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A Study of the Sensitivity of Oil Recovery to Production Rate

By

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ABSTRACT

With the world wide high demand for oil, the rate of oil production from Alberta pools has dramatically increased over the last few years. This investigation was undertaken to determine if reservoirs, typical of the more important Alberta pools, are sensitive to production rate within reasonable economic limits of production. Sensitivity to rate is defined as the ultimate economic recovery being adversely affected by increasing withdrawal rates. Results of the study showed that the reservoirs were not sensitive to production rate insofar as reservoir mechanics were concerned. That is, given reasonable economic parameters and good field operating practice, the ultimate recovery was not adversely affected by increasing production rate. In fact, the studies showed that higher ultimate recovery was obtained at higher producing rates.

INTRODUCTION

As production rates in Alberta have increased to meet high market demand, it has been proposed[1] that in many cases increasing production rate can adversely affect ultimate recovery. This rationale is in turn, partly derived from observations that counter-current imbibition and gravity drainage are time-dependent recovery mechanisms and can more effectively contribute to ultimate recovery at lower reservoir withdrawal rates.

References and illustrations at end of paper.

This paper describes results of a study to determine the effects on oil recovery of production rate. The study was constrained to determination of rate effects solely from the point of view of reservoir fluid mechanics. Besides reservoir flow mechanics considerations, operational strategies and constraints will affect ultimate recovery. For example, the type of water-flood pattern implemented, injectivity and productivity limitations, the allocation of production among wells and complex economic limit considerations at abandonment will affect ultimate recovery. Such operational considerations are outside the scope of this study and do not affect the rate sensitivity conclusions as they relate to reservoir fluid mechanics.

Ultimate oil recovery should be independent of production rate if the reservoir were produced for infinite time with no economic limit imposed. However, the question that must be answered is whether oil recovery is rate sensitive with the reservoir operated at reasonable economic field rates over a reasonable period of time.

The number of reservoir-fluid variables and the complexities of interacting recovery mechanisms prevented an exhaustive or statistical investigation. Accordingly a number of subject reservoirs typical of Alberta's fields were selected. The reservoirs or cases studied include:

1. Swan Hills Beaverhill Lake A Pool - This pool is a fairly thick and homogeneous reservoir under a pattern waterflood.

2. Rainbow Reef - This pool is a thick carbonate low quality reef with a bottom water drive.

3. Countess Upper Mannville B Pool - This reservoir is a high quality sand containing medium-heavy oil underlain by water.

4. Simonette D-3 Pool - This pool is a thick carbonate high quality reef with a bottom water drive.

5. Pembina Keystone Belly River B Pool - This pool is typical of a pattern flood of a thin heterogeneous sand.

Actual reservoir-fluid data from these pools were used in the simulation studies. Since the recovery process is dependent on permeability, heterogeneity, fluid properties, relative permeability and capillary pressure, runs were done changing the basic reservoir-fluid properties to determine any sensitivity to these properties. Reservoir simulation studies were performed for some reservoirs using considerably greater definition (e.g. grid blocks only one foot thick) than commonly used in reservoir studies, in order to define a high degree of heterogeneity. All the cases treated involve pressure maintenance by waterflooding.

PREVIOUS WORK ON RATE SENSITIVITY

Studies to determine the relationship between rate and ultimate oil recovery have been published by numerous authors[2-15]. From field studies Culter[2] and Permyakov et al[3] concluded that higher oil production rates resulted in increased recovery. Other studies[4-6] reached no conclusion on the effect of rate on recovery. They concluded from their field studies that so many parameters affected recovery that the variations in recovery could not be attributed to any one factor such as rate.

The effects of rate on recovery for solution gas drive reservoirs have been studied numerically and experimentally. Levine et al[7] and Heuer et al[8] concluded from numerical studies which ignored gravity forces that ultimate oil recovery was rate independent. The experimental results of Ridings et al[9] confirmed these results and showed the applicability of numerical simulation to study the problem. The numerical study by Morse et al[10] which included gravity concluded, "In general, higher production rates result in higher oil recoveries".

The effect of rate on recovery for water pressure maintenance cases has been investigated experimentally[11-13] and with simulation models[14-15]. All these investigations have shown a higher oil recovery at any point in time with higher producing rates. Miller et al[14] found, "that for the conditions investigated, higher production rates, even with the attendant water production, gave increased ultimate recovery as well as profit".

In summary, the published work on rate sensitivity generally concludes either that recovery is independent of rate or that recovery increases as rate increases.

DISCUSSION OF RECOVERY MECHANISMS AND THEIR DEPENDENCE UPON RESERVOIR PRODUCTION RATES

Four basic recovery mechanisms are active in recovering oil from reservoirs. First, simple fluid expansion accompanying pressure decline results in oil expulsion from and subsequent flow through the porous matrix. Primary depletion of an under-saturated volumetric oil reservoir is the simplest example of this mechanism. A second mechanism is flooding or displacement of oil by injected or naturally encroaching water or gas. A Buckley-Leverett, one dimensional horizontal displacement of oil by water is a simple example of this mechanism.

Third, gravity drainage tends to aid oil recovery. Fluid density differences tend to cause upward drainage of oil from below an advancing bottom water drive and downward oil drainage from above a declining gas-oil contact. Finally, imbibition generally normal to the primary flow direction may be an important mechanism in lateral water floods of heterogeneous sands where vertical permeability variation is pronounced.

In any actual reservoir, generally two or more of these mechanisms are active at significant levels. For example, in a saturated reef reservoir under primary depletion with partial bottom water drive, the flooding or displacement of oil will occur upward at the rising water-oil contact and downward from the expanding gas cap. Gravity drainage will aid oil recovery from behind both of these fronts.

Of these four mechanisms, the first two are, in themselves, not rate-dependent i.e. longer producing life (lower producing rate) in itself would not render them more effective in recovering oil. A horizontal, very thin sand, pattern waterflood involves only the second mechanism, and will yield a unique curve of pore volumes (PV) oil produced vs PV water injected, completely independent of the flooding rate used.

However, the latter two mechanisms of gravity drainage and cross-current imbibition are transient or time-dependent mechanisms, in that they will be more effective in recovering oil if given longer time periods over which to act. Recognition of this time-dependence then leads to the question of whether, or to what extent, oil recovery from reservoirs is dependent upon production rate.

CASE 1 - SWAN HILLS A POOL

This case was a series of runs simulating the performance of a single well in a 160 acre section of the reservoir. The model was assumed to be representative of the outer edges of the Swan Hills A Pool, where the permeability and porosity are of better quality than in the center of the field. The well is assumed to be part of a pattern waterflood project and pressure was maintained by injecting water along the outer full face of the model.

A. MODEL DATA

The model was chosen to represent 160 acres which corresponds to a radius of drainage of 1490 feet. The thickness was 120 feet. The well was perforated full face and water was injected along the outer boundary full face to maintain a constant average reservoir pressure. Rock properties were obtained from a core analysis report on well 4-26-67-10 W5 and are shown in Table I. The horizontal permeability varied from 3.4 to 369 md with an average of 63.6 md and the average vertical to horizontal permeability ratio was 0.42. The porosities varied from 0.035 to 0.172 with the average being 0.116.

PVT properties were obtained from a Shell Canada report on the Swan Hills Beaverhill Lake C Pool, dated October 1973 and are shown in Figure 1. The bubble point of the oil was 1370 psig. However since a pressure maintenance waterflood was studied, the initial pressure is unimportant, and an initial pressure of 3305 psia was used which corresponded to the initial Swan Hills pressure.

Saturation data were obtained from the same Shell report and are shown in Figure 2. No capillary pressure data were reported and zero Pc was assumed in this case. Additional rock and fluid data are:

$c_r = 4 \times 10^{-6}$ psi^{-1}

$c_w = 3.5 \times 10^{-6}$ psi^{-1}

$B_w = 1.02$ RB/STB at 3305 psi

$\rho_w = 65$ lb/ft^3 at stock tank conditions

$\rho_o = 50.85$ lb/ft^3 at stock tank conditions (42^o API)

$\rho_g = 50.0$ lb/MCF (assumed)

The initial fluid distribution was assumed to be oil filled, i.e. there was no underlying water leg. Therefore the well would produce dry oil until breakthrough occurred due to channeling down a permeable streak or due to slumping and underrunning of the water front.

All runs were made with a constant RB/DAY rate of production and injection so that the total fluid volumes handled were constant with time. The effect of fixing the total fluid rate is to reduce the oil production rate as the water cut increases. All the runs were continued until a cut-off oil production rate of 5 STB/D or until 80,000 days were reached.

B. RUN DESCRIPTIONS

Run 1 - This run used the reservoir and fluid properties described above. Three rates of 392, 1570 and 3920 STB/D were used.

Run 2 - Run 2 was made with everything the same as in the first three runs with the exception of the initial pressure. These two additional runs were made starting with an initial pressure of 1600 psi, or 230 psi above the bubble point. Two rates were used, 392 and 1960 STB/D of oil. The low rate was chosen so that the reservoir would not draw down below bubble point and the high rate was chosen so that the pressure would drop below bubble point around the well and release solution gas. The reason these two runs were made was to determine if a gas saturation could adversely affect the oil relative permeability enough to cause a detrimental effect of rate on recovery. The 1960 STB/D rate caused the reservoir pressure to fall below bubble point out to a radius of approximately 75 feet around the well bore. This resulted in gas being evolved and a free gas saturation being formed. After approximately 400 days equilibrium was reached and all the free gas was produced, leaving a critical gas saturation of 3% in the region that fell below bubble point.

C. DISCUSSION OF RESULTS

The results of the two runs are shown in Table II. Figure 3 which is a plot of oil rate and WOR versus percent recovery (based on original oil in place) details the results of run 1. Run 2 generally shows the same behavior as run 1.

For all the runs of this case, the higher rates not only recover oil faster but actually result in slightly higher ultimate recoveries assuming that the higher WOR is economic. The effect of increasing rate is not detrimental to reservoir performance. Run 2 showed that drawing a well down bubble point near the well did not reduce ultimate recovery. This was true because during a pressure maintenance operation, eventually a stabilized condition will occur where the only free gas left around the well will be critical gas. Normally critical gas is a value around 3-5 per cent which is not enough to seriously impair oil mobility.

CASE 2 - RAINBOW REEF

This case was a series of runs simulating the performance of a single well in a 160 acre section of a reservoir. The model was representative of the inner core of a Rainbow reef type pool, where the permeability and porosity are of poorer quality than the edge of the reef. Bottom water drive pressure maintenance conditions were assumed. This case investigated the effect of capillary pressure and relative permeability.

A. MODEL DATA

The model was chosen to represent 160 acres which corresponds to a radius of drainage of 1490 feet. The thickness of the oil column was 350 feet. The well was perforated in the top 100 feet of structure. Water influx occurred along the bottom of the pool, sufficient to maintain average reservoir pressure. This influx was either natural or augmented but of sufficient strength to balance withdrawals. Figure 4 shows a cross-sectional view of the model, which was simulated using a two-dimensional r-z coning model. Rock properties were selected to be typical of the lagoonal part of a Rainbow reef. The pool was assumed to be homogeneous with 12 md permeability and .08 porosity. The vertical to horizontal permeability ratio was assumed as unity.

PVT properties were the same as Case 1, (see Figure 1, Case 1). The bubble point was 1370 psig, and the initial reservoir pressure was 4800 psia at the top of structure. The sets of saturation data which were used are shown in Figures 5 and 6. Additional rock and fluid data are:

$c_r = 4.0 \times 10^{-6}\ psi^{-1}$

$c_w = 3.5 \times 10^{-6}\ psi^{-1}$

$B_w = 1.02$ RB/STB at 4800 psia

$\rho_w = 65.00\ lb/ft^3$ at 4800 psia

$\rho_o = 48.63\ lb/ft^3$ at 4800 psia

The reservoir was oil filled initially. Water influx was assigned along the bottom to simulate a natural or augmented underlying aquifer. The rates for all runs of Case 2 were 80 and 800 STB/D. All runs were continued until 60,000 days.

B. RUN DESCRIPTIONS

Run 1 - Run 1 used the water-wet capillary pressure curves shown in Figure 5 with the "normal" relative permeability curves shown in Figure 6.

Run 2 - Run 2 was identical to run 1 except the oil-wet capillary pressure curve, Figure 5, was used.

Run 3 - Run 3 was identical to run 1 except that capillary pressure was zero.

Run 4 - Run 4 was identical to run 1 except that the "adverse" relative permeability curves as shown in Figure 6 were used.

C. DISCUSSION OF RESULTS

Table III summarizes the results of this case. Figure 7, which is a plot of oil rate and WOR versus percent recovery for run 1 and run 2, typifies the results for all the runs of this case. The results of these runs show that higher production rate does not impair ultimate recovery but in fact will recover more oil if higher WOR's are handled.

The only difference between the two capillary pressure curves shown in Figure 6 is that the oil-wet curve is shifted downward by a constant everywhere, i.e.

$$P_c \text{ oil-wet} = P_c \text{ water-wet} - 35.5$$

$$\text{so } \frac{dP_c}{dS_w} \text{ oil-wet} = \frac{dP_c}{dS_w} \text{ water-wet}$$

Run 2 was made to show that as long as a single rock type is present, the only important feature of a P_c curve is the slope, dP_c/dS_w; the magnitude cancels out. If this is true, then at any rate, the results using either P_c curve would be identical, which was found to be the case as shown in Table III.

Capillary pressure is important even in a homogeneous system in that the slope dP_c/dS_w is important. The effect of this was shown in run 3 by setting the capillary pressure to zero. Although the recoveries are improved by having no capillarity the conclusion concerning rate sensitivity remains the same.

Run 4 was made using the "adverse" relative permeability curves shown in Figure 7 to see if a poorer relative permeability relation could cause rate sensitivity. The adverse curves result in approximately 4 times the water to oil mobility at any saturation than the normal curves. Again, although recovery was affected, higher oil rate resulted in more oil recovery.

CASE 3 - COUNTESS B SINGLE WELL STUDY

This case was a series of runs simulating the performance of a single well in an 80 acre section of the Countess B Pool. The oil is a heavy gravity crude and as such is sensitive to water coning. The pool produces from the Glauconitic sand at a depth of 3575 feet. The total net thickness is 29 feet, of which the bottom four feet are water saturated. The maximum and minimum horizontal permeabilities of the well are 3060 and 35 md, whereas the maximum and minimum vertical permeabilities are 1500 and 8 md. The pool is drilled on an 80 acre well spacing and is presently being water flooded.

A. MODEL DATA

An r-z coning model was used to simulate the performance of the Countess B Pool well. The model consisted of seven radial increments and 10 vertical layers. The rock properties, which are the properties of well 8-17-19-16 W4M are shown in Table IV. No variation in rock properties in the areal direction was introduced. The crude has a formation volume factor of 1.122 RB/STB and a viscosity of 5.58 cp at the bubble point of 1550 psia. Figure 8 shows the relative permeability characteristics. Capillary forces were assumed to be zero.

The simulations were run under pressure maintenance conditions so sufficient water was injected full face along the outer boundary to maintain a constant reservoir pressure of 1550 psia. Only the top two layers which represent 6 feet of the structure were open to production. Four rates of constant fluid withdrawal rates of 50, 200, 500 and 1000 RB/D were used for each run except run 4. The runs were terminated either at 30,000 days or at a water-oil ratio of 100, whichever occurred first.

B. RUN DESCRIPTIONS

Run 1 - Run 1 is the base case using the data described above.

Run 2 - Run 2 investigated the effect of drainage radius. In this run the drainage radius was reduced to 40 acres.

Run 3 - Run 3 was identical to run 1 except for a ten fold decrease in permeability.

Run 4 - Since this case involved the study of a heavy crude, run 4 was made to investigate the effect of oil viscosity. In run 4, the oil viscosity was increased from 5.58 to 75 cp at 1550 psia. The withdrawal rates for this run, were 100, 200 and 300 RB/D.

C. DISCUSSION OF RESULTS

The results of these runs are summarized in Table V. The detailed results of run 1 are shown in Figure 9. All the runs show the same general behavior as run 1.

In all runs the WOR as a function of oil recovered was essentially independent of production rate. The oil production rate at any given recovery was higher at higher fluid withdrawal rates. Therefore, the effect of increased rate was to increase ultimate recovery. This result did not change over the range of drainage radii, permeability level and fluid viscosity investigated.

CASE 4 - SIMONETTE D-3 POOL

A significant part of Alberta reserves is contained in D-3 reef reservoirs. In general, these reservoirs are characterized by high relief, high permeabilities and low viscosity crudes. The recovery mechanism is primarily one of gravity drainage. Natural bottom water influx sometimes supplemented by water injection into the aquifer results in many of the pools experiencing little or no pressure decline during their lives.

With the domination of gravity in these reservoirs, oil tends to be displaced vertically upwards at reasonably slow rates ahead of the displacing water. This displacement process in these reservoirs is highly efficient, achieving over 70% recovery in some cases.

The primary concern of producing these pools at higher rate is the effect of coning on their oil recovery. At higher rates, the gravity forces around wells are overcome by the higher drawdowns associated with the higher rates. As a result, coning takes place and the wells begin to produce water and/or excess gas. For any practical depletion scheme, the wells within these reservoirs will eventually cone water. Therefore, the question for adverse rate sensitivity consideration in this type of pool is whether the early coning of water is detrimental to ultimate recovery. This problem was studied using a two dimensional, three phase radial coning model. The pool chosen to study the effect of rate on recovery of bottom water drive pools under pressure maintenance is the Simonette D-3 Pool.

A. MODEL DATA

The porosities and horizontal and vertical permeabilities were obtained from the core analysis of the well 12-16-63-25 W5. The 12-16 well initially had 116 feet of pay. The rock properties for each of the grid layers in the model are shown in Table VI. Fluid properties, relative permeability and capillary pressure relationship were obtained from a recent study[16] of the pool. The 12-16 well was drilled into the reef facies area of the pool. Accordingly, the relative permeability and capillary pressure data for the reef facies were used. The model was produced from the top twenty-four feet of pay with the drainage area being 160 acres. Except for run 4 the well in the simulation runs was produced at a constant total reservoir barrel rate of 3000 and 15000 RB/D. Pressure was maintained by injection along the bottom face of the model. All runs were terminated at an oil rate of 25 STB/D.

B. RUN DESCRIPTIONS

Run 1 - This run used the basic rock and fluid properties described above.

Run 2 - Run 2 is identical to Run 1 except capillary forces were assumed to be negligible. Therefore, initially the pool had no transition zone. This compares to a transition zone of about 100 feet in Run 1.

Run 3 - This run is identical to Run 2 except that two flow barriers were added. The vertical flow for some 30 feet around the wellbore at 40 feet and 76 feet below the top of porosity was assumed to be zero.

Run 4 - Run 4 is identical to Run 2 except that the vertical and horizontal permeabilities were reduced by a factor of five. Production rates were reduced by a factor of three.

Run 5 - D-3 reef pools are highly heterogeneous in terms of permeability. For example, the 12-16 well's core analysis showed horizontal permeabilities ranging from 1 md to 2000 md. These permeabilities are so randomly distributed throughout a vertical section of the reservoir that averaging the permeabilities on the basis of any reasonable grid size results in little variation of permeability from block to block. If rate effects depend on heterogeneity, such effects could be masked by the averaging technique. Accordingly, run 5 was done to determine if introducing more heterogeneity in this case would tend to promote an adverse effect of higher rate on oil recovery.

A heterogeneous model was constructed by randomly distributing the permeabilities to each layer in the coning model. The frequency distribution of these permeabilities was the same as that of the core analysis from the 12-16 well. The permeabilities of each layer are shown in Table VII.

Run 6 - In Run 5 each layer in the model was homogeneous in the radial direction but had vertical heterogeneities. Run 6 randomly distributed the permeabilities both vertically and radially to represent a generally heterogeneous system. Run 6 used the same description in each layer of the first radial block as Run 5.

C. DISCUSSION OF RESULTS

The results of these seven runs are summarized in Table VIII. The detailed results of run 1 are shown in Figure 10. The behavior shown in Figure 10 is typical of all the runs. All runs exhibit the same characteristic--higher producing rates result in higher oil rates and higher water-oil ratios at any point of depletion. If we assume that ultimate oil recovery is directly related to breakthrough time we could conclude that indeed recovery is rate sensitive. For this to be true, we would have to make the assumption that no produced water could be handled. In practice large amounts of water can be handled in the field. The ultimate recovery will be dictated by economics which are functions of both WOR and a minimum oil rate. Since at abandonment conditions the fixed costs are generally higher than the injection and lift costs, abandonment conditions in general tend to be more a function of oil rate than WOR. However, upon examining the results and applying reasonable abandonment conditions, one reaches the conclusion that oil recovery is not rate sensitive in such a pool under the conditions studied.

Runs 3, 5 and 6 introduced heterogeneities into the simulation runs. The results of these runs show no greater tendency to be rate sensitive than runs without such a high degree of heterogeneity. Consequently, the presupposition that heterogeneities result in greater rate sensitivity is ill founded in this case.

Run 4 examined the effect of reducing permeability. This again shows the tendency of reservoirs to achieve higher recovery with higher rates. The effect of capillary pressure is shown by comparing runs 1 and 2. Although capillary pressure tends to decrease oil recovery by smearing out the flood front, no increased rate sensitivity is observed.

CASE 5 - BELLY RIVER B POOL

This case typifies a thin heterogeneous sand under pattern water flood. In this type of reservoir, imbibition is an important recovery mechanism, therefore, study of this case allows detailed investigation of this recovery mechanism.

A. MODEL DATA - CROSS SECTIONAL RUNS

Table IX lists horizontal permeability for each of 30 1-foot layers as obtained from a core analysis on well 16-16-48-3 W5M in the Belly River B Pool. These permeabilities, the listed layer porosities, PVT data, relative permeability and capillary pressure data were all obtained from a reserve submission report[17] on the Belly River B Pool. Figure 11 shows four sets of relative permeability curves and Figure 12 shows four sets of capillary pressure curves. The oil relative permeability curve for the 0.1 - 1.0 md permeability range is essentially coincident with curve #3 from a connate water saturation of 0.58. Each grid block in the reservoir was assigned one of these sets of curves based on rock permeability as follows:

Rock Horizontal Permeability, md	P_c - k_r Curve Set No.
0.1 - 1	4
1 - 10	3
10 - 100	2
> 100	1

A ratio of vertical to horizontal permeability, k_v/k_h, of 0.1 was used in all simulation runs unless otherwise noted.

Other pertinent data used in the simulation runs are:

Flood pressure level = 1200 psia

B_w = 1.02 RB/STB

B_o = 1.12 RB/STB

μ_w = .7 cp

μ_o = 2.5 cp

ρ_w = 65 lbs/cu.ft. at reservoir temperature and pressure

ρ_o = 48.63 lbs/cu.ft.

$c_w = 3 \times 10^{-6}$ vol/vol-psi

$c_o = 7.4 \times 10^{-6}$ vol/vol-psi

$c_r = 4 \times 10^{-6}$ vol/vol-psi

The initial fluid distribution consisted of connate (immobile) water throughout with oil in hydrostatic equilibrium. Injection and production wells were completed throughout the entire 30 feet of thickness and injection/production rates were allocated among the layers on the basis of layer kh, fluid mobility (relative permeability/viscosity) and pressure difference between wellbore and reservoir. Zero vertical permeability (shale streaks) was assigned throughout the reservoir between layers 18 and 19 and between layers 23 and 24.

Computer runs were made for the three flood rates of 100, 200 and 400 RB/D water injection. The runs were terminated at an oil rate of 5 STB/D or at 164 years, whichever occurred first.

B. RUN DESCRIPTIONS - CROSS SECTION RUNS

Run 1 - Run 1 was the base case using the properties described above.

Run 2 - The dominant mechanisms in the cross-sectional calculation are viscous displacement laterally (at highly variable rates in the different permeability layers) and counter-current imbibition normal to the main, horizontal direction of flow. The second mechanism was eliminated in run 2 in which zero capillary pressure curves were used.

Run 3 - Run 3 reduced but did not eliminate the imbibition mechanism. This run was the same as run 1 except the capillary pressure was halved.

Run 4 - Run 4 is further pertinent to the question of the time-dependence of additional oil recovery by cross-current imbibition. This run differs from run 1 only in that all layer thicknesses were increased from 1 foot to 5 feet. Thus total sand thickness is 150 feet rather than 30 feet and the "transient" imbibition process must be effective over a 5 times greater distance. This run used withdrawal rates of 200, 400 and 800 RB/D.

Run 5 - Run 5 was made to determine the adequacy of lesser vertical definition for use in 3D calculation of a nine-spot pattern. Adjacent 1-foot layers of similar permeability range were combined to result in 16 layers varying from 1 to 4 feet in thickness. Specifically, the consolidations, relative to original layer numbers, were (2-3, 5-7, 8-10, 11-14, 15-17, 22-23, 24-25, 26-27, 29-30). Layer numbers not listed remained as 1-foot layers.

Run 6 - Run 6 was identical to run 1 except that the vertical permeability was reduced by a factor of 5. This reduction in vertical permeability retards the rate of counter current imbibition.

Run 7 - Run 7 was made to determine the effect of well completion in only the three most permeable layers, 15, 16 and 17. Only 18 1-foot layers were used in these runs due to the shale streak between layers 18 and 19. Original oil in place for this case was 2.277×10^6 STB compared to 3.725×10^6 STB in the original total 30 feet. A k_v/k_h ratio of 1.0 was used for layers 15, 16 and 17. This 3-foot completion interval tends to place more importance on the imbibition mechanism since wells do not contribute to direct flooding of all layers. Furthermore, the imbibition process now has to act over the better part of the upper 14 feet compared to lesser distances in the total interval injection case.

C. DISCUSSION OF RESULTS - CROSS-SECTIONAL RUNS

Table X summarizes the results of the runs for this case. Figure 13 details the results from the base run. The results from all the runs show that oil recovery at any oil production rate increases with increasing flooding rate. Table X shows that for the zero capillary pressure run, Run 2, oil recovery, at any time, again increases with increasing flow rate. However the oil recovery at any rate is considerably less than that calculated in the base run where oil was recovered by imbibition as well as lateral displacement. For example, calculated oil recovery at the 400 RB/D rate at 22 years was 35.8% of OOIP with capillary pressure included as opposed to only 27.57% with zero capillary pressure.

This recovery by cross-current water imbibition into tight layers is a time-dependent process, but this time dependent imbibition recovery generally does not lead to an adverse effect of higher producing rate on ultimate oil recovery. The reason for this is that capillary forces are high in tight rocks and they only have to be effective over short distances (fractions of sand thickness). Thus, this cross-current imbibition process is in many cases nearly "instantaneous" relative to the time scale of the flood. Run 3 illustrates this point in that reducing the capillary pressure forces by a factor of two only marginally reduced oil recovery relative to the base run. For example, at 22 years and at the 400 RB/D rate, oil recoveries calculated using full, 1/2 and zero capillary pressure forces were 35.80, 34.76 and 27.57% of OOIP, respectively. Run 6 further illustrates this point in that cutting the K_v/k_h ratio by an additional factor of 5 (to .02 rather than .1) decreased recovery at 22 years and 200 STB/D rate from 29.43% (Base Run 1b) to only 28.27%.

Runs 4 and 7 which were designed to retard the imbibition mechanism again showed higher oil recovery with higher rates.

Run 5 shows that use of a 16-layer vertical description resulted in calculated recoveries virtually identical to those calculated in the corresponding 400 rate run 1 which used 30 layers.

D. NINE SPOT RUNS

Figure 14 shows an inverted nine-spot pattern with a 6 x 6 areal grid laid over an octant. Three-dimensional runs were made for this 1/8 nine-spot using a 6 x 6 x 16 grid; the 16 layers ranging from 1 to 4 feet in thickness were discussed above. The wells were completed in all 16 layers. Impervious shale streaks occurred between layers 8 and 9 and between layers 12 and 13. Original oil in place was 1.606×10^6 STB.

Since the octant has 3/8 of a producing

well we made simulation runs for water injection rates of 37.5, 75 and 150 RB/D. The injection rate in each run was split equally between the 2 (partial) producing wells in the octant.

As before, the simulations were carried to an economic limit defined as the earlier of 164 years or 5 STB/D (full) well rate. At all rates the well north of the injector reached its production rate limit before 164 years while the other well continued on stream to 164 years. Injection rate was halved at the time of the north well shut-in.

Figure 15 shows oil recovery and WOR versus time for the low and high flood rates of 37.5 and 150 RB/D. Both ultimate recovery and recovery at any time are shown to increase significantly with increasing flood rate. At the low and high rates, respectively, oil recoveries are 14.5 and 32% at 20 years, and ultimate recoveries are 41 and 52% of OOIP.

These nine-spot computer runs were repeated with the introduction of areal heterogeneity. Since layers 6, 7 and 8 of the 16 layers represent 85.6% of the total kh (md-ft), most of the injection, production and lateral flooding occur in these layers. These three layers were blocked by cutting their horizontal and vertical permeabilities by 100 at the areal positions noted by the cross-hatching on Figure 14. Original and altered data for these three layers are as follows:

Layer No.	Horizontal Permeability Original	Horizontal Permeability Altered	Saturation Table Original	Saturation Table Altered
6	56.8	.568	2	4
7	218.7	2.187	1	3
8	79.5	.795	2	4

This areal heterogeneity tends to divert the displacement around the altered blocks and thus considerably reduce recovery from them by the flooding or displacement mechanism. However, the increased capillary pressure levels will lead to some oil recovery by lateral counter-current imbibition. This effect should be small in that the 440 feet square grid blocks result in appreciable distance over which imbibition forces must act.

The x's of Figure 15 show calculated WOR and oil recovery versus time for this areally heterogeneous nine-spot. The calculated oil recovery is only marginally lower than for the areally homogeneous case. Examination of the printed saturation distributions shows why the effect of heterogeneity on recovery was negligible. Oil recoveries from the tightened blocks in layers 6 - 8 were indeed appreciably reduced relative to the areally homogeneous case. However, recoveries from the adjacent blocks having full original permeability were appreciably higher than in the homogeneous case. The tightened blocks diverted the flow in layers 6 - 8 through the permeable paths remaining resulting in greater flushing (more PV throughput) of the remaining permeable channels.

No generalization is made from these results, but in this case, at least, the introduction of significant heterogeneity had a negligible effect on calculated oil recovery.

Also, the areally heterogeneous case again showed a pronounced increase in oil recovery at higher flooding rate.

CASE 6 - IMBIBITION TEST RUNS

Although counter-current imbibition is time dependent, the degree of time dependence of the imbibition mechanism is a very important factor. That is, if time periods of only days, weeks, or possibly even months, are necessary to achieve equilibrium states of these rate processes, then relative to field depletion times, these processes can in effect be considered instantaneous; thus longer life due to lower producing rate will not achieve any significantly greater oil recovery.

This case was a series of studies of imbibition tests into a ten foot cylinder of rock from a free water surface. These runs were made by contacting the bottom of a ten foot rock cylinder with a free water surface and then calculating the rate of water imbibition. This simulation is exactly representative of a laboratory experiment. The purpose in these runs was to determine the approximate time required to reach equilibrium by imbibition using properties from the Belly River Field.

Figure 16 shows a diagram of the cylinder used in this case. The height was 10 feet and the radius was 5 feet. The cylinder was assumed to be open on all sides, with the sides and top covered with oil at time zero, a free water surface was brought into contact with the bottom of the cylinder. Four different runs were made using permeabilities and porosities representative of the spectrum found in the Belly River field. These data are shown in Table XI where the permeability varies from 0.2 md to 220 md. The oil and water PVT data from Case 5 are used.

Saturation data were assumed to vary with permeability level. The relative permeability data are shown in Figure 12 and the capillary pressure data are shown in Figure 17. These capillary pressure data were estimated from drainage P_c data measured in the laboratory. The zero capillary pressure points, which represent the maximum final water saturations, were estimated because no laboratory imbibition data were available.

Results are shown in Figure 18 as a plot of per cent recovery of recoverable oil versus time for the four different permeability levels, where:

$$\% \text{ Recovery} = 100 \times \frac{S_w - S_{wc}}{S_{w/Pc=0} - S_{wc}}$$

This is not exact because the formation volume factors vary with pressure. However since the system was run at constant pressure, the small variation in volume factors over a ten foot height was negligible so the above expression is almost exact.

The results show that the recovery from a 200 md sand is very fast. Essentially 100% is recovered in 2 days while the time for recovery from the 0.2 md sand is much slower. The time required to recover essentially 100% from the 0.2 md sand was 800 days.

These runs show that complete imbibition is obtained within 70 days for most reservoir rocks of commercial interest with properties similar to the Belly River strata.

CASE 7 - ILLUSTRATION OF IMBIBITION RECOVERY OF BYPASSED OIL

We occasionally encounter the contention that oil in tight lenses is bypassed by waterflood fronts in adjacent, looser layers such that the bypassed oil remains unrecoverable because of the zero permeability to oil in the adjacent water-flushed layers or channels.

Figure 19 shows a cross-section 2600 feet long, 30 feet thick and 2640 feet wide. We represented this section by 20 (130-foot) grid blocks in the horizontal x-direction and 5 6-foot blocks in the vertical z-direction. Zero horizontal permeability to the top 4 layers (top 24 feet) and 800 md to the bottom layer were assigned. Vertical permeability is 1 md in the top four layers and 800 md in the bottom layer. Porosity is uniform throughout at .22. Relative permeability and capillary pressure curves of type 1 and of type 3 in Figures 11-12 were assigned to the bottom 6 feet and upper 24 feet, respectively.

PVT data are identical to those used in the Case 5 Belly River runs except that we increased water viscosity from .7 cp to 15 cp.

Zero horizontal permeability was assigned to the top 24 feet so that no oil can be recovered from that interval by lateral flooding. Cross-current imbibition is the only recovery mechanism active in that interval and it must act against the gravity force since water must imbibe upward from the bottom permeable layer. Water viscosity was increased to favor a piston-like displacement in the bottom permeable layer. This tends to quickly establish zero or very nearly zero oil permeability at any point in the bottom layer after the flood front reaches that point.

Injection and production wells at the ends of the section were completed in the bottom layer 5 and a flood rate of 200 RB/D was specified. A first run was made with zero vertical permeability at 24 feet down from the top of porosity - i.e. between layers 4 and 5. This sealed off the entire upper 24 feet so that a nearly piston-like one-dimensional displacement occurred in the bottom layer. The displacement is not quite piston-like due to the low relative permeability to oil at saturations near residual.

The dotted curve in Figure 20 shows calculated oil saturation in the bottom layer after 10 years' injection for the case of zero vertical permeability along the section 24 feet from the top. Residual oil saturation is .2120 and calculated saturations (printed to four decimal places) were exactly .2120 out to 520 feet from the injection well. Calculated saturation rose to only .2152 at 1170 feet from the well. Thus if bypassed oil will not or cannot enter a water flushed layer (as corresponds to this case where such entrance was prevented by zero k_z), this run shows that the waterflood would indeed establish zero oil mobility in the loose layer.

The second simulation run was made without the zero vertical permeability barrier. The calculated oil saturation profile in the bottom layer for this case is shown by the solid curve in Figure 21. Comparison of the two profiles clearly shows the extra oil present in the bottom layer represented by the area between the two curves. This extra oil is oil which has been recovered by cross-current imbibition from the top 24 feet into the bottom flooded layer. The long, gently rising slope of the (solid line) oil saturation profile from 0 to about 1700 feet from the well arises as follows. As oil from the tight sand is forced into the bottom layer by counter-current imbibition it is swept along with the flowing water in that layer. The flow rate of oil at any point in the bottom layer must represent the total of integrated rates of oil entrance by imbibition over the total distance from the injection well to that point. Thus the oil flow rate in the bottom layer must increase with distance along the section. This increased flow rate requires additional mobility hence increased oil saturation. The overall two-phase flow situation is certainly not steady-state, nor is it truly even a pseudo or semi-steady state situation. However, it can loosely be viewed as a shifting pseudo-steady-state flow regime.

In summary, this cross-sectional example illustrates the recovery of oil by counter-current imbibition into adjacent loose, water flushed layers. More important, it shows that this recovery occurs in situations of essentially piston-like displacement in the permeable layer where zero oil mobility would exist if not for the imbibition-caused oil recovery.

Although this is a hypothetical reservoir and rate sensitivity was not the question considered, it is interesting to note the calculated dependence of recovery on rate. The nature of this example is such as to strongly promote an adverse effect of higher rate on oil recovery. The piston-like displacement due to the 15 cp water viscosity tends to water out the production well (below economic oil rate) quickly after breakthrough and the only factor keeping oil rate above 5 STB/D is the transient counter-current imbibition acting against gravity over 24 feet. A higher rate might thus be expected to reach the 5 STB/D rate more quickly thus reducing the time for imbibition and therefore reducing the oil recovered by that mechanism.

The following table gives oil recovery at various times for flood rates of 100 and 200 RB/D.

Time, Years	Oil Recovery % of Original Oil in Place 100 RB/D	200 RB/D
26	21.66	26.75
40	26.7	28.6
60	33.0	33.8

For the 200 RB/D rate, the 5 STB/D limit was reached at 158 years with a recovery of 36.79% of OOIP. At 164 years the 100 RB/D case reached the 5 STB/D limit and recovery was 36.63%. Thus even in this case oil recovery increased with increased rate.

DISCUSSION

The seven cases described above examined rate sensitivity over a wide range of permeability, capillary pressure, relative permeability, fluid viscosity, reservoir heterogeneity and type of waterflood scheme. All these runs showed the same result--increased production rate results in higher oil recovery.

The reason for this consistent result is readily understandable. The time dependent recovery mechanism of cross-current imbibition was shown to be essentially instantaneous in comparison to the field life for Case 5 for example. In Case 4, gravity drainage was essentially instantaneous. Therefore, in these cases in which capillary or gravity equilibrium was achieved relatively quickly, the behavior in terms of recovery vs rate is the same as a simple viscous controlled waterflood displacement. That is, the displacement has a unique curve of pore volume oil produced vs pore volume water injected independent of rate. Such a displacement mechanism results in higher recovery for higher displacement rate at all times.

However, the above discussion does not explain Cases 2 and 7 in which gr vity or capillary equilibrium was not reached, and yet these cases showed higher recoveries with increasing rates. The recovery vs time in these cases is controlled by the viscous as well as the time dependent gravity or imbibition, mechanisms. As explained above the viscous displacement mechanism will result in higher recovery with higher rate at all times. The imbibition or gravity mechanisms are only time dependent and not rate dependent. Therefore, the recovery because of gravity or imbibition is essentially the same for all rates at any point in time. Adding the recoveries from the two mechanisms, therefore, results in a higher oil recovery for higher producing rates at all times.

CONCLUSIONS

The conclusion from this investigation is:

within reasonable limits of economic rates, reservoirs that are pressure maintained are at the worst insensitive to rate. In fact the cases studied in this investigation showed monotonically increasing recovery with increasing producing rate.

This conclusion may be qualified by:

1. The scope of the investigation was limited to several types of important pools in Alberta;

2. Operating procedures or economic parameters may cause well abandonment at lower producing rates thereby affecting ultimate recovery.

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TABLE I

LAYER PROPERTIES FOR SWAN HILLS WELL

LAYER Nº	PERMEABILITIES, md.		POROSITY	THICKNESS FEET
	K_h	K_v		
1	51.0	45.0	.127	10
2	63.0	36.0	.172	10
3	69.0	20.0	.129	10
4	74.0	65.0	.156	10
5	369.0	79.0	.161	10
6	34.0	17.0	.128	10
7	22.0	14.0	.141	10
8	43.0	18.0	.147	10
9	25.0	7.0	.105	10
10	5.7	0.27	.047	10
11	3.4	0.70	.041	10
12	4.6	0.90	.035	10
TOTAL	KH= 7637	—	Φh= 13.89	120

TABLE II

SUMMARY OF RESULTS
FOR SWAN HILLS A POOL

Run	Run Description	Rate STB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
		392	52.01	5	97.8
1	Base Case	1570	52.82	5	397.0
		3920	52.90	5	1045.0
		392	47.71	7.8	62
2	Drawn Below P_b	1960	52.01	5	496

TABLE III

SUMMARY OF RESULTS FOR RAINBOW REEF

Run	Run Description	Rate STB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
1	Water-Wet P_c	80	19.80	36	1.47
		800	34.35	31	30.3
2	Oil-Wet P_c	80	19.80	36	1.47
		800	34.35	31	30.3
3	Zero P_c	80	26.00	63	0.3
		800	43.88	49	18.8
4	Adverse k_r	80	13.93	25	2.7
		800	25.04	29	32.9

TABLE IV
COUNTESS B POOL
MODEL DESCRIPTION

h,ft.	k_h,md.	k_v,md.	ø,fraction	S_{wi},fraction	S_{oi},fraction
2	35	8	0.195	0.325	0.675
4	65	16	.208	0.325	0.675
3	750	260	.259	0.325	0.675
4	1600	620	.275	0.325	0.675
2	530	170	.252	0.325	0.675
4	1600	620	.275	0.325	0.675
2	1170	420	.268	0.325	0.675
2	3060	1500	.292	0.325	0.675
3	1550	580	.274	0.47	0.53
3	820	320	.263	1.0	0.00

TABLE V

SUMMARY OF RESULTS
FOR COUNTESS B POOL

Run	Run Description	Rate RB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
		1000	45	10	100
		500	45	6	100
1	Base Case	200	42	6	30
		50	26	13	2.7
		1000	45	11	100
		500	45	5	100
2	Reduced Drainage Radius	200	45	1.5	100
		50	36	5	8
		500	45	5	100
3	k/10	200	45	1	100
		50	36	5	10
		300	30	6	55
4	Increased μ	200	24	5	40
		100	15	5	22

TABLE VI
SIMONETTE D-3 POOL
MODEL DESCRIPTION
BASE CASE

LAYER	Kh-md	kv-md	Ø -%	Thick-ft
1	140	1.8	7.8	8
2	181	3.9	8.1	8
3	150	2.4	9.4	8
4	116	3.0	6.6	8
5	268	15.2	6.9	8
6	174	3.4	4.8	8
7	44	3.8	4.3	10
8	323	30.7	7.8	10
9	323	30.7	7.8	20
10	323	30.7	7.8	20

TABLE VII
SIMONETTE D-3 POOL
MODEL DESCRIPTION
HETEROGENEOUS CASE

Layers	kH-md	Thick-ft
1	120	6
2	18	6
3	200	6
4	72	6
5	7	6
6	150	6
7	4	6
8	45	6
9	95	6
10	280	6
11	34	6
12	2000	6
13	580	6
14	12	6
15	380	8
16	1000	8
17	250	8
18	50	8

$k_v/k_h = 0.1$

$\phi = 7.1\ \%$

TABLE VIII

SUMMARY OF RESULTS
FOR SIMONETTE D-3 POOL

Run	Run Description	Rate RB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
1	Base Case	3000	63.5	25	150
		15000	64.2	25	200
2	Zero P_c	3000	66.3	25	130
		15000	67.0	25	150
3	Vertical Barriers	3000	67.0	25	100
		15000	67.9	25	100
4	k/5	1000	64.6	25	41
		5000	67.2	25	150
5	Layered Heterogeneous	3000	67.9	25	170
		15000	68.4	25	150
6	Generally Heterogeneous	3000	67.9	25	120
		15000	68.4	25	150

TABLE IX

CORE ANALYSIS DATA BELLY RIVER B POOL
WELL 16-16-48-3W5

ALL LAYERS 1 FOOT THICK

LAYER NO.	HORIZONTAL PERMEABILITY, MD	POROSITY FRACTION
1	1.8	.155
2	.2	.117
3	.6	.137
4	3.8	.167
5	.1	.108
6	.1	.106
7	.1	.108
8	2.8	.162
9	2.9	.162
10	2.7	.161
11	19.4	.193
12	48.4	.208
13	77.2	.216
14	82.0	.217
15	219.6	.233
16	203.3	.232
17	233.1	.234
18	79.5	.216
19	.1	.11
20	4.8	.17
21	11.6	.185
22	9.0	.181
23	6.5	.175
24	9.1	.181
25	1.5	.152
26	23	.196
27	22	.195
28	8.8	.18
29	20.1	.194
30	18.5	.193

TABLE X

SUMMARY OF RESULTS FOR BELLY RIVER
B POOL CROSS-SECTION

RUN	INJECTION RATE RB/D	CAPILLARY PRESSURE	THICKNESS OF EACH OF 30 LAYERS FEET	OIL RECOVERY % OF OOIP		OIL RATE STB/D		WOR STB/STB		REMARKS
				22 YRS	164 YRS	22 YRS	164 YRS	22 YRS	164 YRS	
1a	100	FULL	1	19.07	44.68	87	7	.026	13.16	BASE CASE
1b	200	FULL	1	29.43	50.49	53	5	2.66	36.75	
1c	400	FULL	1	35.80	53 (1)	46	5 (1)	7.411	79 (1)	
2a	100	ZERO	1	16.76	34.86	41	7	1.31	12.00	ZERO PC NO RECOVERY BY WATER IMBIBITION NORMAL TO FLOW
2b	200	ZERO	1	21.85	43.22	36	6	4.31	29.60	
2c	400	ZERO	1	27.57	48.75	43	5	8.07	79	
3a	100	1/2	1	19.06	43.35	87	7	.027	12.67	Pc = BASE CASE LESS RECOVERY BY IMBIBITION
3b	400	1/2	1	34.76	51.85 (1)	45	5 (1)	7.712	79 (1)	
4a	200	FULL	5	7.65	31	178	29	0	5.57	THICKER LAYERS RETARD RATE OF RECOVERY BY IMBIBITION NORMAL TO FLOW
4b	400	FULL	5	15.36	36.84	346	30	.034	11.91	
4c	800	FULL	5	24.09	43.02	227	27	2.385	28.00	
5	400	FULL	16 LAYERS	35.93	53.13 (1)	48	5 (1)	7.08	79 (1)	EFFECT OF GRID DEFINITION
6	200	FULL	1	28.27		48		2.99		Kv/Kn = .02
7a	100	FULL	1	31.04	51.65 (2)	84	5 (2)	.062	19 (2)	WELLS COMPLETED ONLY IN LAYERS 15, 16, 17.
7b	400	FULL	1	48.18	54.23 (3)	20	5 (3)	18.73	79 (3)	

(1) 134 YEARS
(2) 97 YEARS
(3) 65 YEARS

TABLE XI
PROPERTIES OF CYLINDRICAL BLOCK

PROPERTY	PERMEABILITY LEVELS			
	220 md	40 md	5 md	0.2 md
POROSITY	0.23	0.20	0.17	0.11
LENGTH, FT.	10	10	10	10
DIAMETER, FT.	10	10	10	10
COMP., PSI^{-1}	4×10^{-6}	4×10^{-6}	4×10^{-6}	4×10^{-6}

OIL PVT PROPERTIES FOR SWAN HILLS WELL

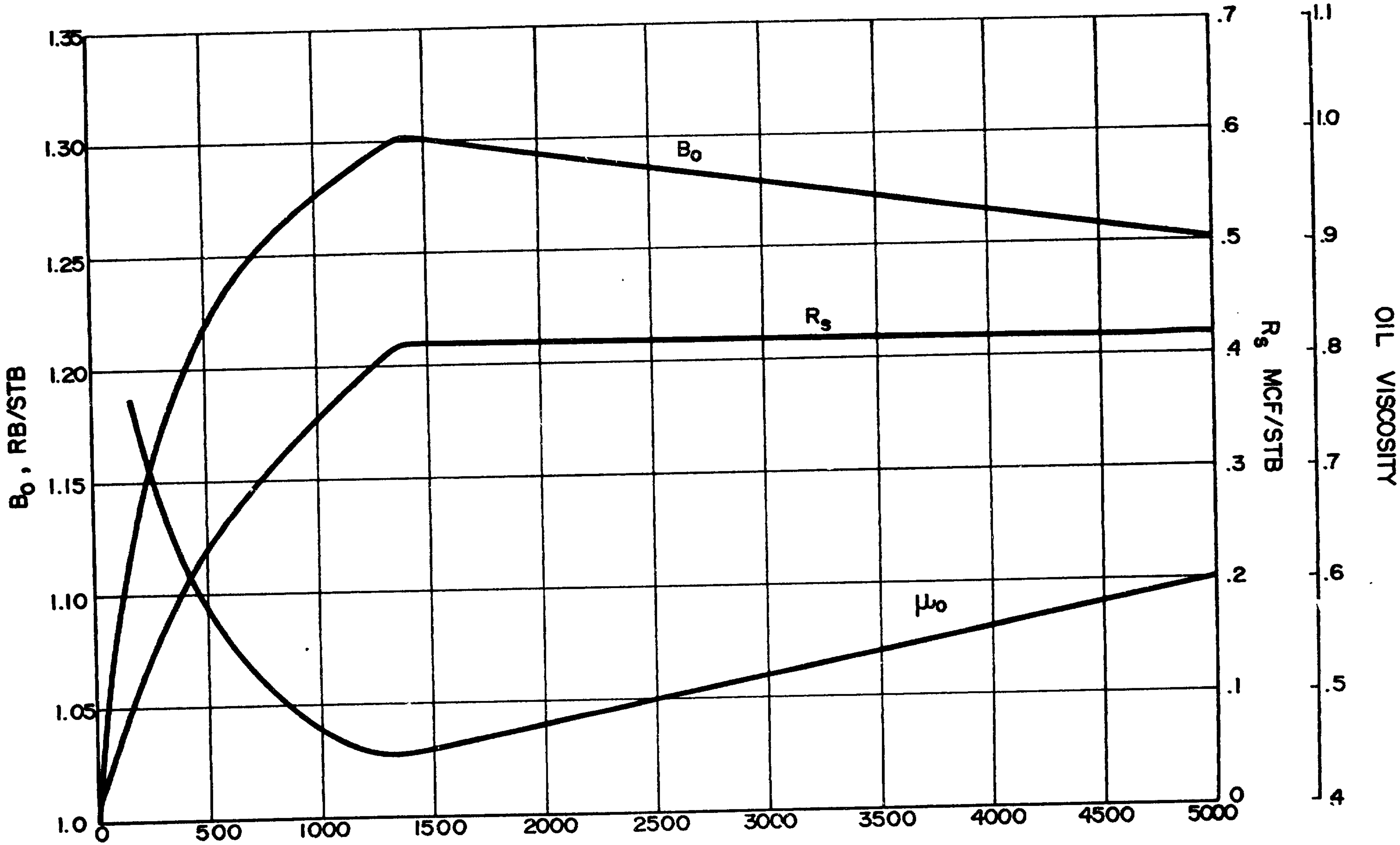

FIGURE 1

RELATIVE PERMEABILITY DATA FOR SWAN HILLS WELL

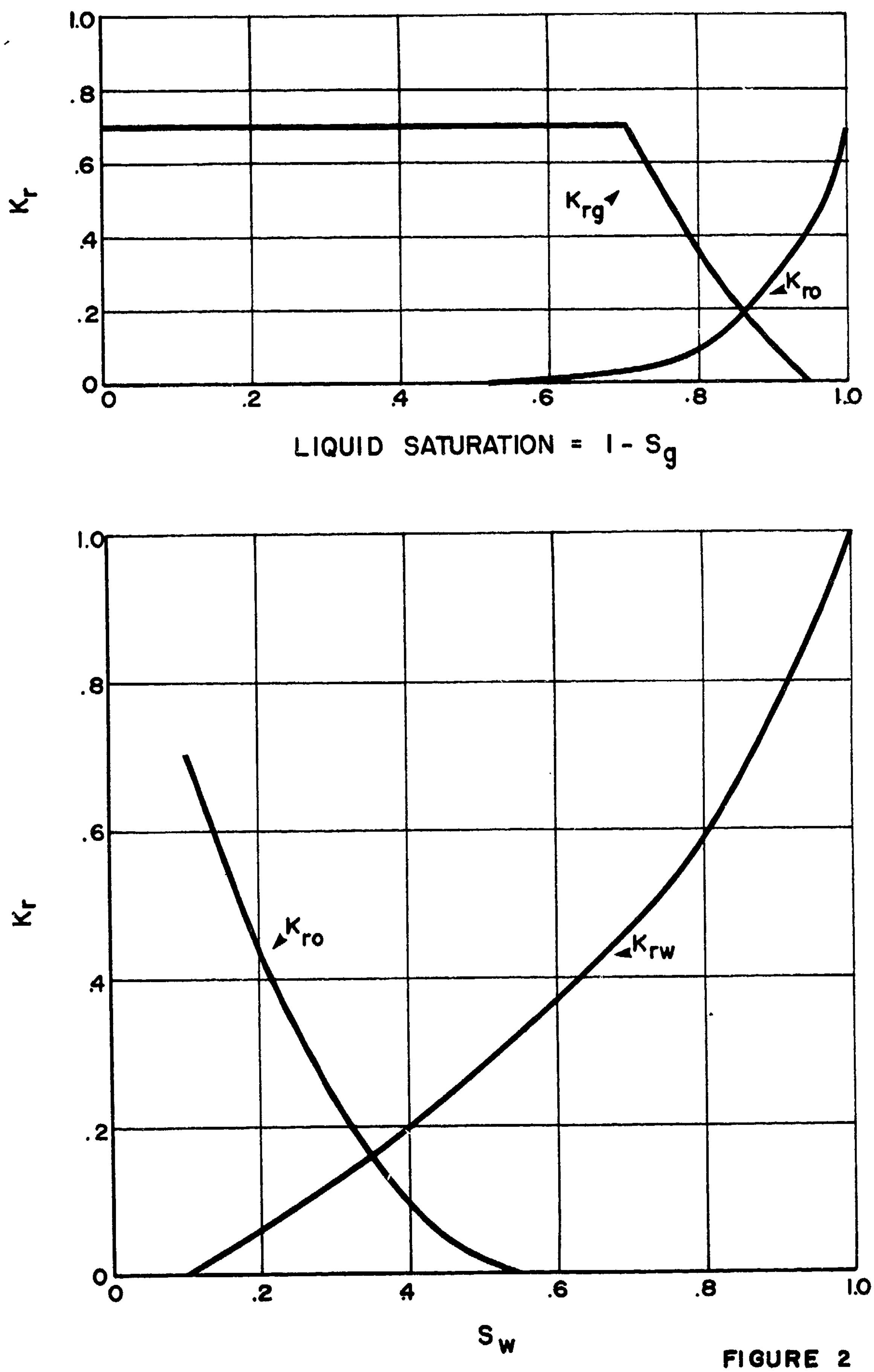

FIGURE 2

TABLE 1 - LAYER PROPERTIES FOR SWAN HILLS WELL

LAYER Nº	PERMEABILITIES, md.		POROSITY	THICKNESS FEET
	K_h	K_v		
1	51.0	45.0	.127	10
2	63.0	36.0	.172	10
3	69.0	20.0	.129	10
4	74.0	65.0	.156	10
5	369.0	79.0	.161	10
6	34.0	17.0	.128	10
7	22.0	14.0	.141	10
8	43.0	18.0	.147	10
9	25.0	7.0	.105	10
10	5.7	0.27	.047	10
11	3.4	0.70	.041	10
12	46	0.90	.035	10
TOTAL	KH= 7637	–	ϕh= 1389	120

TABLE 2 - SUMMARY OF RESULTS FOR SWAN HILLS A POOL

Run	Run Description	Rate STB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
		392	52.01	5	97.8
1	Base Case	1570	52.82	5	397.0
		3920	52.90	5	1045.0
		392	47.71	7.8	62
2	Drawn Below P_b	1960	52.01	5	496

TABLE 3 - SUMMARY OF RESULTS FOR RAINBOW REEF

Run	Run Description	Rate STB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
1	Water-Wet P_c	80	19.80	36	1.47
		800	34.35	31	30.3
2	Oil-Wet P_c	80	19.80	36	1.47
		800	34.35	31	30.3
3	Zero P_c	80	26.00	63	0.3
		800	43.88	49	18.8
4	Adverse k_r	80	13.93	25	2.7
		800	25.04	29	32.9

TABLE 4 - COUNTESS B POOL MODEL DESCRIPTION

h,ft.	k_h,md.	k_v,md.	ø,fraction	S_{wi},fraction	S_{oi},fraction
2	35	8	0.195	0.325	0.675
4	65	16	.208	0.325	0.675
3	750	260	.259	0.325	0.675
4	1600	620	.275	0.325	0.675
2	530	170	.252	0.325	0.675
4	1600	620	.275	0.325	0.675
2	1170	420	.268	0.325	0.675
2	3060	1500	.292	0.325	0.675
3	1550	580	.274	0.47	0.53
3	820	320	.263	1.0	0.00

TABLE 5 - SUMMARY OF RESULTS FOR COUNTESS B POOL

Run	Run Description	Rate RB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
		1000	45	10	100
		500	45	6	100
1	Base Case	200	42	6	30
		50	26	13	2.7
		1000	45	11	100
		500	45	5	100
2	Reduced Drainage Radius	200	45	1.5	100
		50	36	5	8
		500	45	5	100
3	k/10	200	45	1	100
		50	36	5	10
		300	30	6	55
4	Increased μ	200	24	5	40
		100	15	5	22

TABLE 6 - SIMONETTE D-3 POOL MODEL DESCRIPTION BASE CASE

LAYER	Kh-md	kv-md	ø -%	Thick-ft
1	140	1.8	7.8	8
2	181	3.9	8.1	8
3	150	2.4	9.4	8
4	116	3.0	6.6	8
5	268	15.2	6.9	8
6	174	3.4	4.8	8
7	44	3.8	4.3	10
8	323	30.7	7.8	10
9	323	30.7	7.8	20
10	323	30.7	7.8	20

TABLE 7 - SIMONETTE D-3 POOL MODEL DESCRIPTION
HETEROGENEOUS CASE

Layers	kH-md	Thick-ft
1	120	6
2	18	6
3	200	6
4	72	6
5	7	6
6	150	6
7	4	6
8	45	6
9	95	6
10	280	6
11	34	6
12	2000	6
13	580	6
14	12	6
15	380	8
16	1000	8
17	250	8
18	50	8

$k_v/k_h = 0.1$

$\phi = 7.1\ \%$

TABLE 8 - SUMMARY OF RESULTS FOR SIMONETTE D-3 POOL

Run	Run Description	Rate RB/D	Final Oil Recovery % of OOIP	Final Oil Rate STB/D	Final WOR STB/STB
1	Base Case	3000	63.5	25	150
		15000	64.2	25	200
2	Zero P_c	3000	66.3	25	130
		15000	67.0	25	150
3	Vertical Barriers	3000	67.0	25	100
		15000	67.9	25	100
4	k/5	1000	64.6	25	41
		5000	67.2	25	150
5	Layered Heterogeneous	3000	67.9	25	170
		15000	68.4	25	150
6	Generally Heterogeneous	3000	67.9	25	120
		15000	68.4	25	150

TABLE 9 - CORE ANALYSIS DATA BELLY RIVER B POOL
WELL 16-16-48-3W5

ALL LAYERS 1 FOOT THICK

LAYER NO.	HORIZONTAL PERMEABILITY, MD	POROSITY FRACTION
1	1.8	.155
2	.2	.117
3	.6	.137
4	3.8	.167
5	.1	.108
6	.1	.106
7	.1	.108
8	2.8	.162
9	2.9	.162
10	2.7	.161
11	19.4	.193
12	48.4	.208
13	77.2	.216
14	82.0	.217
15	215.6	.233
16	203.3	.232
17	233.1	.234
18	79.5	.216
19	.1	.11
20	4.8	.17
21	11.6	.185
22	9.0	.181
23	6.5	.175
24	9.1	.181
25	1.5	.152
26	23	.196
27	22	.195
28	8.8	.18
29	20.1	.194
30	18.5	.193

TABLE 10 - SUMMARY OF RESULTS FOR BELLY RIVER B POOL CROSS SECTION

RUN	INJECTION RATE RB/D	CAPILLARY PRESSURE	THICKNESS OF EACH OF 30 LAYERS FEET	OIL RECOVERY % OF OOIP		OIL RATE STB/D		WOR STB/STB		REMARKS
				22 YRS	164 YRS	22 YRS	164 YRS	22 YRS	164 YRS	
1a	100	FULL	1	19.07	44.68	87	7	.026	13.16	BASE CASE
1b	200	FULL	1	29.43	50.49	53	5	2.66	36.75	
1c	400	FULL	1	35.80	53 (1)	46	5 (1)	7.411	79 (1)	
2a	100	ZERO	1	16.76	34.86	41	7	1.31	12.00	ZERO PC NO RECOVERY BY WATER IMBIBITION NORMAL TO FLOW
2b	200	ZERO	1	21.85	43.22	36	6	4.31	29.60	
2c	400	ZERO	1	27.57	48.75	43	5	8.07	79	
3a	100	1/2	1	19.06	43.35	87	7	.027	12.67	Pc = BASE CASE LESS RECOVERY BY IMBIBITION
3b	400	1/2	1	34.76	51.85 (1)	45	5 (1)	7.712	79 (1)	
4a	200	FULL	5	7.65	31	178	29	0	5.57	THICKER LAYERS RETARD RATE OF RECOVERY BY IMBIBITION NORMAL TO FLOW
4b	400	FULL	5	15.36	36.84	346	30	.034	11.91	
4c	800	FULL	5	24.09	43.02	227	27	2.385	28.00	
5	400	FULL	16 LAYERS	35.93	53.13 (1)	48	5 (1)	7.08	79 (1)	EFFECT OF GRID DEFINITION
6	200	FULL	1	28.27		48		2.99		Kv/Kn = .02
7a	100	FULL	1	31.04	51.65 (2)	84	5 (2)	.062	19 (2)	WELLS COMPLETED ONLY IN LAYERS 15, 16, 17.
7b	400	FULL	1	48.18	54.23 (3)	20	5 (3)	18.73	79 (3)	

(1) 134 YEARS
(2) 97 YEARS
(3) 65 YEARS

TABLE 11 - PROPERTIES OF CYLINDRICAL BLOCK

PROPERTY	PERMEABILITY LEVELS			
	220 md	40 md	5 md	0.2 md
POROSITY	0.23	0.20	0.17	0.11
LENGTH, FT.	10	10	10	10
DIAMETER, FT	10	10	10	10
COMP., PSI^{-1}	4×10^{-6}	4×10^{-6}	4×10^{-6}	4×10^{-6}

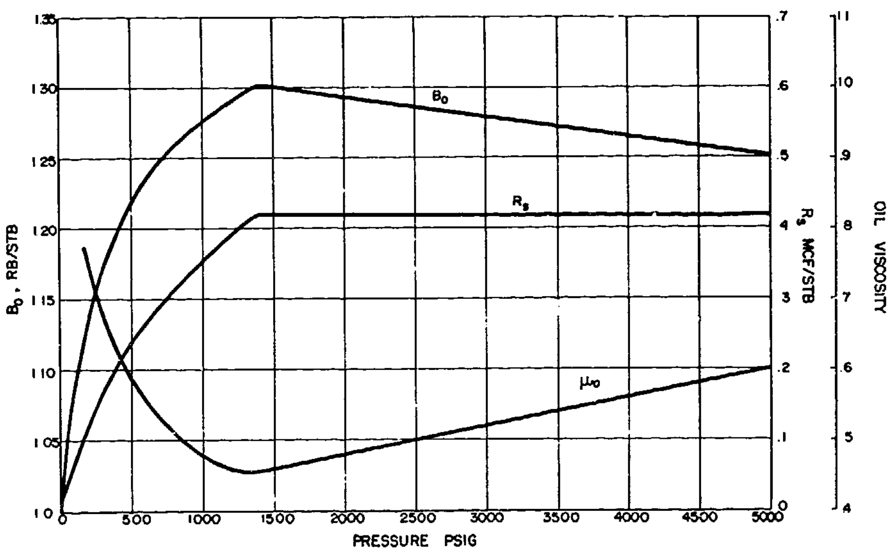

Fig. 1 - Oil PVT properties for Swan Hills well.

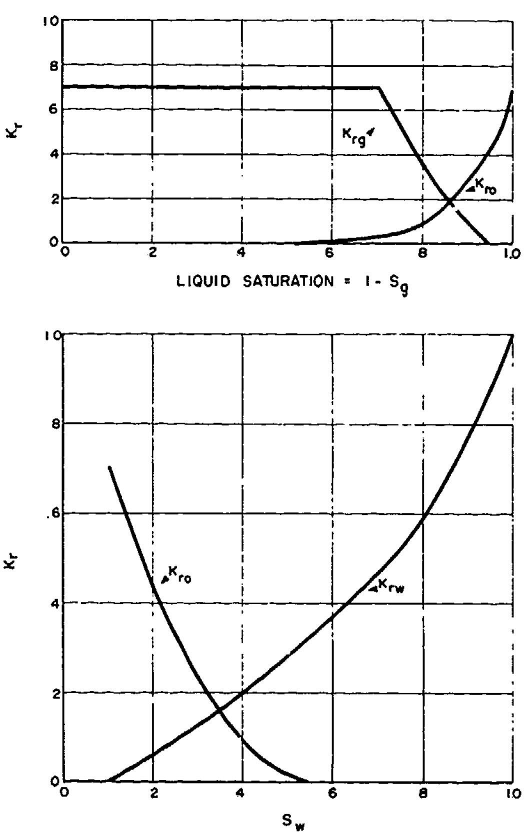

Fig. 2 - Relative permeability data for Swan Hills well.

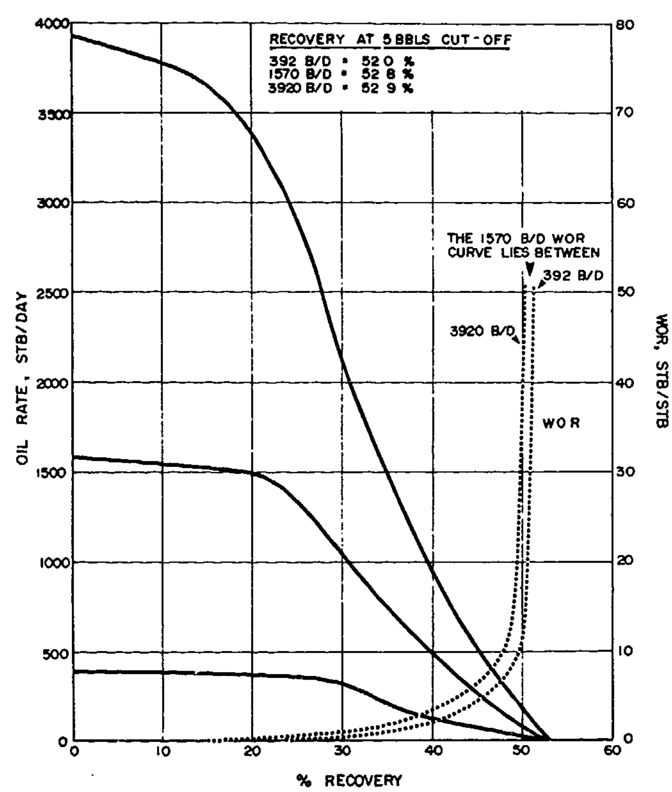

Fig. 3 - Oil rate vs recovery for a Swan Hills model.

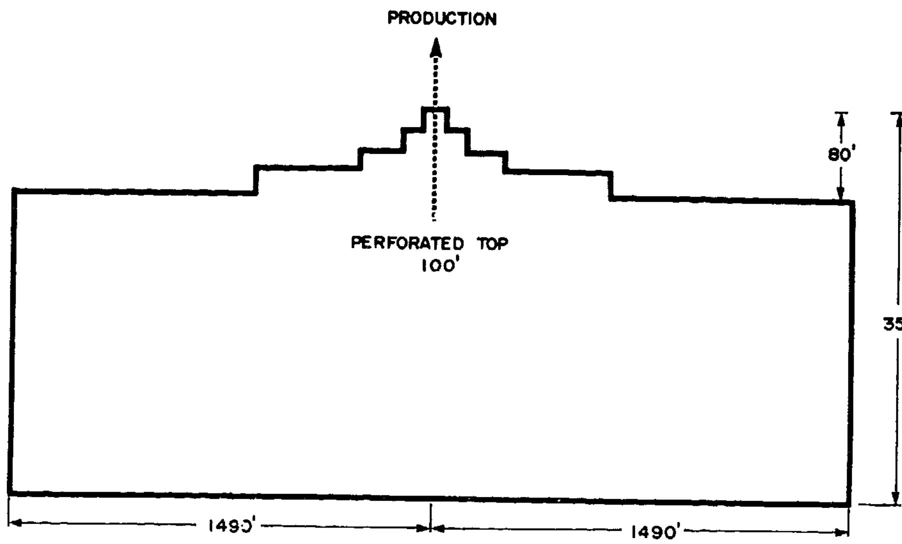

Fig. 4 - Cross section of a Rainbow-type reef.

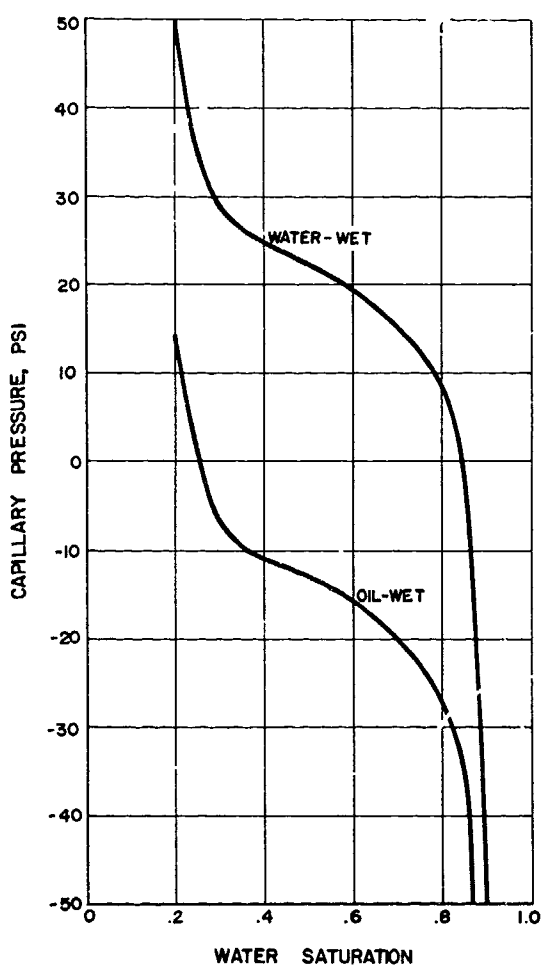

Fig. 5 - Capillary pressure curves for Rainbow Reef.

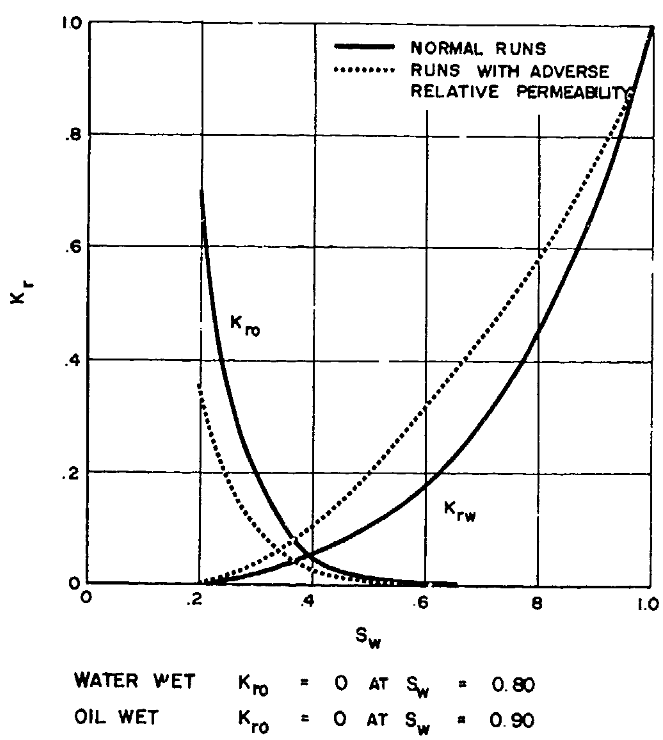

Fig. 6 - Relative permeability data for Rainbow Reef.

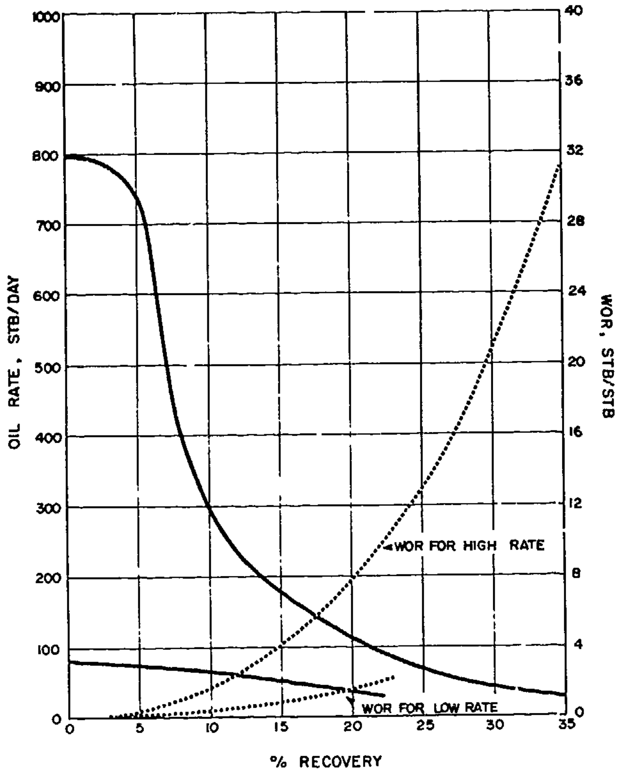

Fig. 7 - Oil rate vs recovery for Rainbow-type reef.

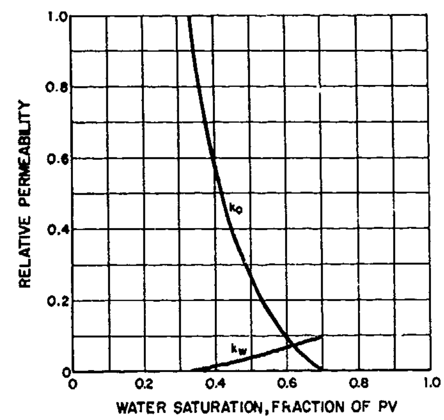

Fig. 8 - Relative permeability curve, heavy gravity pool.

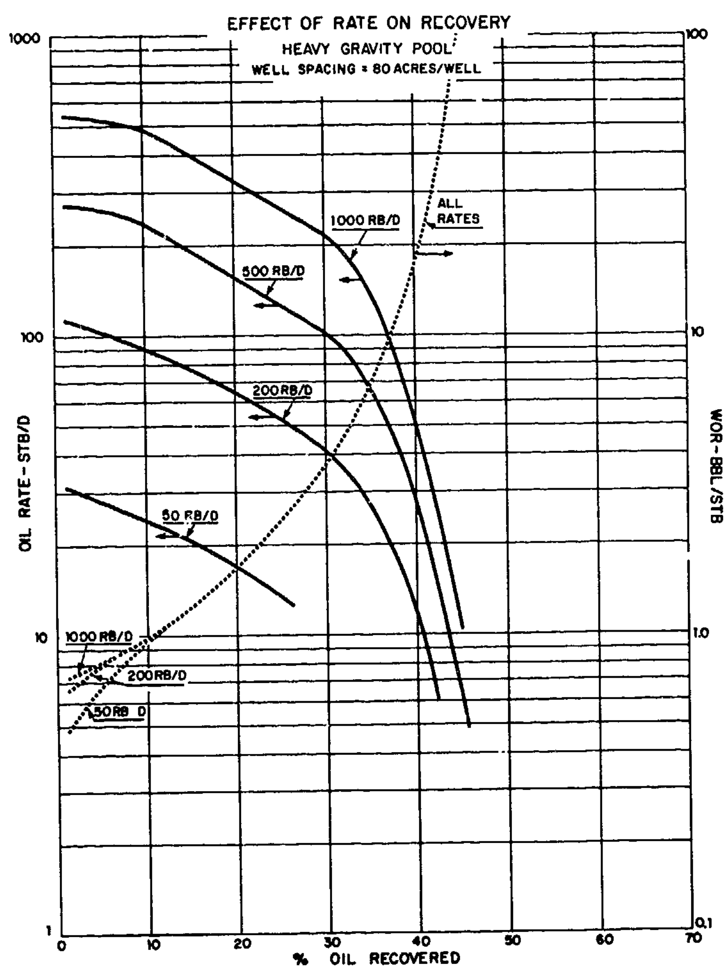

Fig. 9

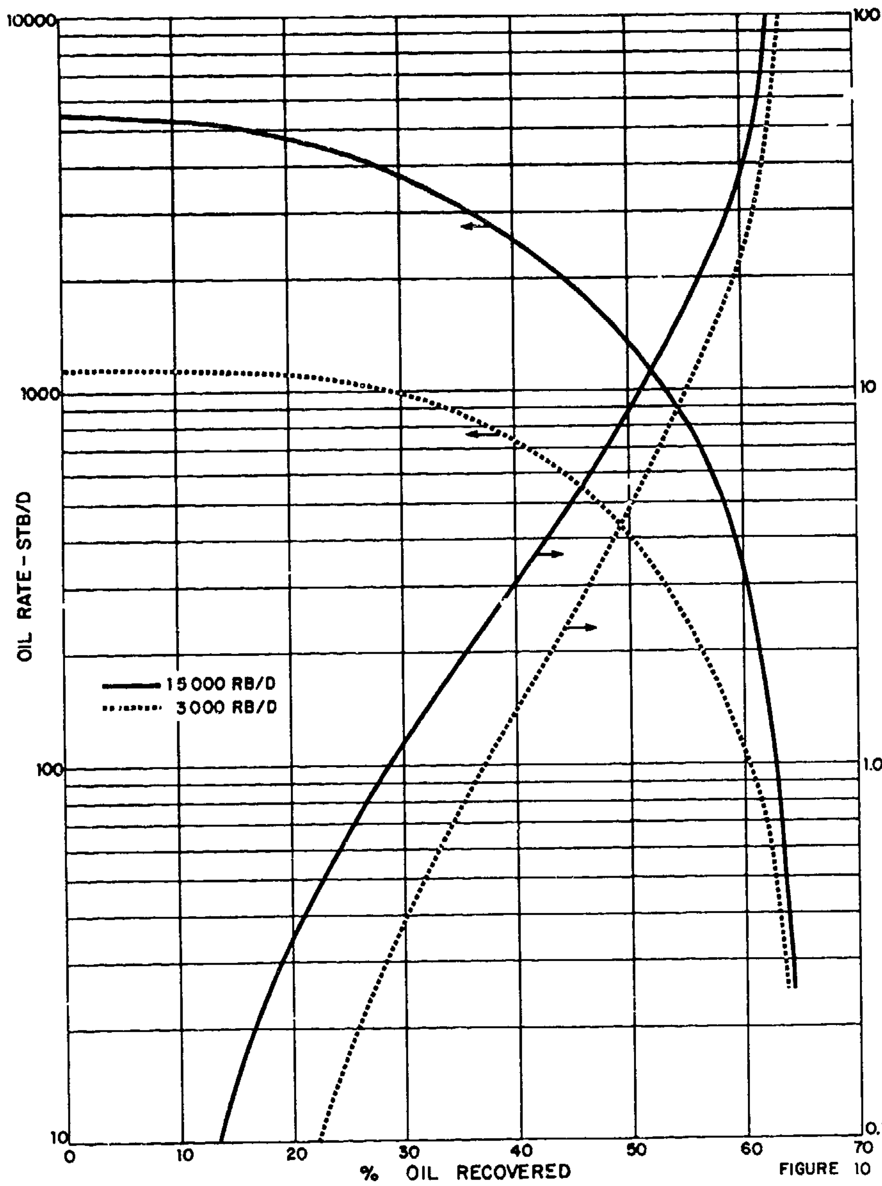

Fig. 10 - Simonette D-3 pool, Run 1.

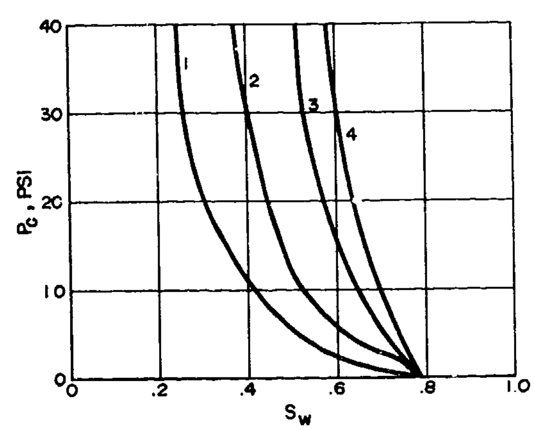

Fig. 11 - Capillary pressure curves, Belly River B pool.

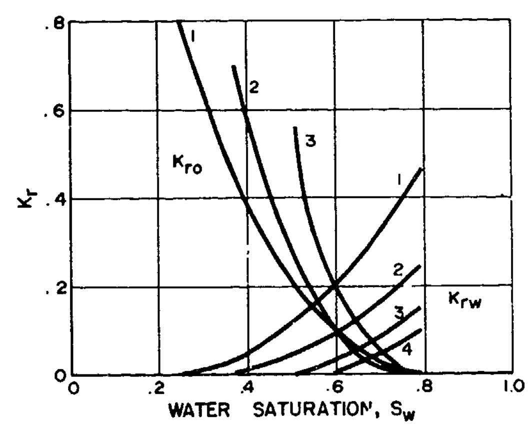

Fig. 12 - Relative permeability curves, Belly River B pool.

BELLY RIVER B POOL CROSS-SECTION

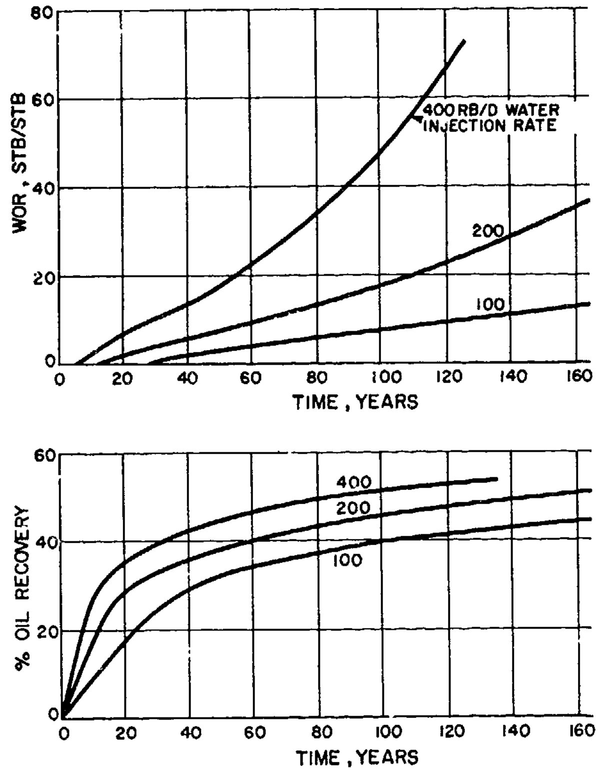

Fig. 13 - Oil recovery and WOR vs time for three flood rates.

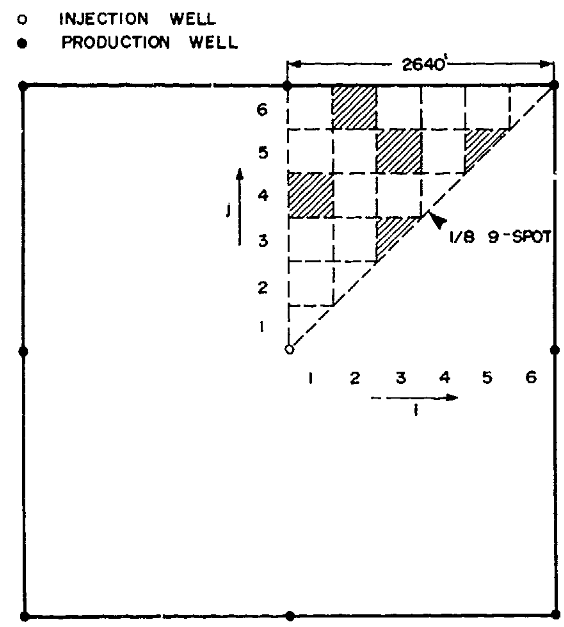

Fig. 14 - Inverted nine-spot pattern.

BELLY RIVER B POOL 1/8 NINE-SPOT

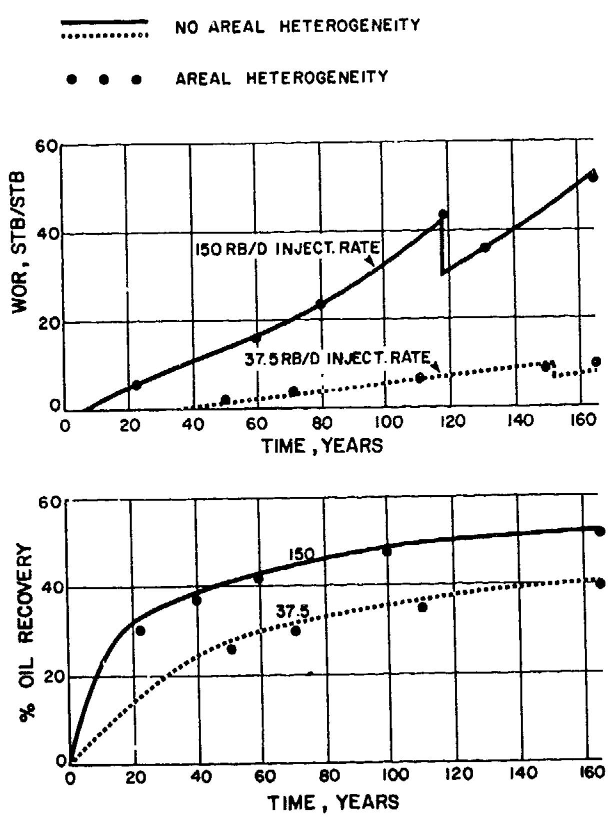

Fig. 15 - Oil recovery and WOR vs time for two flood rates.

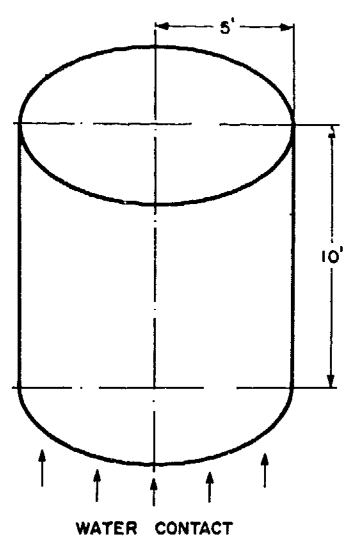

Fig. 16 - Diagram of cylindrical block.

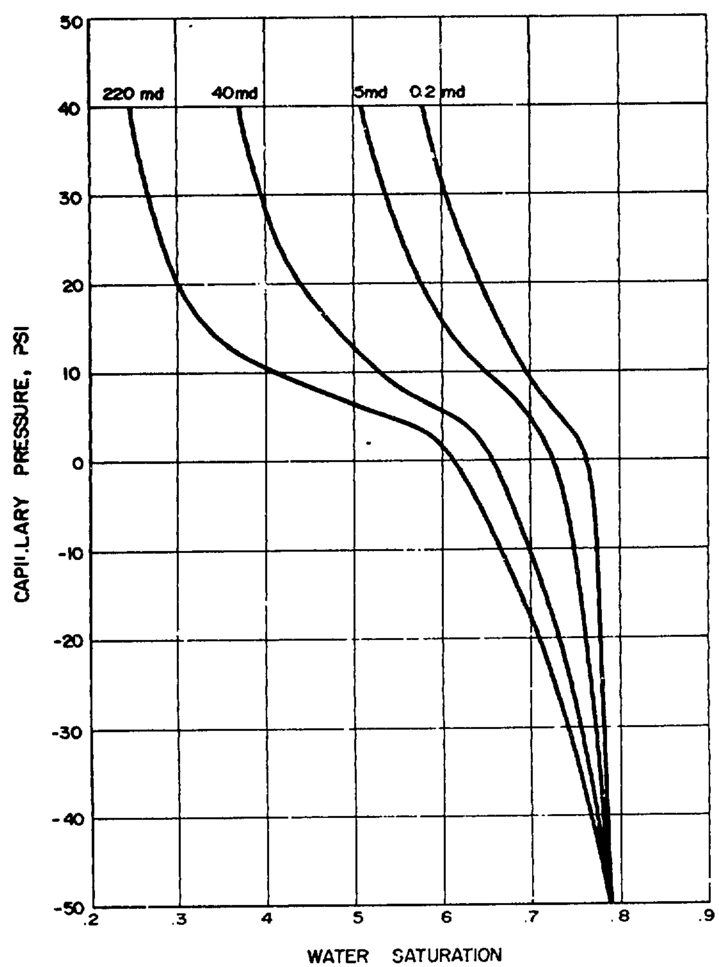

Fig. 17 - Imbibition capillary pressure.

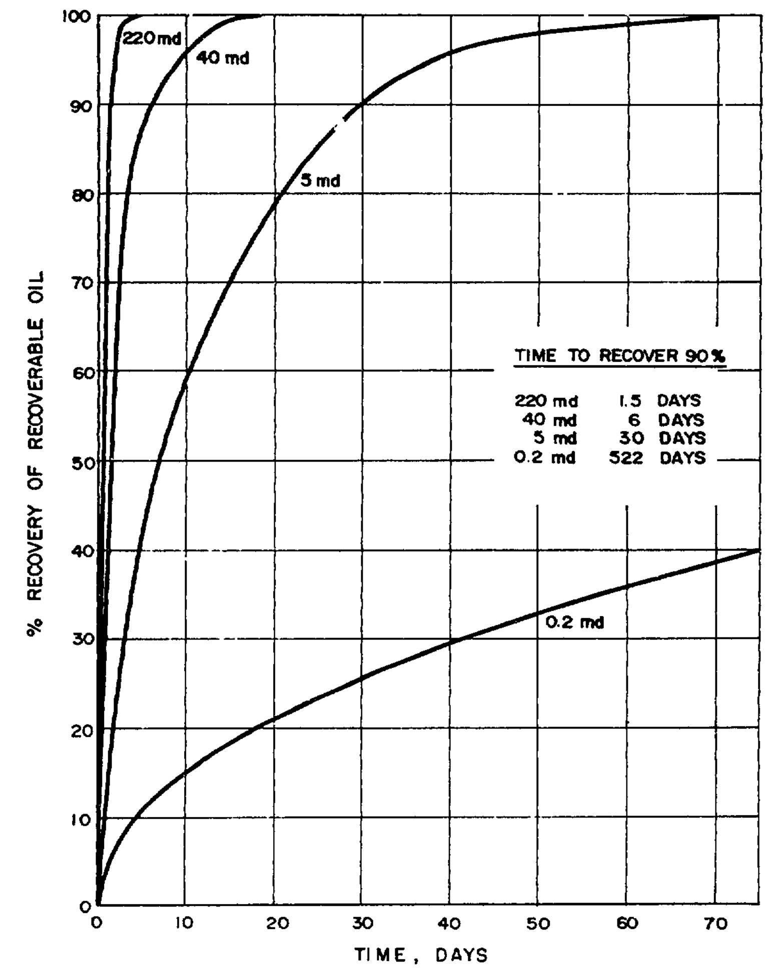

Fig. 18 - Oil recovery vs time for imbibition runs.

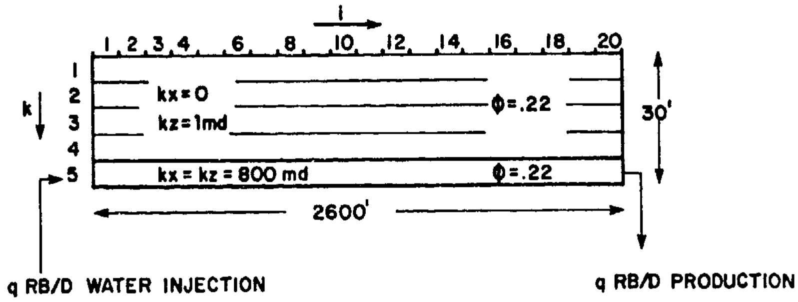

Fig. 19 - Cross section with bottom permeable layer.

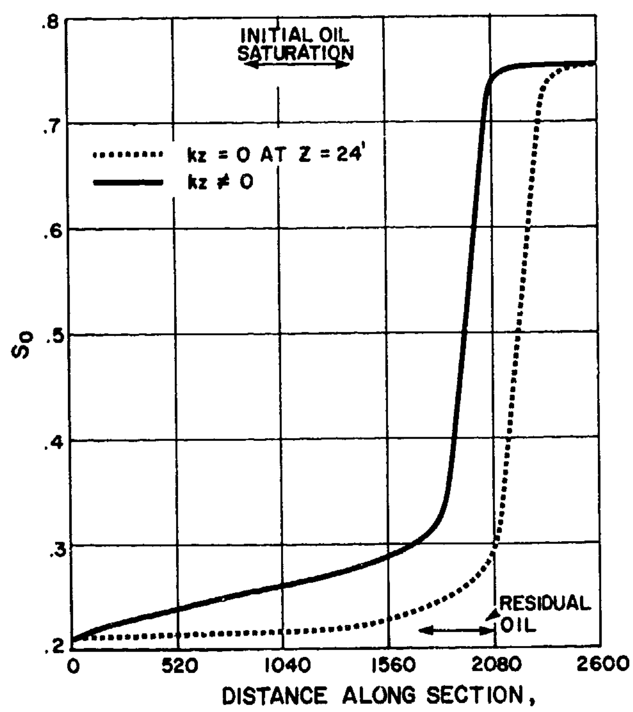

Fig. 20 - Oil saturation profile in bottom layer after 10 years.