THE EFFECTS OF RELATIVE-PERMEABILITY RATIO, CRUDE-OIL CHARACTERISTICS, AND SURFACE-SEPARATION CONDITIONS ON THE BEHAVIOR OF VOLATILE-OIL RESERVOIRS

By

Sherwin D. Yoelin

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Signed: Sherwin D. Yoelin
Sherwin D. Yoelin

Approved: Richard V. Hughes
Richard V. Hughes

W. C. Sheldon
Walter C. Sheldon

Thesis Advisors

D. M. Bass
Dan M. Bass
Head, Department of
Petroleum Engineering

Golden, Colorado

Date: Jan 25, 1963

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ABSTRACT

A phase-behavior approach in which a material balance is performed on each component is the only accurate way to predict performance of reservoirs containing volatile crude oils. This study uses a component-material-balance prediction method to examine the effects of the three variables -- (1) reservoir fluids; (2) rock properties, described by relative-permeability ratios; and (3) surface-separation conditions -- to determine which of the three has the greatest effect on the operation of a volatile-oil reservoir. In order to study the effects of the three variables mentioned above, two fluid systems, three relative-permeability ratios, and four sets of separator conditions are combined to make a total of twenty-four recovery-performance calculations. The component-material-balance method used to make the calculations is outlined in detail.

The results of the calculations show that, for the fluids investigated, the rock characteristics, described by the gas-oil relative-permeability ratio have the greatest effect on the liquid recovery from a volatile-oil reservoir. This is due to the fact that the relative-permeability ratio governs the flow of gas and oil to the wellbore. For example, the predicted recovery for one fluid and one separator combination using the most favorable relative-permeability data was over three times that predicted using the most unfavorable permeability characteristics. In other combinations of fluids and separator conditions, the recovery ratio was about two to one.

The surface separator conditions for the fluids investigated have lesser effect on fluid recovery than the large variations in relative permeability. Their effect is most important in reservoirs with unfavorable permeability characteristics, where recovery may vary 50 per cent or more. The results also show that the first stage of any separator combination should be set at a relatively high pressure, both to obtain maximum recovery and to achieve optimum gas-oil ratio performance.

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INTRODUCTION

As drilling to greater depths has increased and studies of reservoir-fluid properties have become more extensive, crudes approaching the critical state on the phase envelope have been discovered.

These crudes contain relatively large amounts of the hydrocarbons ethane through decane and are found in high-temperature reservoirs (above 200 F). The saturated liquid phase has a large amount of gas in solution (above 2000 cu ft per bbl), and the gravity of the produced stock-tank liquid is relatively high (around 50° API). These crudes are classified as volatile oils and are characterized by apparent high fluid shrinkage.

A volatile-oil reservoir may also be identified by its performance during natural depletion. Because of the shrinkage characteristics of volatile crudes, the gas saturation in the reservoir will increase rapidly to the point where most of the flow into the wellbore will be from the gas phase. However, the gas phase is rich in condensable oil components that will contribute to stock-tank oil production if the surface-separation facilities are properly designed. Therefore, any oil reservoir that produces a rich gas should be suspected of being of the volatile-oil type.

The problem of predicting recovery performance of volatile-oil reservoirs is quite different from that of normal black-oil reservoirs. In black-oil reservoirs, conventional material-balance equations may be combined with differential-vaporization data, flash-vaporization data, or a simple combination of both to predict recovery performance. In most cases, the type of vaporization data used will not affect the results of the performance calculations. Differential-vaporization data are usually applied to dissolved-gas drive reservoirs and to reservoirs where vertical permeability or gravity segregation effectively separates gas from its associated liquid phase. Flash-vaporization data are usually applied to reservoirs where the produced gas-oil ratio remains fairly constant near the original solution gas-oil ratio value.

In volatile-oil reservoirs, relative volume data determined from differential vaporization will differ greatly from those obtained by flash vaporization (Woods, 1955, p. 158). This divergence will lead to a difference in the calculated production history, indicating that the reservoir-vaporization process in volatile-oil reservoirs is extremely difficult to duplicate in the laboratory. Therefore, conventional material-balance equations are not valid when the reservoir fluid is very volatile, because the volume-factor terms do not describe the effects of recovering liquid at the surface from both the produced oil and the gas phases. For volatile fluids, laboratory vaporization procedures must represent the reservoir-depletion process and the effect of surface-separation conditions on the produced fluids. Surface recovery is a function both of the liquid and gas flowing into the wellbore, and of the liquid which can be recovered from the flowing gas phase.

Since the gas evolved from the oil phase contains liquid that may be recovered at the surface, a phase-behavior approach in which a material balance is performed on each component will simulate the pressure-depletion process of the reservoir. This type of approach, involving multi-component flash calculations, will provide the compositional data of the fluid entering the wellbore at each stage of depletion so that surface-separation calculations can be made. This type of approach will account for liquid recovered at the surface from the produced-reservoir gas phase.

Cook and others (1951) were the first to develop a method for calculating the amount of oil contributed by the flowing-gas phase. Their method was based on laboratory differential-vaporization data and may not provide a true answer to the problems under discussion. Later, Brinkman (1954) developed a component-type material-balance method for predicting recovery for solution-gas-type reservoirs. He applied his analysis to a normal black-oil reservoir with excellent results.

Woods (1955) presented a case history of a volatile-oil reservoir and stressed the importance of the subsurface sample analysis of the original reservoir fluid. Jacoby and Berry (1957) presented a calculation method based on the same principles used by Brinkman; however their method was somewhat shorter and maintained essentially the same accuracy as Brinkman's method. Calculations were presented for a volatile-crude-oil reservoir, and the predicted tank-oil recovery for primary depletion was more than twice that predicted by conventional methods; thus, the importance of adequately describing the reservoir-vaporization process and effects of surface separation is clear.

Reudelhuber and Hinds (1957) presented a laboratory technique using a constant-volume process to develop data to permit calculation of ultimate recoveries from highly volatile-oil reservoirs.

Ridings (1958) presented a compositional material-balance method which used both the principles of reservoir-fluid phase behavior and the reservoir-performance history as a basis for predicting future performance. His method allowed for the effects of water encroachment and was the first to consider this type of depletion.

Since data on volatile-oil reservoirs are available, the methods described above may be used to gain a thorough understanding of the factors that affect the operation of these reservoirs. A study of all the factors affecting performance of these complex systems would be impractical, so the purpose of this work is to study the effects of the most important variables on the operation of volatile-oil reservoirs. These variables are:

1. The reservoir fluids.
2. The reservoir rock, described by its relative-permeability ratio.
3. The surface-separation conditions.

Two volatile fluids, three relative-permeability ratio curves, and four sets of surface-separation conditions were selected to study these variables and determine which is the most important. Six reservoir solutions and twenty-four surface solutions were made.

In the following pages, the calculation procedure, the data, and the results of the calculations are discussed.

CALCULATION OR RECOVERY FROM VOLATILE-OIL RESERVOIRS

As mentioned earlier, the analysis of natural-depletion performance in a volatile-oil reservoir requires the use of a material-balance type of approach on a component basis. The method outlined below is similar to those presented by Brinkman (1954) and Jacoby and Berry (1957, p. 27), and is described in three parts: (1) the assumptions made for the study; (2) the analysis, including a description of the equations and the techniques of solution; and (3) the derivation of the equations.

Assumptions

To confine the study to the three variables--reservoir fluids, relative-permeability ratios, and separator conditions--the following assumptions were made:

1. The crude oil in the reservoir is at its bubble point initially.
2. The reservoir pore volume is constant.

3. Relative permeability is a function of average oil saturation.
4. There is complete equilibrium between oil and gas phases throughout the reservoir.
5. There is no gravity drainage effect.
6. There are no well-behavior effects.
7. Computed pressures and saturations are representative of the average pressure-saturation relationship throughout the reservoir.

Analysis

The analysis involves an incremental type of material balance to predict the pressure-production performance. In this process, a pressure increment is fixed and the gas and oil produced are varied--first, until the volumes of oil and gas remaining in the reservoir equal the original reservoir volume, and second, until the producing gas-oil ratio equals that indicated by relative-permeability data.

The three basic equations used in the analysis of natural-depletion performance are the following. (See "Nomenclature" for definition of terms, noting that some of units are defined differently from those used in the standard A.I.M.E. nomenclature).

1. The volatile-oil flash equation

$$\sum_{n=1}^{n=j} y_{n2} = \sum_{n=1}^{n=j} \frac{m_1 \cdot z_{n1} \; \frac{-\Delta G_p \cdot y_{n1}}{2} \; \frac{-\Delta N_p \cdot x_{n1}}{2}}{L_2\left(\frac{1}{K_{n2}} - 1\right) + m_1 \; \frac{-\Delta G_p}{2} \; -\Delta N_p\left(1 - \frac{1}{2K_{n2}}\right)} = 1 \qquad (1)$$

2. The flowing gas-oil ratio equation

$$\left\{\Delta G_p \cdot B_{g\ avg}\right\} \Big/ \left\{\Delta N_p \cdot B_{o\ avg}\right\} = \left\{\frac{k_g}{k_o} \cdot \frac{\mu_o}{\mu_g}\right\}_{\substack{S_{o\ avg} \\ P_{avg}}} \qquad (2)$$

3. The reservoir-volume equation

$$U_{res} = V_2 \cdot B_{g2} + L_2 \cdot B_{o2} \qquad (3)$$

The vapor-volume factor (B_g) may be computed directly from the gas-law equation: $B_g = 10.7332 \cdot Z \cdot T/P$

The liquid-volume factor (B_o) may be computed using the method described by Alani and Kennedy (1960, p. 288). Their equations are summarized below.

Equation A is in the form that is similar to Van der Waals' equation.

$$(10.7332)(T) = \left(P + \frac{a_m}{B_o^2}\right)(B_o - b_m) \qquad A$$

where a_m and b_m are calculated from constants for each hydrocarbon and are weighted according to the mole fraction of the hydrocarbon in the liquid phase. The procedure for forming a_m and b_m is discussed in detail by Alani and Kennedy (1960, p. 290).

Equation A may be expanded and solved for B_o. The actual B_o is the lowest real root of equation A and is given by:

$$B_o = I + J + 1/3\left(\frac{(10.7332)(T)}{P} + b_m\right) \qquad \text{B}$$

where $I = \sqrt[3]{\frac{-r}{2} + \sqrt[2]{\frac{r^2}{4} + \frac{s^3}{27}}}$

$$J = \sqrt[3]{\frac{-r}{2} - \sqrt[2]{\frac{r^2}{4} + \frac{s^3}{27}}}$$

and $r = \frac{1}{27}\left[(-2)\left(\frac{(10.7332)(T)}{P} + b_m\right)^3 + (9)\left(\frac{a_m}{P}\right)\left(\frac{10.7332}{P} + b_m\right) - (27)(a_m)(b_m)/P\right]$

$$s = 1/3\left[\frac{(3)(a_m)}{P} - \left(\frac{(10.7332)(T)}{P} + b_m\right)^2\right]$$

The unknowns in the three equations 1, 2, and 3, are ΔG_p, ΔN_p, and L_2; and the equations must be solved by a trial and error process because of the complex mathematical manipulations and substitutions required. The gas produced, ΔG_p, and the oil produced, ΔN_p, over the predetermined pressure increment are first assumed. Equation 1 is solved for L_2, and the composition of the vapor phase is determined automatically. The composition of the liquid phase is then determined from the definition of the equilibrium vaporization ratio (K-ratio), $K_n = y_n/x_n$. The values of ΔG_p and ΔN_p are adjusted until the volume of the reservoir determined from equation 3 is equal to the original reservoir volume determined at original conditions. When the two volumes agree, one check on the assumed gas and oil production has been made.

Equation 2 is used to test the assumed value of $\Delta G_p/\Delta N_p$. The relative-permeability ratio is read at the oil saturation between the upper and lower pressure points. Oil saturation is the oil volume divided by the original reservoir volume. The viscosity ratio is determined at the average pressure of the increment. When the left-hand side of equation 2, which describes the oil and gas flow, is equal to the right-hand side, then the second check on ΔG_p and ΔN_p has been satisfied, and the pressure-step performance has been determined. If either or both checks are not satisfied, then new values of ΔG_p and ΔN_p must be assumed and equations 1, 2, and 3 must be solved again. This procedure is followed for each pressure increment.

After the three basic equations are solved, the oil and gas production in moles as a function of pressure is obtained. This well-stream production may be converted to stock-tank oil and gas production by performing the proper separator calculations. This adequately accounts for the liquid recovered at the surface from the produced reservoir gas phase. The performance-calculation procedure is outlined in flow diagram form in figure 1.

The separator-recovery calculation requires the use of the basic flash equation:

$$\sum_{n=1}^{n=j} y_n = 1 = \sum_{n=1}^{n=j} \frac{m \cdot z_n}{L/K_n + m - L} \qquad (4)$$

where the fluid entering the first separator is the produced fluid, and the resultant oil phase flows to the next separator or finally to the stock tank. Gas production is equal to the sum of the gas produced from all separators and the stock tank. Liquid volumes may be determined from the composition of the stock-tank liquid using the method recommended by the NGAA (Brown and others, 1940, p. 50-56).

An IBM 7090 computer was used to solve both the reservoir and separator problems. A study of this type would be impossible without the use of a high-speed computer, because the calculations are repetitious, tedious, and time consuming. For example, a reservoir analysis with eight pressure increments would take approximately fifteen days using a desk calculator.

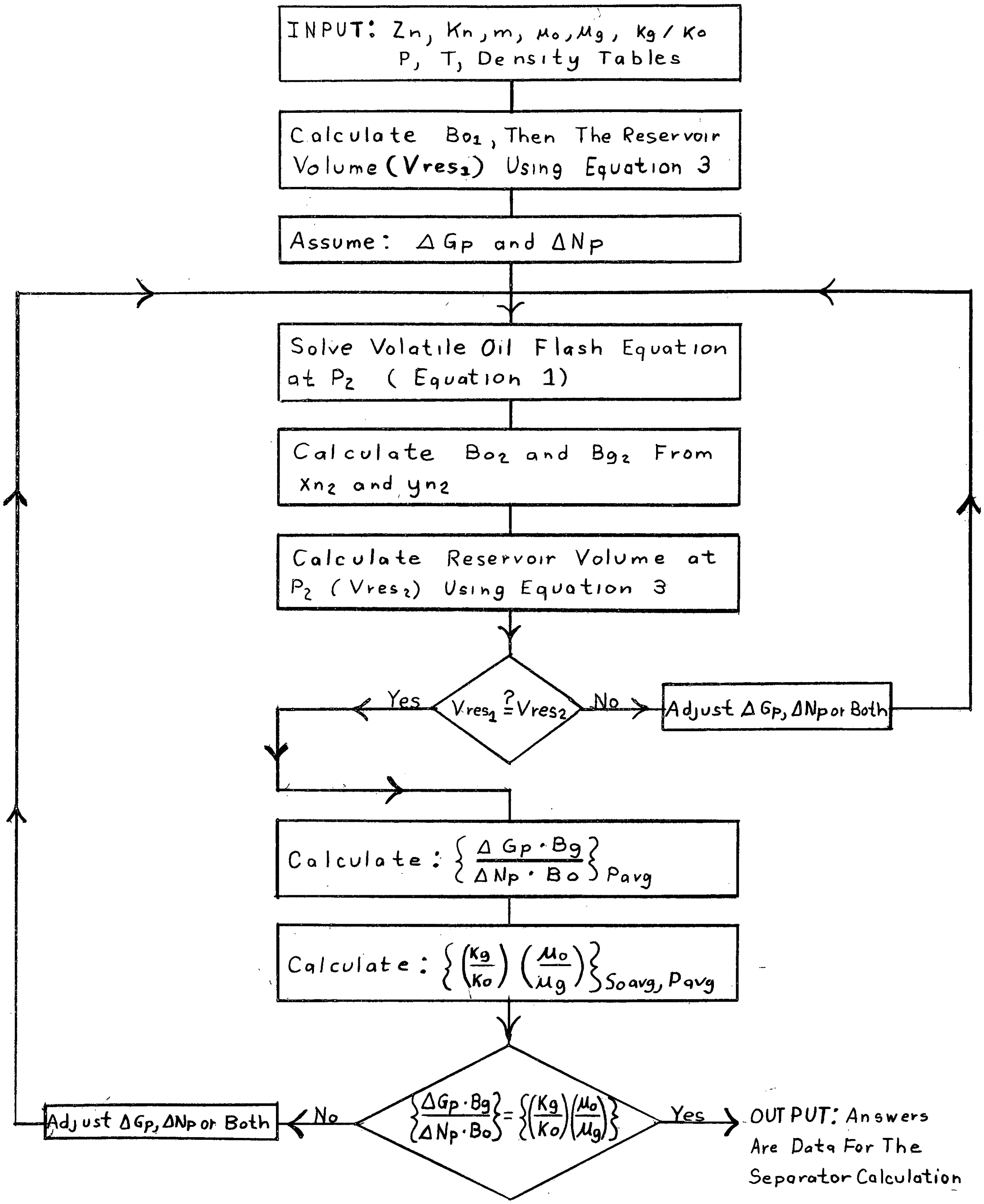

FIGURE 1 - FLOW DIAGRAM OF THE PERFORMANCE-PREDICTION METHOD

Derivation of the Basic Equations

The moles of both gas and liquid remaining in the reservoir at the lower pressure in an increment are equal to the moles present at the upper pressure minus the moles of fluid produced. On a component basis, this relationship may be expressed as follows:

$$m_2 \cdot z_{n2} = m_1 \cdot z_{n1} - \Delta G_p \cdot y_{pn} - \Delta N_p \cdot x_{pn} \tag{5}$$

Over a pressure increment, the produced oil and gas are assumed to have the average compositions between those at the upper and lower pressures, or

$$y_{pn} = \frac{y_{n1} + y_{n2}}{2} \quad \text{and} \quad x_{pn} = \frac{x_{n1} + x_{n2}}{2} \tag{6}$$

and the moles of fluid remaining at the lower pressure are also equal to the moles in the liquid phase plus the moles in the vapor phase; on a component basis, this may be expressed as follows:

$$m_2 \cdot z_{n2} = L_2 \cdot x_{n2} + V_2 \cdot y_{n2} \tag{7}$$

Equation 8 results from combining equations 5, 6, and 7.

$$L_2 \cdot x_{n2} + V_2 \cdot y_{n2} = m_1 \cdot z_{n1} - \frac{\Delta G_p}{2} (y_{n1} + y_{n2}) - \frac{\Delta N_p}{2} (x_{n1} + x_{n2}) \tag{8}$$

Equation 1 is developed by solving equation 8 for y_{n2}, and summing over the j components, noting that $x_{n2} = y_{n2}/K_{n2}$, and $V_2 = m_1 - \Delta G_p - \Delta N_p - L_2$.

Equation 2 is the flowing gas-oil ratio equation for material leaving the reservoir applied at the average pressure in an increment. The volume of free gas flowing is $\triangle G_p \cdot B_g$, and the volume of oil flowing is $\triangle N_p \cdot B_o$.

Equation 3 is a volumetric balance on the oil and gas phases in the reservoir where:

$$V_2 = m_1 - \triangle G_p - \triangle N_p - L_2$$

Simultaneous solution of the three basic equations for a pressure increment takes around 30 seconds on an IBM 7090 computer, and a complete separator analysis takes 15 seconds.

RESERVOIR AND SEPARATOR DATA

As mentioned earlier, two reservoir-fluid systems and three relative-permeability ratio curves were used to make six reservoir calculations. The results of the reservoir calculations were used as data for four sets of separator conditions for a total of twenty-four surface-recovery solutions. This section of the report presents the data used for the reservoir and surface-recovery calculations. The fluids are discussed first, then the relative-permeability ratios, and finally, the separator conditions.

Reservoir Fluids

Fluid A: Jacoby and Berry (1957, p. 30) described a volatile oil and used it to illustrate their performance-prediction method. Their fluid was selected as one of the volatile oils to be used in this study.

The temperature of the reservoir from which fluid A is produced is 246 F, and its depth is about 10,000 ft. Discovery pressure was 5070 psia. Bubble-point pressure as determined from bottom-hole sample analysis was 4836 psia. Producing gas-oil ratio at discovery was 2000 cu ft per bbl, and the gravity of the stock-tank fluid was over 50° API.

The hydrocarbon analysis of fluid A is shown in table 1, the K-ratios are shown in figure 2, and viscosity data are shown in figure 3.

K-ratios for this system were developed at reservoir conditions in the following manner. K-ratios for all components were estimated at reservoir conditions by extrapolating the data of Katz and Hachmuth (1937, p. 1072). The values of the methane and heptanes-plus K-ratios were then carefully adjusted until the laboratory flash-vaporization curve for the bottom-hole sample could be reproduced by calculation.

Jacoby furnished viscosity and additional data not presented in the 1957 paper.

Fluid B: The other volatile fluid selected for this study was described by Woods (1955, p. 156).

The reservoir containing this volatile fluid is at a depth of 8200 ft, and the reservoir temperature is 250 F.

TABLE 1--HYDROCARBON ANALYSIS OF FLUID A

4836 psia - 246 F

Component	Mole Fraction
Carbon Dioxide	0.0218
Nitrogen	0.0167
Methane	0.6051
Ethane	0.0752
Propane	0.0474
Butane	0.0412
Pentane	0.0297
Hexane	0.0138
Heptanes +	0.1491
	1.0000

Heptanes-Plus Properties	
Specific Gravity	0.799
Molecular Weight	181
Critical Temperature	1066 ^{o}R
Critical Pressure	375 psia

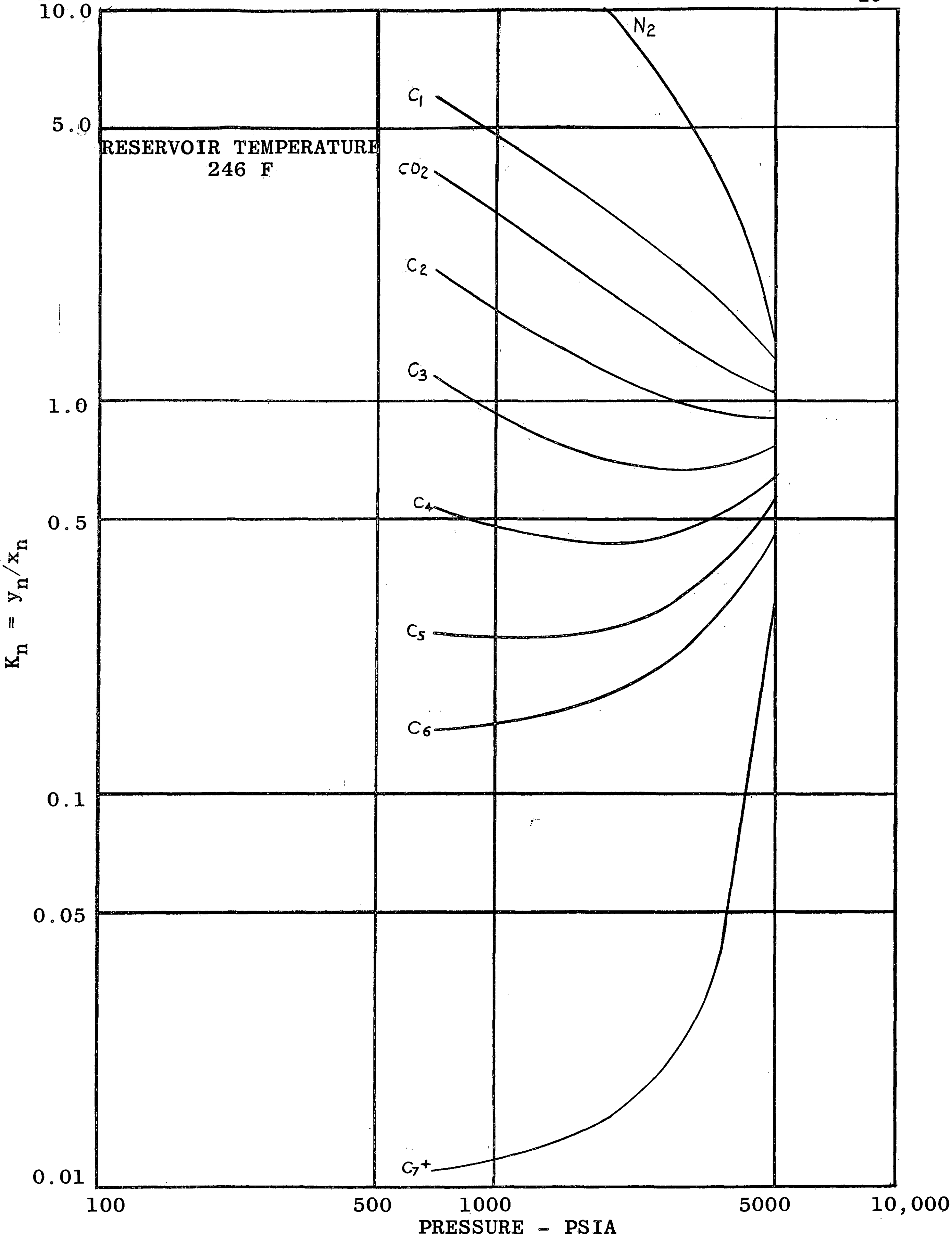

FIGURE 2 - EQUILIBRIUM-VAPORIZATION RATIO CHART, FLUID A

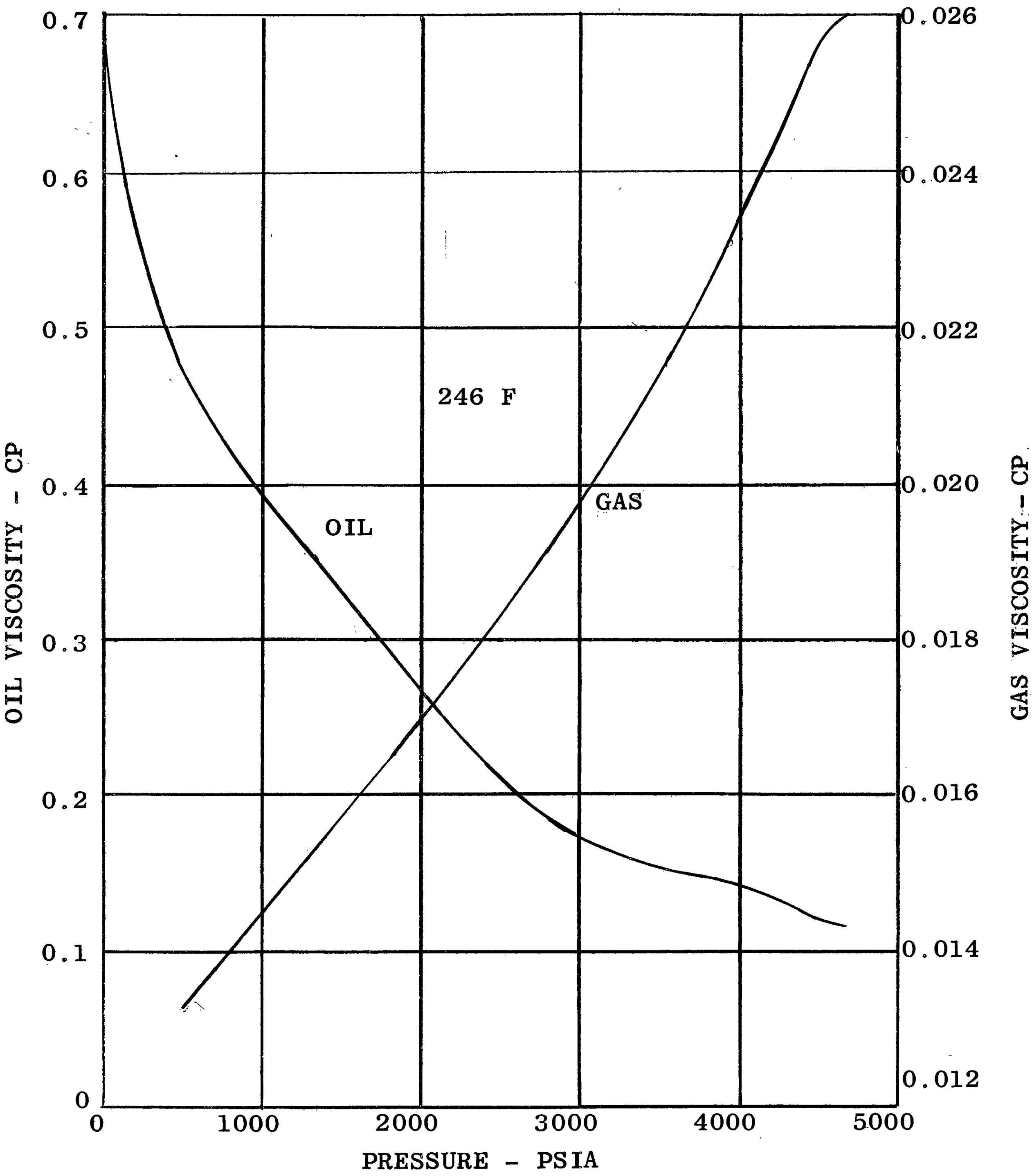

FIGURE 3 - GAS-OIL VISCOSITY DATA, FLUID A

Initial producing gas-oil ratio was 3200 cu ft per bbl, and the initial stock-tank oil gravity was reported to be 44° API.

Ridings (1958) used Wood's data for a sample reservoir-recovery calculation, and fluid B was developed from Wood's data as presented by Ridings.

The hydrocarbon analysis of fluid B is shown in table 2, the K-ratios are shown in figure 4, and the viscosity data are shown in figure 5.

K-ratios for fluid B were developed in the following manner. The charts presented in the NGSMA Data Book (1957) were used to determine a convergence pressure (5300 psia) and K-ratios that produced a calculated bubble-point of 4260 psia. The K-ratios for the entire range of reservoir pressures were selected using the charts in the NGSMA Data Book and a convergence pressure of 5300 psia. Ridings found that his recovery calculations using these K-ratios matched reservoir performance quite well.

Viscosity data were developed from data on a very similar system.

<u>Comparison of Fluid Data</u>: Fluid A is more volatile than fluid B. This is true for two reasons: (1) the composition of fluid A reveals a greater concentration of material in the methane fraction, and less in the heavy fractions; and

TABLE 2--HYDROCARBON ANALYSIS OF FLUID B

4260 psia - 250 F

Component	Mole Fraction
Methane	0.5515
Ethane	0.1115
Propane	0.0920
Iso-Butane	0.0230
N-Butane	0.0290
Iso-Pentane	0.0130
N-Pentane	0.0060
Hexane	0.0175
Heptanes +	0.1565
	1.0000

Heptanes-Plus Properties	
Specific Gravity	0.816
Molecular Weight	181
Critical Temperature	1065 ^{o}R
Critical Pressure	376 psia

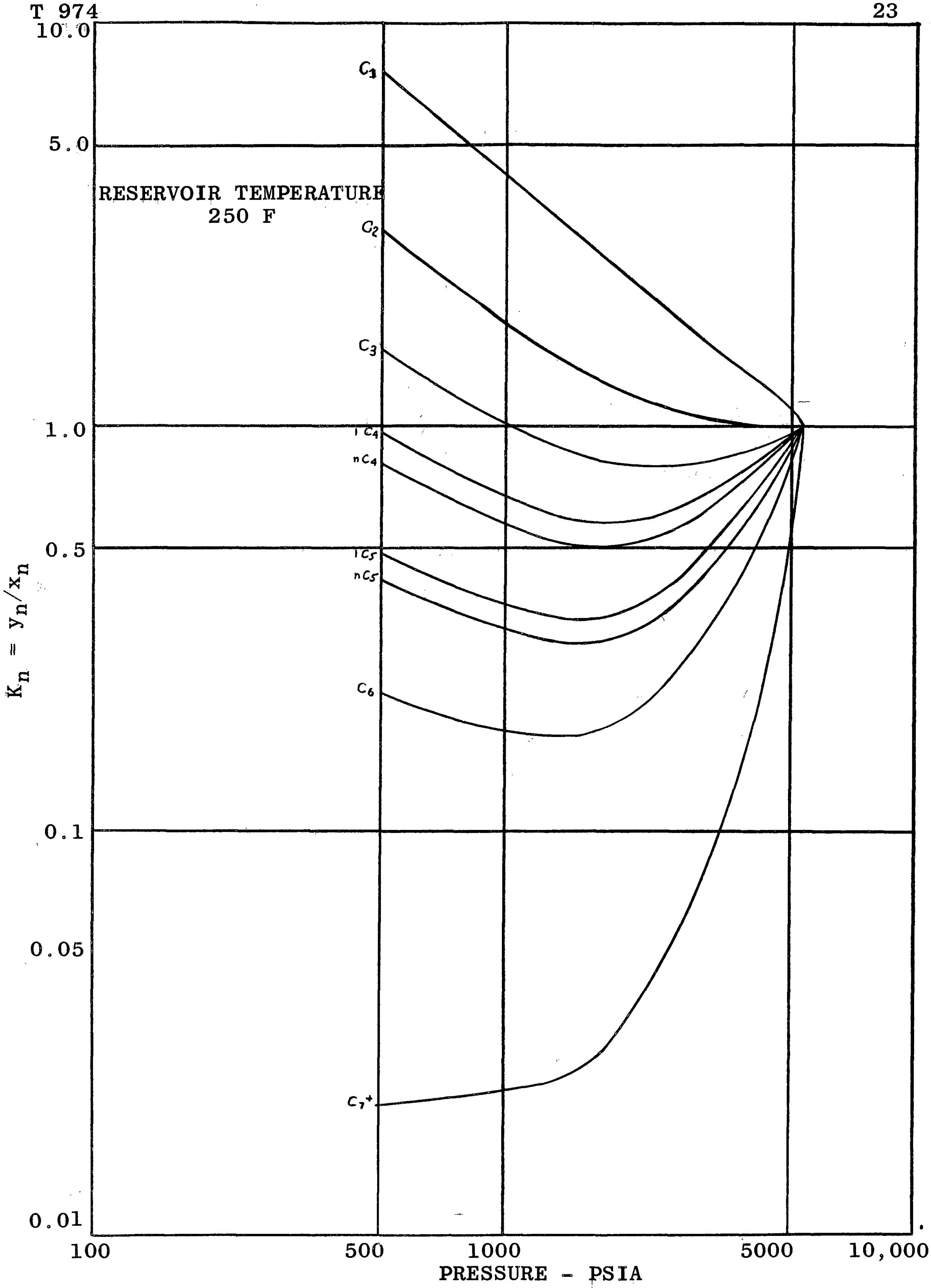

FIGURE 4 - EQUILIBRIUM-VAPORIZATION RATIO CHART, FLUID B

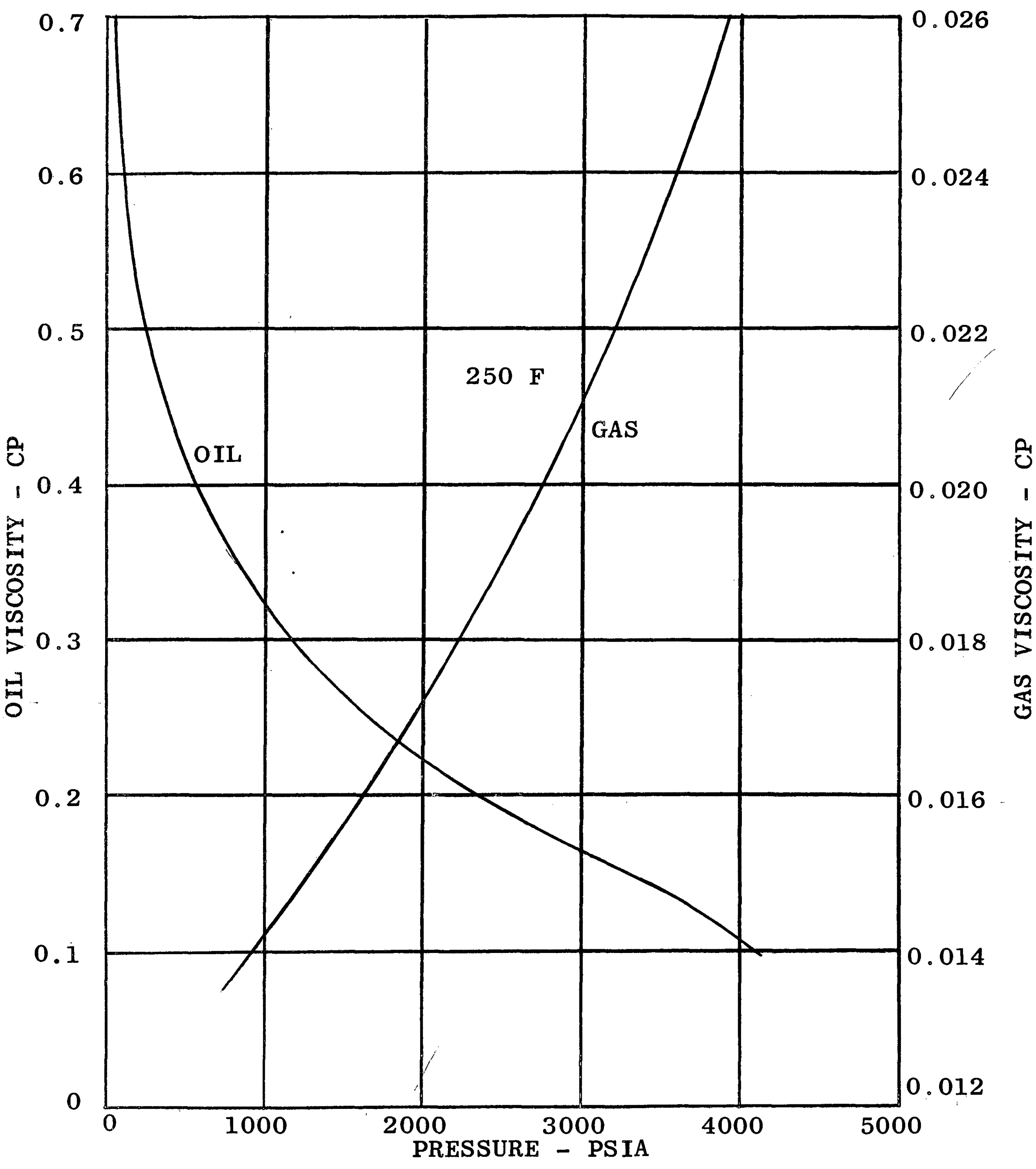

FIGURE 5 - GAS-OIL VISCOSITY DATA, FLUID B

(2) the comparison of the two sets of K-ratios shows those of fluid A are higher for most of the heavy components. This implies that more material will be forced into the gas phase during depletion, increasing the effects of crude-oil volatility.

Fluid A contains small amounts of the non-hydrocarbon constituents nitrogen and carbon dioxide, which tend to be in the vapor phase during depletion, whereas fluid B contains all hydrocarbons. Fluid A has a higher oil viscosity and a lower gas viscosity generally throughout the pressure range; however, the differences are not significant.

Relative-Permeability Ratios

Relative-permeability ratio at any saturation is defined as the relative permeability to gas divided by the relative permeability to oil. Relative-permeability data used in this study are shown in figure 6. Ratios 1 and 2 were taken from figure 2 and Arps and Roberts' paper (1954, p. 122). Arps and Roberts designed these curves to represent approximately 20 relative-permeability ratio curves which they had obtained for their study. Ratio 1 represents their minimum curve corrected for a connate-water saturation of 15 per cent. This curve, steep and unfavorable, is probably representative of a fractured

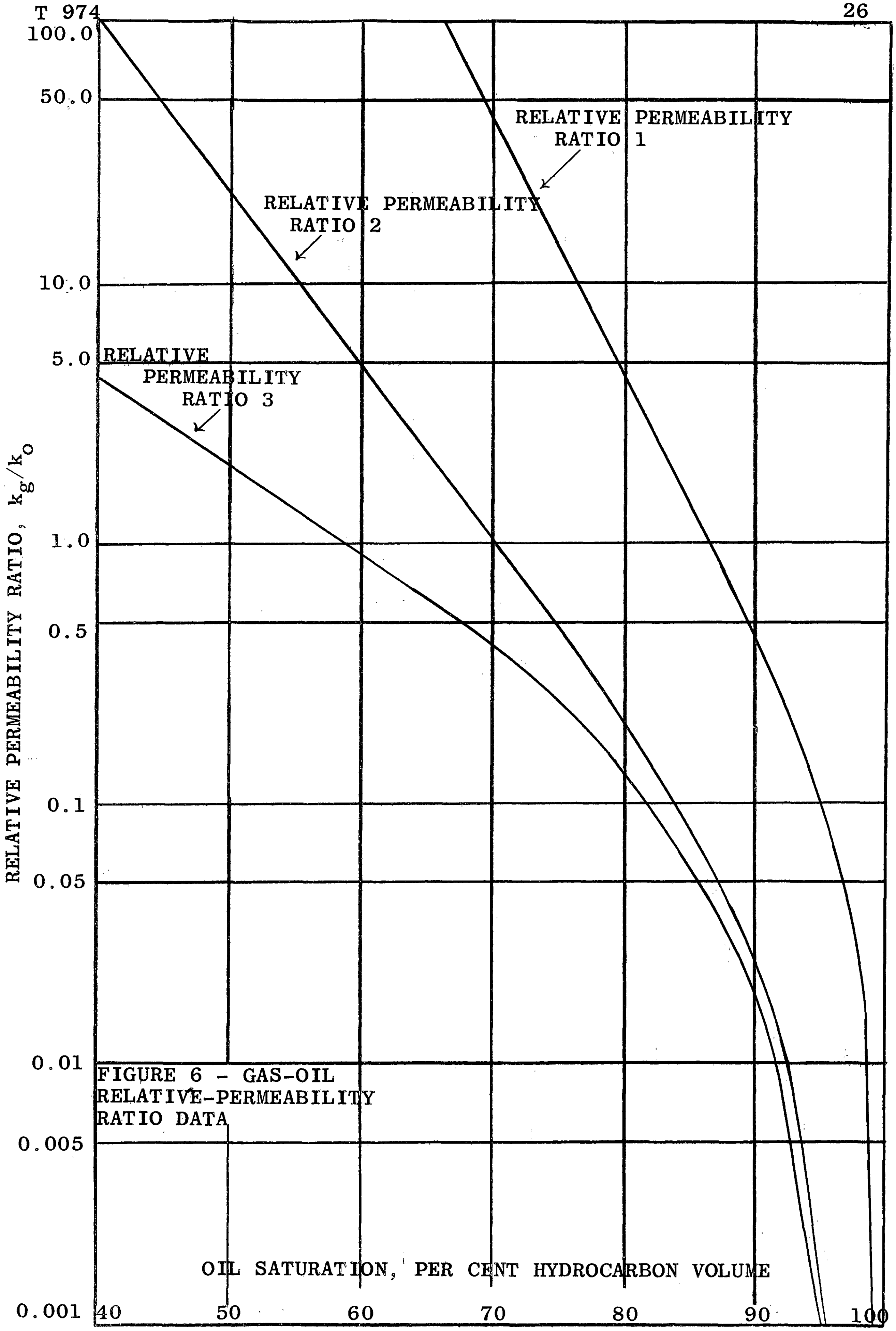

FIGURE 6 - GAS-OIL RELATIVE-PERMEABILITY RATIO DATA

chert. Ratio 2 represents their average curve corrected for a connate-water saturation of 15 percent and is probably representative of the vugular types of limestone. Ratio 3, the most favorable, was designed to represent a consolidated sand or sandstone.

The wide range in permeability data was designed to adequately show the effects of permeability on recovery.

Separator Conditions

The four cases of surface separation investigated are shown in table 3. It was assumed that the separators would operate at 68 F.

TABLE 3--STAGE SEPARATION CONDITIONS

	1st Stage psia	2nd Stage psia	3rd Stage psia	Stock Tank psia
Case 1	35			14.7
Case 2	500			14.7
Case 3	500	35		14.7
Case 4	500	125	35	14.7

K-ratios were developed for separator and stock-tank conditions using data presented in the NGSMA Data Book (1957). The K-ratios are shown in table 4.

TABLE 4--SEPARATOR EQUILIBRIUM VAPORIZATION RATIOS

Component	K_n 500 psia	K_n 125 psia	K_n 35 psia	K_n 14.7 psia
Nitrogen	23.5	86.0	290.0	680.0
Carbon Dioxide	3.0	11.0	36.0	82.0
Methane	5.5	20.2	69.0	160.0
Ethane	1.1	3.5	14.6	39.5
Propane	0.335	0.940	3.5	7.6
Iso-Butane	0.160	0.365	1.18	2.7
N-Butane	0.151	0.269	0.845	1.91
Iso-Pentane	0.0635	0.106	0.305	0.70
N-Pentane	0.0491	0.083	0.240	0.555
Hexane	0.0159	0.0241	0.0645	0.148
Heptanes +	0.00081	0.0015	0.00408	0.009

RESULTS

As mentioned earlier, all calculations were made using IBM 7090 computers. This section of the report presents the results of the recovery-performance calculations and discusses the effects of the three variables on performance. All reservoir calculations were stopped at a reservoir pressure of 750 psia.

Performance Calculations

Oil recoveries are expressed as cumulative stock-tank oil production in stock-tank barrels per barrel of hydrocarbon pore volume, because the stock-tank barrels initially in place vary with the separator conditions. The separator combinations are identified in the same order as in table 3. That is, separator combination 1 is the 35-14.7 psia separators; separator combination 2 is the 500-14.7 psia separators; separator combination 3 is the 500-35-14.7 psia combination; and, separator combination 4 is the 500-125-35-14.7 psia combination.

Table 5 shows the results of the recovery calculations to a reservoir pressure of 750 psia. This table, summarizing the recovery calculations, is designed to show the effects of the three variables considered in the study. The fluids are arranged vertically to show their effect. In each vertical column, the relative-permeability ratios are arranged so that their effect can be noted. In each relative-permeability ratio grouping, the separator combinations are arranged to show their effect.

Table 6 shows the separator gas-oil ratio performance by presenting cumulative gas-oil ratios at 750 psia. This table is also designed to show the effects of the three variables considered in the study.

Figures 7 through 12 present the pressure-production performance of the various combinations of fluids, relative-permeability ratios, and separator combinations. The recoveries are quite low, because they are expressed as a fraction of hydrocarbon pore volume. They would be larger if expressed on a stock-tank basis.

Effect of Fluids

Figure 13 shows the effect of the fluids on recovery for the combinations of relative-permeability ratios and

TABLE 5--SUMMARY OF CALCULATIONS

Recoveries to 750 psia expressed as stock-tank bbl per bbl hydrocarbon pore volume

Fluid A			Fluid B		
Permeability Ratio	Separator Combination	Recovery	Permeability Ratio	Separator Combination	Recovery
1	1	0.0273	1	1	0.0397
1	2	0.0427	1	2	0.0526
1	3	0.0452	1	3	0.0559
1	4	0.0447	1	4	0.0566
2	1	0.0519	2	1	0.0634
2	2	0.0686	2	2	0.0771
2	3	0.0711	2	3	0.0806
2	4	0.0712	2	4	0.0818
3	1	0.0826	3	1	0.0904
3	2	0.1022	3	2	0.1057
3	3	0.1045	3	3	0.1097
3	4	0.1052	3	4	0.1114

TABLE 6--SUMMARY OF SEPARATOR GAS-OIL RATIO PERFORMANCE

Cumulative gas-oil ratios to 750 psia expressed as cu ft per stock-tank barrel

Fluid A			Fluid B		
Permeability Ratio	Separator Combination	Gas-Oil Ratio	Permeability Ratio	Separator Combination	Gas-Oil Ratio
1	1	31,900	1	1	21,700
1	2	20,100	1	2	16,200
1	3	18,900	1	3	15,100
1	4	19,100	1	4	14,900
2	1	16,800	2	1	13,600
2	2	12,400	2	2	11,000
2	3	12,000	2	3	10,500
2	4	12,000	2	4	10,300
3	1	10,500	3	1	9,600
3	2	8,300	3	2	8,000
3	3	8,100	3	3	7,700
3	4	8,100	3	4	7,600

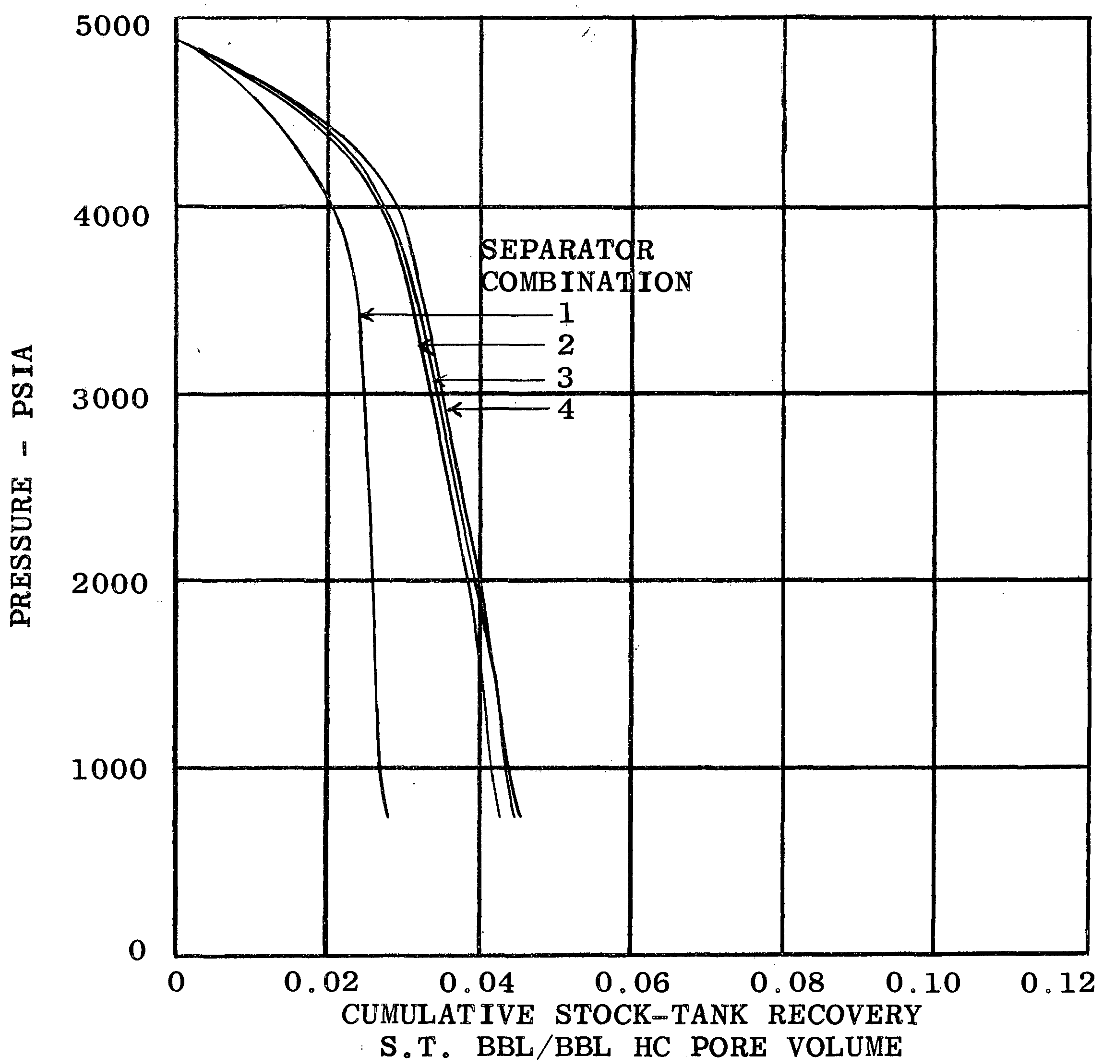

FIGURE 7 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID A, AND RELATIVE-PERMEABILITY RATIO 1

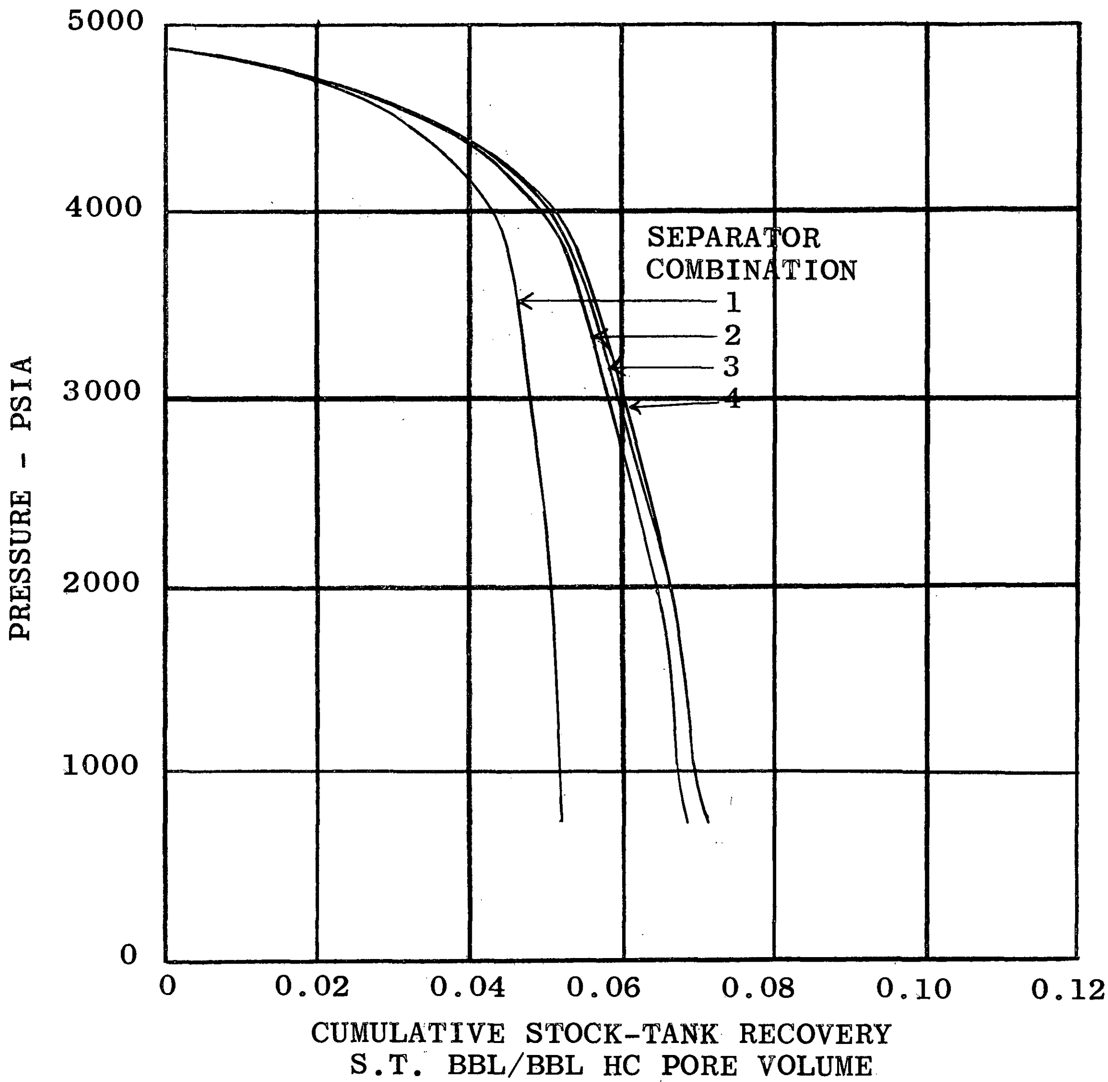

FIGURE 8 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID A, AND RELATIVE-PERMEABILITY RATIO 2

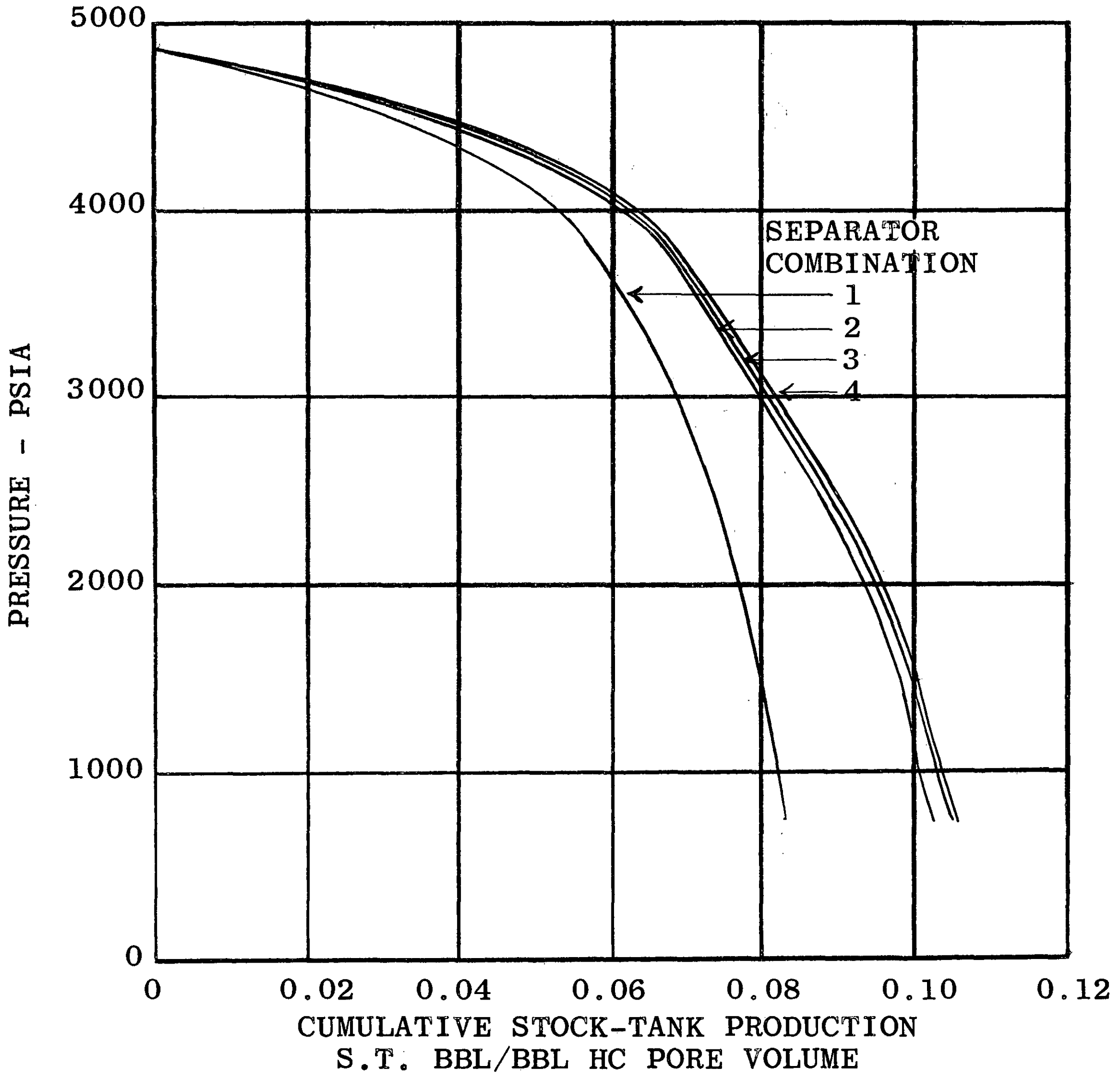

FIGURE 9 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID A, AND RELATIVE-PERMEABILITY RATIO 3

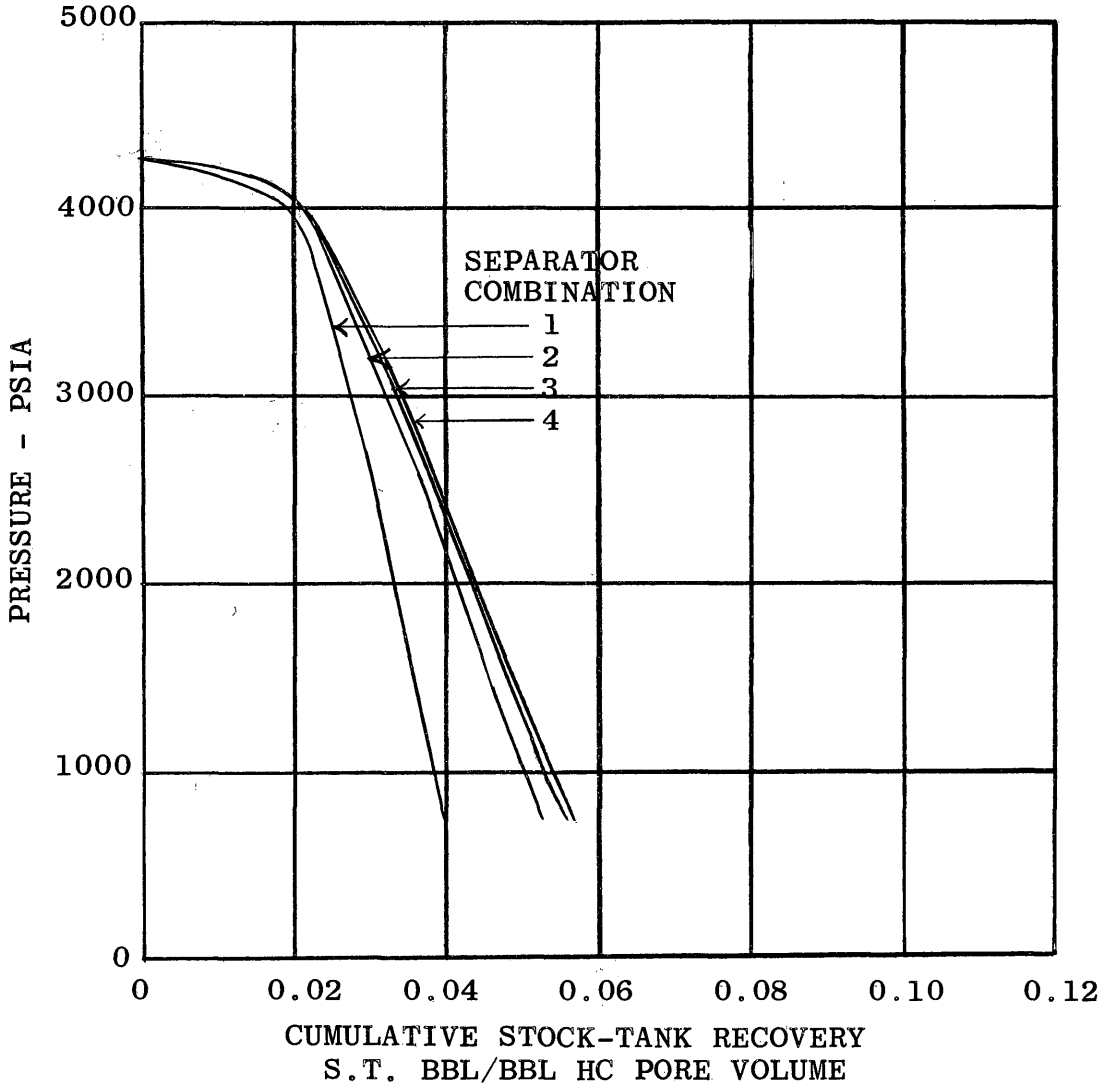

FIGURE 10 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID B, AND RELATIVE-PERMEABILITY RATIO 1

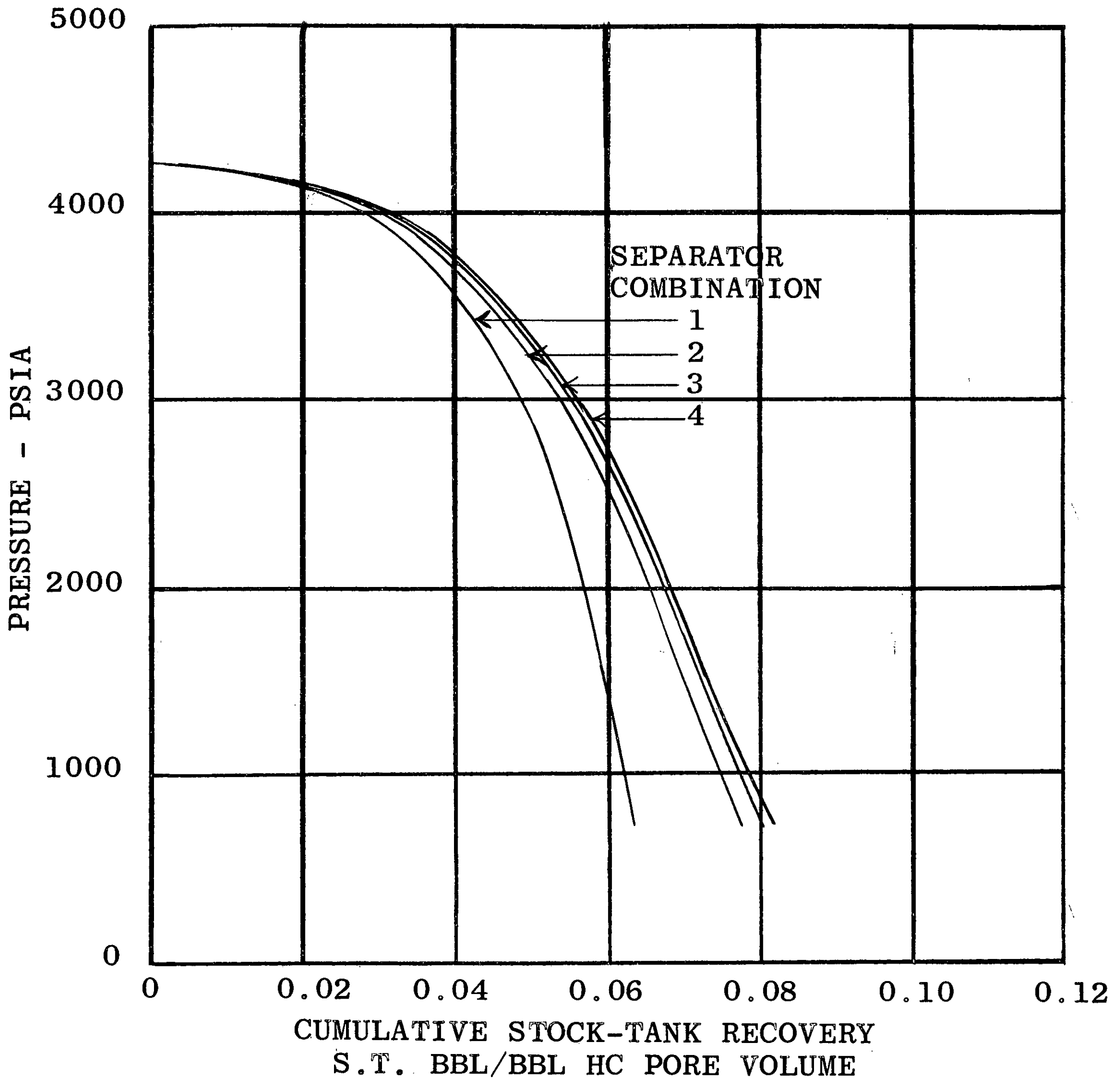

FIGURE 11 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID B, AND RELATIVE-PERMEABILITY RATIO 2

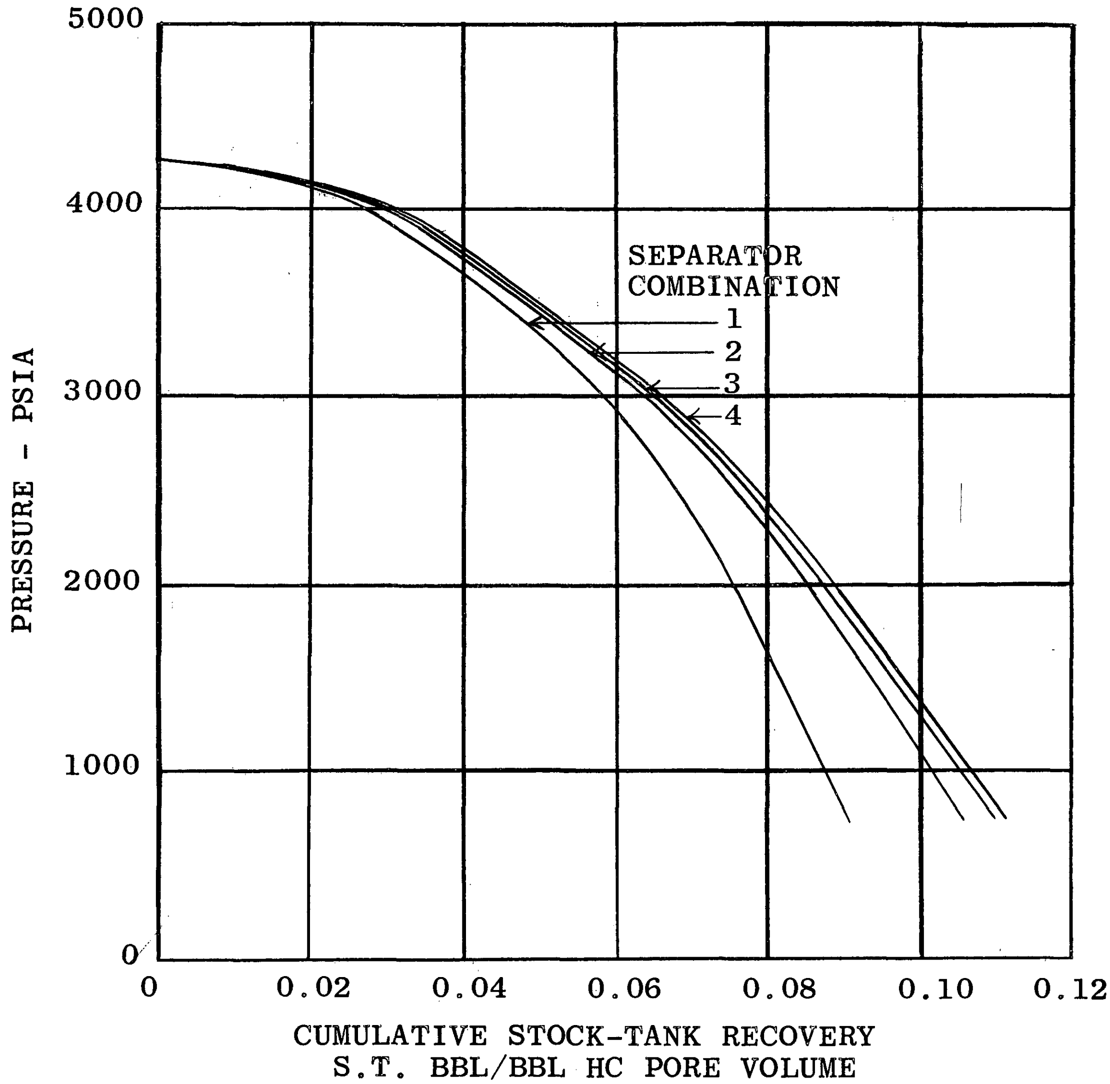

FIGURE 12 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON OIL RECOVERY FOR FLUID B, AND RELATIVE-PERMEABILITY RATIO 3

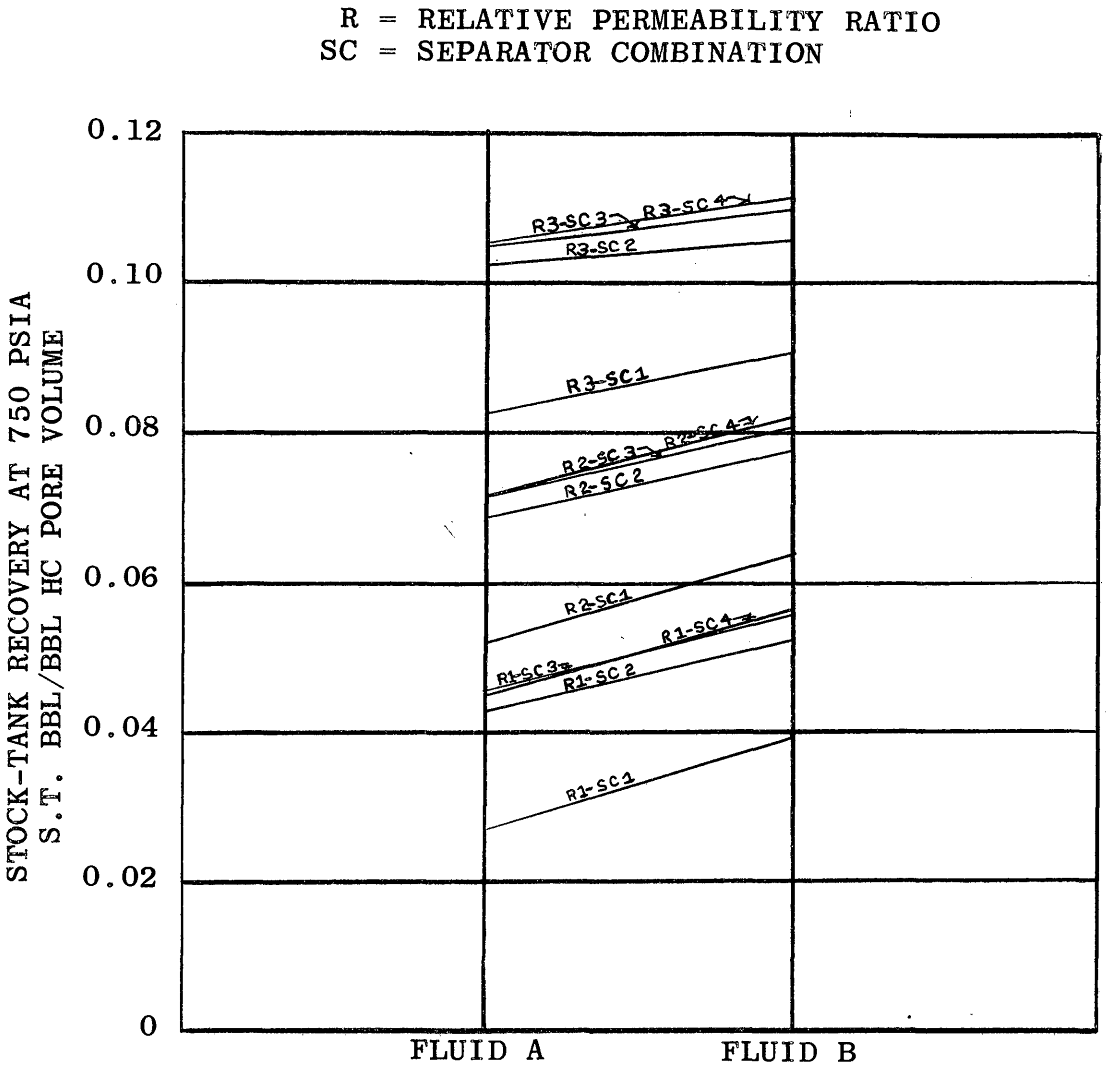

FIGURE 13 - EFFECT OF FLUID COMPOSITION ON RECOVERY AS A FUNCTION OF RELATIVE-PERMEABILITY RATIO AND SURFACE-SEPARATION CONDITIONS

separator combinations. Inspection of the plot shows the following:

1. Recovery increases as the degree of volatility decreases.
2. The differences in recovery between the two fluids decrease as the relative-permeability ratio becomes favorable. This is due mainly to more oil flowing throughout the depletion in favorable permeability reservoirs.

Effect of Relative-Permeability Ratio

Figure 14 shows the variation in recovery as relative-permeability ratios change from unfavorable (ratio 1) to favorable (ratio 3).

The curves show that identical fluids will perform quite differently in reservoirs with different rock characteristics. In fact, the recovery-factor differences may be as high as three to one, as indicated by the lowest curve in figure 14.

Effect of Surface Separation

Figure 15 shows the effect of surface separation on recovery. Recoveries increase as the pressure of the first-stage separator is increased. However, examination of this plot reveals other interesting facts:

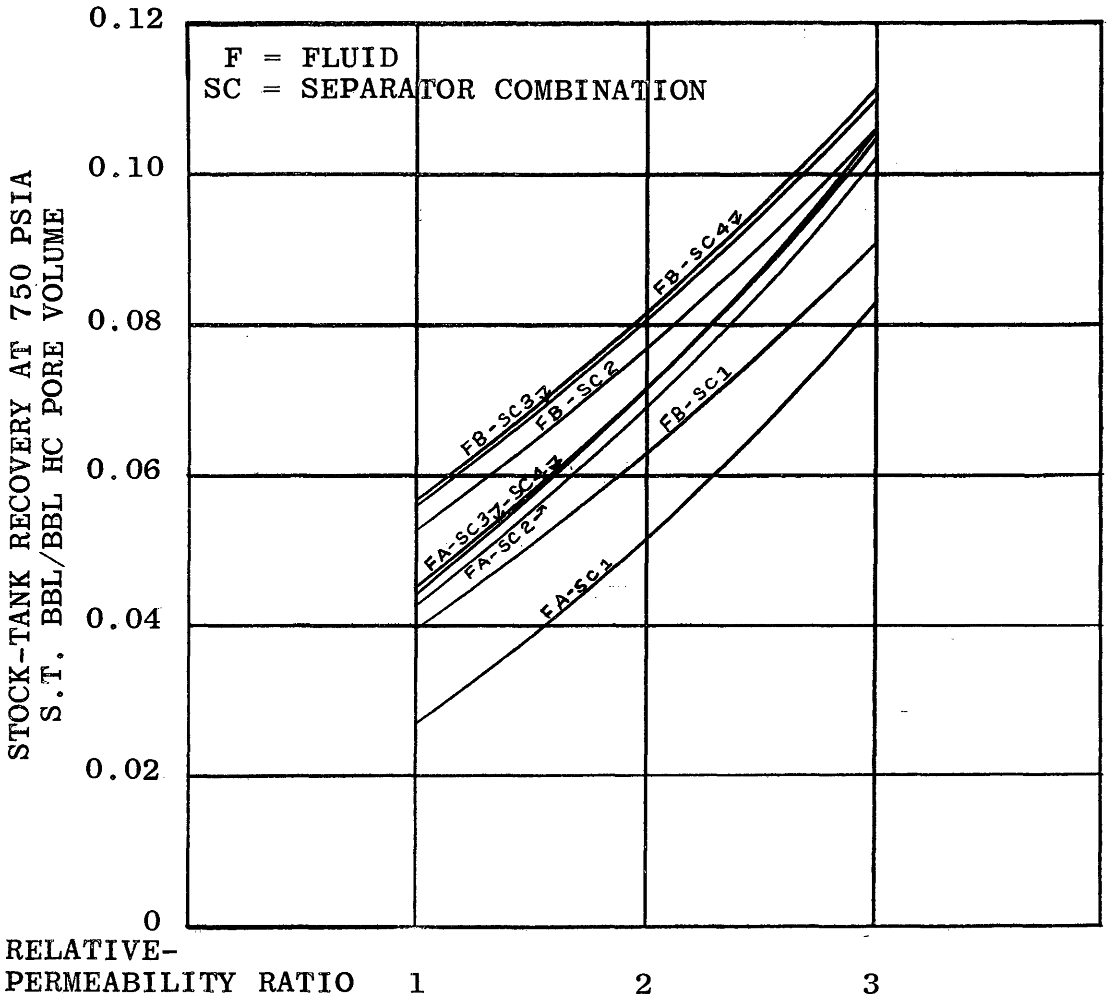

FIGURE 14 - EFFECT OF RELATIVE-PERMEABILITY RATIO ON RECOVERY AS A FUNCTION OF FLUID COMPOSITION AND SURFACE-SEPARATION CONDITIONS

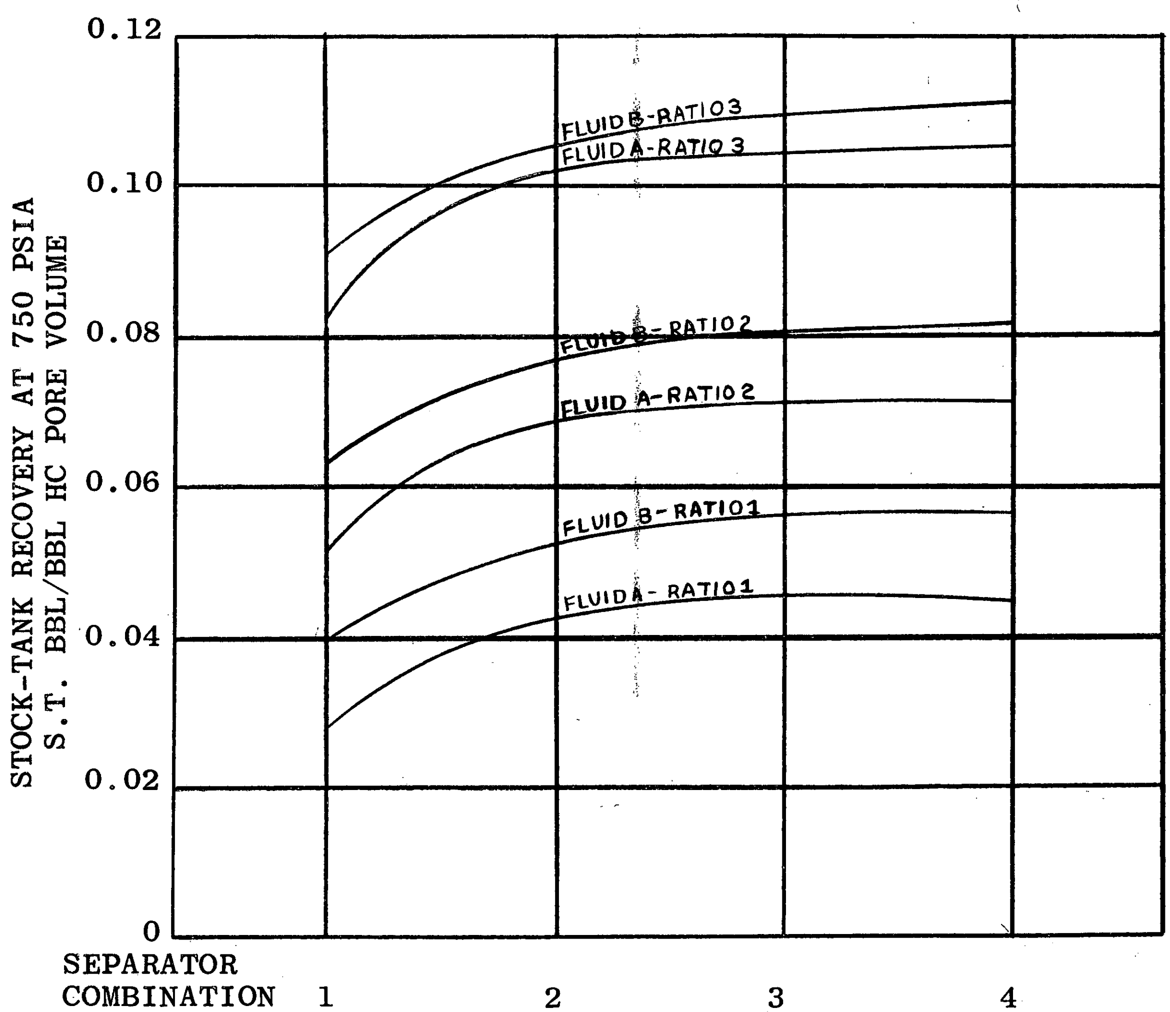

FIGURE 15 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON RECOVERY AS A FUNCTION OF FLUID COMPOSITION AND RELATIVE-PERMEABILITY RATIO

1. Separator pressure settings are most critical for reservoirs with unfavorable permeability characteristics. For the combination of fluid A and relative-permeability ratio 1, recovery is almost doubled when the first-stage separator is increased from 35 to 500 psia (figure 14). For fluid B and ratio 1, recovery also increases, but not as much as for fluid A.
2. As long as the first-stage separator is set at a high pressure (500 psia in this study), the effects of multi-stage separation are not significant in improving stock-tank recovery.
3. The combination of fluid A with ratios 1 and 2 shows a constant or decreasing stock-tank recovery as separator combination 4 is introduced. This points up the necessity, in order to maximize fluid recovery, of optimizing separator pressures and temperatures as the composition of the produced fluid changes during depletion.

Separator combinations had little effect on the gravity of the stock-tank oil in those separator combinations where the first-stage separator pressure was high. However, for separator combination 1, the gravity of the stock-tank oil was 10-15° API lower. The variation in stock-tank oil gravity between the two fluid systems was around 10^{o} API throughout the calculated producing history in all cases. This variation was to be expected, however, because the variation at original conditions was large (50^{o} API for fluid A, 44^{o} API for fluid B).

Separator combinations had a large effect on the separator gas-oil ratio behavior. Figure 16 shows the gas-oil ratio performance for the combination of fluid B and relative-permeability ratio 2. This performance was typical for all combinations of fluids and relative-permeability ratios. The consistently high gas-oil ratio for separator combination 1 indicates that the pressure of the first-stage separator should be set at a relatively high level for best performance.

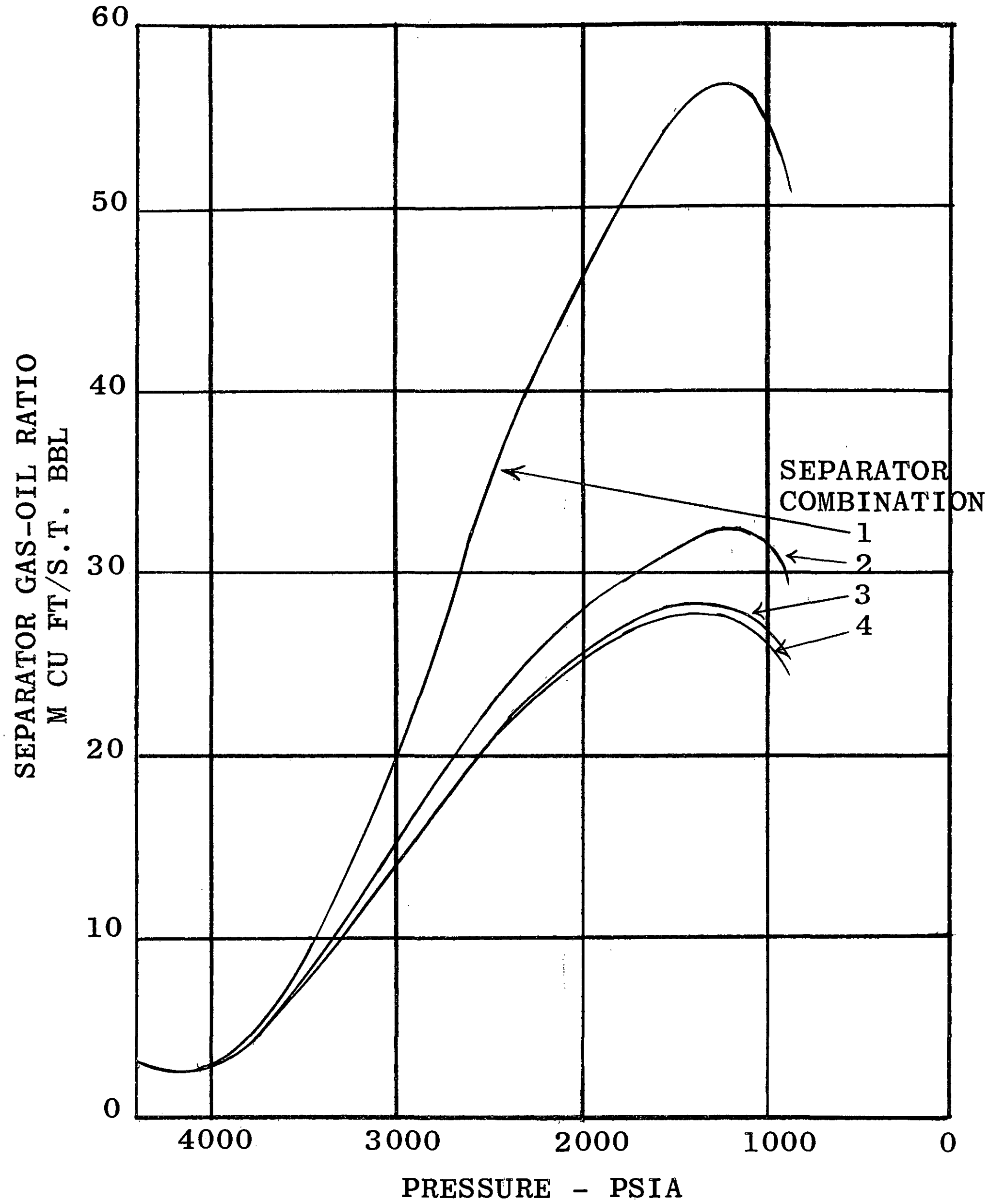

FIGURE 16 - EFFECT OF SURFACE-SEPARATION CONDITIONS ON SEPARATOR GAS-OIL RATIO PERFORMANCE FOR FLUID B, AND RELATIVE-PERMEABILITY RATIO 2

CONCLUSIONS

The purpose of this study was to determine which variable--the reservoir fluids, the relative-permeability ratio, or the separator conditions-- is the most important in the operation of a volatile-oil reservoir. A study of the results of the performance calculations and an inspection of figures 13, 14, and 15 show that the relative-permeability ratio is the variable that has the greatest effect on operation and performance. Its effect is due to the control that the relative-permeability ratio has over the amounts of oil and gas flowing and the composition of the produced fluid.

Next in importance are the surface-separation conditions determined by pressures, temperatures, and the number of stages. The large compositional changes in the produced fluids suggest that it is wise to alter periodically the separator conditions during the life of the reservoir to gain maximum recovery.

The fluids also are important, but did not cause much variation in recovery behavior in this study. Nevertheless, it must be remembered that the fluid behavior and relative-permeability characteristics are interdependent during the reservoir-depletion process.

This study is the first of its kind to be published in the area of volatile-oil reservoirs. Others of the same type will be made in the future, examining these and other variables affecting volatile-oil reservoirs. An extension to this study should be to examine three additional fluids: one more volatile than the two studied, one less volatile, and one containing high percentages of non-hydrocarbon constituents. A wide range of volatile-oil systems would then be covered. The separator part of the study could be extended to finding the optimum separator conditions as a function of the properties of the produced fluid. Then the effects of optimum stage separation for a different number of stages could be determined.

NOMENCLATURE

Symbol	Description	Units
B_g	Gas volume as a function of gas composition	cu ft per mole
B_o	Liquid volume as a function of liquid composition	cu ft per mole
$\triangle G_p$	Gas produced in a pressure increment	moles
k	Relative permeability	
K	Equilibrium vaporization ratio	
L	Moles of liquid	moles
m	Total moles of fluid (gas plus liquid)	moles
$\triangle N_p$	Oil produced in a pressure increment	moles
P	Pressure	psia
S	Oil saturation, per cent hydrocarbon volume	
T	Reservoir temperature	^oR
U	Reservoir volume	cu ft

Symbol	Description	Units
V	Moles of vapor	moles
x	Mole fraction of a component in the liquid phase	
y	Mole fraction of a component in the vapor phase	
z	Mole fraction of a component in the total fluid (oil and gas)	
Z	Gas compressibility factor	
μ	Viscosity	cp

Subscripts

avg	Average pressure in an increment
g	Gas
j	Number of components in the system
n	Component
o	Oil
p	Produced
res	Reservoir
1,2	Pressure levels

Other

I, J, r, s, a_m, b_m, are parameters formed during the liquid-volume-factor calculation

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