, in figure 28 for unit 6, and in figure 29 for the combined units.

The gross gas:oil ratio was computed by dividing the gross gas production by the total oil production; and the net gas:oil ratio was computed by dividing the net gas production by the total oil production. Using this procedure, the cumulative gross gas:oil ratio to August 1, 1949, was calculated to be 1,978 cubic feet per barrel and the cumulative net gas:oil ratio, 1,449 cubic feet per barrel.

### Water Production

Water production has been negligible from the K.M.A. reservoir, but some water has been produced from wells along the southern and eastern edges of the field. The original oil-water contact could be determined only along the southern and eastern edges of the field, where it was approximately 2,850 feet below sea level. The water encroachment into the reservoir along these edges of the field has been slow, and water production from wells in this area has increased only slightly.

Although the original oil-water contact along the northern and western edges of the field could not be determined accurately, it is believed to have been considerably deeper than along the southern and eastern edges of the field.

Chemical analyses of three samples of produced water from the K.M.A. reservoir are given in table 28.

TABLE 24.—Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

		UNIT 4 (Subdivided)																			
Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft. <sup>1/</sup>	Cumulative gross gas production, M cu. ft. <sup>1/</sup>	Average daily gross gas production, M cu. ft. <sup>1/</sup>	Monthly net gas production, M cu. ft. <sup>1/</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced, cu. ft.	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2/</sup>
1931	2	26,415	26,415	72		13,887	13,887	38		525	525	525									
1932	2	39,530	65,945	108		20,753	34,640	57		525	525	525									
1933	3	55,945	121,890	153		29,371	64,011	80		525	525	525									
1934	6	63,504	185,394	174		33,340	97,351	91		525	525	525									
1935	8	71,252	256,646	195		37,407	134,758	102		525	525	525									
1936	11	69,433	346,079	245		46,952	181,710	129		525	525	525									
1937																					
January	11	13,342	359,421	430	39.1	7,005	188,715	226		525	525	525									
February	12	14,758	374,179	527	43.9	7,748	196,463	277		525	525	525									
March	13	22,442	396,621	724	55.7	11,782	208,245	380		525	525	525									
April	15	25,374	421,995	846	56.4	13,321	221,566	444		525	525	525									
May	17	29,678	451,675	957	56.3	15,581	237,147	503		525	525	525									
June	20	29,375	481,048	979	49.0	15,422	252,569	514		525	525	525									
July	23	33,432	514,480	1,078	46.9	17,552	270,121	566		525	525	525									
August	27	48,935	563,415	1,579	58.5	25,691	295,812	829		525	525	525									
September	31	62,193	625,608	2,073	66.9	32,651	328,463	1,088		525	525	525									
October	52	51,374	676,982	1,657	51.8	26,971	355,434	870		525	525	525									
November	36	53,372	730,354	1,779	49.4	28,020	383,454	934		525	525	525									
December	37	54,225	784,579	1,749	47.3	28,468	411,922	918		525	525	525								1,131	
1938																					
January	36	55,496	840,076	1,790	49.7	29,135	441,057	940	25,270	525	525	455	2	3,865	3,865	125	63	70	1.3	18.0	1,131
February	36	44,278	884,353	1,581	43.9	23,246	464,303	830	18,357	525	525	415	2	4,889	8,754	175	88	110	2.1	18.0	1,107
March	36	53,804	938,157	1,736	48.2	28,247	492,550	911	20,415	525	525	379	2	7,832	16,586	253	127	146	2.8	18.0	1,096
April	38	49,411	987,568	1,647	43.3	25,941	518,491	865	19,171	525	525	388	2	6,770	23,356	226	113	137	2.6	19.0	1,064
May	39	46,952	1,034,520	1,515	38.8	24,650	543,141	795	18,059	525	525	385	2	6,591	29,947	213	107	140	2.7	19.5	1,072
June	40	34,514	1,069,034	1,150	28.8	18,120	561,261	604	9,944	525	525	288	2	6,176	38,123	273	137	237	4.5	20.0	1,062
July	43	36,873	1,105,907	1,189	27.7	19,358	580,619	624	11,605	525	525	315	2	7,753	45,876	250	125	210	4.0	21.5	1,050
August	45	30,616	1,136,523	988	22.0	16,073	596,692	518	9,282	525	525	303	2	6,791	52,667	219	110	222	4.2	22.5	1,039
September	44	24,997	1,161,520	833	18.9	13,123	609,815	437	6,915	525	525	277	3	6,208	58,875	207	69	248	4.7	14.7	1,028
October	44	24,751	1,186,271	798	18.1	12,994	622,809	419	4,920	525	525	199	3	8,074	66,349	260	87	326	6.2	14.7	1,017
November	44	26,668	1,212,939	889	20.2	14,001	656,810	467	6,839	525	525	256	3	7,162	74,111	239	80	269	5.1	14.7	1,006
December	44	34,202	1,247,141	1,103	25.1	17,956	684,766	579	9,104	525	525	266	3	8,852	82,963	286	95	259	4.6	14.7	993
1939																					
January	46	33,098	1,280,259	1,068	23.2	13,901	668,667	448	6,724	420	522	203	2	7,177	90,140	232	116	217	5.2	23.0	983
February	47	30,732	1,310,971	1,098	23.4	19,668	688,355	702	14,009	640	525	456	2	5,659	95,799	202	101	184	2.9	23.5	971
March	50	34,312	1,345,283	1,107	22.1	20,587	708,922	664	12,515	600	527	365	2	8,072	103,871	260	130	235	3.9	25.0	961
April	50	38,842	1,384,125	1,295	25.9	22,396	731,518	747	15,052	577	528	388	2	7,344	111,215	245	123	189	3.3	25.0	949
May	50	39,462	1,423,587	1,273	25.5	26,964	758,282	870	18,394	683	533	466	2	8,570	119,785	276	138	217	3.2	25.0	938
June	51	33,804	1,457,391	1,127	22.1	23,210	781,492	774	15,823	687	536	468	2	7,387	127,172	246	123	219	3.2		



TABLE 24.—Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

## UNIT 4 (Subdivided) - Continued

Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft. <sup>1/</sup>	Cumulative gross gas production, M cu. ft. <sup>1/</sup>	Average daily gross gas production, M cu. ft. <sup>1/</sup>	Monthly net gas production, M cu. ft. <sup>1/</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced,	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2/</sup>
1943																					
January	60	24,405	2,829,178	787	13.1	59,263	2,994,502	1,912	40,290	2,428	1,058	1,651	4	18,973	889,465	612	153	777	3.2	15.0	494
February	60	20,910	2,850,088	747	12.5	51,954	3,046,456	1,856	36,100	2,485	1,069	1,726	4	15,854	905,319	566	142	758	3.1	15.0	486
March	60	21,784	2,871,872	703	11.7	53,892	3,100,348	1,738	34,292	2,474	1,080	1,574	4	19,600	924,919	632	158	908	3.5	15.0	471
April	60	19,835	2,891,707	661	11.0	51,000	3,151,348	1,700	32,994	2,571	1,090	1,663	4	18,006	942,925	600	150	908	3.5	15.0	465
May	60	20,165	2,911,872	650	10.8	52,996	3,204,344	1,710	36,605	2,628	1,100	1,815	4	16,391	959,316	529	132	813	3.1	15.0	458
June	61	19,497	2,931,369	650	10.7	52,805	3,257,149	1,760	2,708	1,111	1,868	1,388	3	16,388	975,704	546	182	841	3.1	20.3	451
July	61	19,943	2,951,312	643	10.5	49,693	3,306,842	1,603	31,853	2,492	1,120	1,597	3	17,840	993,544	575	192	895	3.6	20.3	446
August	61	18,553	2,969,965	602	9.9	48,467	3,355,309	1,563	32,410	2,598	1,130	1,738	3	16,057	1,009,601	518	173	861	3.3	20.3	439
September	61	19,911	2,989,876	664	10.9	49,050	3,404,359	1,535	31,392	2,465	1,139	1,577	3	17,658	1,027,259	589	195	887	3.6	20.3	432
October	61	18,728	3,008,604	604	9.9	46,290	3,450,649	1,493	30,306	2,472	1,147	1,618	3	15,984	1,043,243	516	172	853	3.5	20.3	425
November	61	17,779	3,026,383	593	9.7	43,895	3,494,544	1,463	26,353	2,469	1,155	1,482	3	17,542	1,060,785	585	195	987	4.0	20.3	425
December	61	18,740	3,045,123	605	9.9	46,941	3,541,485	1,514	29,824	2,505	1,163	1,591	3	17,117	1,077,902	552	184	913	3.7	20.3	419
1944																					
January	61	18,151	3,063,274	586	9.6	43,307	3,584,792	1,397	26,367	2,386	1,170	1,453	3	16,940	1,094,842	546	182	933	3.9	20.3	413
February	61	16,414	3,079,688	566	9.3	42,236	3,627,028	1,456	26,997	2,573	1,178	1,645	3	15,239	1,110,081	525	175	928	3.6	20.3	407
March	61	16,864	3,096,552	544	8.9	40,084	3,667,112	1,293	26,936	2,377	1,184	1,597	3	13,148	1,125,229	424	141	780	3.3	20.3	395
April	61	15,564	3,112,116	519	8.5	42,869	3,709,981	1,429	30,557	2,754	1,192	1,963	3	12,312	1,135,541	410	137	721	2.9	20.3	389
May	61	16,280	3,128,396	525	8.6	44,369	3,754,350	1,431	30,614	2,725	1,200	1,880	3	13,755	1,149,296	444	148	845	3.1	20.3	383
June	61	17,530	3,145,926	584	9.6	44,550	3,798,900	1,485	30,944	2,541	1,208	1,740	3	14,056	1,163,352	469	156	802	3.2	20.3	377
July	61	16,487	3,162,413	532	8.7	46,363	3,847,263	1,560	35,555	2,933	1,217	2,163	3	12,708	1,176,060	410	137	771	2.6	20.3	371
August	61	17,126	3,179,539	552	9.0	49,202	3,896,465	1,587	36,075	2,873	1,225	2,106	3	13,127	1,189,187	423	141	766	2.7	20.3	361
September	61	17,522	3,197,061	584	9.6	47,918	3,944,383	1,597	32,237	2,735	1,234	1,840	3	15,681	1,204,688	523	174	895	3.3	20.3	350
October	61	15,809	3,212,870	510	8.4	42,092	3,986,475	1,358	25,506	2,663	1,241	1,620	3	16,484	1,221,352	532	177	1,043	3.9	20.3	340
November	61	15,604	3,228,474	520	8.5	41,604	4,028,079	1,387	25,752	2,565	1,248	1,651	3	15,842	1,237,194	528	176	1,015	3.8	20.3	328
December	61	16,438	3,244,912	530	8.7	45,152	4,073,231	1,457	27,803	2,747	1,255	1,691	3	17,349	1,254,543	560	187	1,055	3.8	20.3	328
1945																					
January	61	15,493	3,260,405	500	8.2	42,325	4,115,556	1,365	25,291	2,732	1,262	1,632	3	17,034	1,271,577	549	183	1,099	4.0	20.3	316
February	60	13,666	3,274,073	488	8.1	34,510	4,150,066	1,233	18,638	2,525	1,268	1,564	4	15,872	1,287,449	567	142	1,161	4.6	15.0	306
March	59	15,458	3,289,531	499	8.5	44,294	4,194,360	1,429	28,432	2,685	1,275	1,639	4	15,862	1,303,311	512	128	1,026	3.6	14.8	294
April	59	15,116	3,304,647	504	8.5	43,524	4,237,884	1,451	21,721	2,879	1,282	1,437	4	21,803	1,325,114	727	182	1,442	5.0	14.8	282
May	59	14,465	3,319,112	467	7.9	45,227	4,283,111	1,459	23,382	3,127	1,290	1,616	4	21,645	1,346,959	705	176	1,510	4.8	14.8	270
June	59	14,591	3,333,703	486	8.2																



TABLE 25.—Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

		UNIT 5																			
Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft. <sup>1/</sup>	Cumulative gross gas production, M cu. ft. <sup>1/</sup>	Average daily gross gas production, M cu. ft. <sup>1/</sup>	Monthly net gas production, M cu. ft. <sup>1/</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced, cu. ft.	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>	
1935	1	3,537	3,537	10		1,857	1,857	5		525	525	525									
1936	1	3,952	7,489	11		2,075	3,932	6		525	525	525									
1937																					
January	1	209	7,698	7	7.0	110	4,042	4		525	525	525									
February	1	264	7,962	9	9.0	139	4,181	5		525	525	525									
March	1	286	8,248	9	9.0	150	4,331	5		525	525	525									
April	1	1,165	9,413	39	39.0	612	4,943	20		525	525	525									
May	1	1,010	10,423	33	33.0	530	5,473	17		525	525	525									
June	1	856	11,279	29	29.0	449	5,922	15		525	525	525									
July	1	847	12,126	27	27.0	445	6,367	14		525	525	525									
August	1	793	12,919	26	26.0	416	6,783	13		525	525	525									
September	1	661	13,580	22	22.0	347	7,130	12		525	525	525									
October	1	757	14,337	24	24.0	397	7,527	13		525	525	525									
November	4	6,155	20,492	205	51.3	3,231	10,758	108		525	525	525									
December	8	13,031	33,523	420	52.5	6,841	17,599	221		525	525	525									
1938																					
January	28	42,174	75,697	1,360	48.6	22,141	39,740	714		525	525	525									1,490
February	50	61,203	136,900	2,186	43.7	32,132	71,872	1,148		525	525	525									1,475
March	80	89,123	226,023	2,875	35.9	46,790	118,662	1,509		525	525	525									1,460
April	115	134,845	360,868	4,495	39.1	70,794	189,456	2,360		525	525	525									1,440
May	150	149,470	510,338	4,822	32.1	78,472	267,928	2,531		525	525	525									1,425
June	170	121,262	631,600	4,042	23.8	63,663	331,591	2,122		525	525	525									1,405
July	189	134,834	766,434	4,349	23.0	70,788	402,379	2,283		525	525	525									1,390
August	207	126,659	893,093	4,086	19.7	66,496	468,875	2,145		525	525	525									1,375
September	219	107,956	1,001,049	3,599	16.4	56,577	525,552	1,889		525	525	525									1,360
October	224	113,930	1,114,979	3,675	16.4	59,813	585,365	1,929		525	525	525									1,340
November	225	114,686	1,229,665	3,823	17.0	60,210	645,575	2,007		525	525	525									1,325
December	229	146,111	1,375,776	4,713	20.6	76,708	722,283	2,474		525	525	525									1,310
1939																					
January	232	145,910	1,521,686	4,707	20.3	55,446	777,729	1,789		380	511	511									1,290
February	239	130,608	1,652,294	4,665	19.5	58,121	635,850	2,076		445	506	506									1,275
March	240	149,666	1,801,960	4,828	20.1	59,866	895,716	1,931		400	497	497									1,260
April	241	165,155	1,967,115	5,305	22.8	70,191	965,907	2,340		425	491	491									1,245
May	243	160,232	2,127,347	5,169	21.3	74,508	1,040,415	2,403		465	489	489									1,230
June	247	149,010	2,276,357	4,967	20.1	83,446	1,123,861	2,782		560	494	494									1,210
July	254	159,594	2,435,951	5,148	20.3	86,181	1,210,042	2,780		540	497	497									1,195
August	260	84,943	2,520,894	2,740	10.5	42,472	1,252,514	1,970		500	497	497									1,180
September	263	159,883	2,680,777	5,329	20.3	75,145	1,327,659	2,505	73,960	470	495	463	2	1,185	1,185	40	20	7	1.6	131.5	
October	269	175,220	2,855,997	5,652	21.0	84,106	1,411,765	2,713	77,924	480	494	445	4	6,182	7,357	199	50	35	7.4	67.3	
November	277	181,489	3,037,486	6,050	21.8	78,948	1,490,713	2,632	77,273	435	491	426	4	1,675	9,042	56	14	9	2.1	69.3	
December	281	189,032	3,226,518	6,098	21.7	94,516	1,585,229	3,049	89,322	500	491	473	6	5,194	14,236	168					



TABLE 25.—Production history K.N.A. reservoir, southwestern part of K.N.A. field, Wichita and Archer Counties, Tex.

		UNIT 5 - Continued																			
Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, per well, bbl.	Gross gas production, M cu. ft. <sup>1</sup>	Cumulative gross gas production, M cu. ft. <sup>1</sup>	Average daily gross gas production, M cu. ft. <sup>1</sup>	Monthly net gas production, M cu. ft. <sup>1</sup>	Gross produced gas/oil ratio, cu. ft. per bbl.	Cumulative gross produced gas/oil ratio, cu. ft. per bbl.	Net produced gas/oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected, M cu. ft.	Average injected per well, M cu. ft.	Average gas injected per barrel oil produced, cu. ft.	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>	
1942	318	213,069	8,322,626	6,873	21.6	180,018	5,076,949	5,807	135,514	845	610	636	15	44,504	741,587	1,436	96	209	24.7	21.2	920
January	318	185,490	8,508,116	6,625	21.0	171,739	5,248,688	6,134	129,245	926	617	697	16	42,494	764,081	1,518	95	229	27.9	19.8	905
February	316	161,111	8,669,227	5,197	16.4	162,111	5,411,299	5,246	117,292	1,009	624	728	16	45,319	829,400	1,462	91	281	24.7	19.8	898
March	316	159,271	8,828,498	5,309	16.7	145,617	5,559,916	4,954	111,300	933	630	699	16	37,317	866,717	1,244	78	234	26.1	18.6	890
April	317	196,055	9,024,553	6,324	20.0	209,852	5,769,768	6,769	163,462	1,070	639	834	17	46,390	913,107	1,496	88	237	22.1	18.7	882
May	317	182,724	9,207,277	6,091	19.2	208,330	5,978,096	6,944	159,415	1,140	649	872	17	48,915	962,022	1,631	96	266	23.5	18.6	874
June	318	182,917	9,390,194	5,901	18.6	211,718	6,189,816	6,830	163,048	1,157	659	891	17	48,570	1,010,692	1,570	92	259	21.8	19.6	865
July	317	187,465	9,577,659	6,047	19.1	222,812	6,412,528	7,167	174,198	870	929	1,037	17	48,614	1,059,306	1,568	92	231	19.4	18.6	857
August	317	184,803	9,762,462	6,160	19.4	220,055	6,632,683	7,335	177,444	1,191	879	1,037	17	44,383	1,146,300	1,432	84	240	20.8	18.6	849
September	317	185,257	9,947,729	5,976	18.9	236,597	6,869,280	7,632	192,214	1,277	651	1,066	16	40,513	1,186,813	1,350	84	230	17.5	19.9	840
October	317	176,106	10,123,834	5,870	18.5	231,786	7,101,066	7,726	191,273	1,316	701	1,066	16	45,512	1,222,325	1,468	92	245	20.1	19.9	830
November	318	186,136	10,309,970	6,004	18.9	226,698	7,327,764	7,313	181,186	1,218	711	1,042	16	45,590	1,281,490	1,503	100	258	13.5	21.3	705
December	318	186,136	10,309,970	6,004	18.9	226,698	7,327,764	7,313	181,186	1,218	711	1,042	15	46,590	1,818,490	1,503	100	258	13.5	19.9	691
1943	318	170,598	10,480,568	5,503	17.3	215,879	7,543,643	6,964	170,354	1,265	720	999	16	45,525	1,277,850	1,469	92	267	21.0	19.9	812
January	319	154,150	10,534,718	5,505	17.3	207,669	7,751,312	7,417	164,887	1,347	729	1,068	16	43,082	1,320,932	1,533	96	279	20.7	19.9	803
February	319	177,757	10,812,475	5,734	18.0	241,614	7,993,006	7,797	189,767	1,360	739	1,068	16	51,927	1,372,859	1,675	105	292	21.5	19.9	794
March	319	169,920	10,982,395	5,664	17.8	251,886	8,244,892	8,395	205,260	1,482	751	1,208	16	46,626	1,419,485	1,554	97	274	18.5	19.9	783
April	319	179,157	11,161,552	5,779	18.1	279,670	8,524,562	9,022	233,388	1,561	764	1,303	16	46,288	1,465,773	1,493	93	258	16.6	19.9	772
May	319	170,292	11,331,844	5,676	17.7	273,485	8,798,047	9,116	222,693	1,606	776	1,308	16	50,792	1,516,565	1,693	106	272	18.6	20.0	760
June	320	187,158	11,519,002	6,037	18.9	319,048	9,117,095	10,292	264,183	1,705	791	1,412	16	54,865	1,571,430	1,770	111	293	17.2	20.0	750
July	320	183,972	11,702,974	5,935	18.5	327,666	9,444,761	10,570	273,223	1,781	807	1,485	16	54,443	1,625,873	1,756	110	296	16.6	20.0	742
August	320	181,160	11,884,134	6,039	18.9	301,678	9,746,439	10,056	258,191	1,665	820	1,425	16	51,661	1,721,021	1,666	104	279	14.4	20.2	732
September	320	184,555	12,068,689	5,953	18.5	319,866	10,066,305	10,318	268,205	1,733	834	1,453	16	50,879	1,771,900	1,696	106	279	16.4	19.9	720
October	321	182,401	12,251,090	6,080	19.1	309,529	10,375,834	10,318	258,650	1,697	847	1,418	15	46,590	1,818,490	1,503	100	258	13.5	21.3	705
November	321	182,401	12,251,090	6,080	19.1	309,529	10,375,834	10,318	258,650	1,697	847	1,418	15	46,590	1,818,490	1,503	100	258	13.5	19.9	691
December	321	181,918	12,432,008	5,836	18.2	300,256	10,576,090	9,686	253,666	1,660	859	1,402	15	46,590	1,818,490	1,503	100	258	13.5	19.9	675
1944	319	185,971	12,617,979	5,999	18.8	299,030	10,295,120	9,646	252,561	1,608	870	1,358	16	46,469	1,864,959	1,499	94	250	15.5	19.9	657
January	319	170,976	12,788,955	5,896	18.5	310,917	11,286,037	10,721	267,830	1,818	882	1,566	16	43,087	1,908,046	1,486	93	252	20.7	19.9	649
February	319	169,412	12,973,367	5,949	18.7	356,611	11,642,648	11,504	313,571	1,934	897	1,700	17	43,040	1,951,066	1,388	82	233	21.5	19.9	634
March	318	181,243	13,114,610	6,041	19.0	380,268	12,022,916	12,676	330,931	2,098	914	1,826	16	49,337	2,000,423	1,645	97	272	15.0	18.6	620
April	318	188,847	13,343,457	6,092	19.1	399,776	12,422,692	12,896	338,793	2,117	931	1,794	17	60,983	2,061,406	1,967	116	323	16.3	18.8	604
May	318	170,148	13,584,606	6,036	18.9	416,697	12,839,369	13,890	354,137	2,300	949	1,955	17	62,560	2,123,966	2,065	123	345	15.0	18.8	590
June	319	186,148	13,710,742	6,004	18.8	434,506	12,723,995														



TABLE 26.—Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

		UNIT 6																			
Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft. <sup>1</sup>	Cumulative gross gas production, M cu. ft. <sup>1</sup>	Average daily gross gas production, M cu. ft. <sup>1</sup>	Monthly net gas production, M cu. ft. <sup>1</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average daily gas injected per well, M cu. ft.	Average gas injected per barrel oil produced,	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>
1937	December	2	1,711	1,711	55	27.5	898	898	29	525	525	525	525								1,750
1938	January	2	3,522	5,233	114	57.0	1,849	2,747	60	525	525	525	525								1,735
	February	4	4,934	10,167	176	44.0	2,590	5,337	93	525	525	525	525								1,720
	March	8	12,057	22,224	389	48.6	6,330	11,667	204	525	525	525	525								1,705
	April	12	15,525	37,749	518	43.2	8,151	19,818	272	525	525	525	525								1,683
	May	21	19,539	57,286	630	30.0	10,256	30,076	331	525	525	525	525								1,662
	June	25	22,159	79,447	739	29.6	11,633	41,709	368	525	525	525	525								1,640
	July	36	24,759	104,206	799	22.2	12,998	54,707	419	525	525	525	525								1,619
	August	47	32,111	136,317	1,036	22.0	16,858	71,565	544	525	525	525	525								1,598
	September	55	32,151	168,468	1,072	19.5	16,879	88,444	563	525	525	525	525								1,577
	October	68	35,430	203,898	1,143	16.8	18,601	107,045	600	525	525	525	525								1,556
	November	80	41,979	245,877	1,399	17.5	22,039	129,064	735	525	525	525	525								1,535
	December	87	52,743	298,620	1,701	19.6	27,990	156,774	893	525	525	525	525								1,513
1939	January	95	66,168	364,788	2,134	22.5	26,467	183,241	854	400	502										1,491
	February	106	62,825	427,613	2,244	21.2	25,758	208,999	920	410	489										1,470
	March	120	80,009	507,822	2,581	21.5	33,604	242,603	1,084	420	478										1,449
	April	137	101,110	608,732	3,370	24.6	43,477	286,080	1,449	430	470										1,428
	May	158	114,229	722,961	3,685	23.3	51,403	337,483	1,658	450	467										1,406
	June	174	117,970	840,931	3,932	22.6	54,266	391,749	1,809	460	466										1,384
	July	187	130,099	971,030	4,197	22.4	61,147	452,896	1,972	470	466										1,364
	August	191	66,325	1,037,355	2,140	11.2	32,499	485,395	1,048	32,170	490	468	485	2	329	329	11	6	5	1.0	95.5
	September	191	137,804	1,175,159	4,593	24.0	68,902	554,297	2,297	64,048	500	472	465	5	4,854	5,183	162	32	35	7.0	38.2
	October	197	144,780	1,319,939	4,670	23.7	72,390	626,687	2,335	66,870	500	475	462	5	5,520	10,703	178	36	38	7.6	39.4
	November	207	142,247	1,462,186	4,742	22.9	71,124	697,811	2,371	70,619	500	477	496	4	505	11,206	17	4	4	0.7	51.8
	December	218	156,849	1,619,035	5,060	23.2	78,425	776,236	2,530	77,283	500	479	493	3	1,142	12,350	37	12	7	1.5	72.7
1940	January	227	152,503	1,771,538	4,919	21.7	77,905	854,141	2,513	77,818	511	482	510	3	87	12,437	3	1	0.1	75.7	1,275
	February	229	224,922	1,996,460	7,756	35.9	94,364	948,505	3,254	92,079	420	475	409	6	2,285	14,722	79	13	10	2.4	38.2
	March	234	255,422	2,251,982	8,239	35.2	128,539	1,077,044	4,146	123,433	503	478	483	9	5,106	19,828	165	18	20	4.0	26.0
	April	239	211,184	2,463,066	7,039	29.5	121,278	1,198,382	4,043	102,686	574	487	486	9	18,592	38,420	620	69	88	15.3	26.6
	May	249	195,695	2,658,761	6,313	25.4	120,528	1,318,850	3,888	97,828	616	496	499	11	22,700	61,120	732	67	116	18.8	22.6
	June	251	192,887	2,851,648	6,430	25.6	109,971	1,428,821	3,666	86,166	570	447	13	25,805	84,925	794	61	123	21.6	19.3	
	July	257	187,344	3,038,992	6,043	23.5	112,330	1,541,151	3,624	86,560	600	507	462	13	25,770	110,695	831	64	138	22.9	19.8
	August	257	175,636	3,214,528	5,666	22.0	105,953	1,647,104	3,418	73,724	603	512	420	17	32,229	142,924	1,040	61	183	30.4	15.1
	September	266	206,163	3,420,791	6,872	25.8	110,126	1,757,250	3,671	70,624	534	514	343	17	39,502	182,426	1,317	77	192	35.9	15.6
	October	273	265,806	3,686,597	8,574	31.4	149,433	1,906,563	4,820	100,968	562	517	379	17	48,468	230,894	1,563	92	182	32.4	16.1
	November	278	204,076	3,890,673	6,803	24.5															



TABLE 26.—Production history K.W.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

UNIT 6 - Continued

Year end month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production per well, bbl.	Average daily oil production, bbl.	Gross gas production, M cu. ft. <sup>1</sup>	Cumulative gross gas production, M cu. ft. <sup>1</sup>	Average daily gross gas production, M cu. ft. <sup>1</sup>	Monthly net gas production, M cu. ft. <sup>1</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced,	Produced gas returned to reservoir, cu. ft.	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>	
1944																					
January	301	200,279	11,311,501	6,461	21.5	336,015	10,583,971	10,839	221,748	1,578	936	1,107	24	114,267	3,941,404	3,686	154	571	34.0	12.5	632
February	300	185,040	11,496,541	6,381	21.3	353,612	10,937,583	12,194	252,628	1,911	951	2,365	25	100,964	4,042,388	3,482	139	546	38.6	12.0	618
March	300	200,973	11,697,514	6,483	21.6	406,816	11,344,399	13,123	291,969	2,024	970	1,453	25	114,847	4,157,235	3,705	148	571	38.2	12.0	604
April	300	199,735	11,897,241	6,658	22.2	449,426	11,793,825	14,981	323,841	2,250	991	1,621	25	125,586	4,282,820	4,186	167	629	37.9	12.0	790
May	300	210,501	12,107,750	6,790	22.6	517,748	12,311,573	16,702	371,129	2,460	1,017	1,763	25	146,619	4,429,439	4,730	189	697	38.3	12.0	776
June	300	199,669	12,307,439	6,656	22.8	533,388	12,844,361	17,780	368,214	2,671	1,044	1,844	25	165,174	4,594,613	5,506	220	827	31.0	12.0	761
July	300	208,082	12,518,491	6,711	22.4	584,351	13,429,312	18,850	400,789	2,809	1,073	1,926	25	183,562	4,778,175	5,921	237	862	31.4	12.0	747
August	301	203,344	12,718,836	6,559	21.8	555,469	13,984,781	17,918	393,078	2,732	1,100	1,933	24	162,391	4,940,566	5,238	218	799	29.2	12.5	733
September	300	199,246	12,918,061	6,642	22.1	551,586	14,536,369	18,386	375,070	2,768	1,125	1,882	25	176,518	5,117,084	5,984	235	866	32.0	12.0	716
October	300	203,971	13,122,052	6,580	21.9	553,466	15,089,835	17,854	378,155	2,713	1,150	1,854	25	175,311	5,292,395	5,655	226	859	31.7	12.0	700
November	299	198,540	13,320,592	6,618	22.1	501,073	15,590,908	16,702	327,872	2,524	1,170	1,651	26	173,201	5,465,596	5,773	222	872	34.6	11.5	683
December	300	197,535	13,518,127	6,372	21.2	513,748	16,104,656	16,573	343,446	2,601	1,191	1,739	26	170,302	5,635,898	5,494	211	862	35.1	11.5	667
1945																					
January	300	197,660	13,715,787	6,376	21.3	506,111	16,610,767	16,326	342,930	2,561	1,211	1,735	27	163,181	5,799,079	5,264	195	826	32.2	11.1	650
February	300	179,912	13,895,599	6,425	21.4	500,035	17,110,802	17,858	349,000	2,779	1,231	1,940	28	151,035	5,950,114	5,394	193	839	30.8	10.7	634
March	300	203,808	14,099,501	6,574	21.9	581,062	17,691,864	18,744	437,770	2,851	1,255	2,148	28	143,292	6,093,406	4,622	165	703	24.7	10.7	618
April	300	196,731	14,296,232	6,656	21.9	591,325	18,283,189	19,711	416,756	3,006	1,279	2,118	28	174,569	6,267,975	5,819	278	867	29.5	10.7	601
May	300	200,881	14,497,113	6,480	21.6	642,152	18,925,341	20,715	464,139	3,197	1,305	2,311	28	178,013	6,445,988	5,742	235	866	27.7	10.7	584
June	301	187,039	14,684,152	6,235	20.7	651,986	19,577,327	21,733	448,076	3,486	1,333	2,396	27	203,910	6,649,898	6,797	252	1,090	31.3	11.1	568
July	300	199,823	14,883,975	6,446	21.5	729,334	20,306,661	23,527	495,156	3,650	1,364	2,478	28	234,178	6,884,076	7,554	271	1,172	32.1	10.7	552
August	300	195,268	15,079,243	6,299	21.0	755,555	21,062,216	24,373	504,289	3,869	1,397	2,583	28	251,266	7,135,342	8,105	289	1,287	33.3	10.7	537
September	301	140,704	15,219,947	4,690	15.6	610,754	21,672,970	20,358	418,402	4,341	1,424	2,621	28	192,352	7,327,694	6,412	239	1,587	31.5	9.2	522
October	300	148,524	15,368,471	4,791	16.0	576,439	22,249,409	18,595	389,239	4,881	1,448	2,447	28	187,200	7,514,894	6,039	216	1,260	32.5	10.7	507
November	300	170,925	15,539,396	5,698	19.0	651,720	22,901,129	21,724	418,264	3,813	1,474	2,213	28	233,456	7,748,350	7,782	278	1,366	35.8	10.7	492
December	296	176,360	15,715,756	5,689	19.2	629,500	23,530,629	20,306	390,316	3,569	1,497	2,213	28	239,184	7,987,534	7,716	276	1,356	38.0	10.6	477
1946																					
January	297	171,482	15,887,238	5,532	18.6	587,955	24,116,584	18,966	353,309	3,429	1,518	2,060	28	234,646	8,222,180	7,569	270	1,368	39.9	10.6	462
February	297	156,548	16,043,786	5,591	18.8	579,526	24,698,110	20,697	372,719	3,702	1,539	2,381	28	206,807	8,428,987	7,986	264	1,321	35.7	10.6	447
March	298	174,763	16,218,549	5,638	18.9	681,520	25,379,630	21,985	466,519	3,900	1,565	2,669	27	215,001	8,643,988	6,936	257	1,230	31.5	11.0	432
April	299	165,732	16,384,281	5,524	18.5	727,132	26,106,762</td														



TABLE 27.--Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

Units 4 (subdivided), 5, and 6 combined

Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft./ <sup>1</sup>	Cumulative gross gas production, M cu. ft./ <sup>1</sup>	Average daily gross gas production, M cu. ft./ <sup>1</sup>	Monthly net gas production, M cu. ft./ <sup>1</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced, cu. ft.	Produced gas returned to reservoir, cu. ft.	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>
1931	2	26,415	26,415	72		13,887	13,887	38		525	525	525								
1932	2	39,530	65,945	108		20,753	34,640	57		525	525	525								
1933	3	55,945	121,890	153		29,371	64,011	80		525	525	525								
1934	6	63,504	185,394	174		33,340	97,351	91		525	525	525								
1935	9	74,789	260,183	205		39,264	136,615	108		525	525	525								
1936	12	93,385	353,568	256		49,027	185,642	134		525	525	525								
1937																				
January	12	13,551	367,119	437	36.4	7,115	192,757	230		525	525	525								
February	13	15,022	382,141	537	41.3	7,887	200,644	282		525	525	525								
March	14	22,728	404,869	733	52.4	11,932	212,576	385		525	525	525								
April	16	26,539	431,408	885	55.3	13,933	226,509	164		525	525	525								
May	18	30,688	462,096	990	55.0	16,111	242,620	520		525	525	525								
June	21	30,231	492,327	1,008	48.0	15,871	258,491	529		525	525	525								
July	24	34,279	526,606	1,106	46.1	17,997	276,488	581		525	525	525								
August	28	49,728	576,334	1,604	57.3	26,107	302,595	842		525	525	525								
September	32	62,854	639,188	2,095	65.5	32,998	335,593	1,100		525	525	525								
October	33	52,131	691,319	1,682	51.0	27,368	362,961	883		525	525	525								
November	38	59,527	750,846	1,984	52.2	31,251	394,212	1,042		525	525	525							1,582	
December	47	68,967	819,813	2,225	47.3	36,207	430,419	1,168		525	525	525								
1938																				
January	66	101,192	921,005	3,264	49.5	53,125	483,544	1,714	49,260	525	487	2	3,865	3,865	125	63	38	7.3	33.0	
February	90	110,415	1,031,420	3,943	43.8	57,968	541,512	2,070	53,079	525	481	2	4,889	8,754	175	88	44	8.4	45.0	
March	124	154,984	1,186,404	4,999	40.3	81,367	622,879	2,625	73,535	525	474	2	7,832	16,586	253	127	51	9.6	62.0	
April	165	199,781	1,386,185	6,659	40.4	104,866	721,765	3,496	98,116	525	491	2	6,770	23,356	226	113	34	6.5	82.5	
May	210	215,961	1,602,146	6,966	33.2	113,380	841,145	3,657	106,789	525	494	2	6,591	29,947	213	107	31	5.8	105.0	
June	235	177,935	1,780,081	5,931	25.2	93,416	93,561	3,114	85,240	525	479	2	8,176	38,123	273	137	46	8.8	117.5	
July	268	196,466	1,976,547	6,338	23.6	103,144	1,037,705	3,327	95,391	525	486	2	7,753	45,876	250	125	39	7.5	134.5	
August	299	189,386	2,165,933	6,109	20.4	99,427	1,137,132	3,207	92,636	525	489	2	6,791	52,667	219	110	36	6.8	149.5	
September	318	165,104	2,331,037	5,503	17.3	86,679	1,223,811	2,889	80,471	525	487	3	6,208	58,875	207	69	38	7.2	142.0	
October	336	174,111	2,505,148	5,616	16.7	91,408	1,315,219	2,949	83,334	525	479	3	8,074	66,949	260	87	46	8.8	112.0	
November	349	183,333	2,688,481	6,111	17.5	96,250	1,411,469	3,208	89,088	525	486	3	7,162	74,111	239	80	39	7.4	116.3	
December	360	233,056	2,921,537	7,518	20.9	122,354	1,533,823	3,947	113,502	525	487	3	8,852	82,963	286	95	38	7.2	120.0	
1939																				
January	373	245,176	3,166,713	7,909	21.2	95,814	1,629,637	3,091	88,637	391	515	2	7,177	90,140	232	116	29	7.5	186.5	
February	392	224,165	3,390,878	8,006	20.4	103,547	1,733,184	3,698	97,888	462	511	2	5,659	95,799	202	101	25	5.5	196.0	
March	410	263,987	3,654,865	8,516	20.8	114,057	1,847,241	3,679	105,985	432	505	2	8,072	103,871	260	130	31	7.1	205.0	
April	428	305,107	3,959,972	10,170	23.8	136,064	1,983,305	4,921	128,720	446	501	2	7,344	111,215	245	123	24	5.4	214.0	
May	451	313,923	4,273,895	10,127	22.5	152,875	2,136,180	4,921	144,305	487	500	2	8,570	119,785	276	138	27	5.6	225.5	
June	472	300,784	4,574,679	10,026	21.2	160,922	2,297,102	5,364	221,326	487	502	2	8,993	136,165	290	145	28	5.2	236.0	
July	492	326,491	4,901,170	10,532	21.4	172,961	2,470,063	5,579	163,968	530	504	2	5,214	141,379	246.0	123.5	30	5.8	1,245	
August	502	171,204	5,072,374	5,523	11.0	89,923	2,559,986	2,901	84,709	525	505	4	17,483	158,862	53	61	192	10.4	1,214	
September	505	332,310	5,104,684	11,077	21.9	168,570	2,728,556	5												



TABLE 27.—Production history K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

Units 4 (subdivided), 5, and 6 combined - continued

Year and month	Number of active oil wells	Oil production, bbl.	Cumulative oil production, bbl.	Average daily oil production, bbl.	Average daily oil production per well, bbl.	Gross gas production, M cu. ft. <sup>1</sup>	Cumulative gross gas production, M cu. ft. <sup>1</sup>	Average daily gross gas production, M cu. ft. <sup>1</sup>	Monthly net gas production, M cu. ft. <sup>1</sup>	Gross produced gas:oil ratio, cu. ft. per bbl.	Cumulative gross produced gas:oil ratio, cu. ft. per bbl.	Net produced gas:oil ratio, cu. ft. per bbl.	Number of active gas injection wells	Monthly gas injected, M cu. ft.	Cumulative gas injected, M cu. ft.	Average daily gas injected per injection well, M cu. ft.	Average gas injected per barrel oil produced, cu. ft.	Produced gas returned to reservoir, percent	Active oil well:injection well ratio	Weighted average reservoir pressure, lb. per sq. in. <sup>2</sup>	
<b>1943</b>																					
January	678	380,057	22,330,838	12,260	18.1	499,849	17,345,429	16,124	300,946	1,315	777	792	45	198,903	4,637,562	8,416	143	523	39.8	15.1	859
February	679	340,613	22,671,651	12,172	17.9	474,334	17,819,763	16,941	287,071	1,392	786	842	45	187,263	4,824,825	6,688	149	549	39.5	15.1	850
March	679	390,749	23,062,400	12,605	18.6	555,876	18,375,639	17,931	34,339	1,423	797	880	45	218,107	5,036,932	6,842	152	543	38.2	15.1	841
April	680	371,758	23,434,158	12,392	18.2	564,484	18,940,123	18,816	370,752	1,518	808	997	44	193,732	5,230,664	6,456	147	521	34.3	15.5	831
May	680	391,350	23,825,508	12,624	18.6	631,664	19,571,787	20,376	440,799	1,614	821	1,126	44	190,865	5,421,529	6,159	149	488	30.8	15.5	821
June	682	371,937	24,197,445	12,398	18.2	637,087	20,208,874	21,236	446,072	1,713	835	1,199	43	191,015	5,612,544	6,367	148	514	30.0	15.9	810
July	682	404,248	24,601,693	13,040	19.1	725,202	20,934,076	23,394	519,147	1,794	851	1,284	43	206,055	5,818,599	6,847	155	510	28.4	15.9	800
August	682	399,909	25,001,602	12,900	18.9	726,778	21,660,854	23,444	524,213	1,817	866	1,318	43	201,965	6,020,564	6,515	152	505	27.8	15.9	789
September	682	389,648	25,391,250	12,988	19.0	693,616	22,354,470	23,121	513,191	1,780	880	1,317	43	180,425	6,200,989	6,014	140	463	26.0	15.9	778
October	683	401,052	25,792,302	12,937	18.9	717,545	23,072,015	23,147	551,426	1,789	895	1,375	43	166,119	6,367,108	5,359	125	414	23.8	15.9	766
November	681	397,768	26,190,070	13,259	19.5	698,448	23,770,463	23,282	527,413	1,756	908	1,327	43	170,635	6,537,743	5,688	132	429	24.4	15.8	754
December	682	398,283	26,588,353	12,848	18.8	695,068	24,465,531	22,422	509,282	1,745	920	1,279	42	185,766	6,723,529	5,993	143	466	26.7	16.2	741
<b>1944</b>																					
January	681	404,401	26,992,754	13,045	19.2	678,352	25,143,883	21,882	500,676	1,677	932	1,238	43	177,876	6,901,205	5,731	133	439	26.8	15.8	728
February	680	372,430	27,365,184	12,842	18.9	706,765	25,850,648	24,371	547,455	1,898	945	1,470	44	159,310	7,060,515	5,498	128	428	22.8	15.5	713
March	679	402,249	27,767,433	12,976	19.1	803,511	26,654,159	25,920	632,476	1,998	960	1,572	45	171,036	7,231,580	5,517	123	425	21.6	15.1	700
April	679	396,542	28,163,975	13,218	19.5	872,563	27,526,722	29,086	685,499	2,200	977	1,728	45	187,234	7,418,784	6,241	139	472	21.5	15.1	687
May	680	415,626	28,579,603	13,407	19.7	961,893	28,482,615	30,029	740,556	2,314	997	1,782	45	221,357	7,640,141	7,141	159	533	22.0	15.1	674
June	680	398,367	28,977,970	13,279	19.5	994,635	29,483,250	35,155	752,645	2,497	1,017	1,890	45	241,790	7,881,931	8,080	178	607	24.3	15.1	661
July	680	410,576	28,388,646	13,248	19.5	1,067,320	30,550,570	34,430	805,583	2,569	1,040	1,957	45	263,737	8,145,668	8,508	189	642	24.7	15.1	648
August	681	407,656	29,796,302	13,150	19.3	1,037,616	31,568,386	33,478	796,581	2,546	1,060	1,954	44	241,235	8,386,903	7,782	177	592	23.2	15.5	635
September	682	405,156	30,201,458	13,505	19.8	1,040,700	32,629,066	34,690	781,975	2,569	1,080	1,930	43	258,725	8,648,688	8,684	201	639	24.9	15.9	621
October	681	403,356	30,604,814	13,011	19.1	1,023,751	33,652,837	33,024	763,572	2,588	1,100	1,898	44	258,179	8,903,807	8,388	189	640	25.8	15.5	604
November	681	396,270	31,001,084	13,209	19.4	958,928	34,611,765	31,964	702,034	2,420	1,116	1,772	44	256,894	9,160,701	8,563	195	648	26.8	15.5	589
December	682	395,598	31,396,682	12,761	18.7	973,078	35,584,843	31,390	714,766	2,460	1,133	1,807	44	258,210	9,418,911	8,389	189	653	26.5	15.5	593
<b>1945</b>																					
January	681	393,693	31,790,375	12,700	18.6	960,706	35,545,549	30,991	709,469	2,440	1,118	1,802	46	251,237	9,670,148	8,104	176	638	26.2	14.8	559
February	680	359,308	32,149,683	12,832	18.9	919,815	37,465,364	32,851	684,732	2,560	1,165	1,905	48	236,483	9,906,631	8,410	175	655	26.6	14.2	543
March	679</td																				



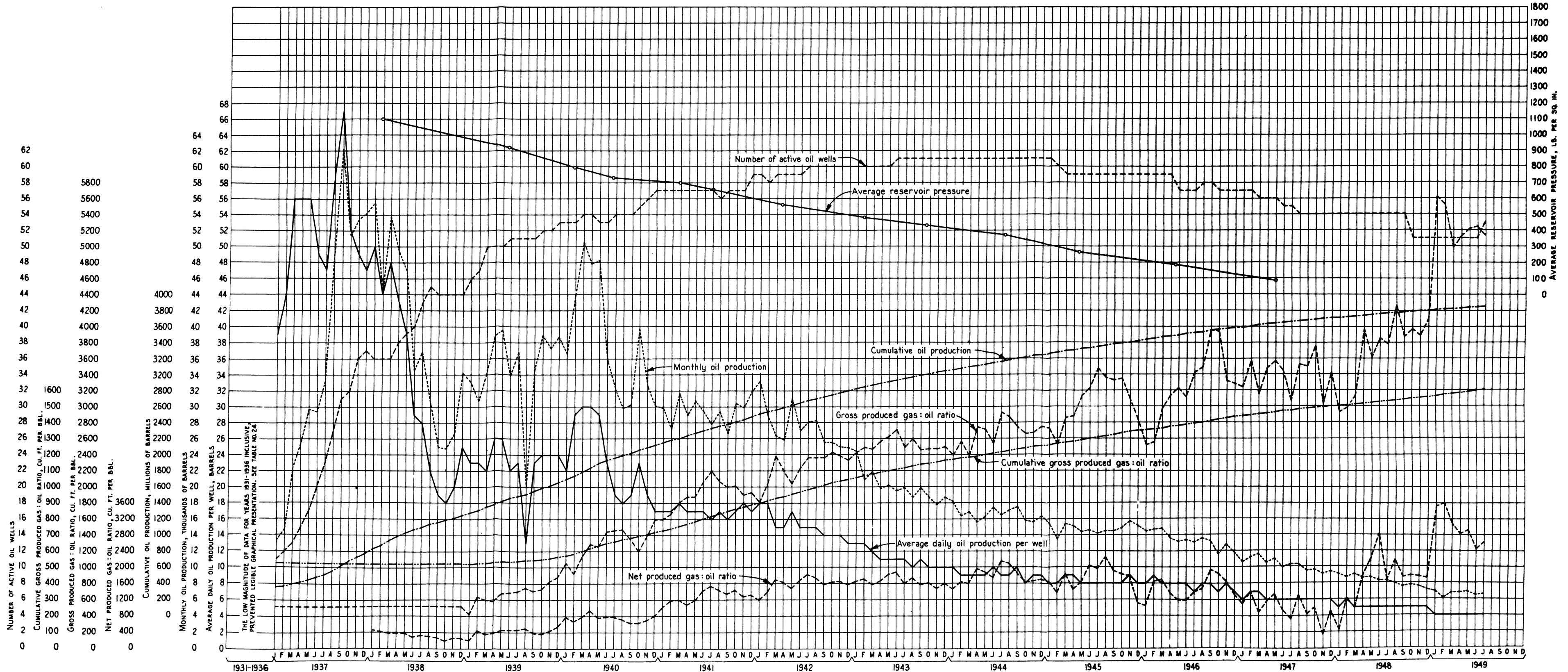


Figure 22—Reservoir performance curves showing oil production history and related data, Unit 4 (subdivided), K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



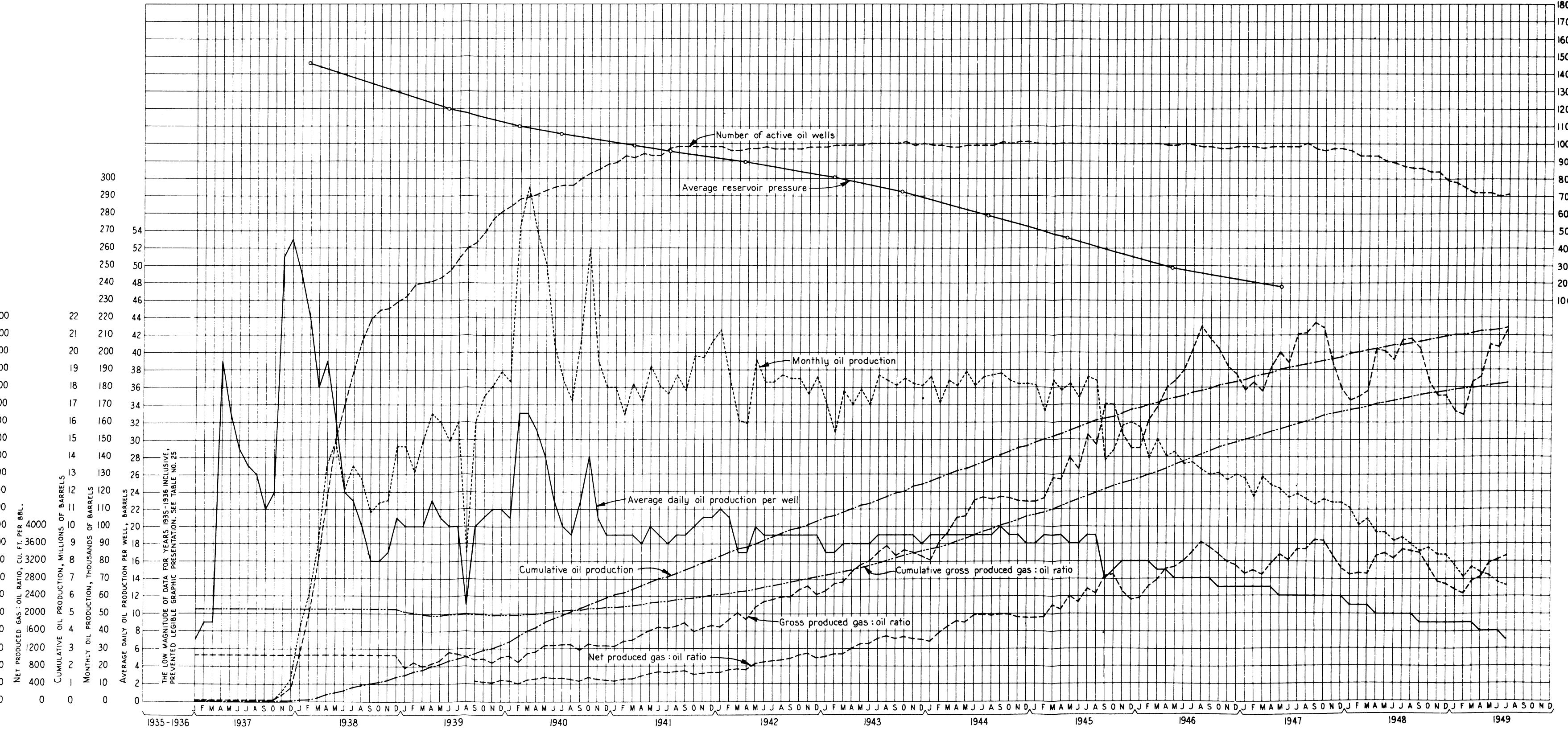


Figure 23.-Reservoir performance curves showing oil production history and  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and A



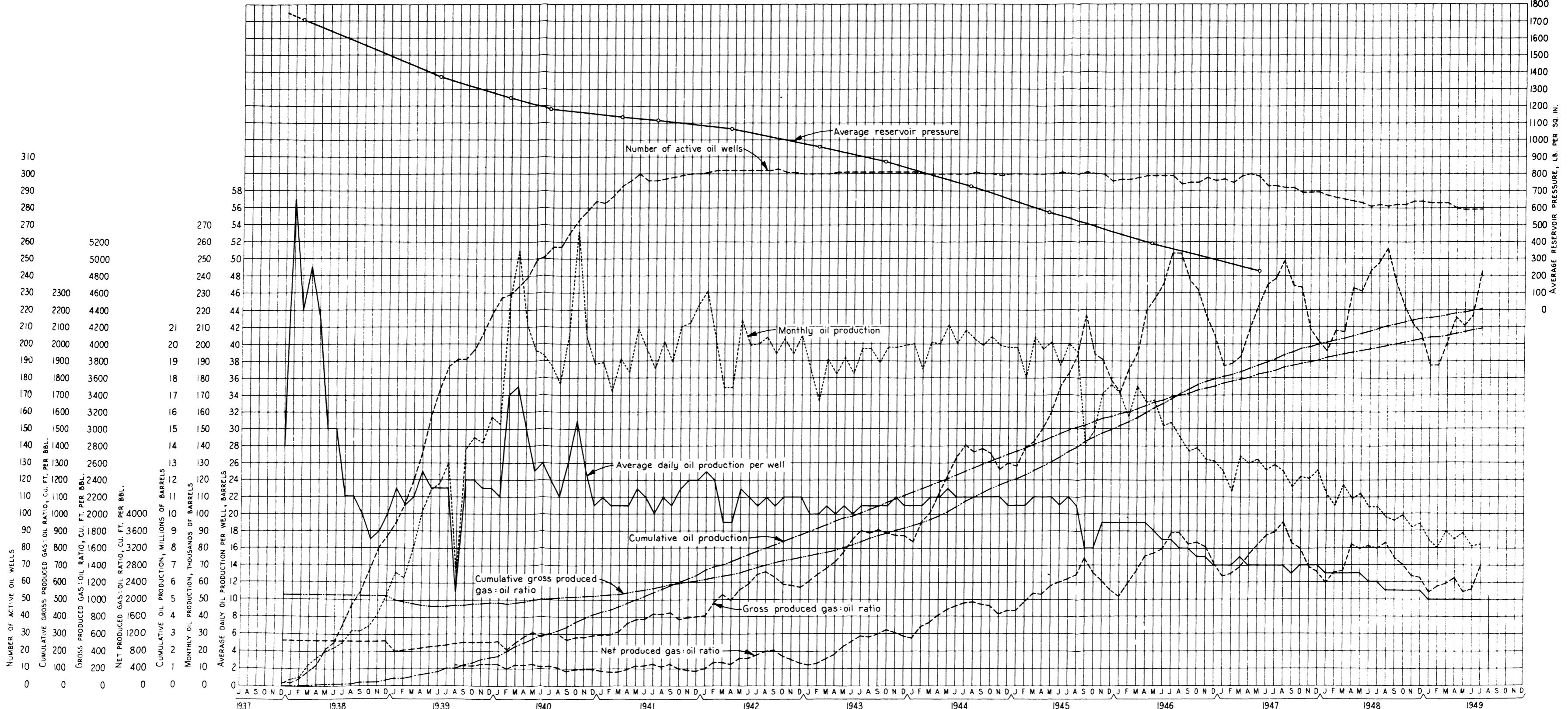


Figure 24.-Reservoir performance curves showing oil production history and related data, Unit 6,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



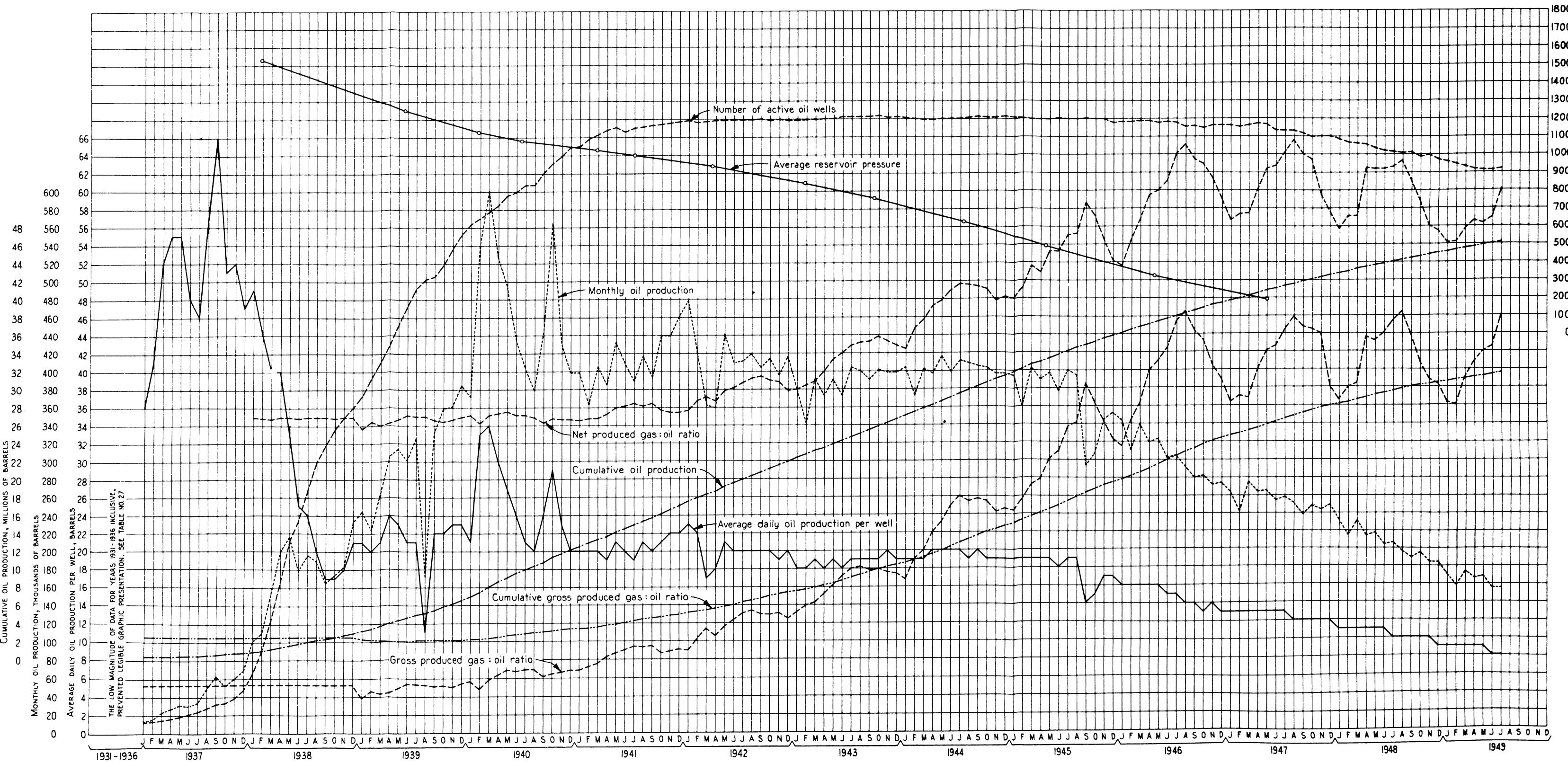


Figure 25.-Reservoir performance curves showing oil production history and related data, Unit 4 (subdivided), Unit 5, and Unit 6 combined, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.





e 26.-Reservoir performance curves showing gas production history and related K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer



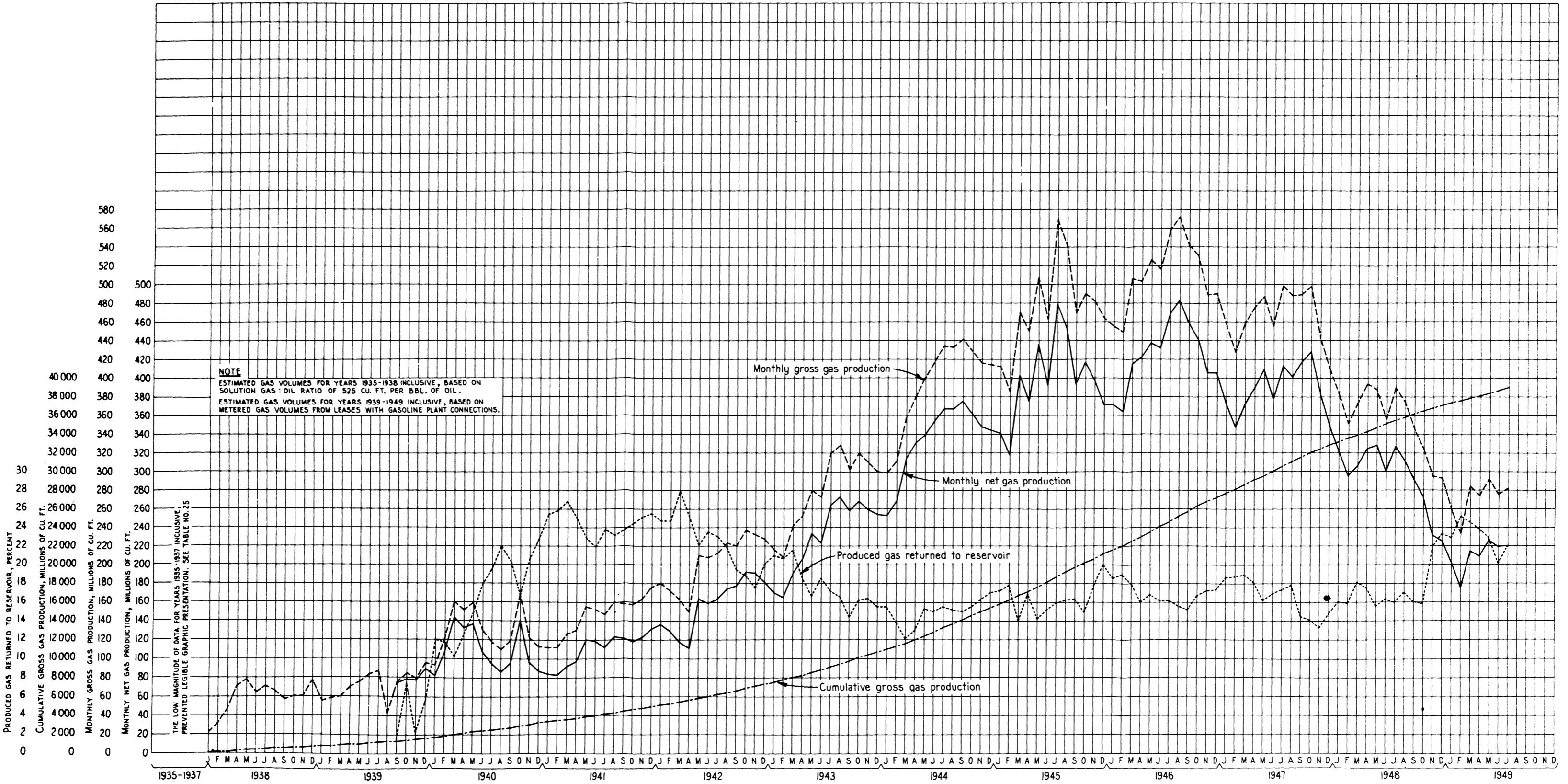


Figure 27.-Reservoir performance curves showing gas production history and related data, Unit 5, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



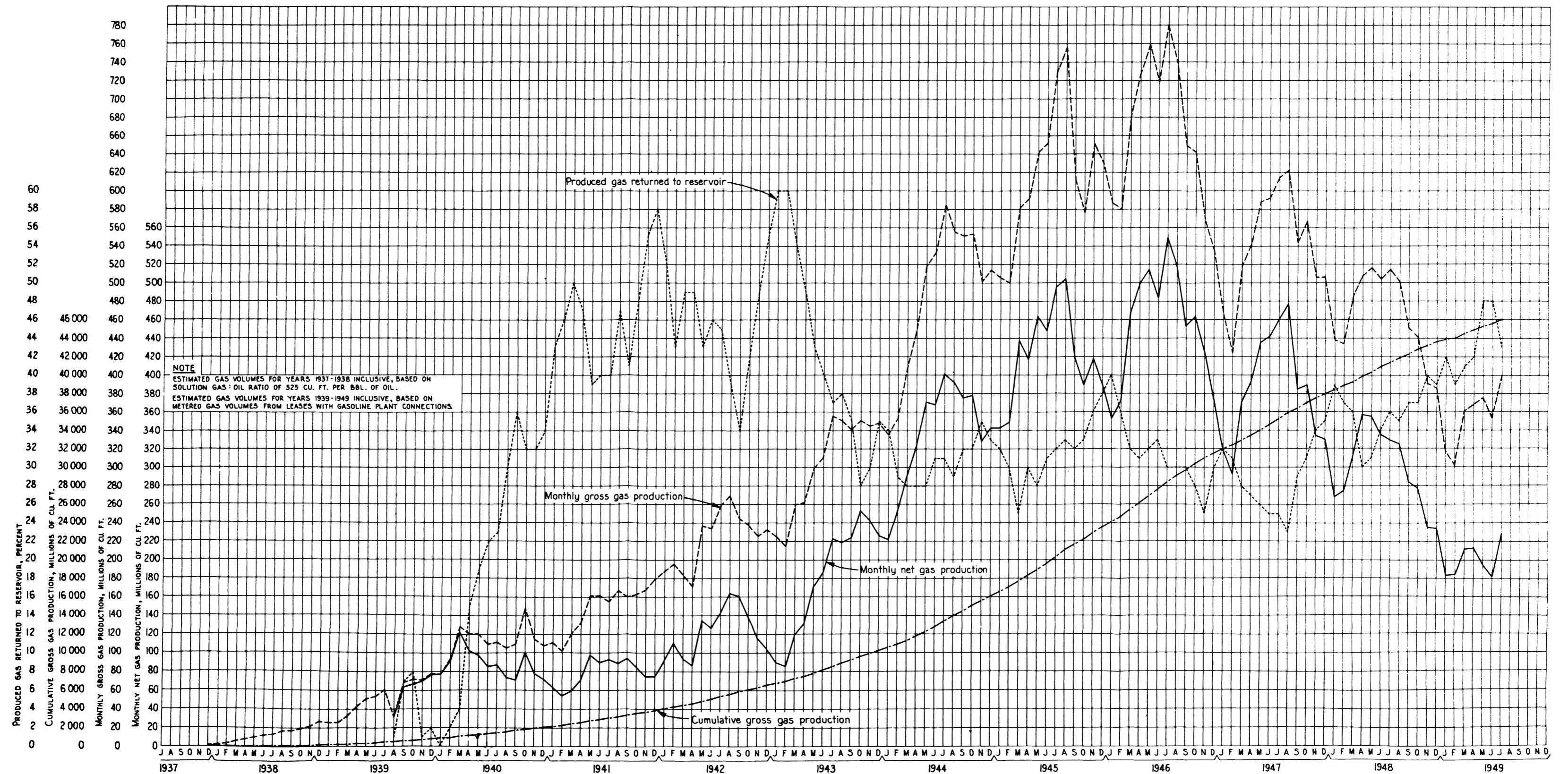


Figure 28.-Reservoir performance curves showing gas production history and related data, Unit 6,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.





Figure 29.-Reservoir performance curves showing gas production history and related data, Unit 4 (subdivided), Unit 5, and Unit 6 combined, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



TABLE 28.—Analyses of produced water from K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

N. C. Griffin 1/ lease  
 3,750 - 3,950 feet  
 Shell Oil Co. and Phillips Petroleum Co.  
 September 9, 1941

K.M.A. field  
 K.M.A. formation (Strawn)  
 Floyd Jordan Survey

Texas  
 Wichita County

Radical	Parts per million, (mg. per liter)	Reacting values percent (Palmer)
Calcium (Ca) . . . . .	12,001	11.93
Magnesium (Mg) . . . . .	2,306	3.77
Sodium (Na) . . . . .	39,596	34.30
Bicarbonate ( $\text{HCO}_3$ ) . . . . .	165	.05
Sulfate ( $\text{SO}_4$ ) . . . . .	404	.17
Chloride (Cl) . . . . .	88,643	49.78
Total solids . . . . .	143,115	100.00

Specific gravity at 15.6°C. (60°F.), 1.098.

1/ 16 wells producing into K.M.A. battery.

Fred Thom well No. 9  
 3,836 - 3,850  
 Texas Co.  
 May 27, 1949

K.M.A. field  
 K.M.A. formation (Strawn)

Texas  
 Wichita County  
 W. H. Spillers  
 Survey A-257

Radical	Parts per million, (mg. per liter)	Reacting values percent (Palmer)
Calcium (Ca) . . . . .	17,030	11.55
Magnesium (Mg) . . . . .	2,782	3.11
Sodium (Na) . . . . .	59,791	35.34
Bicarbonate ( $\text{HCO}_3$ ) . . . . .	64	.01
Sulfate ( $\text{SO}_4$ ) . . . . .	167	.05
Chloride (Cl) . . . . .	130,308	49.94
Total solids . . . . .	210,142	100.00

Specific gravity at 15.6°C. (60°F.), 1.148.

Resistivity at 124°F., 0.0321 ohm-m<sup>2</sup>m.

TABLE 28.--Analyses of produced water from the K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex. - continued

Ferguson well No. 17  
3,738 - 3,850 feet  
Tide Water Associated Oil Co.  
June 20, 1949

K.M.A. field  
K.M.A. formation (Strawn)

Texas  
Wichita County  
W. H. Spillers  
Survey A-257

Radical	Parts per million, (mg. per liter)	Reacting values percent (Palmer)
Calcium (Ca) .....	10,939	11.01
Magnesium (Mg) .....	2,057	3.41
Sodium (Na) .....	40,567	35.58
Bicarbonate ( $\text{HCO}_3$ ) .....	104	.04
Sulfate ( $\text{SO}_4$ ) .....	154	.06
Chloride (Cl) .....	87,756	49.90
Total solids .....	141,577	100.00

Specific gravity at 15.6°C. (60°F.), 1.100.

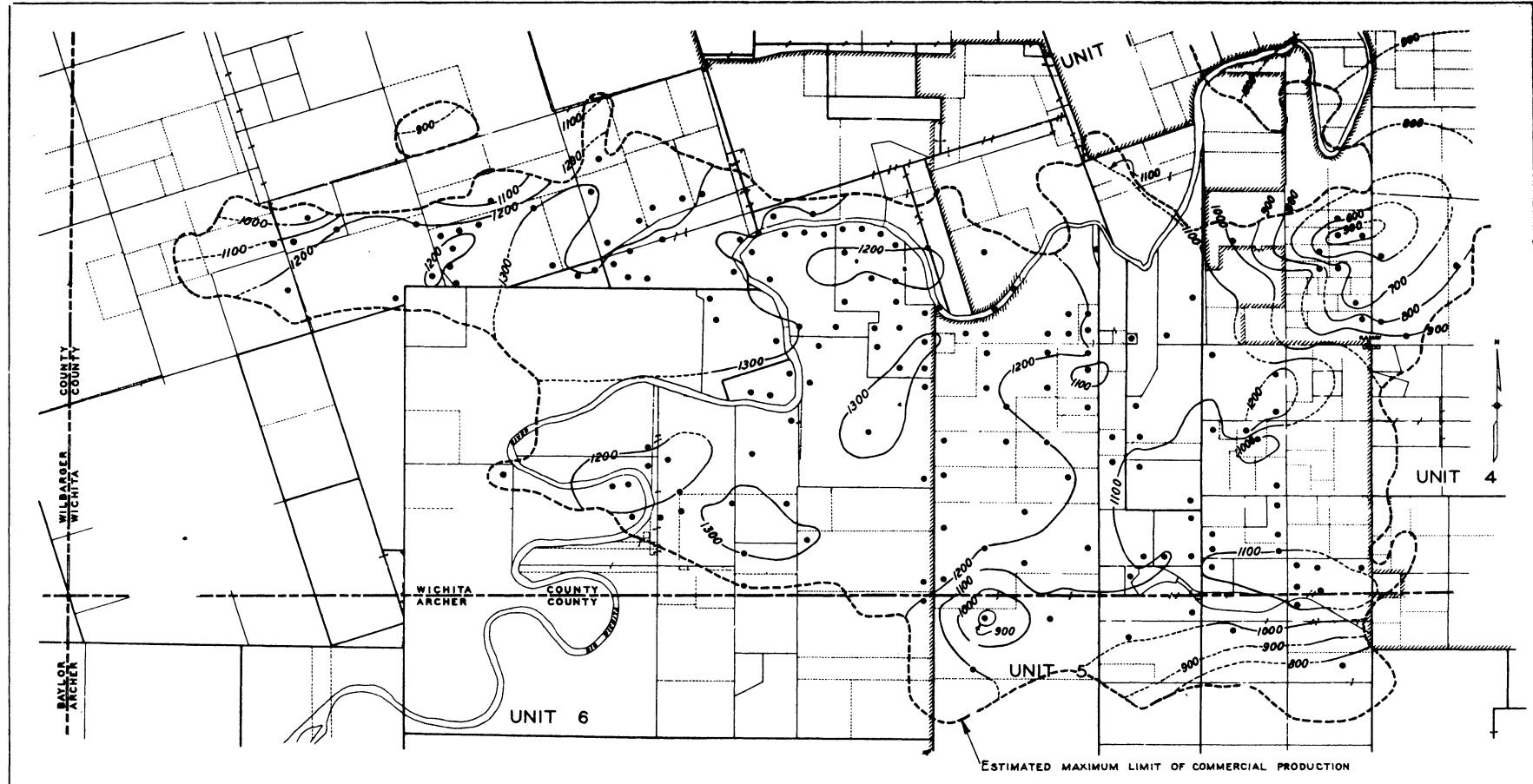
#### Reservoir Pressures

The original subsurface pressure in the K.M.A. reservoir was estimated to be 1,750 p.s.i. at a datum 2,600 feet below sea level, which agrees with the pressure normally expected at that depth. The highest pressure measured by a subsurface recording gage was 1,655 p.s.i. in Gulf Oil Corp. Ferguson-Buffalo well No. 3. This pressure was measured 17 days after the well was completed on February 5, 1938.

Pressure surveys were made from 1938 through 1947, but no systematic procedure was followed. The time interval between surveys varied, and the same wells were not used consistently for pressure measurements. All pressures were either measured at or corrected to a common datum of 2,600 feet below sea level.

Subsurface pressures were adjusted by straight-line interpolation to 13 different dates, and these adjusted pressures were used to construct isobaric maps of the field. Four of these isobaric maps are shown in figures 30 and 31.

The weighted-average reservoir pressure for each isobaric map was computed by multiplying the area between isobars by the mean pressures, adding these products, and dividing this sum by the total area measured. Reservoir pressures were calculated by units and then combined for determining the weighted-average pressure of the southwestern part of the K.M.A. reservoir. The results of 13 pressure surveys are as follows:



ISOBARIC MAP, 2-23-40

Estimated weighted average reservoir pressures

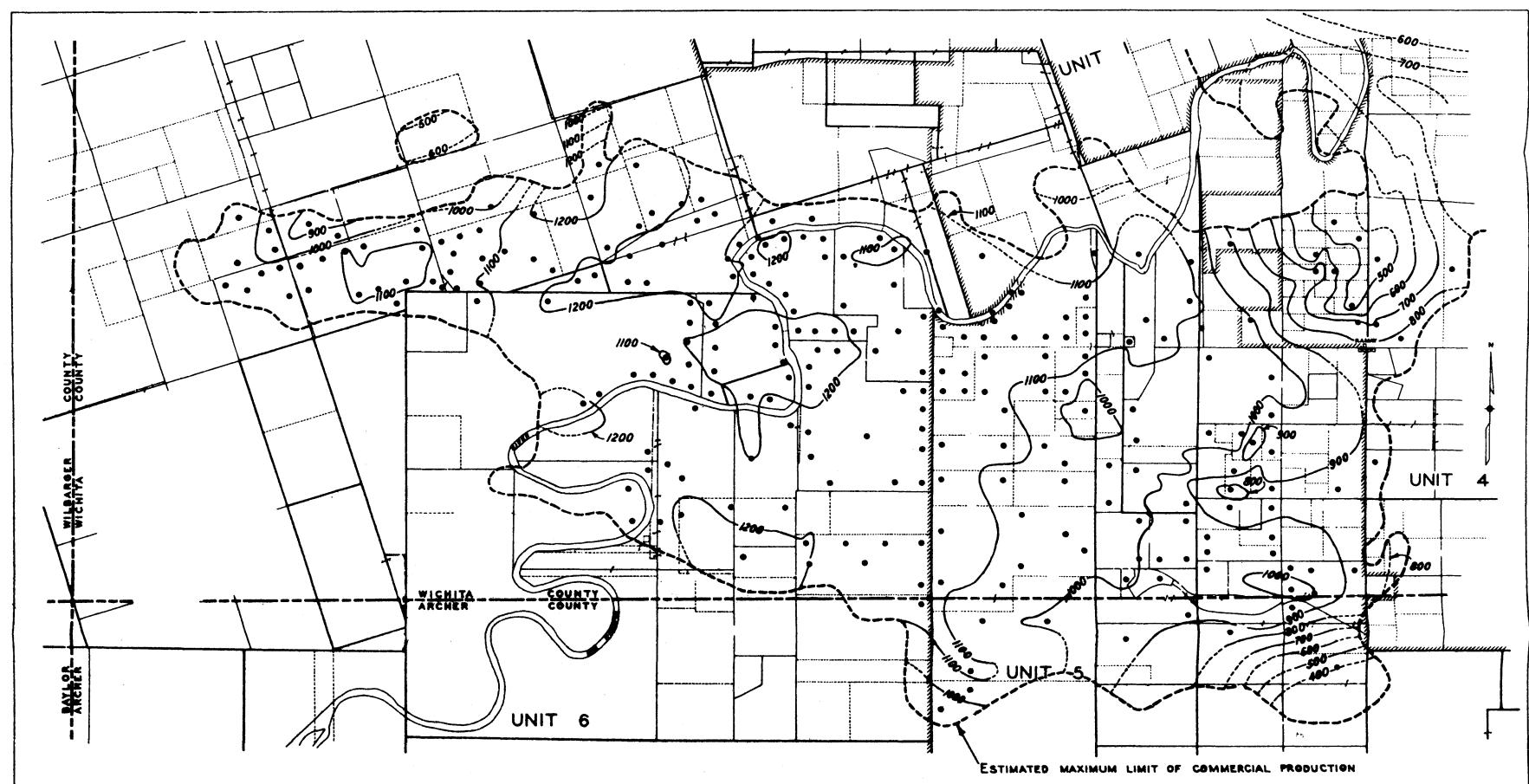
at datum, 2600 ft. below sea level:

Unit 4 (subdivided) 796 lb. per sq. in.

Unit 5 1100 lb. per sq. in.

Unit 6 1247 lb. per sq. in.

Combined Units 1131 lb. per sq. in.



NOTE

Reservoir pressure measurements were made in all wells shown

ISOBARIC MAP, 3-26-41

Estimated weighted average reservoir pressures

at datum, 2600 ft. below sea level:

Unit 4 (subdivided) 898 lb. per sq. in.

Unit 5 991 lb. per sq. in.

Unit 6 1137 lb. per sq. in.

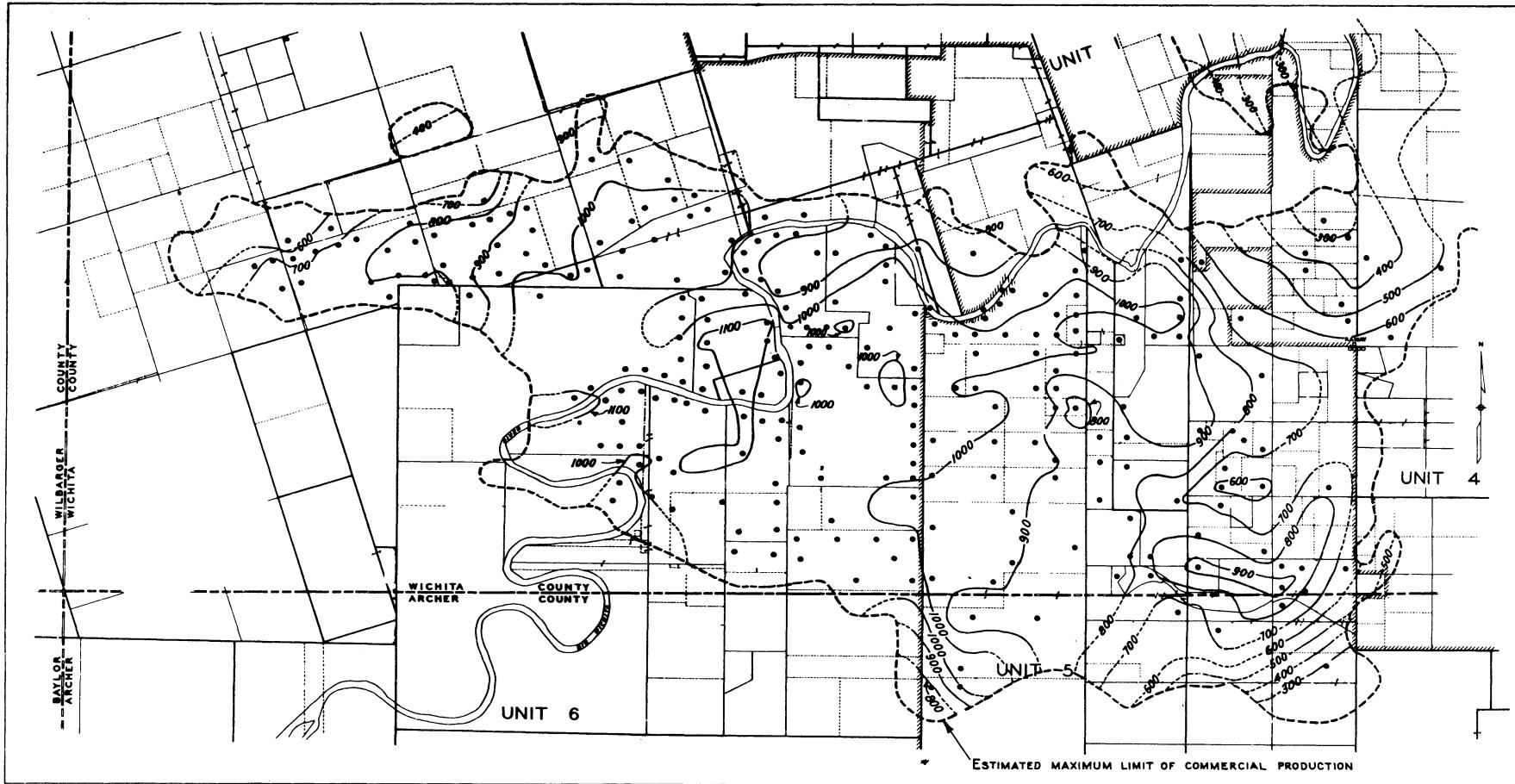
Combined Units 1029 lb. per sq. in.

Isobars represent estimated subsurface pressures, lb. per sq. in. at datum, 2600 ft. below sea level.

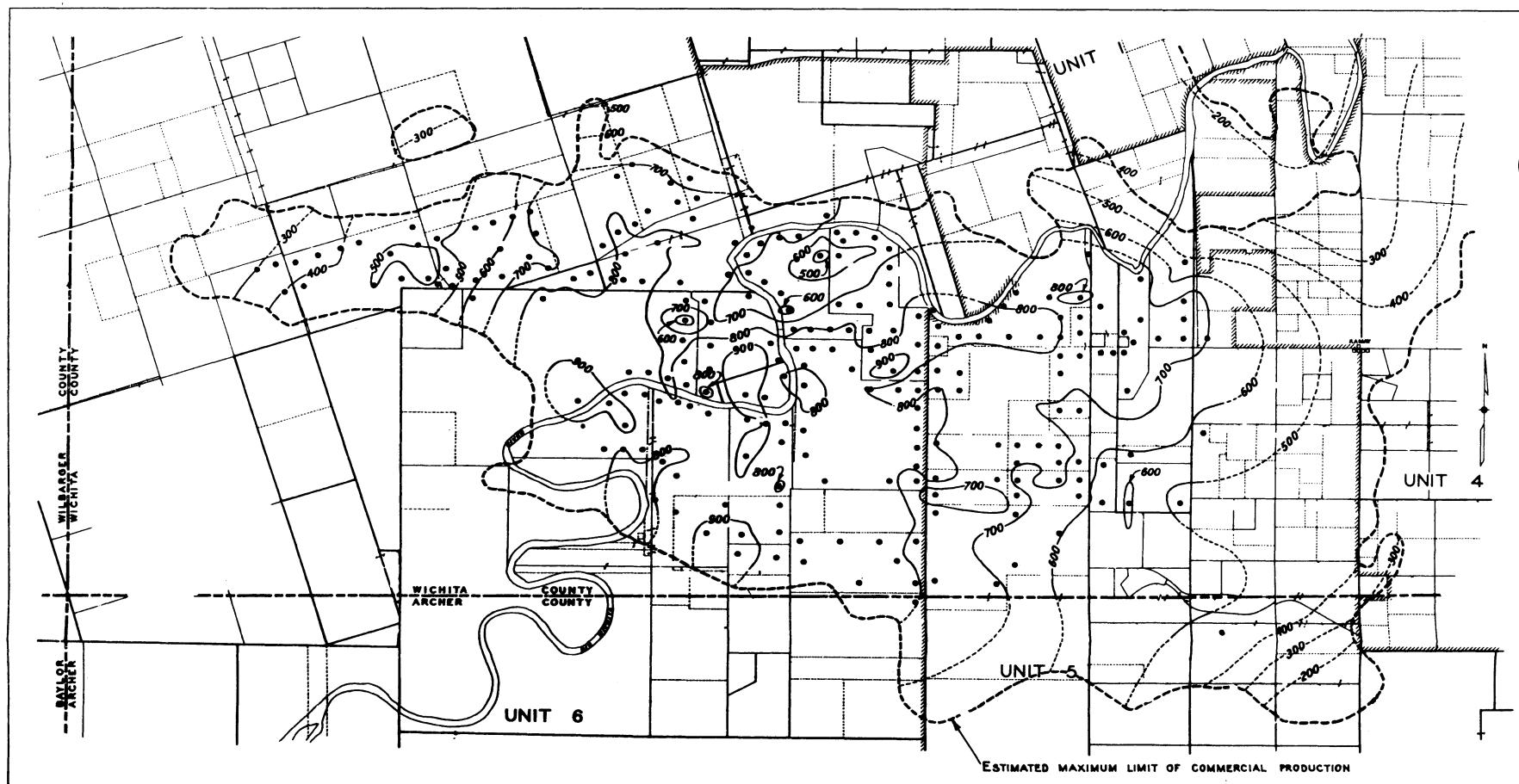
Estimated original static reservoir pressure at datum, 2600 ft. below sea level, 1750 lb. per sq. in.

Figure 30.-Progressive isobaric maps, 2-23-40 and 3-26-41, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.





ISOBARIC MAP, 2-22-43  
Estimated weighted average reservoir pressures  
at datum, 2600 ft. below sea level:  
Unit 4(subdivided) 480 lb. per sq. in.  
Unit 5 805 lb. per sq. in.  
Unit 6 959 lb. per sq. in.  
Combined Units 844 lb. per sq. in.



**NOTE**  
Reservoir pressure measurements were made in all wells shown

ISOBARIC MAP, 8-10-44  
Estimated weighted average reservoir pressures  
at datum, 2600 ft. below sea level:  
Unit 4(subdivided) 369 lb. per sq. in.  
Unit 5 587 lb. per sq. in.  
Unit 6 727 lb. per sq. in.  
Combined Units 651 lb. per sq. in.

Isobars represent estimated subsurface pressures, lb. per  
sq. in. at datum, 2600 ft. below sea level.  
Estimated original static reservoir pressure at datum, 2600  
ft. below sea level, 1750 lb. per sq. in.

Figure 31.-Progressive isobaric maps, 2-22-43 and 8-10-44, K.M.A. reservoir,  
southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



Pressure, pounds per square inch				
Date	Unit 4 (subdivided)	Unit 5	Unit 6	Combined units
2-25-38	1,101	1,460	1,707	1,530
6-20-39	919	1,200	1,370	1,250
2-23-40	796	1,100	1,247	1,131
7-17-40	731	1,055	1,179	1,080
3-26-41	698	991	1,137	1,029
8-1-41	657	955	1,114	1,000
4-17-42	562	895	1,063	939
2-22-43	480	805	959	844
10-14-43	429	724	867	760
8-10-44	369	587	727	631
5-15-45	264	458	575	493
5-15-46	183	288	391	325
5-30-47	84.	179	227	192

Examination of the progressive isobaric maps did not reveal evidence of pressure increases or maintenance of pressures as a result of gas injection. The variation in the pressure gradient across the field probably can be attributed to the ability of some wells to stabilize more readily than other wells in the same length of time. The over-all reservoir-pressure decline, however, was retarded considerably by the gas pressure-maintenance program.

The reservoir pressures in the vicinity of the Shell Oil Co. Griffin "A" lease and the Panhandle Refining Co. Reilly-Griffin "A" lease were observed to be higher than normally would be expected. The production of water from wells in this area, together with the pressure high, is evidence of a water drive along this edge of the field; however, the small volume of water that has been produced, together with other reservoir-performance data, indicates that the water drive has been negligible as a source of reservoir energy for the reservoir as a whole.

To show the efficiencies of the oil production from the units with respect to each other and the efficiencies of the oil production from the combined units, the reservoir-pressure-oil-production relations were calculated for 6-month periods, starting January 1, 1938, and ending July 1, 1947 (see table 29). Unit 4 (subdivided) and unit 6 obtained their peak efficiency of oil production from July 1, 1940, to January 1, 1941; unit 5 from January 1, 1941, to July 1, 1941; and the combined units from July 1, 1940, to January 1, 1941.

#### Flowing Life of Wells

From the available data on 248 oil wells completed in the K.M.A. formation, the average flowing life of the wells was determined to be approximately  $6\frac{1}{2}$  years. The flowing life ranged from a few days to 124 months. Although these data were available for only one-third of the wells,  $6\frac{1}{2}$  years is probably a representative average, because the wells used in computing this average represented all parts of the field.

#### Remedial Work

In general, the amount of remedial work required on wells in the field was moderate, and such work usually consisted of one or more of the following: Cleaning out the well bore; deepening the hole; plugging back the hole; shooting the formation with nitro-glycerin; and treating the formation with acid.

The wells completed in sandstone generally required periodic clean-outs after being placed on a pump. Many completed wells did not penetrate all of the K.M.A. formation; consequently, numerous wells were deepened later. A few wells, however, were drilled deep enough to be near the oil-water contact, and some of these wells were plugged back to exclude water. Several wells drilled to the Ellenburger limestone were either dry or poor producers in that formation, and some were successfully plugged back and recompleted in the K.M.A. formation. Although most K.M.A. wells were either shot or acidized at completion, many of the wells that were not treated at completion were shot or acidized later. As considerable sloughing of the formation was experienced in many wells, some operators set liners opposite the K.M.A. formation after a clean-out. Some leases required much more remedial work than others, and the extent of this work varied widely among the operators.

#### Gasoline Plants

With development of the K.M.A. oil field, several companies constructed gasoline plants to process the increasingly large quantities of produced gas. The first gasoline plant was placed in operation late in 1937 by the Deep Oil Development Co. (plant subsequently purchased by W. A. Moncrief & Sons). During August 1938, the Continental Oil Co. began operating its three K.M.A. gasoline plants, and a plant was constructed by the Phillips Petroleum Co. and placed in operation in July 1938. The gas processed by these plants is taken from both K.M.A. and Ellenburger wells, but only the K.M.A. reservoir was subjected to pressure maintenance.

#### W. A. Moncrief & Sons Gasoline Plant

The discovery well and earliest development of the K.M.A. field was on the Deep Oil Development Co. Munger lease. This operator also constructed the first gasoline plant in the K.M.A. field primarily for pressure maintenance. Deep Oil Development Co. sold its Munger leases and gasoline plant on January 1, 1948, to W. A. Moncrief & Sons. The operation of the gasoline plant was discontinued during November 1950.

The plant began operation in late 1937 as a compression-type plant with a capacity of 1,500,000 cubic feet per day. Later the capacity was increased to approximately 2,750,000 cubic feet per day. During the latter part of 1937 and the early part of 1938, the production from this plant was about 2.5 gallons of raw gasoline per 1,000 cubic feet of gas. The plant then processed 1,000,000 cubic feet a day and returned the residue gas to the reservoir through one injection well. During the fall of 1950, about 1,250,000 cubic feet a day was being processed by this plant, from which 2,000 gallons of 14-pound product (14 p.s.i.a. Reid vapor pressure) was obtained. The plant operated with an intake vacuum of 2 inches of mercury. Some of the residue gas was compressed to a pressure of 1,400 p.s.i. for injection into the reservoir; however, most gas-injection wells require much less pressure. The residue gas for injection was returned to the reservoir hot and was not dried. Because the gas-return lines were short, no hydrate was deposited.

#### Continental Oil Co. Gasoline Plants

The three Continental Oil Co. gasoline plants began operation on August 15, 1938. These three plants used a total of 2,800-horsepower and had an initial processing capacity of 14,000,000 cubic feet per day, which was increased later to 36,000,000 cubic feet per day, using 10,800-horsepower. The increased ratio of power to volume was the result of lowering the plant-intake pressure, thereby increasing the compression range. The daily flow capacities of the individual plants are 9,000,000 cubic feet for the main plant; 15,000,000 cubic feet for auxiliary plant 1; and 12,000,000 cubic feet for auxiliary plant 2. The plants were originally the compression type, but in 1945 they were converted to the compression-absorption type. The total amount invested in the

TABLE 29.—Relationship between reservoir pressure decline and oil production, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Period and unit	Oil production, bbl.		Average reservoir pressure, p.s.i. 1/		Loss in reservoir pressure, p.s.i.		Oil produced per 1,000 loss in reservoir pressure, bbl.		Loss in reservoir pressure per 100 thousand bbl. oil produced, p.s.i.	
	During period	Cumulative	Start of period	End of period	During period	Cumulative	During period	Cumulative 2/	During period	Cumulative 3/
1-1-38 to 7-1-38										
Unit 4 (Subdivided)	264,455	1,069,034	1,121	1,050	71	700	4,006	1,587	25.0	65.5
Unit 5	598,377	631,600	1,490	1,390	100	360	5,981	1,584	16.7	57.0
Unit 6	77,736	79,447	1,735	1,619	116	131	670	6,066	149.2	164.9
Units 4, 5, and 6 combined	960,268	1,780,061	1,563	1,457	106	293	9,059	6,075	11.0	16.5
7-1-38 to 1-1-39										
Unit 4 (Subdivided)	178,107	1,247,141	1,050	983	67	767	2,658	1,772	37.6	61.5
Unit 5	744,176	1,375,776	1,390	1,290	100	460	7,442	2,591	13.4	33.4
Unit 6	219,173	296,620	1,619	1,491	128	259	1,712	1,184	56.4	86.7
Units 4, 5, and 6 combined	1,141,456	2,921,537	1,457	1,350	107	400	10,668	7,704	9.4	13.7
1-1-39 to 7-1-39										
Unit 4 (Subdivided)	210,250	1,457,391	983	915	68	835	3,092	1,745	32.3	57.3
Unit 5	900,581	2,276,357	1,290	1,195	95	555	9,480	4,195	10.5	24.4
Unit 6	542,311	840,931	1,491	1,364	127	366	4,270	2,172	23.4	45.9
Units 4, 5, and 6 combined	1,653,142	4,574,679	1,350	1,245	105	505	15,744	9,799	6.4	11.0
7-1-39 to 1-1-40										
Unit 4 (Subdivided)	206,320	1,663,711	915	822	93	928	2,218	1,791	45.1	55.8
Unit 5	950,161	3,226,518	1,195	1,120	75	630	12,669	5,151	7.9	19.5
Unit 6	778,104	1,619,035	1,364	1,275	89	475	8,743	3,478	11.4	29.3
Units 4, 5, and 6 combined	1,934,585	6,509,264	1,245	1,155	90	595	21,495	10,940	4.7	9.1
1-1-40 to 7-1-40										
Unit 4 (Subdivided)	263,182	1,826,893	822	738	84	1,012	3,133	1,804	31.9	52.5
Unit 5	1,475,442	4,701,960	1,120	1,060	60	690	54,591	4,711	4.1	14.7
Unit 6	1,232,613	2,851,648	1,275	1,186	89	564	13,850	5,766	7.2	19.8
Units 4, 5, and 6 combined	2,971,237	9,480,501	1,155	1,087	68	663	43,695	14,099	2.3	7.0
7-1-40 to 1-1-41										
Unit 4 (Subdivided)	194,926	2,121,619	738	709	29	1,041	6,722	2,038	14.9	49.1
Unit 5	1,105,466	5,897,495	1,060	1,012	48	738	24,906	7,991	4.0	12.5
Unit 6	1,227,215	4,078,863	1,186	1,150	36	600	34,089	6,798	2.9	14.7
Units 4, 5, and 6 combined	2,617,607	12,098,108	1,087	1,046	41	704	63,844	17,188	1.6	5.8
1-1-41 to 7-1-41										
Unit 4 (Subdivided)	177,648	2,299,467	709	667	42	1,083	4,230	2,123	23.6	47.1
Unit 5	1,070,893	6,968,319	1,012	963	49	787	21,855	8,564	4.6	11.3
Unit 6	1,141,927	5,220,790	1,150	1,120	30	630	38,064	8,197	2.6	12.1
Units 4, 5, and 6 combined	2,390,468	14,488,576	1,007	977	39	743	61,294	19,500	1.6	5.1
7-1-41 to 1-1-42										
Unit 4 (Subdivided)	175,889	8,475,356	667	600	67	1,150	2,625	2,151	38.1	46.5
Unit 5	1,141,238	8,109,557	963	820	43	630	26,540	9,771	3.8	10.2
Unit 6	1,220,534	6,441,324	1,120	1,085	35	665	34,972	9,301	2.9	10.3
Units 4, 5, and 6 combined	2,537,661	17,026,237	1,007	964	43	786	59,015	21,682	1.7	4.6
1-1-42 to 7-1-42										
Unit 4 (Subdivided)	172,246	2,647,602	600	542	58	1,208	2,070	2,191	33.7	45.6
Unit 5	1,097,720	9,207,277	920	874	46	876	23,863	10,511	4.2	9.5
Unit 6	1,194,970	7,636,294	1,065	1,039	46	711	25,976	10,740	3.8	9.3
Units 4, 5, and 6 combined	2,464,936	19,491,173	964	859	48	834	51,353	23,391	1.9	4.3
7-1-42 to 1-1-43										
Unit 4 (Subdivided)	157,171	2,804,773	542	494	48	1,256	3,274	2,123	30.5	44.8
Unit 5	1,102,693	10,309,970	874	822	52	928	21,206	11,110	4.7	9.0
Unit 6	1,199,744	8,836,038	973	966	66	777	16,178	11,592	5.5	8.8
Units 4, 5, and 6 combined	2,459,608	21,950,761	916	859	57	891	43,151	24,586	2.3	4.1
1-1-43 to 7-1-43										
Unit 4 (Subdivided)	126,596	2,931,369	494	451	43	1,299	2,944	2,157	34.0	44.3
Unit 5	1,021,874	11,331,844	822	760	62	990	16,424	11,446	6.1	8.7
Unit 6	1,098,194	9,934,232	973	907	66	843	16,639	11,754	6.0	8.5
Units 4, 5, and 6 combined	2,246,684	24,197,445	859	800	59	950	38,079	25,471	2.6	3.9
7-1-43 to 1-1-44										
Unit 4 (Subdivided)	113,754	3,045,123	451	413	38	1,337	2,994	2,155	33.4	43.9
Unit 5	1,100,164	12,432,006	691	661	69	1,059	18,944	11,733	6.3	8.5
Unit 6	1,176,990	11,111,222	907	832	75	918	15,694	12,174	6.4	8.3
Units 4, 5, and 6 combined	2,390,908	26,586,353	800	728	72	1,022	33,207	22,716	3.0	3.8
1-1-44 to 7-1-44										
Unit 4 (Subdivided)	100,803	3,145,926	413	377	36	1,373	2,800	2,191	35.7	43.6
Unit 5	1,092,597	13,584,605	691	604	87	1,146	12,559	11,817	8.0	8.5
Unit 6	1,196,217	12,307,439	832	747	85	1,003	14,073	12,371	7.1	8.1
Units 4, 5, and 6 combined	2,389,617	28,977,970	728	646	80	1,102	29,870	26,199	3.3	3.8
7-1-44 to 1-1-45										
Unit 4 (Subdivided)	98,986	3,244,912	377	316	61	1,434	1,623	2,223	61.6	44.2
Unit 5	1,109,038	14,633,643	604	522	82	1,228	13,585	11,917	7.4	8.4
Unit 6	1,210,688	13,518,127	747	650	97	1,100	12,481	12,595	8.0	8.1
Units 4, 5, and 6 combined	2,418,712	31,396,682	559	559	89	1,191	27,177	26,702	3.7	3.8
1-1-45 to 7-1-45										
Unit 4 (Subdivided)	88,791	3,333,703	316	255	61	1,495	1,456	2,030	68.7	44.8
Unit 5	1,063,055	15,696,698	522	438	84	1,312	12,655	11,964	7.9	8.4
Unit 6	1,166,025	14,684,152	650	552	98	1,198	11,696	12,257	8.4	8.2
Units 4, 5, and 6 combined	2,317,871	33,714,553	559	469	90	1,281	25,754	24,710	3.9	3.8
7-1-45 to 1-1-46										
Unit 4 (Subdivided)	88,932	3,422,635	255	214	41	1,536	2,169	2,158	46.1	44.9
Unit 5	970,504	16,667,202	438	350	88	1,400	11,028	11,008	9.1	8.4
Unit 6	1,031,604	15,715,756	552	462	90	1,288	11,462	11,136	8.7	8.2
Units 4, 5, and 6 combined	2,091,040	35,805,553	469	384	85	1,366	24,690	26,011	4.1	3.8
1-1-46 to 7-1-46										
Unit 4 (Subdivided)	84,124	3,506,759	214	172	42	1,528	2,003	2,028	49.8	45.0
Unit 5	864,007	17,531,209	350	273	77	1,477	17,991	17,019	8.9	8.4
Unit 6	987,614	16,703,370	452	372	90	1,398	16,161	15,141	9.1	8.2
Units 4, 5, and 6 combined	1,935,745	37,741,328	384	309	75	1,441	25,810	26,191	3.9	3.8
7-1-46 to 1-1-47										
Unit 4 (Subdivided)	76,060	3,582,819	172	123	49	1,627	1,552	2,020	64.4	45.4
Unit 5	789,424	18,320,633	273	222	51	1,528	15,479	11,960	6.5	8.3
Unit 6	837,671	17,541,041	372	294	78	1,456	10,739	12,047	9.3	8.3
Units 4, 5, and 6 combined	1,703,155	39,444,493	309	250	59	1,500	28,567	26,390	3.5	3.8
1-1-47 to 7-1-47										
Unit 4 (Subdivided)	64,758	3,647,577	123	76	47	1,674	1,778	2,179	72.6	45.9
Unit 5	737,371	19,086,004	222	170	52	1,580	14,170	13,266	7.1	8.3
Unit 6	759,800	18,300,841	294	214	80	1,536	9,438	11,915	10.5	8.4
Units 4, 5, and 6 combined	1,561,929	41,006,422	246	182	64	1,568	24,405	26,152	4.1	3.8

1/ Original reservoir pressure was 1,750 p.s.i. at 2,600 feet below sea level. Pressures shown were obtained by interpolation from reservoir pressure decline curve for respective units.

2/ Cumulative oil production divided by cumulative loss in reservoir pressure at end of period. 3/ Cumulative loss in reservoir pressure divided by cumulative oil production at end of period.





three plants, including measuring equipment and gas lines to and from the leases, was approximately \$3,500,000.

During the fall of 1950, the three plants were processing 20,700,000 cubic feet of gas a day. The main plant was processing 4,700,000 cubic feet, auxiliary 1 7,500,000 cubic feet, and auxiliary 2 8,500,000 cubic feet. The plants originally took gas from lease separators at pressures slightly above atmospheric; however, the plant intake pressure subsequently was reduced to a vacuum ranging from 6 to 15 inches of mercury.

Since absorbers were installed in 1945, the three plants have been operating as one unit. Lean oil is pumped from the main plant to auxiliary plants 1 and 2, where it is enriched and then returned to the main plant for distillation. The rich oil is preheated by hot, outgoing, lean oil before undergoing steam distillation. The residue gas is sold, used for fuel, or used for pressure maintenance. Deposits of hydrates in the lease return lines is prevented by passing the gas through driers before final compression.

The three plants produce a P.B.C. (propane, butane, and casing-head) product, which is delivered to the Continental Oil Co. refinery at Wichita Falls by pipeline. The main plant has four horizontal storage tanks that have a total capacity of approximately 100,000 gallons, but the tanks are for emergency use only. Emergency storage at auxiliary plant 1 is 5,000 gallons and at auxiliary plant 2 10,000 gallons. On account of the tank design, the vapor pressure of the products must be reduced to approximately the vapor pressure of 26-70 gasoline before the liquids can be stored.

Periodic test-car analyses of the gas are run throughout the field, primarily for purposes of equity. The equity agreement with the operators is a standard Natural Gasoline Association of America contract, which involves royalty payments on a sliding scale, depending on the richness of the gas. Average recoveries indicate that the 26-70 gasoline content of K.M.A. gas was 2.19 g.p.m. at discovery, 2.90 g.p.m. in June 1941, and approximately 3.40 g.p.m. in July 1947. Podbielniaak analyses also have been made periodically on the gas and on the products to measure the stripping efficiency and to aid in plant control. The stripping efficiencies for the three plants are approximately 55 percent for propane, 94 percent for isobutane, 97 percent for n-butane, and 100 percent for pentanes plus. Plant production of P.B.C. products per 1,000 cubic feet of gas is approximately 100 percent of test-car analyses. Propane recovery is decreased during the summer because of the decreased demand for liquefied petroleum gases. The total volume of P.B.C. products potentially recoverable in the summer is higher, however, as more gas is produced at higher separator temperatures.

The Continental Oil Co. plants supplied approximately 71 percent of the injection gas during 1950 at pressures of 1,200 and 1,800 p.s.i. Most wells require less than 1,200 p.s.i. injection pressure, but the necessity of high pressure for certain tight wells has caused high outlet pressures to be maintained.

Because the produced gas is sweet, no appreciable internal corrosion has occurred in the flow lines. Soil corrosion is evident, however, and all buried lines are coated and wrapped. Water for the cooling towers and boilers is taken from Beaver Creek for the main plant and from an irrigation canal system for auxiliary plants 1 and 2. The boiler water for the three plants is treated in the boiler for scale-forming calcium and magnesium carbonates and sulfates. The cooling water is not treated.

#### Phillips Petroleum Co. Gasoline Plant

The original Phillips plant was converted from a compression-type system with a capacity of 10,000,000 cubic feet a day to an absorption-type system with a capacity of

27,000,000 cubic feet a day. During the fall of 1950, the Phillips plant was processing 8,000,000 cubic feet of gas a day, from which 22,000 gallons of gasoline was stripped. The plant produces 26-70 gasoline and a 100 pound LP-gas product (100 p.s.i.a. Reid vapor-pressure mixture of liquefied petroleum gases). The products are shipped by railroad, motor truck, and pipeline. The plant has storage facilities for approximately 200,000 gallons. During the fall of 1950, this plant was furnishing approximately 3,000,000 cubic feet of injection gas a day at a pressure of about 750 p.s.i. The residue gas for injection is dried before final compression to prevent the formation of hydrates in the lease return lines. Most residue gas is used for fuel and pressure maintenance. Approximately 400,000 cubic feet of residue gas is sold a day. No gas is flared.

The cooling water and boiler water for the plant come from an irrigation-canal system. This water is treated with soda ash and lime before it is used in the boilers. The cooling water is treated with an algaecide.

#### PRESSURE MAINTENANCE BY GAS INJECTION

##### Organization of K.M.A. Pressure-Maintenance Association

By the time the K.M.A. field was developed, the operators realized that the rapid drop in reservoir pressure accompanying the production of oil was indicative of a solution gas-drive reservoir containing oil undersaturated with gas. As there was a limited market for the produced gas, some of the operators soon began considering the feasibility of returning the produced gas to the reservoir. Because the field was divided into many small leases with separate operators, it was obvious that any pressure-maintenance program would have to be a cooperative plan.

In November 1939, John F. O'Donohoe, who was then president of the North Texas Oil and Gas Association, invited all operators in the K.M.A. field to meet and discuss a cooperative gas-return agreement. This meeting resulted in the forming of the K.M.A. Pressure-Maintenance Association, a voluntary organization with no contracts or legal obligations affecting the cooperating operators. Fifteen operators were elected to serve on an executive committee whose main objective was to complete the organization and arrange for facilities necessary to return gas to the K.M.A. reservoir. The Pressure Maintenance Association was to assume the responsibility of directing the future operations, and an office for the association was opened in January 1940. A petroleum engineer, William H. Rouzer, Jr., who was placed in charge of the office and appointed chairman of the engineering committee composed of employees of the various companies active in the field. The three companies operating gasoline plants in the field entered into the cooperative agreement. Riders were attached to the regular gasoline-plant contracts guaranteeing the return of dry gas to the various leases at a scheduled charge per 1,000 cubic feet. The field was divided into units, and the expense of compressing the gas returned to each unit was distributed among the operators within the unit on the basis of the number of wells the operator owned in the unit.

##### Unit Areas

The K.M.A. Pressure-Maintenance Association divided the field into six unit areas. The boundaries of units 4 (subdivided), 5, and 6 are indicated by hachure lines on the development map (see fig. 3). These unit boundaries were chosen to facilitate the grouping of royalty interests so that waivers could be obtained to permit the return of gas to leases within a unit without a title charge for gas produced by one lease and returned to another. The cost of labor for laying the gas lines from the gasoline plants to the injection wells and the gas-compression charge are shared by the operators in each unit according to the fraction of the total number of oil wells in that unit owned by the operator. With the approval of the association, the necessary billing

and accounting are done by the gasoline plants. Leases in each unit without injection wells are billed on the same basis as those leases with injection wells. No compensation is given operators whose oil wells are converted for injection purposes, except that the allowable is transferred to the remaining oil wells on the lease.

#### Gas-Injection Wells

The locations for gas-injection wells usually were chosen at the suggestion of the engineering committee of the K.M.A. Pressure Maintenance Association or by the operator involved. The performance of the reservoir was used as a guide in selecting the proper wells for gas-injection. In addition to the recommendations of the engineering committee, the executive committee of the association considered the economics involved in each suggested location for a gas-injection well. As the cost of labor for a connection to the gasoline-plant system was shared by all the operators in the unit area, the executive committee acted as an analyzing body before a request for a connection to the gasoline plant was approved. Legally, the K.M.A. Pressure-Maintenance Association could not force the gasoline plants to make connections to the gas-injection wells, but a request from the association for connections has never been rejected by the gasoline plants.

The spacing of gas-injection wells in the southwestern part of the K.M.A. field has no definite pattern because of the method used in selecting wells for input purposes; consequently, gas-injection well density is greater in some areas than in others.

A few gas-injection wells were dually completed to control the volumes of gas injected into zones I and II. In most gas-injection wells, however, all of the K.M.A. formation below the casing seat was exposed, and no attempts were made to control the entry of injected gas into a particular part of the formation. The streaks of high permeability frequently encountered in the K.M.A. formation caused a moderate amount of gas channeling between gas-injection and oil wells.

The number of gas-injection wells has increased considerably since gas return was begun on an extensive scale. At the time the K.M.A. Pressure Maintenance Association was organized in November 1939, there were only 10 gas-injection wells. Since then the number of gas-injection wells has gradually increased to a maximum of 56 in April 1949. At that date, the oil-well:gas-injection-well ratio of units 4 (subdivided), 5, and 6 combined reached a minimum of 11.1:1. Oil-well:gas-injection-well ratios of the three units studied show how the density of gas-injection wells varied among the units (see tables 24 through 27). Minimum values of this ratio are 12.8 for unit 4 (subdivided), 16.1 for unit 5, and 8.2 for unit 6.

#### Gas-Injection Volumes

Produced gas from the southwestern part of the K.M.A. field was returned to the reservoir in small quantities as early as December 1937. Gas injection on a large scale, however, was not begun until the K.M.A. Pressure-Maintenance Association was organized in late 1939.

At the beginning of 1940 approximately 10 percent of the produced gas was being returned to the reservoir. A maximum of 40 percent of the produced gas was being returned by early 1943, and the cumulative volume returned as of August 1, 1949, was approximately 27 percent. The cumulative average daily injection rate per injection well to August 1, 1949, was approximately 140,000 cubic feet.

The gas-injection program in the southwestern part of the K.M.A. field has done much to conserve the natural-gas and reservoir energy, as can be seen readily by comparing the cumulative produced-gas volume of 91.19 billion cubic feet with the

estimated volume of initial gas in the reservoir of 88.25 billion cubic feet. In addition to increasing oil recovery, the pressure-maintenance program has resulted in the increased recovery of many thousands of gallons of natural gasoline and has reduced greatly the volume of gas that would have been flared.

A compression charge based on pressure and volume delivered is shared by the operators in each unit. The rate changes directly with injection pressure and inversely with volume delivered. The average price has been approximately 2.25 cents per 1,000 cubic feet.

Complete gas-injection statistics, by units, for the southwestern part of the K.M.A. field to August 1, 1949, are shown in tables 24 to 27, inclusive, and are shown graphically in figures 32 to 35, inclusive.

Oil Recovery, Residual-Oil Saturation, and  
Free-Gas Saturation as of August 1, 1949

The cumulative oil production for the southwestern part of the K.M.A. field to August 1, 1949, was 46,107,738 barrels, which represented an average recovery of 3,689 barrels per acre. The unit recoveries in barrels per acre were 2,887 for unit 4 (sub-divided); 3,886 for unit 5; and 3,686 for unit 6. The recoveries of individual leases, in barrels per acre, to August 1, 1949, are shown in figure 36. Because the method used in calculating the net volume of the K.M.A. reservoir is not applicable to individual leases, the individual lease recovery, in barrels per acre-foot, could not be determined. In addition, it is difficult to arrive at any conclusions or compare individual lease recoveries because of the differences in well completion and production methods, extent of remedial work, formation characteristics, and well density. The oil recovery from the southwestern part of the K.M.A. field to August 1, 1949, was calculated to be 216 barrels per acre-foot, and the residual-oil saturation in the reservoir at this date was calculated to be 574 barrels of stock-tank oil per acre-foot. As of August 1, 1949, 27.4 percent of the initial volume of oil in place had been produced and 72.6 percent remained in the reservoir. The oil recoveries to August 1, 1949, are summarized in table 30.

The free-gas saturation in the K.M.A. reservoir as of August 1, 1949, was calculated to be 30.0 percent of the pore volume by the following procedure:

Free-gas saturation = the gas volume at reservoir conditions (which is the pore volume minus the volume of remaining reservoir oil minus the volume of connate water) divided by the pore volume,

when:

$$269.8 \times 10^6 = \text{pore volume, barrels (see table 13);}$$

$$50.6 \times 10^6 = \text{volume of connate water, barrels (see table 13);}$$

$$168.1 \times 10^6 = \text{initial volume of stock-tank oil in place, barrels (see table 13);}$$

$$46.1 \times 10^6 = \text{volume of stock-tank oil produced as of August 1, 1949, barrels (see table 26);}$$

$$122.0 \times 10^6 = \text{volume of stock-tank oil remaining in reservoir as of August 1, 1949, barrels;}$$

$$56 \text{ p.s.i.} = \text{reservoir pressure, August 1, 1949, (calculated by trial and error material-balance method);}$$

TABLE 30.—Summary of computed oil recovery, residual-oil saturation, and free-gas saturation, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

(Zones I and II combined)

	As of Aug. 1, 1949	At economic limit 1/
Stock-tank oil recovery of combined units:		
Barrels . . . . .	46,107,738	53,000,000
Barrels per acre-foot . . . . .	216	249
Percent of pore volume . . . . .	17.0	19.6
Percent of initial stock-tank oil in place . . . . .	27.4	31.5
Stock-tank oil recovery by units:		
4 (subdivided)- barrels per acre . . . . .	2,887	
5 - barrels per acre . . . . .	3,886	
6 - barrels per acre . . . . .	3,686	
Combined units- barrels per acre . . . . .	3,689	4,230
Residual stock-tank oil saturation of combined units:		
Barrels . . . . .	122,000,000	115,100,000
Barrels per acre-foot . . . . .	574	541
Percent of pore volume . . . . .	45.2	42.7
Percent of initial stock-tank oil in place . . . . .	72.6	68.5
Free-gas saturation of combined units		
percent of pore volume . . . . .	2/ 30.0	38.5

1/ Assuming present methods of production are continued to an arbitrarily assumed daily oil-production rate of 2 barrels per well and atmospheric reservoir pressure.

2/ Using a calculated reservoir pressure of 56 p.s.i.

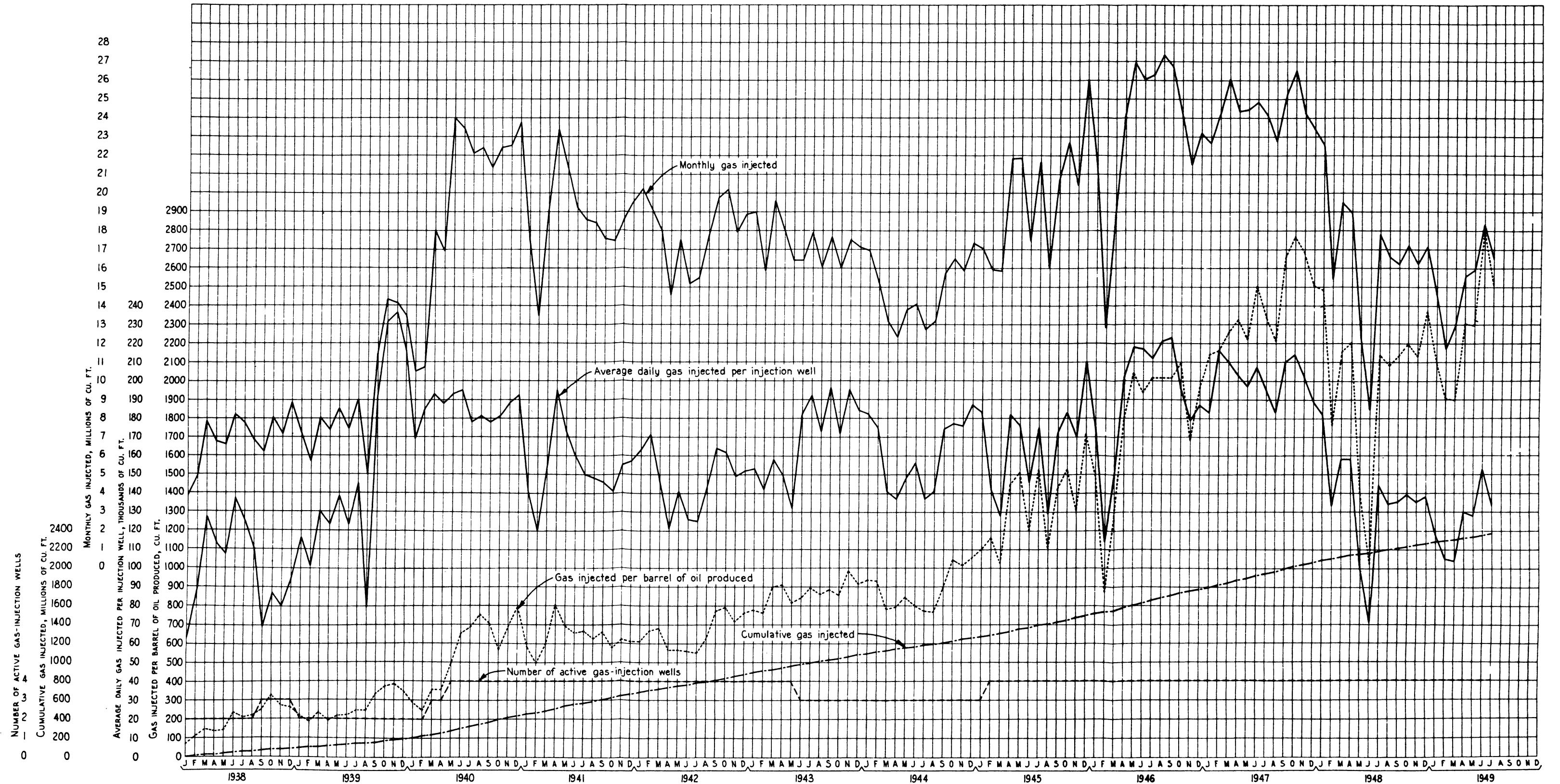


Figure 32.-Reservoir performance curves showing gas injection history and related data, Unit 4 (subdivided), K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.





Figure 33.-Reservoir performance curves showing gas injection history and related data, Unit 5,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



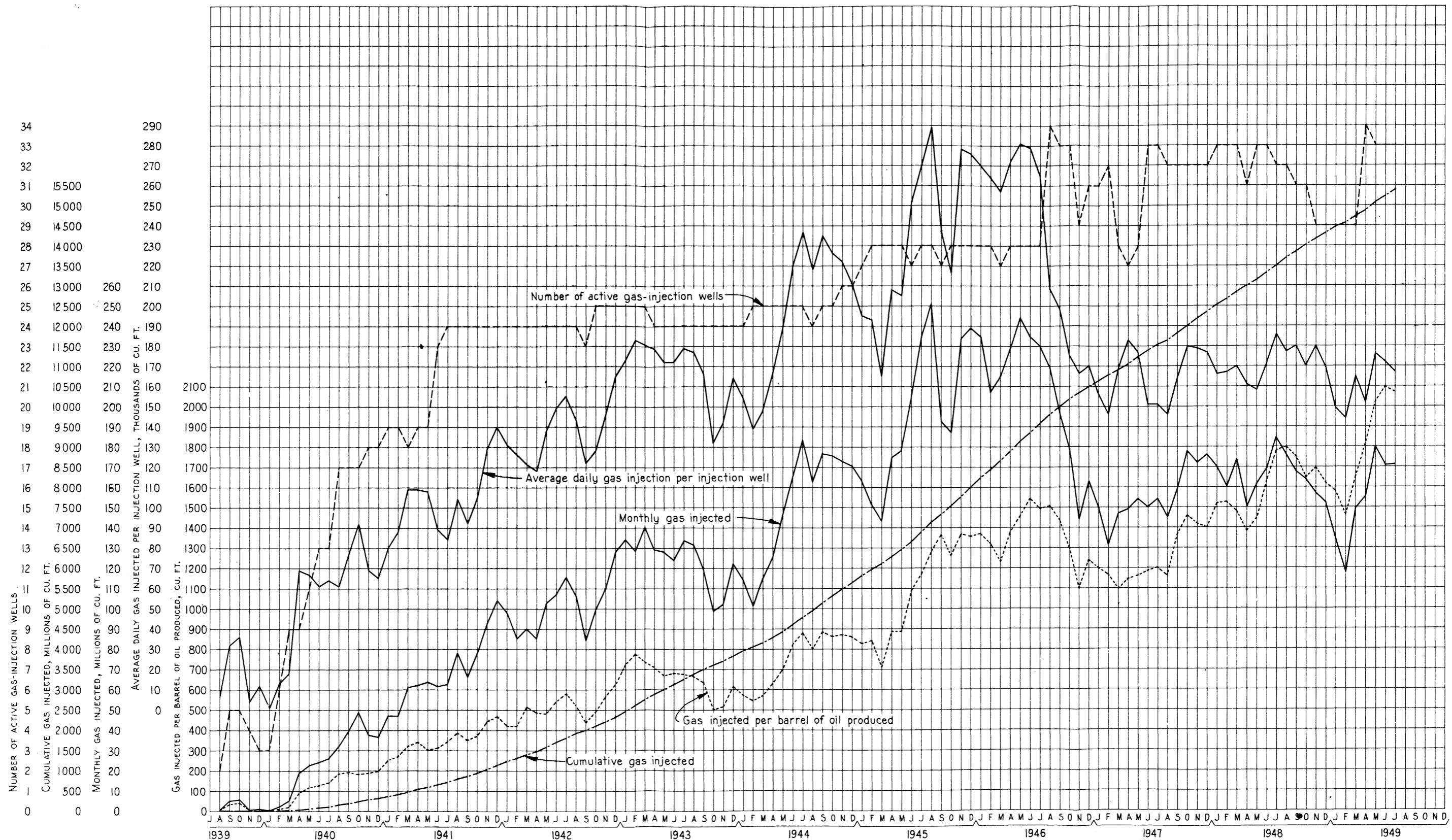


Figure 34.-Reservoir performance curves showing gas injection history and related data, Unit 6,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



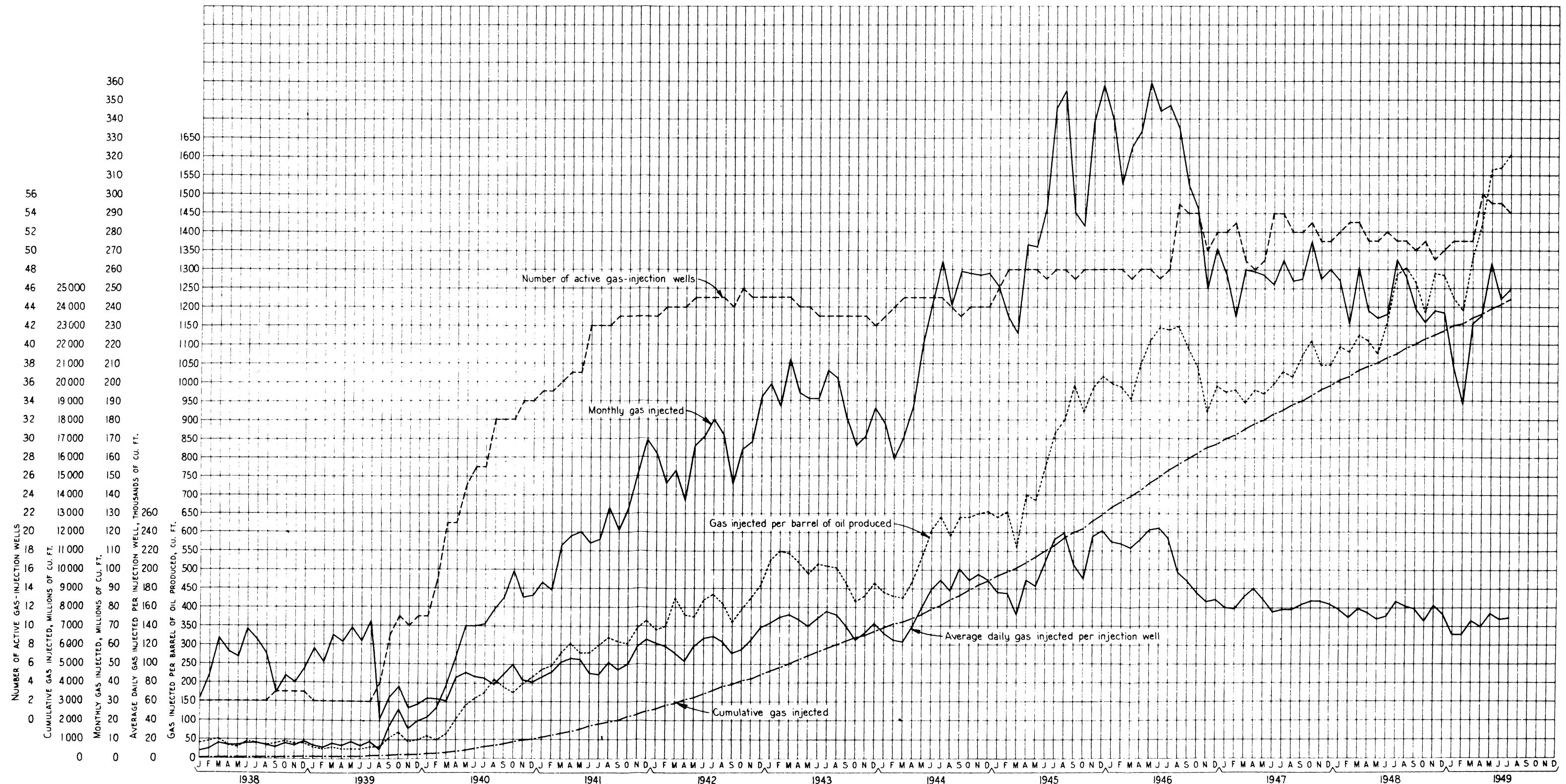


Figure 35.-Reservoir performance curves showing gas injection history and related data, Unit 4 (subdivided), Unit 5, and Unit 6 combined, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



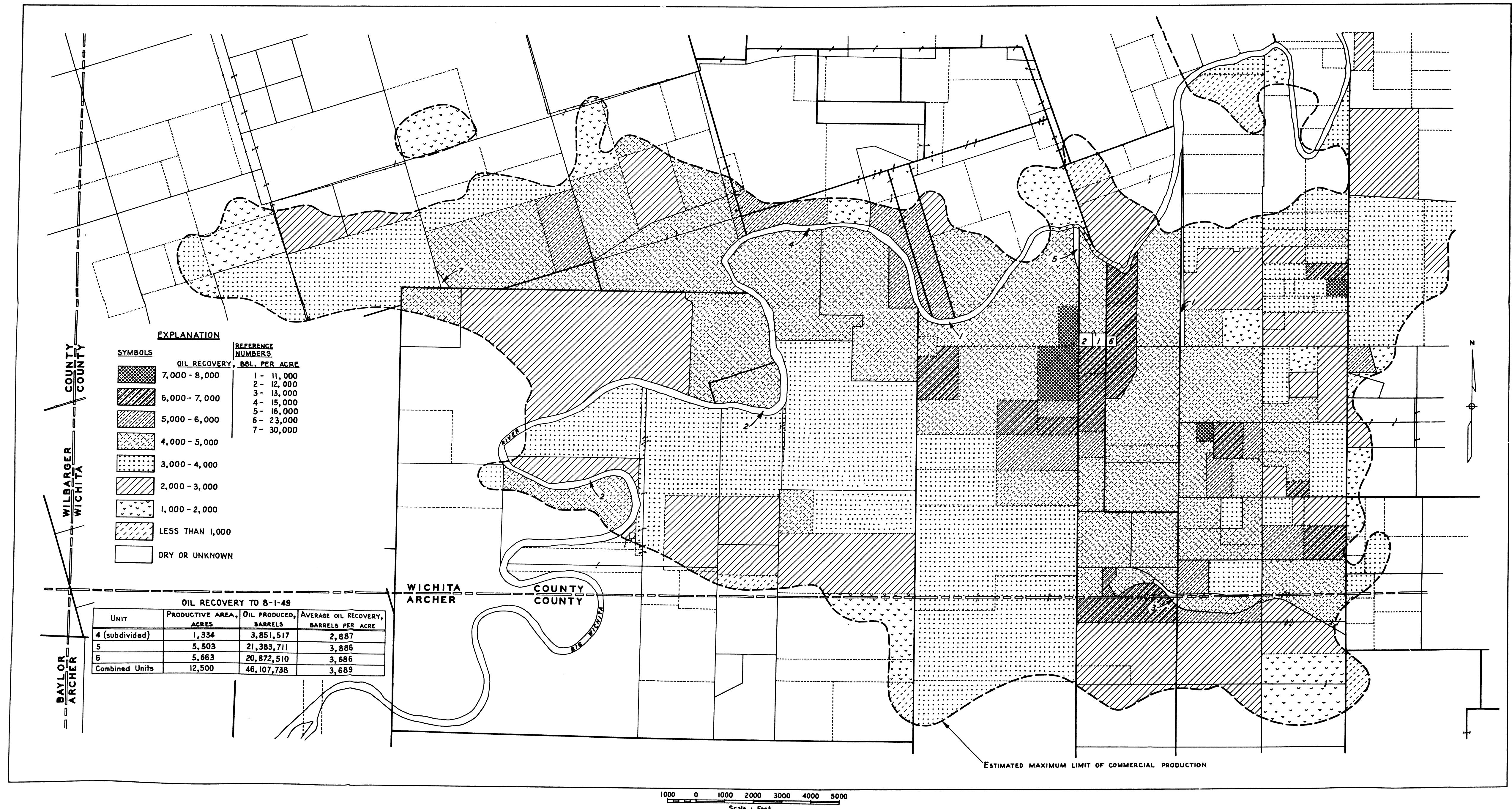


Figure 36.-Recovery of oil from individual leases in barrels per acre, K.M.A. formation, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



1.133 = relative oil-volume factor at 56 p.s.i. (fig. 19).

Hence:

The volume of reservoir oil in place, as of August 1, 1949, equals the volume of stock-tank oil in place on that date times the relative oil-volume factor or

$$122.0 \times 10^6 \times 1.133 = 138.2 \times 10^6 \text{ barrels.}$$

Therefore:

$$\text{Free-gas saturation} = \frac{(269.8 - 138.2 - 50.6)(10^6)}{(269.8)(10^6)} = 30 \text{ percent of pore volume.}$$

#### Evaluation of the Pressure-Maintenance Program as of August 1, 1949

Calculations were made using a method described by Patton<sup>19/</sup> to predict the oil recovery in the southwestern part of the K.M.A. field without pressure maintenance. According to these calculations, primary production methods without pressure maintenance would have recovered 41,100,000 barrels of stock-tank oil by the time the reservoir pressure had declined to approximately 56 p.s.i. (the reservoir pressure as of August 1, 1949). The actual oil production to August 1, 1949, was 46,107,738 barrels, an increase of approximately 5,000,000 barrels as a result of gas-pressure maintenance. The increased oil production represents a gain of 12.2 percent of the theoretical primary production, not including the gain in liquid hydrocarbons recovered by the gasoline plants. Expressed in other units, the oil recovery by pressure maintenance was 216 stock-tank barrels of oil per acre-foot or 27.4 percent of the original oil in the reservoir. By comparison, calculated theoretical primary production methods would have recovered 193 stock-tank barrels of oil per acre-foot or 24.6 percent of the original oil in place. As most Strawn sands in North Texas yield 180 to 190 barrels of oil per acre-foot by natural depletion, the calculated theoretical primary yield of 193 barrels of oil per acre-foot is considered reasonable. A graphical representation of the recoveries and the gas:oil ratios of the two production methods can be seen from figure 37.

The method of calculating the theoretical primary performance curves in figure 37 is based on material-balance principles. In addition to the information necessary to make a material-balance calculation, Kg:Ko<sup>20/</sup> data are needed to calculate the performance curves. The Kg:Ko ratio is a function of liquid saturation and reservoir rock characteristics. The relation may be determined in the laboratory, calculated from field production statistics, or approximated from data published in the literature. The ratios of Kg:Ko (fig. 38) used in calculating the theoretical primary performance curves were calculated from field-production statistics.

The theoretical primary-performance curve and the Kg:Ko curve were calculated by solving the equations given in Appendix B. A sample calculation showing the application of these equations also is included in Appendix B.

The difference in cumulative production between the theoretical primary and the actual pressure-decline curves (fig. 37) is considered to be the gain received from

<sup>19/</sup> Patton, E. Charles, Jr., Pressure Maintenance by Internal Gas Injection: Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 170, 1947, pp. 112-155.

<sup>20/</sup> Kg:Ko =  $\frac{\text{relative permeability to gas}}{\text{relative permeability to oil}}$ .

pressure maintenance. Considering the fact that as of August 1, 1949, only approximately 27 percent of the produced gas had been returned to the reservoir, an increase in recovery of 12.2 percent over recovery by natural depletion is thought reasonable. Two other benefits received by the operators from the pressure-maintenance program were the additional income from natural gasoline extracted from the gas and a longer flowing life of the wells. The latter benefit was of particular significance during World War II, when pumping equipment was difficult to obtain.

#### Estimated Ultimate Recovery, Utilizing Pressure Maintenance by Gas Injection

The ultimate recovery in the southwestern part of the K.M.A. field is estimated to be 53 million barrels of stock-tank oil (31.5 percent of the oil initially in place) at an arbitrarily assumed economic limit of 2 barrels of oil per day per well. This estimate was made by the loss-ratio method<sup>21/</sup> of extrapolating production decline curves. A plot of the monthly oil production for units 4 (subdivided), 5, and 6 combined versus time was extrapolated to an economic limit of 37,400 barrels per month in the middle of 1956. This monthly economic limit for the combined units was obtained by multiplying the total number of active oil wells on August 1, 1949, by 2 barrels per day times 30 days per month.

The area under the extrapolated portion of the monthly production decline curve represents an additional 7 million barrels of recoverable oil. The cumulative oil production of approximately 46 million barrels as of August 1, 1949, added to the estimated additional production of 7 million barrels equals an ultimate recovery of 53 million barrels. This ultimate recovery, expressed in other units, is shown in table 30.

#### POSSIBILITIES OF WATER FLOODING SOUTHWESTERN PART OF K.M.A. RESERVOIR

##### Calculated Theoretical Oil Recovery by Water-Flooding One 20-acre, Five-Spot Project

As the K.M.A. field is rapidly approaching its economic limit under the present methods of production, the feasibility of water-flooding the K.M.A. formation is considered worthy of investigation. The procedure discussed in a report prepared by Suder and Calhoun<sup>22/</sup> is used as a guide in calculating the probable response of the K.M.A. reservoir to water flooding. Suder and Calhoun point out in their paper that their water-flood calculations are based on the assumptions that the injected water displaces the oil in a pistonlike manner and that the flow through a heterogeneous formation may be represented by the sum of the flow through a number of separate individual beds that will have horizontal flow only. The heterogeneity of the producing formation is evaluated from core-analysis data and an average permeability profile for the formation was constructed to proportion the average thickness of the formation into beds called permeability brackets.

The calculations are divided into two parts. The volume of injected water for a single well is first computed, then the oil production for a single well is computed. After the calculations have been made on the single-well basis, the expected recoveries may be applied to the reservoir as a whole or to any part of it; however, as the core-analysis data were taken from the entire southwestern part of the K.M.A.

<sup>21/</sup> Arps, J. J., Analysis of Decline Curves: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 160, 1945, p. 456.

<sup>22/</sup> Suder, Floyd E., and Calhoun, John C., Jr., Water-Flood Calculations: Presented at the spring meeting of the Mid-Continent district A.P.I. Division of Production, Mayo Hotel, Tulsa, Okla., Mar. 23-25, 1949.

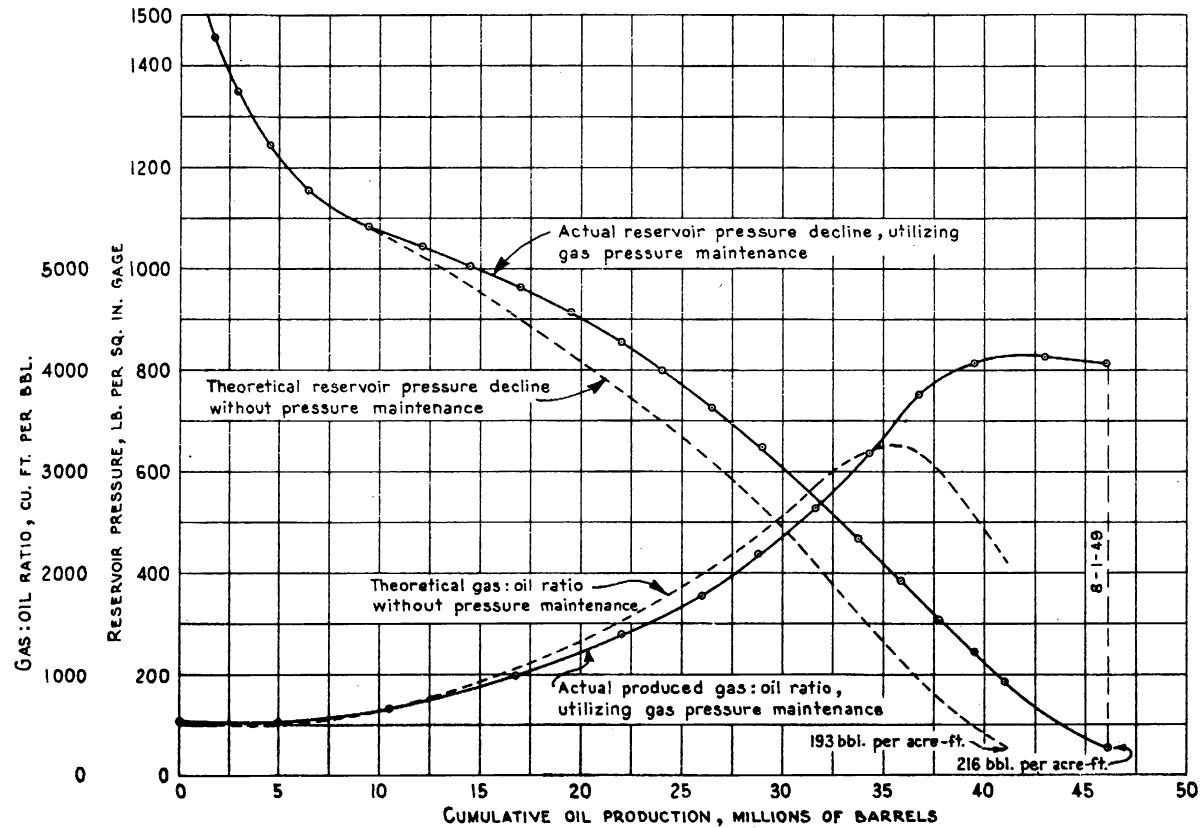


Figure 37.- Comparison of actual reservoir performance utilizing pressure maintenance and calculated theoretical reservoir performance without pressure maintenance, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.

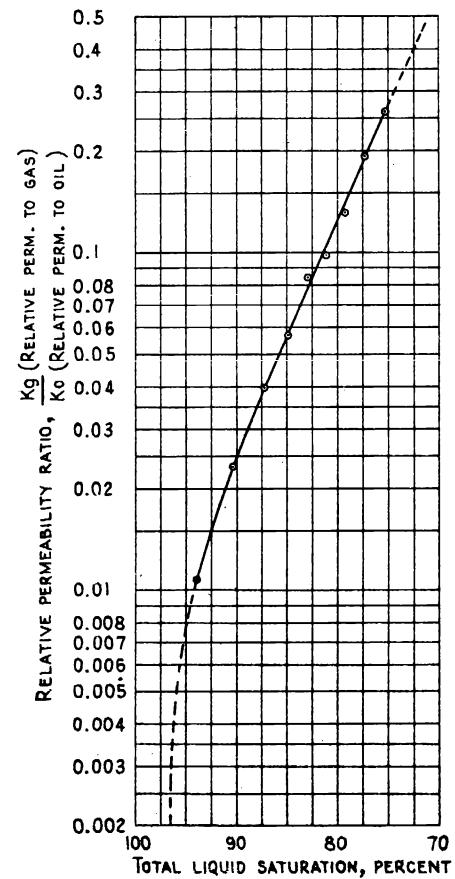


Figure 38.- Calculated relative permeability ratio,  $\frac{K_g}{K_o}$ , using actual production data, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



field, the application of the recovery factor to a small part of the field may involve some error. The calculations presented in this report are illustrative and are designed to give average values that will apply to the whole area studied.

From studies of the core analyses, sand records, and electric logs, zone I appears to have reservoir conditions generally more favorable for water flooding than zone II. However, zone I is very thin and poorly developed in the southern and eastern parts of the field. Figure 39 was prepared to depict the areas where zones I and II are believed to have the best possibilities for water flooding.

To simplify the calculations, it was assumed that the reservoir conditions at the time water flooding began were as shown in table 30 under the column headed "At economic limit". Separate calculations were made for each zone, but only the calculations for zone I are discussed in the detailed explanation to follow. The volume of injection water for a single well was calculated from average reservoir data for zone I, and the average porosity used in these calculations was determined by an arithmetical average. This average porosity was then used to determine the correlative permeability from the porosity-permeability relationship curve (fig. 15), and the correlative permeability was used to determine the percent connate water from the permeability-connate water relationship curve (see fig. 17). The average thickness for zone I was obtained by dividing the net productive volume of the zone by the areal extent of the zone. For zone I, the average porosity is 16.5 percent, the correlative permeability is 42.1 millidarcys, and the average connate water saturation is 17.5 percent. The average thickness of zone I is 9.9 feet; therefore, a bed of this thickness with the above average characteristics is assumed to be representative of the formation in the injection well. The reservoir pressure was assumed to be atmospheric at the start of the flood. At atmospheric reservoir pressure, the gas saturation was calculated to be 38.5 percent. This gas saturation was assumed to be the same in zones I and II, and the oil saturation was calculated for each zone by subtracting from 100 percent the sum of the gas and connate-water saturations. For zone I the known data are tabulated as follows:

$s_w$  = 17.5 percent -- connate-water saturation;

$s_o$  = 44.0 percent -- oil saturation at start of flood;

$\phi$  = 16.5 percent — average porosity;

$s_{or}$  = 15.5 percent — residual-oil saturation after water flood, determined from core analyses data.

By assuming a 20-acre, five-spot flood pattern, the following measurements are known:

$w$  = 933.38 feet — distance from water well to water well;

$d$  = 0.7071 ( $w$ ) = 660 feet — distance from water well to oil well.

The following data were assumed to permit the calculations that follow:

$r_w$  = 1 foot — radius of injection well bore through formation;

$P$  = 1,000 p.s.i. — pressure difference between the sand face and the reservoir during injection;

$K_w/K = 0.625$  ----- relative permeability to water at 15.5 percent oil saturation from Leverett's curve; 23/

$u = 0.8$  centipoise ----- viscosity of the injected water; 24/

The initial radial-flow phase is believed to last until the injected water completes the filling of the bed to a point halfway between the injection well and the producing well. 25/ The volume of injected water required to reach the limit of radial flow is designated  $V_R$ .

$V_R = \text{Volume of water injected when } r = \frac{d}{2};$

$$V_R = 0.178 \pi \left(\frac{d}{2}\right)^2 h \phi (1 - S_w - S_o);$$

However:

$$d = 0.707W;$$

therefore:

$$\frac{d}{2} = \frac{0.707W}{2},$$

$$\left(\frac{d}{2}\right)^2 = \left(\frac{0.707W}{2}\right)^2 = 0.5 \left(\frac{W}{2}\right)^2,$$

$$\left(\frac{d}{2}\right)^2 = \frac{\left(\frac{W}{2}\right)^2}{2};$$

and:

$$V_R = 0.178 \frac{\pi}{2} \left(\frac{W}{2}\right)^2 h \phi (1 - S_w - S_o); \text{ barrels.} \quad (1)$$

where 0.178 converts cubic feet to barrels and  $h$  denotes the thickness of the bed.

The rate of water injection during the radial-flow phase was computed from the following equation:

$$Q_{re} = \frac{0.00308 K_w h P}{u \log_{10} \frac{r_e}{r_w}}; \text{ barrels per day.} \quad (2)$$

23/ Leverett, M. C., Flow of Oil-Water Mixtures Through Unconsolidated Sands: Reprinted Trans. Am. Inst. Min. and Met. Eng., Petrol. Devel. and Technol., vol. 132, 1939, p. 394.

24/ Jones, Park J., Petroleum Production: Reinhold Publishing Corp., New York, N. Y., vol. I, 1946, p. 37.

25/ Muskat, M., The Flow of Homogeneous Fluids Through Porous Media: McGraw-Hill Book Co., Inc., New York, N. Y., 1st ed., 1937, pp. 569-570.



Figure 39.-Map delimiting areas believed to have possibilities of water-flooding, K.M.A. reservoir,  
southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



Where  $r_e$  is the instantaneous radius of the water front, the volume of water injected to the radius  $r_e$  is given by the following equation:

$$V_{re} = 0.178 \pi r_e^2 h \phi (1 - S_w - S_o) ; \text{ barrels .} \quad (3)$$

The time at which a given radius of injection is reached was calculated from the following equation expressed by Dickey and Andresen 26/:

$$\frac{V_{re}}{0.5595 hf} (2.3026 \log_{10} \frac{V_{re}}{0.5595 hf (r_w)^2} - 1) + r_w^2 = \frac{K_w P_t}{39.51 \mu f} ; \quad (4)$$

where  $f = \phi (1 - S_w - S_o)$  and the units used are millidarcys, pounds per square inch, feet, days, centipoises, and barrels.

Using equations (2), (3), and (4), the water-input rates, volumes, and times for zone I were computed for assumed values of  $r_e$  up to the limit of the radial-flow phase, where  $r_e = \frac{0.707 (933.38)}{2} = 330.0$  feet. These values are tabulated below, and the injection rate is plotted in figure 40.

#### Radial encroachment phase

$r_e$ , ft.	$Q_{re}$ , bbl. per day	$V_{re}$ , bbl.	$t$ , months
10	1,002.0	35.2	0.0009
25	716.7	219.8	.0085
45	605.8	712.2	.0336
75	534.1	1,978.3	.1077
100	501.0	3,517.0	.2058
125	477.8	5,495.3	.3390
150	460.5	7,913.3	.5088
175	446.7	10,770.8	.7160
200	435.3	14,068.0	.9621
225	425.9	17,804.8	1.2476
250	417.8	21,981.3	1.5731
275	410.7	26,597.3	1.9397
300	404.4	31,653.0	2.3477
325	398.8	37,148.3	2.7973
330	397.9	38,300.0	2.8923

$$V_R = 0.178 \frac{\pi}{2} \left(\frac{W}{2}\right)^2 h \phi (1 - S_w - S_o) ,$$

$$V_R = 0.178 \frac{\pi}{2} \left(\frac{933}{2}\right)^2 (9.9) (0.165) (0.385) ,$$

$V_R = 38,300$  barrels; volume of water injected to reach the limit of radial flow.

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26/ Dickey, Parke A., and Andresen, Kurt H., The Behavior of Water-input Wells: Secondary Recovery of Oil in the U. S., 2d ed., Am. Petrol. Inst., 1950, p. 319.

The steady-state phase is assumed to begin when 72.3 percent <sup>27/</sup> of the formation included in the five-spot pattern is completely filled with liquid. From these assumptions, the volume of injected water necessary to reach steady-state flow is calculated by the following equation:

$$V_s = 0.723 W^2 h \phi (1 - S_w - S_o) (0.178); \text{ barrels} . \quad (5)$$

When making this calculation, the rate of injection during steady-state flow is assumed to be constant, and this rate is determined from the following equation:

$$Q_s = \frac{0.00154 K_w h P}{u (\log_{10} \frac{W}{r_w} - 0.420)}; \text{ barrels per day} . \quad (6)$$

The interval between the radial-flow phase and the steady-state flow phase is designated as the intermediate- or transitional-flow phase. The volume of water injected during the intermediate-flow phase is the volume necessary to complete the radial-flow phase subtracted from the volume necessary to reach the beginning of steady-state flow phase. It is assumed that the decrease in the injection rate during the intermediate-flow phase is constant; therefore, the rate graph in figure 40 is a straight line for the intermediate phase. The average rate of injection is calculated by dividing by 2 the sum of the rate at the end of the radial-flow phase and the steady-state phase rate. The time interval during intermediate flow is calculated by dividing the volume injected by the average injection rate. The time interval to the start of steady state is determined by adding the intermediate-phase time interval to the radial-phase time interval. These calculations for zone I are shown below.

#### Steady-state phase

$$Q_s = \frac{0.00154 K_w h P}{u (\log_{10} \frac{W}{r_w} - 0.420)} = \frac{0.00154 (0.625)(42.1)(9.9)(1,000)}{0.8 (\log_{10} \frac{933}{1.0} - 0.420)},$$

$$Q_s = 197 \text{ barrels per day};$$

$$V_s = 0.723 W^2 h \phi (1 - S_w - S_o)(0.178) = (0.723)(933)^2(9.9)(0.165)(0.385)(0.178),$$

$$V_s = 70,518 \text{ barrels} .$$

#### Intermediate phase

$$\text{Average rate} = \frac{398 + 197}{2} = 297.5 \text{ barrels per day} ;$$

$$\text{Interim cumulative} = 70,518 - 38,300 = 32,218 \text{ barrels} ;$$

$$\text{Interim time} = \frac{32,218}{297.5} = 108.30 \text{ days} = 3.56 \text{ months} ;$$

$$\text{Time to beginning of steady state} = 2.89 + 3.56 = 6.45 \text{ months} .$$

The heterogeneity of the producing formation is taken into account for computing the rate of oil production by constructing an average permeability profile from one

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<sup>27/</sup> See footnote 25, pp. 596-597.

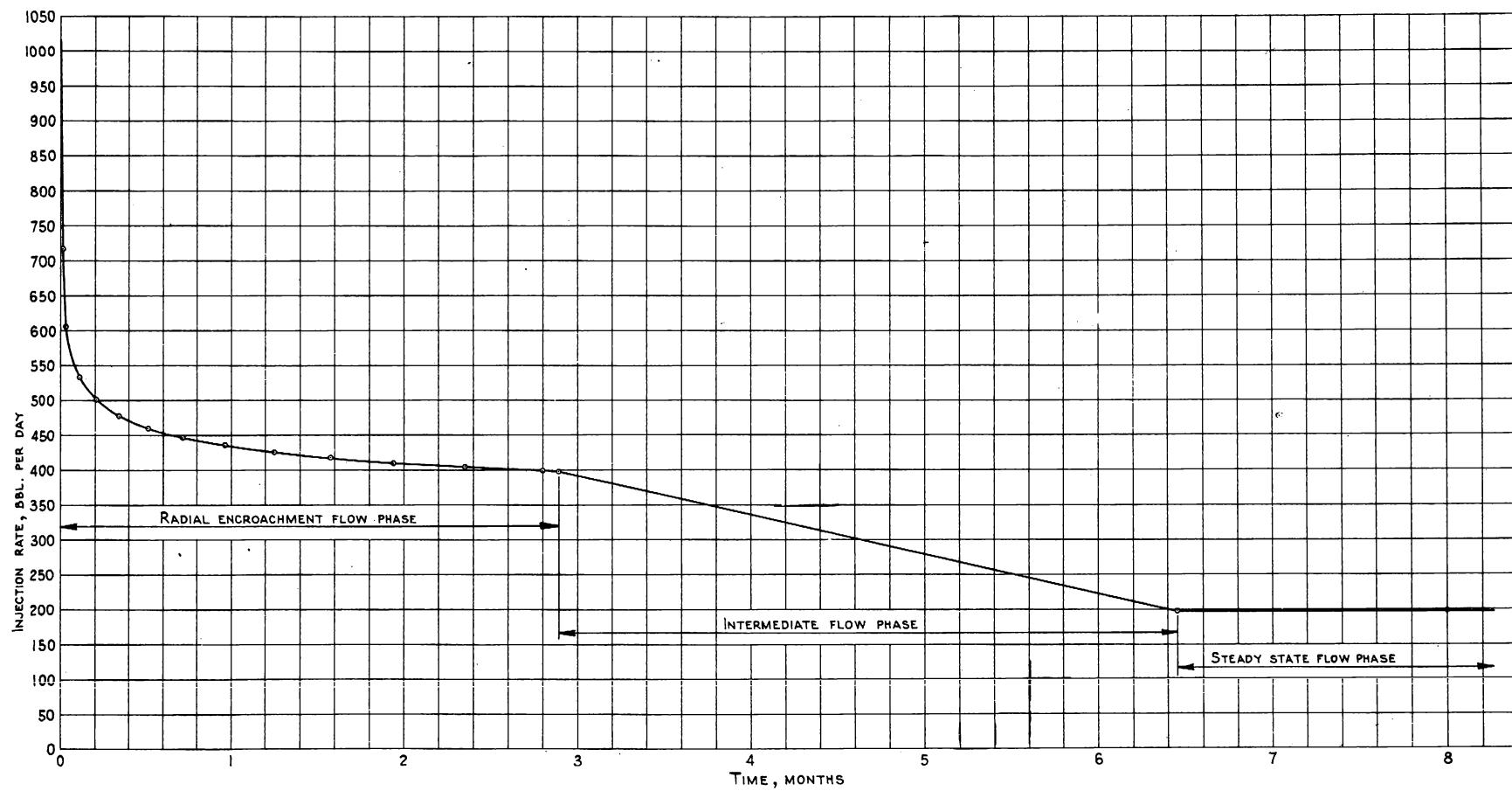


Figure 40.-Calculated theoretical water-injection rates for one 20-acre, 5-spot water-flood project,  
Zone I, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



consolidated core analysis representative of the entire formation. The calculations for the oil-production rate from zone I will be referred to in the following explanation. The lower limit of productive capacity was chosen at a permeability of 5 millidarcys, and the permeability profile was made by grouping the samples of 5 millidarcys or over into permeability brackets. For zone I, 16 permeability brackets were selected from a total number of 360 samples. The brackets containing permeabilities over 32.0 millidarcys were formed with approximately an equal number of samples in each bracket, whereas the brackets containing permeabilities less than 32.0 millidarcys were formed with a slightly increasing number of samples for the brackets of decreasing permeabilities. Table 31 shows the permeability brackets in tabular form. As each sample is assumed to represent 1 foot, the number of samples within each bracket represents the number of feet within each bracket. The average permeability of each bracket is the arithmetical average of the permeabilities of the samples within the bracket. The footage of formation represented by each bracket ( $h_b$ ) was computed by dividing the number of samples within each bracket by the total number of samples and multiplying this quotient by the average formation thickness of 9.9 feet.

Each permeability bracket was assumed to represent a separate producing bed from which the oil will be produced at a rate equal to the rate of the water injected into the bracket. The oil production from the producing well is then the summation of the oil production for the individual brackets. The volume of injection water that enters the individual permeability brackets is proportional to the fraction of the total millidarcy-foot capacity ( $K \cdot h_b$  fraction) that each bracket represents. It is assumed that no oil production will occur from a bracket until all of the gas space is filled with injected water in the 72.3 percent of the flood pattern that is considered to be affected by the flood. This volume of injected water for each bracket is calculated from the equation for  $V_1$ :

$$V_1 = 0.723 (W)^2 h_b \phi (1 - S_w - S_o)(0.178); \text{ barrels ,} \quad (7)$$

where  $h_b$  is the bracket thickness, in feet. It should be noted that equation (7) is the same as equation (5) except for  $h_b$ . The calculated volumes of  $V_1$  for each bracket are shown in table 31.

Oil production continues from each bracket until the oil saturation has been reduced to the residual-oil saturation,  $S_{or}$ . The oil saturations of the core samples that were cored with water-base drilling fluids were plotted versus porosity in figure 41 for the two zones. As these cores probably were highly flushed by the drilling fluid, the remaining oil saturation is believed to be representative of the minimum oil saturation after gas depletion and water flooding.<sup>28/</sup> The values of  $S_{or}$  for zones I and II were obtained from arithmetical averages of the oil saturations of all samples from each zone having porosities of 6 percent or over (see p. 22). The volume of injected water ( $V_2$ ) necessary to fill the gas space and displace the oil down to the residual oil saturation is calculated from the following equation:

$$V_2 = 0.723 (W)^2 h_b \phi (1 - S_w - S_{or})(0.178); \text{ barrels .} \quad (8)$$

Equation (8) is the same as equation (7), except for the term  $S_{or}$ . The calculated volumes of  $V_2$  for each bracket are shown in table 31.

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<sup>28/</sup> See footnote 16, pp. 155, 175.

TABLE 31.—Summary of calculations for theoretical oil production from one 20-acre, five-spot, water-flood project, zone I, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Bracket number	Number of samples	Average permeability, millidarcys	Thickness, feet	Flow capacity, md. ft	Flow capacity fraction	Cumulative water injected		Total oil produced, barrels	Time interval from start of water flood —	
						At start of oil production, barrels	At end of oil production, barrels		To start of oil production, months	To end of oil production, months
Symbols		k	$h_b$	$k \cdot h_b$	$k \cdot h_b$	$V_1$	$V_2$	$V_o$	$t_1$	$t_2$
1	32	6.1	0.881	5.374	0.006468	6,275	10,920	4,645	156.8	276.8
2	26	9.5	.713	6.774	.008153	5,079	8,837	3,758	98.8	175.8
3	25	12.9	.683	8.811	.010605	4,865	8,466	3,601	71.3	128.0
4	25	17.4	.683	11.884	.014304	4,865	8,466	3,601	51.4	93.5
5	25	22.7	.683	15.504	.018661	4,865	8,466	3,601	38.2	70.4
6	25	28.7	.683	19.602	.023594	4,865	8,466	3,601	29.1	54.6
7	20	36.6	.554	20.276	.024405	3,946	6,867	2,921	21.7	41.7
8	20	45.6	.554	25.262	.030406	3,946	6,867	2,921	16.4	32.4
9	20	55.1	.554	30.525	.036741	3,946	6,867	2,921	12.6	25.9
10	20	66.0	.554	36.564	.044010	3,946	6,867	2,921	9.7	20.7
11	20	79.7	.554	44.154	.053145	3,946	6,867	2,921	7.1	16.2
12	20	92.6	.554	51.300	.061746	3,946	6,867	2,921	5.5	13.2
13	20	115.1	.554	63.765	.076749	3,946	6,867	2,921	4.08	9.6
14	20	139.4	.554	77.228	.092954	3,946	6,867	2,921	3.25	7.0
15	21	195.7	.574	112.332	.135206	4,089	7,115	3,026	2.24	4.21
16	21	525.2	.574	301.465	.362852	4,089	7,115	3,026	.75	1.39
Total	360		9.9	830.820		70,518	122,707	52,189		

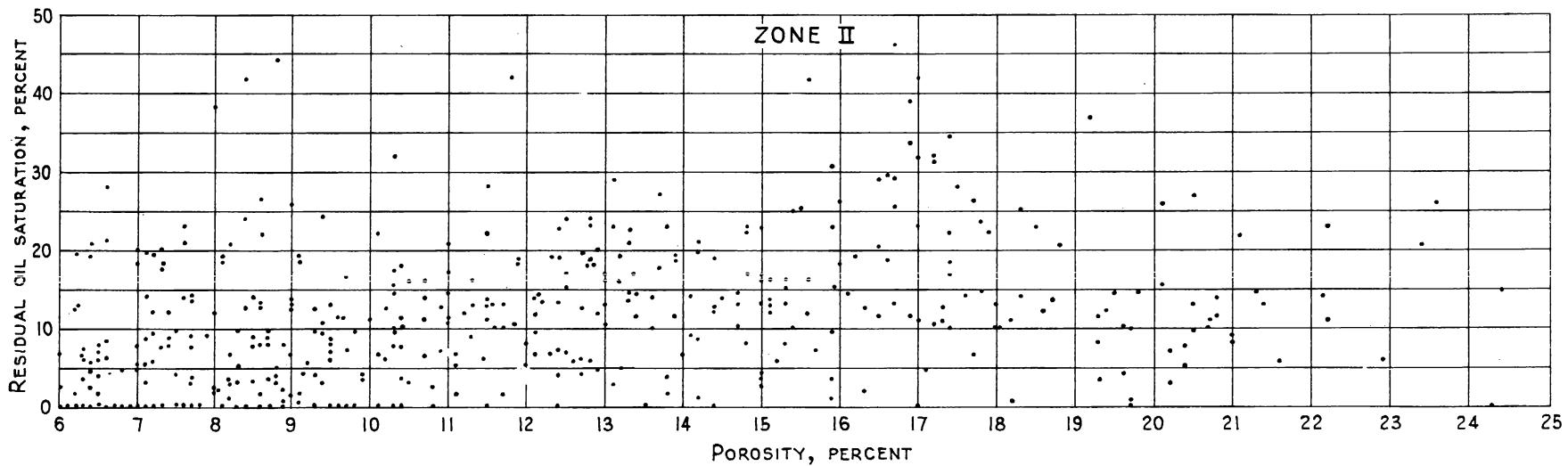
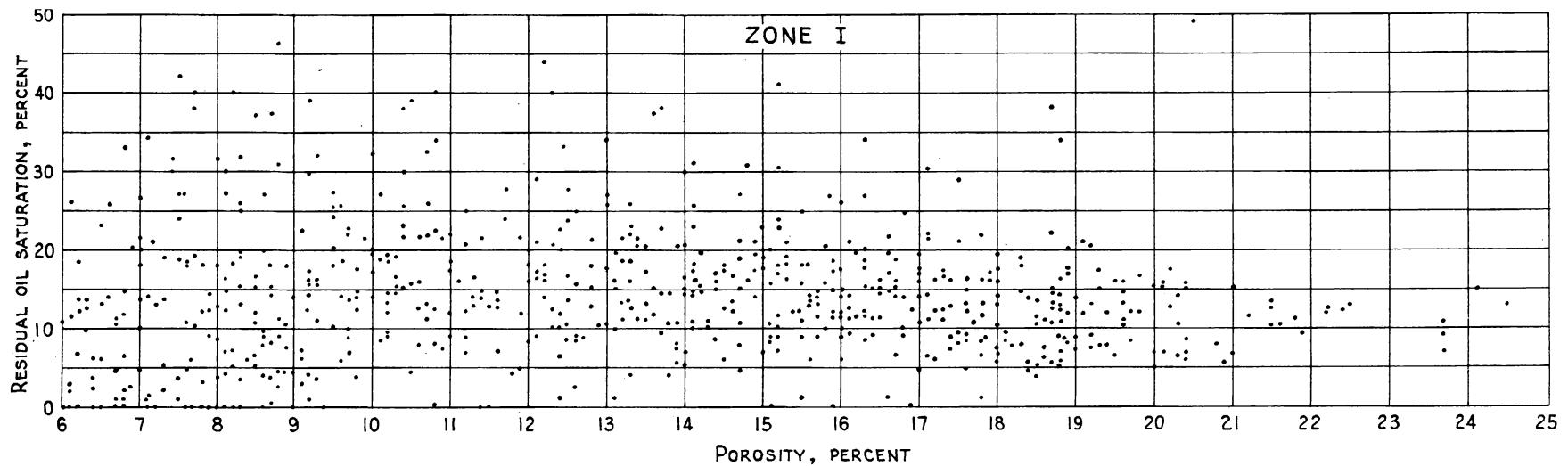


Figure 41.-Plot of porosity versus residual oil saturation from core analyses of Zone I and Zone II,  
K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



The time lapse for injecting the volume of water  $V_1$  into each bracket is designated as  $t_1$ . The time lapse for injecting the volume of water  $V_2$  into each bracket is designated as  $t_2$ . The time  $t_1$  is also the time interval from the start of the flood until the first oil production, while  $t_2$  is the time interval from the start of the flood to the end of oil production. The difference between  $t_1$  and  $t_2$  is the time interval during which oil is being produced from each bracket. The values of  $t_1$  and  $t_2$  are determined for each bracket, according to the flow rate of the injection water entering each bracket. These water-injection rates are listed in table 32.

The monthly injection rates were calculated for table 32 by determining the average rate for the injection well during each month. By multiplying the rate for the injection well by the  $K \cdot h_b$  fraction for each bracket, the rate for each bracket is determined. From the data tabulated for radial flow, a curve was drawn by plotting volume versus time during the radial-flow phase. From this curve, the volume injected at the end of the first month, at the end of the second month, and at the end of the radial-flow phase at 2.89 months was read. The difference between the cumulative volumes at the first and last of a month gives the average rate for that month in barrels per month. The monthly rates for intermediate flow were calculated from the injection-rate curve in figure 40 by converting the daily rate at the middle of each month to barrels per month. The rate for the third month was determined by adding the volume injected during the radial-flow interval to the volume injected during the intermediate-flow interval. The same method was used to calculate the rate during the seventh month when the flow changed from intermediate to steady state. The rate remains constant during steady-state flow.

The times  $t_1$  and  $t_2$  in table 31 were computed from equation (4) during the radial-flow phase and from table 32 during the intermediate and steady-state phases. For example, time  $t_1$  for bracket 16 was determined by dividing its volume  $V_1$  by bracket 16  $K \cdot h_b$  fraction and entering this new volume in equation (4). The same procedure is repeated to find  $t_2$ , except  $V_2$  is used. Equation (4) can be used only to calculate time during radial flow, which was 2.89 months for zone I. An alternate method to determine  $t_1$  for bracket 16 would be to read  $V_1$  for the bracket in table 31 and then enter table 32 opposite bracket 16 for the first month. As the monthly rate for the first month is greater than volume  $V_1$ , it is evident that time  $t_1$  is less than 1 month. The time is then determined by dividing volume  $V_1$  by the monthly rate for the first month. Using this alternate method to find  $t_2$  for bracket 16, volume  $V_2$  is read, and then the rate in table 32 opposite bracket 16 is examined. As the rate for the first month is less than  $V_2$ , the time is known to be greater than 1 month. However, the sum of the rates for the first and second months is greater than  $V_2$ , so the time is now known to occur between 1 and 2 months. The exact time is determined by subtracting the rate for the first month from  $V_2$  and dividing the remainder by the rate for the second month. Time  $t_2$  is all of the first month plus the fractional part of the second month. The alternate method just described was used to find time  $t_1$  and  $t_2$  where the volumes extended into intermediate flow; however, the method was not used for the radial-flow phase because equation (4) gives the best answer. When the injected volume for a bracket becomes great enough to extend into steady-state flow, time  $t_1$  is computed by first multiplying the  $K \cdot h_b$  fraction of the bracket by the volume of water,  $V_s$ , injected into the injection well to reach steady-state flow. This determines the volume of water received in each bracket to reach steady-state flow in the injection well and is known to require a time interval of 6.45 months. The difference between volume  $V_1$  for the bracket and the volume injected into the bracket to reach steady-state flow is known to be injected under the steady-state rate. The steady-state rates for the individual brackets are equal to the  $K \cdot h_b$  fractions multiplied by the steady-state rate for the injection well. These rates are listed in table 32 for the eighth month. The volume injected during steady-state flow divided by the steady-state rate determines the time interval for the steady-state phase. The sum of the time interval for steady-state

TABLE 32.—Average monthly water-injection rates into indicated permeability brackets, zone I, K.M.A. reservoir,  
southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Bracket number	Injection rates (Q) per bracket, barrels per month							
	Q <sub>1</sub> */	Q <sub>2</sub>	Q <sub>3</sub>	Q <sub>4</sub>	Q <sub>5</sub>	Q <sub>6</sub>	Q <sub>7</sub>	Q <sub>8</sub>
1	94.3	82.5	79.5	71.5	60.4	49.3	39.9	38.7
2	118.8	104.0	100.3	90.2	76.1	62.2	50.2	48.8
3	154.6	135.2	130.4	117.3	99.1	80.8	65.4	63.5
4	208.5	182.4	175.9	158.2	133.6	109.0	88.2	85.7
5	272.0	237.9	229.5	206.4	174.3	142.3	115.0	111.8
6	343.9	300.8	290.1	261.0	220.4	179.9	145.4	141.3
7	355.7	311.2	300.1	269.9	227.9	186.0	150.4	146.2
8	443.2	387.7	373.9	336.3	284.0	231.8	187.4	182.1
9	535.2	468.4	451.8	406.4	343.2	280.1	226.4	220.0
10	641.4	561.1	541.1	486.8	411.1	335.5	271.2	263.6
11	774.6	677.6	653.5	587.8	496.4	405.1	327.5	318.3
12	899.9	787.3	759.2	683.0	576.7	470.7	380.5	369.8
13	1,118.6	978.5	943.7	848.9	716.8	585.1	473.0	459.6
14	1,354.8	1,185.2	1,143.0	1,028.2	868.2	708.6	572.9	556.7
15	1,970.6	1,723.9	1,662.5	1,495.5	1,262.8	1,030.7	833.3	809.7
16	5,288.6	4,626.4	4,461.6	4,013.5	3,389.0	2,766.0	2,236.3	2,173.1
Total	14,575	12,750	12,296	11,061	9,340	7,623	6,163	5,989

\*/ Subscript numbers denote month of operation.

phase and 6.45 determines the total time interval for the volume injected into the brackets. This is the most frequent method used to calculate  $t_1$  and  $t_2$  from  $V_1$  and  $V_2$ , respectively.

The oil produced from each bracket is designated as  $V_o$  in table 31 and is the difference of  $V_2$  and  $V_1$  for each bracket. Using the times  $t_1$  and  $t_2$  and the rates for the brackets in table 32, the production was computed for the producing well. The individual brackets have no oil production until time  $t_1$  is reached; then the bracket produces oil from time  $t_1$  to  $t_2$ . At time  $t_2$ , the bracket begins and continues to produce water. As the production for each month was computed, the rates for the brackets were determined from table 32 for the proper month concerned. The production of oil and water was computed for all of the brackets and the results plotted in figure 42, showing the daily oil production, water production, water:oil ratios, and water injection for one 20-acre, five-spot, water-flood pattern in zone I.

The following tabulation shows the oil recovery, time lapse, and required make-up injection water at the indicated water:oil ratios for one 20-acre, five-spot, water-flood project in zone I.

Zone	Producing water: oil ratio	Time, months	Oil recovery, barrels per acre-foot	Total make-up water required for injection, bbl. <u>1/</u>
I	20	55	175	94,000
	30	70	190	99,000
	40	93	207	105,000
	100 percent Water	277	263	124,000

1/ Assuming all of the produced water is returned to the producing formation.

The water-flood calculations discussed above were applied also to zone II; however, it was necessary to assume that the beds of permeability over 300 millidarcys could be selectively plugged after these beds had been watered out approximately 7 months from the start of the flood. This theoretical plugging was necessary to keep the water:oil ratio from reaching an excessive value. The justification for assuming successful plugging of the beds of high permeability was based on the belief that most of the beds of high permeability are isolated by impermeable beds and are not adjacent to the beds of low and moderate permeabilities. This theory is substantiated by the core graph shown in figure 12. After the beds of high permeability were flooded and plugged, the water-flood was continued in zone II until all of the brackets were flooded. The following tabulation shows the oil recovery, time lapse, and required make-up injection water at the indicated water:oil ratios for one 20-acre, five-spot, water-flood project in zone II.

Zone	Producing water: oil ratio	Time, months	Oil recovery, barrels per acre-foot	Total make-up water required for injection, bbl. <u>1/</u>
II	20	64	197	96,300
	30	126	246	108,000

1/ Assuming all of the produced water is returned to the producing formation.

The results of the above calculations for a single well in a 20-acre project were applied to the entire field, and the results of water-flooding zones I and II are shown separately and combined in table 33. The sample calculations and curves for zone II are not included in this report.

The water-flood calculations presented in this report are a theoretical approach to the moot question of predicting the susceptibility of a reservoir to water flooding. Very few actual field tests are available to substantiate this method of calculation; however, the writers believe that the method has considerable merit, and, with the proper application and interpretation of all of the field data and results of the calculations, a reasonably accurate prediction can be made.

The primary prerequisite to any successful water flood is a sufficient volume of residual oil in place in the reservoir. This can be determined in two ways -- by coring the depleted formation and determining the residual oil saturation by core analyses or by calculating the residual-oil saturation from actual production statistics and the initial volume of stock-tank oil in place.

When a particular area is being considered for water flooding, it is recommended that the residual-oil saturation in that area be determined before the flood is initiated. If there is enough residual-oil saturation to warrant a water-flood, an investigation should be made to determine the best and the most economical means of recovering the maximum volume of this oil. Some of the most important factors that influence the decision to water-flood a reservoir are: (1) Well spacing, (2) water-flood pattern, (3) availability of injection water, (4) viscosity of the residual oil, (5) reservoir-gas saturation, (6) structural configuration and lithology of the producing formation, (7) condition of old oil wells, (8) volume of oil recoverable by water flooding, (9) water-injection pressures, (10) water-injection rates, (11) limiting economical water:oil ratios, (12) surface equipment required, and (13) depth.

Careful consideration should be given to all of the above factors before a decision is made to water-flood the K.M.A. reservoir. Each factor should be weighted according to its relative importance in influencing the economics of the water-flood. To flood any reservoir successfully, it is imperative that movement of the injected water be controlled, which in turn would dominate movement of the reservoir oil. Proper well spacing and uniform water-flood patterns are the easiest means of obtaining this control. If old oil wells are utilized in the K.M.A. field, the well spacing is fixed, but the water-flood pattern may be arranged as desired by drilling new wells or selecting the proper oil wells for conversion to water-injection wells. Selection of the proper water-flood pattern will determine the sweep efficiency of the injected water. The commonest water-flood pattern in use is the typical five-spot, which has a calculated theoretical sweep efficiency of 72.3 percent. Because of the arrangement of the existing wells in the K.M.A. field, the development of the area on a typical five-spot pattern would be economically impractical. However, application of the five-spot principle in a modified form so that the drilling of new wells will be held to a minimum is definitely possible and desirable, both from the standpoint of efficiency and the control over movement of injected water and reservoir oil. Because of the numerous individual operators, oil companies, and land owners, some type of cooperative agreement between offset leaseholders will be essential to protect the royalty interests, to achieve the maximum economical oil recovery, and to insure positive control over the movement of the reservoir fluids during water flooding.

The operators probably will face many production problems during the development of the area for water flooding. As approximately 80 percent of the old wells have been shot with nitroglycerin, it will be difficult to inject water selectively into the two producing zones. Recompletion of these old wells to water-injection wells will

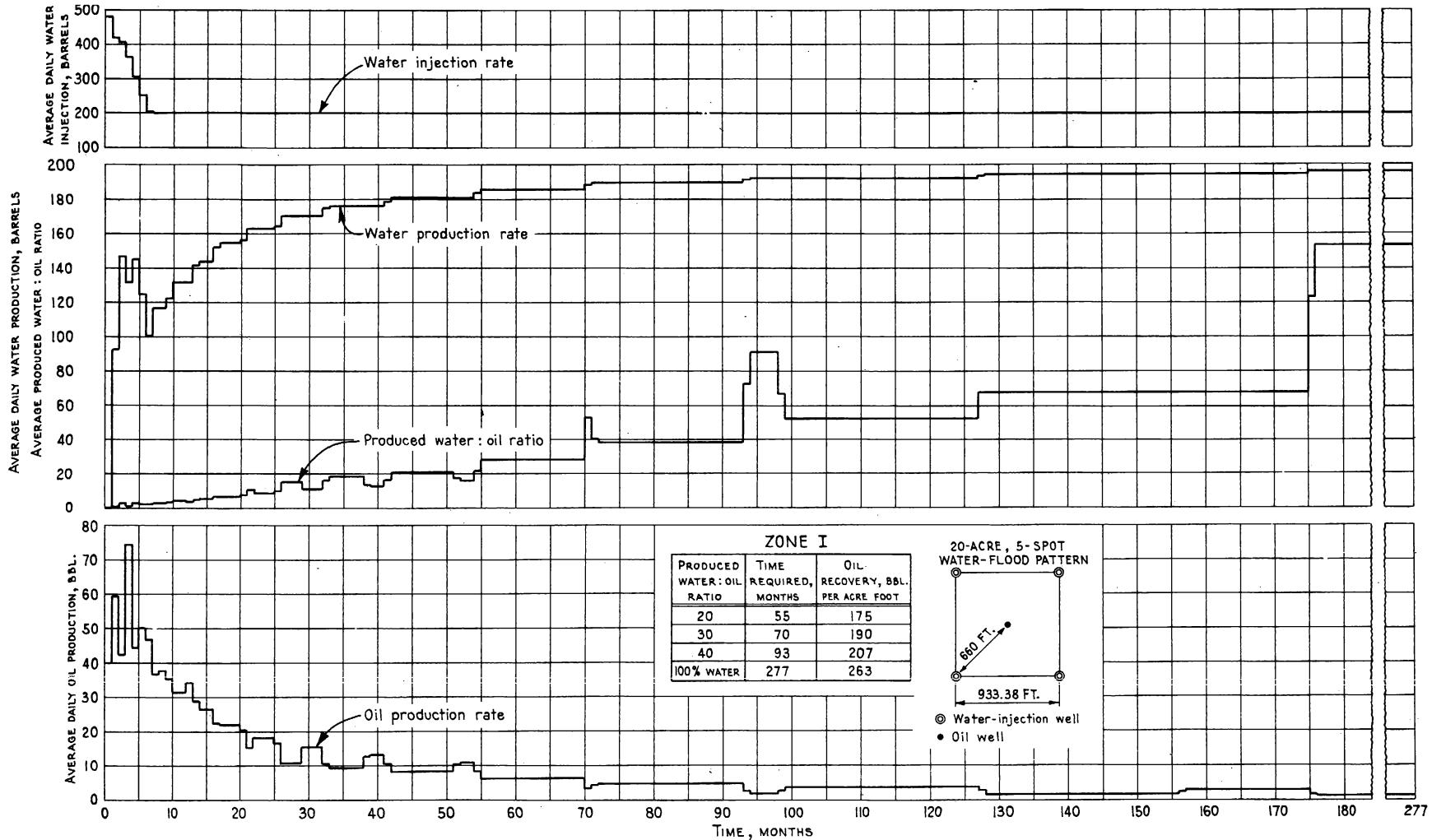


Figure 42.-Calculated theoretical production history of one 20-acre, 5-spot water-flood project, Zone I, K.M.A. reservoir, southwestern part of K.M.A. field, Wichita and Archer Counties, Tex.



TABLE 33.—Calculated theoretical oil recovery by water flooding zone I and zone II to selected water:oil ratios, K.M.A. reservoir, southwestern part, K.M.A. field, Wichita and Archer Counties, Tex.

Zone	Area, acres	Volume, acre-feet	Number of 20-acre, five-spot, flood patterns	Produced water:oil ratio	Time interval from start of flood, months	Oil recovery		Total make-up water required for injection, <sup>1</sup> / million barrels
						Barrels per acre-foot	Barrels	
I	10,851	107,119	542	20	55	175	18,745,000	50.9
				30	70	190	20,353,000	53.7
				40	93	207	22,174,000	56.9
				100 percent water	277	263	28,172,000	67.2
II <sup>2</sup>	11,642	106,214	582	20	64	197	20,924,000	56.1
				3/30	126	246	26,129,000	62.9
I and II combined	12,500	213,333		20		186	39,669,000	107.0
				30		218	46,482,000	116.6

<sup>1</sup>/ Assuming all of the produced water is returned to the producing formation.

<sup>2</sup>/ Assuming that beds over 300 md. permeability can be selectively plugged.

<sup>3</sup>/ Average of the fluctuations in water:oil ratios during the remainder of the flood.

present a perplexing problem, the solution of which will depend to a great extent on the size of the shot hole. If liners can be cemented, then perforated opposite the zone or zones to be water-flooded, it would be possible to inject the water selectively into the proper sections of the zone. If the shot hole is too large, the perforations may not penetrate the cement. The wide range of permeability in the K.M.A. formation will necessitate a flow-rate survey to determine whether all parts of the formation are taking water at equal rates. Excessive channeling or bypassing may be remedied in injection wells having perforated liners by closing off the sections of the zone causing the trouble.

The viscosity of the reservoir oil will not present a problem. The gas saturation in the reservoir should be helpful, as recent investigators <sup>29/</sup> have reported laboratory experiments that indicate moderate gas saturation in the reservoir before water flooding should result in a lower residual oil saturation after water flooding.

There are two sources of injection water in the K.M.A. field. Fresh water from an irrigation canal, which traverses the area, is readily available; however, this water has considerable hardness and probably would require extensive treating facilities to condition it for injection. Salt or brine water could be obtained from shallow Permian and Cisco sands, the Caddo limestone, or the Ellenburger limestone. Because of the presence of illite clay in the K.M.A. reservoir, the writers recommend the use of brine water to preclude any possibility of deflocculating the illite clays. If deflocculated, the illite clays might eventually plug the formation to such an extent the intake rates of water-injection wells would be reduced. Many water-flood operators in the North Texas area are injecting brine waters successfully by using a closed system and have not had any serious corrosion problems.

An analysis of a water sample taken from Lake Diversion, the source of the irrigation-canal water, and an analysis of water produced from an Ellenburger limestone well are as follows:

Constituents	Ellenburger-formation water, mg. per liter	Lake Diversion water, mg. per liter
Sodium, Na . . . . .	65,490	480
Calcium, Ca . . . . .	18,970	200
Magnesium, Mg . . . . .	3,420	40
Chloride, Cl . . . . .	143,800	750
Sulphate, SO <sub>4</sub> . . . . .	1,010	530
Bicarbonate, HCO <sub>3</sub> . . . . .	34	120
Total . . . . .	232,724	2,120

Indicated pH	4.70	7.55
Specific gravity at 60° F.	1.1548	1.0019

The injection rates are controlled by the injection pressures. The proper rate of injection depends on the economic aspects of the individual operator. A high injection rate will mean a shorter life for the water flood. The advantages and disadvantages of a fast flooding rate are still a moot question among water-flood experts; however, the fast flood will naturally mean a faster return on the money invested.

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<sup>29/</sup> Holmgren, C. R., and Morse, R. A., Effect of Free Gas Saturation on Oil Recovery by Water Flooding: Am. Inst. Min. and Met. Eng., Jour. Petrol. Technol., vol. 3, No. 5, May 1951, pp. 135-140.

High injection rates nevertheless mean more costly surface equipment to maintain the high injection pressures required.

The limiting economical water:oil ratio will depend largely on the operating costs of the particular water-flood. Because of the 3,600-foot depth of the K.M.A. formation, serious consideration should be given to the advantages of flowing the oil production. One plan that should be feasible in the K.M.A. field would be to pump the wells with the present pumping equipment until it wears out or the volume of produced fluids exceeds its capacity. The oil wells then could be converted to flowing status, and the oil production could be continued to higher water:oil ratios than would be economical with pumping wells.

The theoretical calculations presented in this report indicate that a considerable volume of oil can be recovered in a reasonable time by water flooding. The time to reach the indicated water:oil ratios can be shortened or extended by increasing or reducing the water-injection rate. Higher injection and production rates will necessitate surface and subsurface equipment having larger capacities and a greater initial development cost. The individual operator will have to determine the injection rates that will best fit his financial requirements.

The successful application of water-flooding principles to the southwestern part of the K.M.A. reservoir probably will tax to the fullest extent the ingenuity and resourcefulness of the petroleum technologists; however, the benefits to be derived will more than justify the use of the most modern engineering techniques.

#### WATER-FLOODING ACTIVITIES IN SOUTHWESTERN PART OF K.M.A. FIELD

##### Shell Oil Co. - Preston "A" Pilot Project

Evidence was submitted by Shell Oil Co. to the Railroad Commission of Texas at a hearing on October 13, 1950, to substantiate its application to water-flood the K.M.A. formation under its Preston "A" lease in the southwestern part of the K.M.A. field, Wichita County, Tex. A special order issued by the commission on November 20, 1950, approved the application. The Preston "A" lease is in the H. and T.C.R.R. Co. survey, block 7, section 20, in the southwestern part of the K.M.A. field. This lease has an areal extent of 237 acres, with 15 oil wells and 1 gas-injection well completed in the K.M.A. formation.

The data presented by Shell Oil Co. described the K.M.A. formation under the Preston "A" lease as a uniform calcareous sandstone, having an average permeability of 100 millidarcys and an average porosity of 18.7 percent. The ultimate recovery of oil by present methods of production was estimated to be 238 barrels per acre-foot, and the additional recovery from water flooding was estimated to be 240 barrels per acre-foot.

Well No. E-18, which had been a salt-water disposal well in the Ellenburger formation, was plugged back and converted to a water-injection well in the K.M.A. formation. This injection well was recompleted by perforating the casing opposite zone I. The actual injection of water started on December 29, 1950, and an average water-injection rate of approximately 330 barrels per day has been maintained. The cumulative volume of water injected to April 30, 1951, was 37,981 barrels. The water has entered the formation under a well-head vacuum of 24 to 25 inches of mercury. No increase in oil production has been observed from this pilot flood up to April 30, 1951.

### Lebus Oil Co. - Proposed Projects

The Lebus Oil Co. has given serious consideration to water-flooding its leases in the southwestern part of the K.M.A. field. On February 1, 1951, the Railroad Commission of Texas issued Special Order 9-20,150, which announced that a hearing would be held in Austin, Tex., on March 15, 1951, to consider the application of the Lebus Oil Co. to water-flood the Anna Mangold lease in the K.M.A. field. Special Order 9-20,486, issued by the Railroad Commission of Texas on March 19, 1951, announced that a hearing would be held in Austin, Tex., on April 24, 1951, to consider the application of the Lebus Oil Co. to water-flood the G. F. Lebus, G. W. Lewis, and W. L. Hodges leases.

#### CONCLUDING STATEMENT

The K.M.A. field, Wichita and Archer Counties, Tex., was named by combining the first letter in the last names of three large land owners in the area, J. A. Kemp, S. H. Munger, and Reece Allen. The K.M.A. field is approximately 20 miles due west of Wichita Falls, Tex. Oil was produced from the shallow Cisco formation as early as 1912, and the K.M.A. Strawn formation was discovered to be oil productive on March 11, 1931. The discovery well was a dry hole in the Ellenburger limestone at a depth of 5,430 feet and was plugged back to 3,977 feet and completed in the K.M.A. formation. After a shot of 500 quarts of nitroglycerin from 3,675 to 3,942 feet, the well flowed, by heads, 125 barrels of oil and 18 barrels of water per day. Drilling to this depth was discouraged by the depression years, an unfavorable market, and the East Texas field discovery. Consequently, development in the K.M.A. field was very slow the following 6½ years. In the fall of 1937, Kadane-Griffith Oil Co. drilled the Mangold "A" well No. 1 after determining a magnetometer high in what is now the southwestern part of the field. This Mangold well was completed on November 14, 1937, at a total depth of 3,752 feet, with an initial flowing production of 2,018 barrels in 12 hours. As the Mangold well was 2 miles southwest of the discovery well, a large area was proved oil productive; and development of the southwestern part of the K.M.A. field was immediately accelerated to a fast pace.

Drilling continued until an oil-productive area of approximately 12,500 acres had been delineated and developed by wells drilled on 10- and 20-acre spacing. The wells were drilled with rotary rigs in approximately 3 weeks, at an average cost of about \$18,000 per well.

The K.M.A. structure is a complex anticline with a maximum closure of 250 feet, and the K.M.A. formation is made up of sediments that grade from limestone to sandstone with numerous shale streaks. The average porosities were found by core analyses to be 16.5 percent for zone I and 16.1 percent for zone II. The correlative permeability, as determined from the porosity-permeability relationship curves, was 42.1 millidarcys for zone I and 39.5 millidarcys for zone II. The average connate-water saturation was estimated to be 17.5 percent for zone I and 20.0 percent for zone II. Gross volumes computed from isopachous maps were 300,893 acre-feet for zone I and 525,808 acre-feet for zone II. Thickness-correction factors were determined from the core analyses, using a limiting productive permeability of 5 millidarcys. These core analyses indicated that 35.6 percent of the gross thickness of zone I and 20.2 percent of the gross thickness of zone II were productive. Applying the thickness-correction factors to the gross volumes, the net volumes were calculated to be 107,119 acre-feet for zone I and 106,214 acre-feet for zone II. The estimated initial volumes of stock-tank oil were 86.7 million barrels in zone I and 81.4 million barrels in zone II, or 168.1 million barrels for the combined zones.

The rapid drop in reservoir pressure caused the operators to consider a co-operative program for gas-pressure maintenance soon after the field had been developed; and, during the latter part of 1939, the K.M.A. Pressure-Maintenance Association was organized. Membership was voluntary, and no contracts or legal obligations were made by the operators. Four gasoline plants were built in the field, and the operators of these plants agreed to process the wet gas and return the dry gas to the various leases at a scheduled charge per 1,000 cubic feet. The field was divided into six units to expedite the distribution of the compression charge on the return gas. The units under study in this report include a part of unit 4 and all of units 5 and 6. For purposes of comparison, individual production statistics are given by units, together with reservoir-performance curves. Units 5 and 6 are believed to have been benefited most by the gas pressure-maintenance program. A part of unit 4 was included in this report to round out structurally the area under study without rigidly adhering to surface boundaries delimited by the units. The performance of the part of unit 4 included in this report under gas-pressure maintenance should not be considered representative of the entire unit 4 or compared with units 5 or 6.

A majority of the wells were completed as flowing wells, and the rate of production was controlled by surface chokes. Although the wells had a wide range of initial oil production, these rates were generally high. Initially, the Railroad Commission of Texas regulated the producing rate at a maximum of 58 barrels per day. In all, 751 wells were completed in the K.M.A. formation, and the cumulative oil production to August 1, 1949, was 46,107,738 barrels, representing an average recovery of 3,689 barrels per acre, or 27.4 percent of the oil originally in place.

The early closing date (August 1, 1949) for the compilation of the production statistics was necessary because many K.M.A. and Ellenburger wells were recompleted in the Goen limestone and the oil production from this reservoir was not segregated from that produced from the K.M.A. reservoir. The oil and gas production from the Goen limestone after August 1, 1949, was enough to affect adversely the calculations for the K.M.A. reservoir.

Distillation analyses of crude-oil samples from the K.M.A. reservoir showed the original gravity of the produced oil to be about 43° A.P.I. and the total gasoline and naphtha content to be approximately 40 percent. Analyses of subsurface samples of the reservoir oil indicated that at original reservoir conditions the oil was undersaturated with gas and the relative oil volume was 1.304. The original reservoir pressure was estimated to be 1,750 p.s.i., and there was 525 cubic feet of gas in solution per barrel of residual oil at the estimated saturation pressure of 1,300 p.s.i.

When the K.M.A. Pressure-Maintenance Association started the gas-return program, about 10 percent of the produced gas was returned to the reservoir. The volume of gas returned was increased until 1943, at which time a maximum of 40 percent of the produced gas was returned. The cumulative produced gas returned to August 1, 1949, was approximately 27 percent.

Although the pressure-maintenance program actually did not maintain the reservoir pressure in the field, the program contributed much toward the conservation of natural resources and reservoir energy. The increased flowing life of the wells, the greater ultimate oil recovery, the increased recovery of natural gasoline, and the conservation of the produced gas are definite gains derived from the gas-injection program.

The increase in oil recovery from the pressure-maintenance program was evaluated by calculating the theoretical oil recovery without gas injection. These calculations indicated a theoretical primary recovery of 41,100,000 barrels to August 1, 1949, whereas the actual recovery to that date was 46,107,738 barrels. The increase in oil

recovery, therefore, was approximately 5,000,000 barrels, a gain of 12.2 percent of the theoretical primary recovery. Considering the facts that only 27 percent of the produced gas was returned and the producing well:injection well ratio was never less than 11.1:1, the 12.2 percent increase in oil recovery is thought to be reasonable. The writers believe, however, that a greater return of produced gas would have increased the ultimate oil recovery considerably.

The ultimate recovery by pressure-maintenance methods is estimated to be 53 million barrels of stock-tank oil at an arbitrarily assumed economic limit of 2 barrels of oil per well per day. This ultimate recovery was determined by extrapolating the production decline curve by the loss-ratio method.

The field is rapidly approaching its economic limit under the present methods of production; therefore, the feasibility of water-flooding the K.M.A. formation was investigated. Theoretical water-flood calculations, following the method presented in a report by Suder and Calhoun, were applied to the formation, and the results of these calculations indicated that approximately as much oil could be recovered by water flooding as had been recovered to August 1, 1949.

The field presents several obstacles that must be overcome before a successful water flood may be realized, but the tremendous volume of oil left in the reservoir is a direct challenge to the operators and engineers interested in the field. Irregular well spacing, streaks of high permeability within the producing zones, and the heterogeneity of the producing formation will be important problems in water flooding. The writers believe, however, that the initiation of pilot water floods, which would give a fair test of the susceptibility of the formation to water flooding, are warranted.

APPENDIX A.—MATERIAL-BALANCE EQUATION AND SAMPLE  
CALCULATION TO DETERMINE INITIAL  
VOLUME OF OIL IN PLACE

The initial volume of reservoir oil was calculated from the material-balance equation derived by Cook. <sup>30/</sup> Because there was no gas cap originally and no effective water drive, a modified form of the generalized material-balance equation was used. This equation is as follows:

$$N_1 = \frac{\frac{S_b}{f_x} - \frac{S_x - S_s}{f_x} n_b + n_b F_x}{\frac{F_x}{F_1} + \frac{S_1 - S_x}{F_1 f_x} - 1};$$

where:

$S_b$  = cumulative net volume of gas produced, cubic feet (measured at atmospheric conditions);

$S_1$  = volume of gas in solution at initial reservoir conditions, cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$S_x$  = volume of gas in solution at time "x", cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$S_s$  = volume of gas in solution at gas-oil separator conditions, cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$n_b$  = cumulative volume of stock-tank oil produced, cubic feet;

$N_1$  = initial volume of reservoir oil, cubic feet;

$F_1$  = formation volume factor at initial reservoir conditions, or the relative volume of reservoir oil at initial reservoir conditions to stock-tank oil, volume of stock-tank oil = 1.0 (dimensionless);

$F_x$  = formation volume factor at time "x", or the relative volume of reservoir oil to stock-tank oil, volume of stock-tank oil = 1.0 (dimensionless);

$f_x$  = factor for converting gas volumes from reservoir conditions at time "x" to 14.4 p.s.i.a. and 60°F. (dimensionless).

Substitutions of oil-and gas-production and gas-injection data corresponding to several reference dates were made in the above equation. The reservoir pressures at the reference dates were obtained by interpolation, using weighted average pressures

<sup>30/</sup> Cook, Alton B., Derivation and Application of Material-Balance Equations to the Magnolia Field, Part II: Bureau of Mines Rept. of Investigations 3720, 1943, p. 80.

calculated from consecutive isobaric maps. The "F" factors were obtained from figure 20. The "f" factors were selected from figure 21; however, these factors can be calculated from the following equation:

$$f_x = \left( \frac{\text{abs. res. press.}}{14.4} \right) \left( \frac{520}{\text{abs. res. temp. at time } "x"} \right) \left( \frac{1}{\text{compressibility factor at res. conditions of time } "x"} \right).$$

The following is a sample of the material-balance calculations:

Reference date: March 1, 1943

Reservoir pressure = 841 p.s.i.

$$\begin{aligned} N_1 &= \frac{\frac{s_b}{f_x} - \frac{s_x - s_s}{f_x} n_b + n_b f_x}{\frac{f_x}{F_1} + \frac{s_1 - s_x}{F_1 f_x} - 1}, \\ &= \frac{\frac{1.300 \times 10^{10}}{62.1} - \frac{75.2 - 16.0}{62.1} (1.273 \times 10^8) + 1.273 \times 10^8 (1.265)}{\frac{1.265}{1.304} + \frac{93.6 - 75.2}{1.304 \times 62.1} - 1.000}, \\ &= \frac{2.09 \times 10^8 - 1.213 \times 10^8 + 1.610 \times 10^8}{0.969 + 0.227 - 1.000}, \\ &= 1.270 \times 10^9 \text{ cubic feet of reservoir oil originally in place,} \\ N_1 &= 226,000,000 barrels of reservoir oil originally in place, \end{aligned}$$

where:

cumulative gross gas production = 17,820,000,000 cubic feet (see table 27);

cumulative gas injected = 4,820,000,000 cubic feet (see table 27);

$s_b$  = cumulative gross gas production minus cumulative gas injected,  
 $(17.82 - 4.82) \times 10^9 = 1.300 \times 10^{10}$  cubic feet (measured at atmospheric conditions);

$s_1$  = 93.6 cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil. (93.6 cubic feet per cubic foot = initial solution gas:oil ratio of 525 cubic feet per barrel divided by 5.61);

$s_x$  = 75.2 cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil. (75.2 cubic feet per cubic foot = 422 cubic feet per barrel divided by 5.61, see fig. 20.);

$S_s$  = 16.0 cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil (average separator pressure = 15 p.s.i., see fig. 20.);

$n_b$  = 22,670,000 barrels =  $1.273 \times 10^8$  cubic feet of stock-tank oil;

$F_1$  = 1.304 (at initial reservoir pressure of 1,750 p.s.i.);

$F_x$  = 1.265 (at reservoir pressure of 841 p.s.i.);

$f_x$  = 62.1 (at reservoir pressure of 841 p.s.i.).

A calculation by the above method was made for each of 11 reference dates, using actual production data and interpolated reservoir pressures. In making material-balance calculations, the same size error in reservoir pressure affects the calculated volume of initial reservoir oil to a smaller extent at a low than at a high reservoir pressure. Each calculated volume of initial reservoir oil was weighted on the basis of the difference between initial reservoir pressure and the reservoir pressure at its respective reference date.

#### APPENDIX B.—EQUATIONS AND SAMPLE CALCULATIONS TO EVALUATE PRESSURE-MAINTENANCE PROGRAM

Before the theoretical primary performance of the reservoir could be calculated, the relative permeability ratios of the gas to the oil at various total liquid saturations had to be obtained. The relative permeability ratios ( $K_g:K_o$ ) were calculated from field-production statistics by solving the following equation:

$$(K_g:K_o)_x = \frac{r_x - (S_x - S_s)}{\frac{U_{ox}}{U_{gx}}(f_x)(F_x)}, \quad (a)$$

where:

$(K_g:K_o)_x$  = ratio of relative permeability to gas to relative permeability to oil at reservoir condition "X" (dimensionless);

$r_x$  = instantaneous gross produced gas:oil ratio at reservoir condition "X", cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$S_x$  = volume of gas in solution at reservoir pressure condition "X", cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$S_s$  = volume of gas in solution at gas-oil separator conditions, cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

$\frac{U_{ox}}{U_{gx}}$  = oil-viscosity:gas-viscosity ratio, both measured at reservoir condition "X" (dimensionless, see fig. 21);

$f_x$  = factor for converting gas volumes from reservoir condition "X" to 14.4 p.s.i.a. and 60°F. (dimensionless, see fig. 21);

$F_x$  = formation volume factor at reservoir condition "X", or relative volume of reservoir oil to stock-tank oil, volume of stock-tank oil = 1.0 (dimensionless).

The Kg:Ko ratios calculated at various liquid saturations were plotted on semilog paper versus their corresponding liquid saturations (see fig. 38). Total liquid saturations were calculated from the following equation:

$$(S_t)_x = \left( \frac{\frac{N_2}{F_2} - n_x F_x}{\text{pore volume}} + S_w \right) 100 = \left( \frac{\frac{N_2}{F_2} - n_x F_x}{\frac{N_2}{1 - S_w}} + S_w \right) 100 , \quad (b)$$

where:

$(S_t)_x$  = total liquid saturation at condition "X", percent;

$N_2$  = volume of reservoir oil at saturation pressure, cubic feet;

$n_x$  = cumulative volume of stock-tank oil produced from saturation pressure to reservoir pressure at condition "X", cubic feet;

$F_2$  = formation volume factor at saturation pressure (dimensionless);

$F_x$  = formation volume factor at condition "X" (dimensionless);

$S_w$  = average connate water saturation, expressed as a fraction.

The produced gas:oil ratios, which are needed in calculating Kg:Ko ratios, fluctuated considerably because of the effect seasonal changes had on the average separator temperature (see fig. 25). To smooth out these fluctuations, an average gas:oil ratio was calculated from the volumes of gas and oil produced during a period of several months. The Kg:Ko ratio calculated from this average gas:oil ratio was plotted versus the total liquid saturation at the middle of the period. The following calculations are samples of those made in the preparation of figure 38.

Calculation of Kg:Ko at 750 p.s.i.:

$$(Kg:Ko)_x = \frac{r_x - (S_x - S_s)}{\left(\frac{U_{ox}}{U_{gx}}\right)(f_x)(F_x)} ;$$

27,365,184 = cumulative oil production when reservoir pressure has declined to 700 p.s.i., stock-tank barrels;

24,197,445 = cumulative oil production when reservoir pressure has declined to 800 p.s.i., stock-tank barrels;

3,167,739 = oil produced during reservoir pressure decline from 800 to 700 p.s.i., stock-tank barrels;

25,850,648 = cumulative gas production when reservoir pressure has declined to 700 p.s.i., M cubic feet;

20,208,874 = cumulative gas production when reservoir pressure has declined to 800 p.s.i., M cubic feet;

5,641,774 = gas produced during reservoir pressure decline from 800 to 700 p.s.i., M cubic feet;

$\frac{5,641,774,000}{3,167,739}$  = 1,781 = average produced gas:oil ratio during reservoir pressure decline from 800 to 700 p.s.i., cubic feet of gas per barrel of stock-tank oil.

therefore:

$$r_x = \frac{1,781}{5.61} = 318 = \text{producing-gas:oil ratio at reservoir pressure of 750 p.s.i., cubic feet of gas per cubic foot of stock-tank oil;}$$

$$S_x = \frac{399}{5.61} = 71.1 \text{ cubic feet of gas in solution at reservoir pressure of 750 p.s.i., cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^{\circ}\text{F.) per cubic foot of stock-tank oil;}$$

$$S_s = 16.0 = \text{cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^{\circ}\text{F.) in solution at a separator pressure of 15 p.s.i. per cubic foot of stock-tank oil;}$$

$$\frac{U_{ox}}{U_{gx}} = 68.0 = \text{oil-viscosity:gas-viscosity ratio, both measured at reservoir pressure of 750 p.s.i. (dimensionless);}$$

$$f_x = 54.3 = \text{factor for converting gas volumes from reservoir pressure of 750 p.s.i. to 14.4 p.s.i.a. and } 60^{\circ}\text{F. (dimensionless).}$$

$$F_x = 1.256 = \text{formation volume factor at reservoir pressure of 750 p.s.i., or relative volume of reservoir oil to stock-tank oil, volume of stock-tank oil = 1.0 (dimensionless).}$$

$$(Kg:Ko)_{750} = \frac{318 - (71.1 - 16.0)}{68.0 \times 54.3 \times 1.256},$$

$$(Kg:Ko)_{750} = 0.0567.$$

Calculation of total liquid saturation at 750 p.s.i.:

$$(St)_x = \left( \frac{\frac{N_2}{F_x^2} - n_x F_x}{\frac{N_2}{1 - S_w}} + S_w \right) 100,$$

where:

$$N_2 = 219 \times 10^6 \text{ barrels} = 1.229 \times 10^9 \text{ cubic feet of reservoir oil at saturation pressure;}$$

$$n_x = 25.78 \times 10^6 \text{ barrels (obtained by averaging the cumulative oil production at reservoir pressure of 800 p.s.i. with that at reservoir pressure of 700 p.s.i. and subtracting } 0.8 \times 10^6 \text{ barrels of oil theoretically produced above the bubble point) = } 1.402 \times 10^8 \text{ cubic feet of stock-tank oil;}$$

$F_2$  = 1.310 at saturation pressure of 1,300 p.s.i.;

$F_x$  = 1.256 at reservoir pressure of 750 p.s.i.;

$S_w$  = 0.1875 = average connate water saturation expressed as a fraction.

$$(S_t)_{750} = \frac{\left( \frac{1.229 \times 10^9}{1.310} - 1.402 \times 10^8 \right) 1.256}{\frac{1.229 \times 10^9}{1 - 0.1875} + 0.1875} 100 ,$$

$$(S_t)_{750} = 85.0 \text{ percent.}$$

After enough Kg:Ko ratios and corresponding total liquid saturations were calculated, the curve shown in figure 38 was prepared. By using this Kg:Ko relationship, it was possible to calculate the theoretical curves shown in figure 37. The calculation of the pressure-decline curve in figure 37 is a progressive procedure with the value of each point depending on the value of the preceding point. A detailed analysis of the procedure is described by Patton, <sup>31/</sup> but the procedure may be described more briefly after rearranging Cook's material-balance equation into the following form:

$$\frac{N_2}{F_2} = \frac{\left\{ \frac{g_x}{n_x} - [(S_x - S_s) - F_x f_x] \right\} n_x}{(S_2 - S_x) + f_x (F_x - F_2)} . \quad (c)$$

For convenience in making trial-and-error solutions this equation may be simplified by combining terms that are constant for a given reservoir pressure. The simplified form is the following:

$$\left( \frac{R_x - C_x}{I_x} \right) (p^{n_x}) = 1 , \quad (d)$$

where:

$\frac{N_2}{F_2}$  is referred to the conditions at saturation pressure and assumed to equal 1;

$C_x = (S_x - S_s) - F_x f_x ;$

$I_x = (S_2 - S_x) - f_x (F_2 - F_x) ;$

$p^{n_x}$  = cumulative stock-tank oil produced from saturation pressure to reservoir pressure "X", expressed as a fraction of stock-tank oil in place at saturation pressure;

$R_x$  = cumulative produced-gas:oil ratio from saturation pressure to reservoir pressure "X", cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil;

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<sup>31/</sup> Work cited in footnote 19.

The subscript "2" denotes conditions at the saturation pressure of 1,300 p.s.i.

From assumed values of  $n_x$  values of  $p^n_x$  are calculated, and then corresponding values of the cumulative produced-gas:oil ratio are calculated using the Kg:Ko data. The method of calculating the cumulative produced-gas:oil ratio involves several steps. From the assumed value of  $n_x$ , the total liquid saturation is calculated. From the total liquid saturation, a Kg:Ko ratio is obtained from figure 38, and an instantaneous gas:oil ratio is calculated from equation (a), which is rearranged as follows:

$$r_x = (S_x - S_s) + \left(\frac{K_{gx}}{K_{ox}}\right) \left(\frac{U_{ox}}{U_{gx}}\right) (f_x) (F_x) ,$$

where:

$r_x$  = instantaneous gross produced gas:oil ratio at reservoir condition "X", cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil.

As the points in figure 37 are calculated at definite pressure decrements, an average produced-gas:oil ratio during each decrement is calculated by:

$$\bar{r}_x = \frac{r_x + r_{xa}}{2} , \quad (e)$$

where:

$\bar{r}_x$  = average produced gas:oil ratio during pressure decrement, cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil.

The subscript  $xa$  denotes appropriate values at the reference point condition immediately preceding the reference point  $x$ .

The gas produced during the pressure decrement is approximated by:

$$\Delta G_x = \bar{r}_x (p^n_x - p^n_{xa}) , \quad (f)$$

where:

$\Delta G_x$  = separator gas produced (measured at 14.4 p.s.i.a. and 60°F.) during a pressure decrement, cubic feet.

The total gas produced with a decline in reservoir pressure from saturation pressure to condition "X" is calculated thus:

$$G_x = \Delta G_x + G_{xa} , \quad (g)$$

where:

$G_x$  = total separator gas produced in association with production of  $p_{n_x}$  volumes of oil (measured at 14.4 p.s.i.a. and 60°F.) with a decline in reservoir pressure from saturation pressure to condition "X", cubic feet.

The cumulative produced-gas:oil ratio needed for trial balance in equation (d) is calculated by:

$$R_x = \frac{G_x}{p_{n_x}} . \quad (h)$$

In using this method to calculate the theoretical primary production of the south-western part of the K.M.A. field, 11 pressure decrements of 100 p.s.i. each were chosen. The primary production curve in figure 37 was plotted only at pressures below 1,050 p.s.i., because the calculations at higher pressures, when only small quantities of gas were being returned, showed no benefit from pressure maintenance.

The total theoretical primary oil production from initial reservoir pressure to reservoir pressure at condition "X" is calculated by:

$$\text{Total production in stock-tank barrels} = \frac{219 \times 10^6}{1.310} p_{n_x} + \left( \frac{219 \times 10^6}{1.304} - \frac{219 \times 10^6}{1.310} \right) ,$$

where:

$219 \times 10^6$  = reservoir oil in place at saturation pressure, barrels;

$1.304$  = formation volume factor at initial reservoir pressure;

$1.310$  = formation volume factor at saturation pressure.

The following calculation is a sample of those made in obtaining the theoretical primary curve in figure 37.

500 p.s.i. = assumed reservoir pressure;

$29.00 \times 10^6$  barrels = assumed  $n_x$  (production below saturation pressure);

then:

$$p_{n_x} = \frac{n_x}{\frac{N_2}{F_2}} = \frac{29.00 \times 10^6 \times 1.310}{210 \times 10^6} = 0.1733 .$$

Calculating total liquid saturation at  $n_x = 29.00 \times 10^6$  barrels:

$$(S_t)_{500} = \left( \frac{\frac{N_2}{F_2} - n_x F_x}{\frac{N_2}{1 - S_w}} + S_w \right) 100 ,$$

$$(s_t)_{500} = \left( \frac{\left( \frac{219 \times 10^6}{1.310} - 29.00 \times 10^6 \right) 1.227}{\frac{219 \times 10^6}{1 - 0.1875}} + 0.1875 \right) 100 ,$$

$$(s_t)_{500} = 81.7 \text{ percent .}$$

At a total liquid saturation of 81.7 percent, figure 38 gives:

$$\text{Kg:Ko} = 0.098 ;$$

therefore:

$$\begin{aligned} r_x &= (s_x - s_s) + \frac{K_o}{K_g} \frac{U_{ox}}{U_{gx}} f_x F_x \\ &= (58.4 - 16.0) + (0.098)(95.6)(34.2)(1.227) \\ &= 42.4 + 392.6 ; \\ r_x &= 435.0 \text{ cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^\circ\text{F.) per} \\ &\quad \text{cubic foot of stock-tank oil;} \end{aligned}$$

then:

$$\begin{aligned} \bar{r}_x &= \frac{r_x + r_{xa}}{2} \\ &= \frac{435.0 + 362.2}{2} ; \end{aligned}$$

$$\bar{r}_x = 398.6 \text{ cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^\circ\text{F.) per} \\ \text{cubic foot of stock-tank oil;}$$

then:

$$\begin{aligned} \Delta G_x &= \bar{r}_x (p^n_x - p^n_{xa}) \\ &= 398.6 (0.1733 - 0.1573) ; \\ \Delta G_x &= 6.38 \text{ cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^\circ\text{F.)} ; \end{aligned}$$

and:

$$\begin{aligned} G_x &= \Delta G_x + G_{xa} \\ &= 6.38 + 26.15 \text{ (from previous calculations) ;} \\ G_x &= 32.53 \text{ cubic feet of gas (measured at 14.4 p.s.i.a. and } 60^\circ\text{F.)} ; \end{aligned}$$

and:

$$\begin{aligned} R_x &= \frac{G_x}{p^{n_x}} \\ &= \frac{32.53}{0.1733} ; \end{aligned}$$

$R_x$  = 187.7 cubic feet of gas (measured at 14.4 p.s.i.a. and 60°F.) per cubic foot of stock-tank oil.

The following are calculations of constants needed in trial balance of equation (d) at an assumed reservoir pressure of 500 p.s.i.:

$$\begin{aligned} C_x &= (S_x - S_s) - F_x f_x \\ &= (58.4 - 16.0) - (1.227)(34.2) , \\ C_x &= 0.5 ; \\ I_x &= (S_2 - S_x) - f_x (F_2 - F_x) \\ &= (93.6 - 58.4) - 34.2 (1.310 - 1.227) , \\ I_x &= 32.4 . \end{aligned}$$

Then by equation (d)

$$\begin{aligned} \frac{R_x - C_x}{I_x} p^{n_x} &= 1 \\ \left( \frac{187.7 - 0.5}{32.4} \right) (0.1733) &= 1 \\ 1.001 &= 1 . \end{aligned}$$

The assumed value of  $n_x$  is substantiated when the trial balance satisfies equation (d).

The total theoretical primary oil production from initial reservoir pressure to reservoir pressure of 500 p.s.i. is:

$$\begin{aligned} \text{Total production} &= \frac{219 \times 10^6}{1.310} p^{n_x} + \left( \frac{219 \times 10^6}{1.304} - \frac{219 \times 10^6}{1.310} \right) \\ &= \frac{219 \times 10^6}{1.310} (0.1733) + \frac{219 \times 10^6}{1.304} - \frac{219 \times 10^6}{1.310} ; \end{aligned}$$

Total production =  $29.80 \times 10^6$  barrels of stock-tank oil.

In like manner, calculations were made at decrements of 100 p.s.i. in reservoir pressure with values for  $r_{xa}$  and  $G_{xa}$  taken from the previous calculation.

