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The Effect of Differential Depletion on Recovery by Solution-Gas Drive

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ABSTRACT

Differential depletion is the term applied to that phenomenon in solution-gas drive reservoirs in which large pressure and saturation gradients develop as a result of high production rates, high oil viscosities, or low formation permeabilities. This paper describes an investigation to ascertain the degree to which variations in the initial production rate and in reservoir fluid properties cause differential depletion to occur in a low permeability (10 md) reservoir, and the resultant effect on recovery at a reasonable economic abandonment rate.

The results of the rate-effect investigation indicate that for the type of reservoir modeled, i.e., thin, linear, horizontal, homogeneous and isotropic, the recovery at economic abandonment is almost completely independent of initial production rate. This fact is true even though the rates investigated varied three hundred fold and a large amount of differential depletion was induced at the higher rates. However, the producing gas/oil ratio behavior and time to abandonment are very definitely rate sensitive. From an economic rate of return standpoint, it appears that an operator can produce oil at a high rate, and thus achieve a greater present worth, while losing very little of the total recoverable oil.

The results of the variable fluid property investigation indicate that as the bubble point pressure and the solution-gas increase at constant API gravity, the amount of differential depletion decreases. This decrease is accompanied by an increase in the amount of total recoverable oil that had been recovered at economic abandonment. For the case of varying API gravity at constant bubble point solution-gas, the amount of differential depletion decreased slightly as the API gravity increased. This decrease in differential depletion was accompanied by the same trend as above.

INTRODUCTION

The mathematical prediction of solution-gas drive performance has been attempted for more than three decades. Muskat and Meres[1] were some of the first to formulate the theory of two-phase fluid flow. Although their equations are referred to as exact, rather gross assumptions regarding such things as relative permeability and phase behavior are made.

Muskat later[2] simplified the two non-linear, second order partial differential

References and illustrations at end of paper.

equations to one non-linear, first order differential equation giving an approximation that could be solved quite easily by numerical means. Unfortunately for simplicity, performance is characterized as taking place at an *infinitesimally small production* rate that does not induce pressure or saturation contrasts within the reservoir. It is postulated that an "average" pressure and saturation can be found that characterize the entire system. Under these assumptions, recovery is entirely dependent upon the relative permeability characteristics of the reservoir rock and the "P-V-T" properties of the reservoir fluids.

Several other authors[3, 4, 5] have proposed similar techniques for predicting reservoir performance using this so-called "steady-state" type of model. These techniques have been extended or revised by several investigators[6, 7, 8]. Theoretical investigations using these techniques to study the effect of relative permeability and fluid properties on recovery have been reported.[9, 10]

The first attempts to circumvent the assumptions that limit the above techniques were reported by Loper and Calhoun[11] and Miller et. al.[12] These techniques combine some of the material balance ideas of the previous methods along with radial flow formulas to creat a "succession of steady-states" analysis that allows calculations of pressure and saturation profiles across the reservoir.

The rigorous solution of the non-linear, partial differential equations governing unsteady-state solution-gas drive behavior did not begin until the development of modern digital computing equipment in the 1950's. The classical unsteady-state paper describing solution-gas drive reservoirs was published by West, Garvin, and Sheldon.[13] They, as did those who came later, replaced the non-linear, partial differential equations with finite difference analogs and solved the resulting system of equations numerically. Their basic equations neglected capillary pressure and gravitational effects. While these investigators presented no startling results, their effect on future work in this area is considerable.

Wallick[14] in reporting an attempt to duplicate the results of West, et.al. discusses an interesting point. In an attempt to verify that this technique is valid, he presents results from a series of three predictions over which the initial production rate was reduced by a factor of 10. As would be hoped, when the producing gas/oil ratio curves were all plotted on the same graph, they, as a group, approached that of a Muskat type prediction.

Stone and Garder[15] presented a somewhat different formulation of the linear gas-drive mechanism. Their equations include gravity effects but neglect capillary pressure and are written in such a manner as to allow a solution technique that is more straightforward and computationally faster than that used by West, et.al. They apply these equations in a limited study of complete pressure maintenance, solution-gas drive, and gas-cap expansion drive.

Using a mathematical formulation almost identical to the radial system of West, et.al., Levine and Prats[16] performed a study of the effect of absolute permeability, well spacing, and, to a certain extent, production rate on solution-gas drive performance. The effect resulting from variations in these three parameters upon recovery at economic abandonment (2 bbl/day) was determined.

Using one fairly "typical" set of "P-V-T" properties they found that spacings ranging from 10 to 80 acres had very little effect on economic recovery. As would be expected the closer spacing was slightly more favorable. However, the effect of permeability was much more pronounced; an increase of permeability from .5 md. to 25 md. increasing the recovery about 1.8 times. With regard to spacing they mention that for a four-fold increase in rate the recovery at economic abandonment is almost completely unaffected.

One factor causes some doubt to be shed on their permeability variation experiments: they held everything constant except permeability. It is known from petrophysics[17] that a basic relationship exists between absolute permeability, porosity, and connate water saturation. Consequently, permeability can not be varied, at constant connate water saturation, without also varying the porosity. Also, as shown by Felsenthal[18], relative permeability to oil and gas is related to absolute permeability. Unfortunately, as yet, no investigation has been carried out to obtain an analytical expression relating the two.

Levine and Prats mention one further point that is hard to accept; using a graph, they show that the gas/oil ratio data for all their runs fall along the same curve. They conclude that GOR behavior is independent of spacing, rate, etc. This seems fairly unlikely.

Also using a model almost identical to that of West, Garvin and Sheldon, Heuer, Clark and Dew[19] studied the effect on economic recovery of well spacing, permeability constructions, and production rate. Their conclusion concerning spacing (40-80 acres) concurs with that of Levine and Prats. However, they do point-out that the time to abandonment is directly proportional to the spacing; this fact should be the main consideration. For the permeability constricted model they found little effect on economic recovery even though their system contain two rather severe permeability variations. They, also, did not vary porosity or relative permeability with changing absolute permeability. With regard to rate variations, their results more or less substantiate those of Levine and Prats: for a two-fold increase in rate, the recovery at economic abandonment was virtually unaffected.

Ridings, Dalton, et.al.[20] present the most rigorous mathematical model yet described in the literature purely for solution-gas drive behavior. Their model considers capillary pressure and gravity and is applicable to either a linear or radial system through proper definition of terms. Also, they use a direct solution technique proposed by Richmyer[21] as opposed to the iterative and semi-iterative methods used by other workers. These investigators concluded that ultimate recovery is independent of production rate and spacing but that gas/oil ratio behavior is dependent upon both producing rate and spacing of wells.

As can be seen from the above discussion, considerable work has been done in unsteady-state solution-gas drive performance prediction, but much more needs to be done. Almost all of the above mentioned papers cover only a small range of data; i.e., most of them use only one set of relative permeability curves, one set of fluid properties and rarely more than one or two producing rates. Consequently, a complete investigation of this mechanism is needed.

With this need in mind, the present study was undertaken. In order to keep involvement with mathematical problems low and allow more effort to be used in investigative studies, this investigation was restricted to a one-dimensional analysis of a low permeability, thin, homogeneous and isotropic, horizontal sandstone reservoir producing by solution-gas drive. The mathematical model was otherwise completely rigorous in the one dimension; i.e., full unsteady-state and capillary pressure effects were included.

The phenomenon defined earlier as differential depletion was investigated and its effect on recovery at economic abandonment was determined. The independent parameters, initial production rate and fluid properties, were varied in an attempt to induce varying degrees of differential depletion. Pressure and saturation behavior within the reservoir and fluid production were monitored as a function of time.

THE INVESTIGATIVE STUDY

Since, as noted above, differential depletion (DD) can be a result of low reservoir permeability, high production rate, or adverse fluid properties (high viscosity) working separately or together, representative values for these various parameters had to be selected for use in the study. Although it is true that relative permeability characteristics are a function of absolute permeability[18], the relationships have not been generally developed; consequently, it was decided to hold the absolute permeability constant at a low value and systematically vary the other two parameters. To this end, a series of production rates and a group of fluid properties were chosen for use that were believed to span a large amount of those conditions found in oil field producing operations.

As mentioned in the introduction, several authors have indicated that ultimate recovery in a solution-gas drive field is independent of such parameters as well spacing, producing rate, etc. However, it has been shown that recovery at some normal economic abandonment rate (say 2-8 bbl/day) is affected by certain of these factors. Consequently, for this study it was decided to use recovery at some economic abandonment condition as an indication of the effect of the two subject parameters on solution-gas drive performance.

The mathematical model used in this study is presented in Appendix A. A proposed method for correlating the production rate for the linear system used in this investigation with that for a more real, radial system is presented in Appendix B.

The Rate Effect Study

For this study, the fluid properties for a fairly "typical" reservoir oil shown in Figures 1a and 1b were used. The capillary pressure curve used is shown in Figure 2, and the reservoir and production parameters are presented in Table 1. The relative permeability correlation used is presented in Appendix C.

All calculations made in this study

were constant terminal rate (CTR) until the production point pressure declined to 70 psi. At that time, the change was made to constant terminal pressure (CTP) production and the producing rate was allowed to decline according to the conditions at the production point. In an attempt to keep "extraneous" variations from effecting the results, the initial time step length was adjusted so as to keep the amount of oil produced per time step as constant as possible.

The initial linear system rates and their corresponding initial time step lengths are shown in columns (1) and (2) of Table 2. Columns (3) and (4) give an indication of the ultimate fractional recovery of oil and gas for all rates. As can be seen there, the general feeling that ultimate recovery is fairly independent of producing rate was verified. Columns (5) and (6) show the ratio of the recovery of the various rates to the recovery at the highest rate, 30 bbl/day, and it can be seen that the greatest deviation are approximately .7% for the oil and .2% for the gas.

An interesting point is apparent when the oil recoveries are viewed beginning with the highest rate and proceeding to the lowest. Upon doing this, it is apparent that the recovery increases slightly as the initial rate is decreased to 2.0 bbl/day; thereafter the recovery decreases to its minimum value at the lowest rate. The oil recovery predicted for the .1 bbl/day case is very close to that of a steady-state prediction (0.2751 at 70 psi). As far as the gas recovery is concerned, it generally decreases very slightly as the rate decreases.

In order to ascertain the degree to which DD is induced in the reservoir by the various initial rates, Figures 3 through 6 should be inspected. For these figures, four of the producing rates -- .1, 1.0, 10.0, and 30.0 bbl/day -- were selected along with six representative stages of reservoir depletion. These six stages are at cumulative fractional recoveries of: 0.00, 0.045, 0.10, 0.15, 0.20, and 0.275. Each figure shows the reservoir profiles, pressure and saturation, for the various stages of depletion for a particular initial rate.

As can be seen from these profiles the amount of DD induced increased tremendously as the initial rate varied over the range covered. The pressure appears to be more responsive in this regard, but the effect is much in evidence in the saturation profiles at the higher rates. It can be noticed that the saturation near the production point continues to decline after the boundary condition change from CTR to CTP production.

Incidently, by examining the reservoir profiles for the 0.1 bbl/day case shown in Figure 3, it is quite evident why this case predicted a recovery extremely close to that of a steady-state prediction. It is evident that for this case the assumption explicit in the steady-state prediction technique that no pressure or saturation difference exists across the reservoir was quite closely approximated.

With these observations concerning the profiles for the various cases in mind, let us examine the average reservoir pressure and producing gas/oil ratio curves for certain of these tests that are shown in Figures 7 and 8, respectively. The average reservoir pressure values are on a volume weighted basis. For reference the curves from a steady-state prediction are also included. As can be seen the average reservoir pressure is not unduly affected by the large variations in rate and amount of DD. As would be expected from examination of the profiles, the greatest deviation from a steady-state performance occurred for the higher rates. However, the producing GOR behavior is tremendously affected by the initial producing rate and amount of DD. This behavior is of course a reflection of the pressure and saturation values in effect at the producing point. As can be observed in Figures 3 through 6, the value of these variables at that point for a particular time in the producing history is very much affected by the initial rate.

The "V" shape characterized minimum point in the GOR curves is a reflection of the change from CTR to CTP production. The rise and resultant hump in the GOR curve after this change is easily explained. As the well bore pressure is drawn down to a minimum by fluid production, the GOR curve takes on a fair approximation to a steady-state curve shape (although it may be shifted considerably). After the change from CTR to CTP, the pressure at the producing point remains constant, but the oil saturation continues to decline. This declining oil saturation allows the GOR to increase (relative permeability considerations). However, later in the performance the oil saturation reaches a minimum value and slowly increases. This increase in saturation decreases the relative permeability to gas, and thus the GOR decreases to a final value fairly close to that of a steady-state prediction at approximately the same average reservoir abandonment pressure.

An interesting point concerns the amount of gas that is produced (and thus must be handled) during various stages of reservoir depletion. By examining Figure 8 it can be seen that as the initial producing rate increas. . the producing GOR curve rises much higher initially but does not reach as large a value later Consequently an operator producing a reservoir at a "high" rate will initially experience a need for much larger gas handling facilities than would be proportionally necessary if producing at a lower rate. Later in field life when the lower initial oil rate GOR curves have higher values than those for the higher initial oil rates, the lower oil producing rates keep the actual amount of gas produced per day from ever exceeding that for the higher initial rates.

Now, to consider the focal point of this variable rate section: the effect of rate on recovery at some economic abandonment. In this regard attention is directed to Figure 9. Here the producing rate is shown as a function of cumulative fractional recovery. It is readily apparent that initial producing rate has little effect on the producing rate at some later time, and thus the recovery at some economic abandonment rate is virtually unaffected by initial producing rate. However, by examining Figure 10 which shows the producing time for various initial rates as a function of cumulative recovery, it can be seen that the time required to achieve a particular amount of production is very definitely rate sensitive. This last observation is, of course, to be expected.

To bring these two points clearer into focus, two values for abandonment radial system equivalent rate (RSER) were chosen and the recovery and time at those points were examined. Referring to Table C-1, if a value of "h" between 25 feet and 30 feet is used, a value of 0.05 for R_T is permissible. Therefore, if values of 3 and 40 bbl/day are selected for use as abandonment (RSER), the linear abandonment rates are .15 and 2.0 bbl/day.

Summaries of the results obtained when production is terminated at these three rates are shown in Tables 3 and 4, respectively. Columns (6), (7), and (8) of these tables are the most important. In these columns the ratios of the oil and gas recoveries and producing time for each rate to those of the highest rate (30 bbl/day) are presented. By observing these columns the percentage increase in oil and gas recovery gained by using a lower initial rate can be weighed against the extra producing time involved.

First for an abandonment RSER of 3.0 bbl/day, Table 3 indicates that using an initial linear rate of 2.0 bbl/day in preference to one of 30.0 bbl/day, will increase oil recovery by about 1% but will increase the producing time by about 62%. This long, extra producing time obviously is not justified. Also very interesting is the fact that for an initial linear rate of 0.5 bbl/day the amount of oil recovered is actually lower than that for the 2.0 bbl/day case eventhough the producing time almost triples. The lower recovery at that rate is a reflection of the closeness of the reservoir profiles to steady-state conditions.

In order to determine whether or not the abandonment RSER of 3.0 bbl/day is too low to be meaningful, the other value was investigated. Here, however, the same general trend was observed; i.e., the extra recovery gained by using a lower initial production rate was drastically over-shadowed by the additional recovery time needed. Table 4 indicates that by using the 2.0 bbl/day linear rate instead of the 30.0 bbl/day rate, the oil recovery is increased only 6% while the producing time increased about 360%.

The two points just made should be reemphasized: (1) Recovery at a reasonable economic abandonment rate is essentially unaffected by initial producing rate even though rates used varied three hundred fold and the amount of DD induced changed tremendously. However, the time to achieve this abandonment rate is very definitely dependent on initial rate. (2) The extra recovery attained by using a lower producing rate is definitely overshadowed by the additional producing time necessary.

The ramifications of these observations in the industry are obvious. While it must be remembered that the reservoir modeled in this study was quite ideal -- linear, horizontal, homogeneous and isotropic -- these results cast considerable doubt on the belief held by many people within the industry that the initial producing rate of a solution-gas drive reservoir should be curtailed to conserve reservoir energy in order to recover more oil later. The results of this study indicate that from an economic standpoint (present worth of money) this practice is false.

The Fluid Property Effect Study

To characterize the various sets of fluids used, the API gravity and the bubble point solution GOR were used as the identifying factors. Using this system, an oil designated by 22-600 indicates an API gravity of 22° and a bubble point solution GOR, R_{sb}, of 600 scf/bbl.

For this study two groups of fluid properties were developed for testing: (1) oils with API gravities of 15°, 22°, 30°, and 40° all with an R_{sb} of 600 scf/bbl; (2) oils with an API gravity of 40° and having R_{sb}'s of 200, 600, 1000 and 1400 scf/bbl. This data was taken from information given in the dissertation of Bullock[22] and Abib[23]. The information presented by these two authors was taken from various correlations in the literature.

Graphic presentation of the fluid data is shown in Figures 11 through 20. In Table 5 the value of the properties for the various oils at the bubble point (initiation of the reservoir prediction) are shown. Also shown are the initial oil and gas contents of the reservoir (see Table 1 for reservoir dimensions, porosity, etc.). For the R_{sb}= 600 oils the initial B_o's are quite similar and this is reflected in the close similarity of the reservoir contents. The main distinguishing characteristic of this set of crude oils is the wide variation in the oil viscosities. For the API = 40° oils, the main distinguishing characteristics are the initial values of R_s, and consequently of B_o. The B_{ob} values range from 1.10 to 1.87 as the corresponding R_{sb} values range from 200 to 1400 scf/bbl. The wide ranging B_{ob} and R_{sb} values are reflected in the widely varying amounts of oil and gas originally in-place: progressing from the 40-200 oil to the 40-1400 data the oil-in-place decreases from 14,330 bbl to 10,310 bbl, but the gas-in-place increases from 3,351,000 scf to 14,245,000 scf.

The reservoir properties and production parameters for this group of tests are much the same conditions as those of the previous section, but with three notable exceptions: (1) the initial producing rate was 3.0 bbl/day and the initial time step length was set at 5.0 days for all tests; (2) the well bore pressure was allowed to decline to 50 psi before the change was made from CTR to CTP boundary conditions; and (3) the equilibrium gas saturation was reduced to 0.035 after examining several field relative permeability curves in reference 18.

Considerable insight into the results of these tests can be gleaned from Tables 6 and 7. In Table 6 the total recovery of oil and gas on both a volumetric and fractional basis are presented along with a notation of the average (volume weighted) oil saturation at reservoir abandonment. Notice should be made that the ultimate oil recovery increased as the API gravity increased for the R_{sb} = 600 oils, but the gas recovery decreased. These observations are true on both a volumetric and fractional basis. For the 40° API oils, it is seen that although the gas recovery increased on both a fractional and volumetric basis as the R_{sb} was increased, the oil shows a somewhat different trend. The ultimate oil recovery increased on a fractional basis as the R_{sb} increased, but due to the rapid corresponding increase in B_{ob}, the actual volumetric recovery decreased. This is true since 34% of the ST oil contained in a reservoir filled with a fluid of B_o = 1.87 is considerably less than 26% of the ST oil contained in the same reservoir filled with a fluid of B_o = 1.10. The trend in increasing fractional oil recovery as a function of R_{sb} and API gravity is in line with those reported by Arps and Roberts[10], and by Bullock[24]. As would be expected, the oil saturation at ultimate abandonment decreased as the fractional oil recovery increased.

With regard to the amount of DD induced in the reservoir, Table 7 should be examined. Columns (2) and (4), respectively, show the maximum pressure and saturation contrasts developed for each oil. Columns (3) and (5) contain the "normalized" equivalents of these "absolute" values. "The normalized" values were calculated using the following formula:

$$\frac{\text{Maximum } \Delta F}{\begin{bmatrix}\text{Initial (maximum)} \\ \text{value of F}\end{bmatrix} - \begin{bmatrix}\text{Minimum value} \\ \text{of F}\end{bmatrix}} \tag{1}$$

where F is either pressure or saturation.

For the R_{sb} = 600 oils, the maximum Δp values varied quite widely, but when these values are "normalized", no clear pattern is discernable. With the exception of the 15-600 data, the values, on this basis, are rather close. For the saturations, a more obvious trend is present: as the API gravity increased, the maximum saturation contrast decreased somewhat on both an absolute and "normalized" basis. These two trends indicate that although the amount of DD induced appears to be about the same on a "normalized" pressure basis, it decreases somewhat as the API gravity increases. This is most likely a reflection of the decreasing viscosity.

For the 40° API oils a somewhat reverse situation exists in the pressure contrasts; i.e., the absolute maximum contrasts are all about the same, but when these values are "normalized" a very definite trend develops. The amount of DD obviously is very high for the 40-200 oil and decreases to a

manner as to decrease the amount of differential depletion, the fraction of total recoverable oil that will be recovered at economic abandonment will increase.

CONCLUSIONS AND RECOMMENDATIONS

Reviewing the work discussed in this paper the following conclusions can be reached.

1. Differential depletion (DD) is a real phenomonon capable of being modeled with an unsteady-state analysis of the fluid flow.

2. Differential depletion can be caused by a high producing rate or by adverse fluid properties.

3. Specifically with regard to producing rate, the following observations are valid:

   a. Increasing the initial producing rate, increases the amount of DD and thus causes reservoir conditions to be entirely different from that indicated by a steady-state analysis.

   b. The deviation of the producing GOR curve from that of a steady-state prediction is a measure of the amount of DD induced.

   c. The DD induced deviation of the producing GOR behavior will cause the producing gas rate to be higher than would be proportionally expected from the increased oil production rate.

   d. While high initial producing rates cause a large amount of DD to occur, their effect on the producing rate later in the producing history is relative small.

   e. Due to the phenomenon described in d. the cumulative fractional recovery at some reasonable economic abandorment rate is essentially the same for all initial rates.

   f. The producing time required to reach the above abandonment rate is very definitely rate sensitive.

   g. Considering points e and f, the belief held by many in the industry that the initial production rate of a solution-gas drive field should be curtailed in order to obtain greater recovery later is not only wrong but very damaging from a present worth of money standpoint.

5. Specifically with regard to fluid properties, the following observations are valid:

   a. The absolute amount of pressure contrast induced in a reservoir decreases as the API gravity increases at constant R_{sb}. However, on a "normalized" basis, the amount of DD indicated is essentially unaffected by changing API gravity. The saturation contrasts indicate that the DD decreases somewhat with increasing API gravity.

   b. For constant API gravity with varying values of R_{sb}, the absolute amount of pressure draw down is essentially the same; however on a "normalized" basis, it is obvious that the amount of DD decreases as the R_{sb} increases. The saturation contrasts indicate that this conclusion is true.

   c. The deviation of the producing GOR curve for an unsteady-state prediction from that of a steady-state prediction is again a good indicator of the amount of DD induced.

   d. The fraction of total recoverable oil and gas that had been recovered at economic abandonment increased with increasing API gravity at constant R_{sb}, and increased with increasing R_{sb} at constant API gravity.

   e. Combining a, b, and d, it seems evident that as the reservoir fluid properties change in such a manner as to decrease the amount of DD the fraction of total recoverable oil that will be recovered at some reasonable economic abandonment rate will increase.

While the results of this study offer many interesting and informative insights into solution-gas drive behavior, several aspects need further investigation. Consequently, it is recommended that the following steps be taken:

1. Expand the present system into a radial geometry and, then, two and three dimensions. Using these expanded models, investigate the validity of the basic conclusions reached here concerning initial producing rate in a more "real" system.

2. Expand the range of fluid data covered, and in conjunction with #1, develop a general discussion of the producing characteristics of solution-gas drive reservoirs.

NOMENCLATURE

B_g Gas Formation Volume Factor, res. ft.^{3}/scf.

B_o Oil Formation Volume Factor, res. bbl/STB.

B_{ob} Bubble Point B_o, res. bbl/STB.

CTP Constant Terminal Pressure

CTR Constant Terminal Rate

DD Differential Depletion

k Absolute Permeability, Darcys

k_{rg} Relative Permeability to Gas

k_{ro} Relative Permeability to Oil

GOR Gas/Oil Ratio

p_c Capillary Pressure, psi

p_g Gas Pressure, psi

p_o Oil Pressure, psi

q_o Oil Production Rate, ft^3/(ft^3 res. vol. * day)

R Producing Gas/Oil Ratio, scf/ST ft^3

R_s Solution Gas/Oil Ratio, scf/ST ft^3

R_{sb} Bubble Point R_s, scf/STB

S_g Gas Saturation, Fractional

S_{ge} Equilibrium Gas Saturation, Fraction

S_o Oil Saturation, Fractional

S_{oir} Irreducible Oil Saturation, Fractional

S_{wc} Connate Water Saturation, Fractional

t Time, days

v_g Gas Velocity, feet/day

v_o Oil Velocity, feet/day

x Distance, feet

ϕ Porosity, fractional

μ_g Gas Viscosity, centipoise

μ_o Oil Viscosity, centipoise

∂ Partial Differential Operator

d Total Differential Operator

Δ Delta, Change in a Quantity

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APPENDIX A.

DEVELOPMENT OF THE MATHEMATICAL MODEL

The equations used describe a thin, linear, horizontal, isotropic and homogeneous reservoir with constant cross-sectional area in which oil and gas are flowing simultaneously. The following assumptions are necessary in this development.

1. The fluid flow in the reservoir is isothermal.

2. The fluid properties can be characterized by the so-called "P-V-T" relationships.

3. The relative permeabilities of the two fluids can be described by a functional relationship dependent only on saturation.

4. The water phase is always at non-movable connate saturation.

5. The reservoir rock is composed of consolidated sandstone containing only intergranular porosity.

The basic equations needed are:

Continuity equation for each phase --

oil:

$$-\frac{\partial}{\partial x}\left(\frac{v_o}{B_o}\right) - q_o = \phi \frac{\partial}{\partial t}\left(\frac{S_o}{B_o}\right)^{*} \quad (A-1)$$

* All terms defined in the nomenclature.

gas:

$$-\frac{\partial}{\partial x}\left(\frac{v_g}{B_g}+\frac{R_s v_o}{B_o}\right)-q_o R^{**}$$

$$=\phi\frac{\partial}{\partial t}\left(\frac{S_g}{B_g}+\frac{R_s S_o}{B_o}\right) \qquad \text{(A-2)}$$

Darcy's law for each phase --

oil:

$$v_o=-\frac{6.328\,k\,k_{ro}}{\mu_o}\frac{\partial p_o}{\partial x} \qquad \text{(A-3)}$$

gas:

$$v_g=-\frac{6.328\,k\,k_{rg}}{\mu_g}\frac{\partial p_g}{\partial x} \qquad \text{(A-4)}$$

Capillary pressure equation relating p_o and p_g --

$$p_c(S_o)=p_g-p_o \qquad \text{(A-5)}$$

And, the saturation sum equation --

$$S_o+S_{wc}+S_g=1.0 \qquad \text{(A-6)}$$

By rearranging A-5 and applying the chain rule while differentiating the result with respect to "x" the result is:

$$\frac{\partial p_o}{\partial x}=\frac{\partial p_g}{\partial x}-\frac{dp_c}{dS_o}\frac{\partial S_o}{\partial x} \qquad \text{(A-7)}$$

Expanding the time derivative on the right hand side of the equations that result when equations A-1, A-2, A-3, A-4, A-6 and A-7 are combined, the following are obtained:

oil:

$$\frac{\partial}{\partial x}\left(\frac{6.328\,k\,k_{ro}}{B_o\mu_o}\frac{\partial p_g}{\partial x}\right)-\frac{\partial}{\partial x}\left(\frac{6.328\,k\,k_{ro}}{B_o\mu_o}\frac{dp_c}{dS_o}\frac{\partial S_o}{\partial x}\right)-q_o=\phi S_o\frac{d}{dp_o}\left(\frac{1}{B_o}\right)\frac{\partial p_g}{\partial t}$$

$$+\phi\left[\frac{1}{B_o}-S_o\frac{d}{dp_o}\left(\frac{1}{B_o}\right)\frac{dp_c}{dS_o}\right]\frac{\partial S_o}{\partial t} \qquad \text{(A-8)}$$

gas:

$$\frac{\partial}{\partial x}\left[6.328\,k\left(\frac{k_{rg}}{B_g\mu_g}+\frac{k_{ro}R_s}{B_o\mu_o}\right)\frac{\partial p_g}{\partial x}\right]$$

$$-\frac{\partial}{\partial x}\left(\frac{6.328\,k\,k_{ro}R_s}{B_o\mu_o}\frac{dp_c}{dS_o}\frac{\partial S_o}{\partial x}\right)-q_oR$$

$$=\phi\left[S_o\left(\frac{1}{B_o}\frac{dR_s}{dp_o}-\frac{R_s}{B_o^2}\frac{dB_o}{dp_o}\right)\right.$$

$$\left.+\left(1-S_{wc}-S_o\right)\frac{d}{dp_g}\left(\frac{1}{B_g}\right)\right]\frac{\partial p_g}{\partial t}$$

$$+\phi\left[\frac{R_s}{B_o}-\frac{1}{B_g}-S_o\left(\frac{1}{B_o}\frac{dR_s}{dp_o}\right.\right.$$

$$\left.\left.-\frac{R_s}{B_o^2}\frac{dB_o}{dp_o}\right)\frac{dp_c}{dS_o}\right]\frac{\partial S_o}{\partial t} \qquad \text{(A-9)}$$

These two non-linear, partial differential equations have nine dependent variables: S_o, p_g, μ_o, μ_g, R_s, B_o, B_g, k_{ro}, and k_{rg}. The auxilary equations necessary to make a consistent set are:

$$B_o=B_o(p_o),\quad \mu_o=\mu_o(p_o),$$
$$B_g=B_g(p_g),\quad \mu_g=\mu_g(p_g);$$
$$R_s=R_s(p_o), \qquad \text{(A-10)}$$

and:

$$k_{rg}=k_{rg}(S_o),\quad k_{ro}=k_{ro}(S_o); \qquad \text{(A-11)}$$

** $R=R_s+\dfrac{B_o}{B_g}\dfrac{\mu_o}{\mu_g}\dfrac{k_{rg}}{k_{ro}}$

Along with the definitions of A-10 and A-11, equations A-8 and A-9 constitute a system in essentially two unknowns, p_g and S_o.

In the present formulation the production terms, q_o and q_oR in the differential equations, are used to take care of fluid flow out of the system, therefore, a no-flow condition must be imposed at the boundaries of the reservoir. This is accomplished by setting the distance derivative of pressure to zero; i.e.,

$$\frac{dp_g}{\partial x} = 0 \qquad \text{(A-12)}$$

Also, we must either specify the production rate or the pressure at the well bore. These two conditions can be represented as follows:

Constant terminal rate (CTR) case --

$$q_o = \text{constant} \qquad \text{(A-13)}$$

Constant terminal pressure (CTP) case --

$$p_{g_1} = \text{constant} \qquad \text{(A-14)}$$

In either case, CTP or CTR, when one quantity is set the other must vary and becomes an unknown in the solution.

Equations A-8 and A-9 are non-linear, second order partial differential equations for which no analytical solution exists; consequently a numerical scheme had to be developed. To this end, a time-distance solution grid was adopted and finite difference analogs to the basic equations were written. An iterative scheme was developed for solving these equations to predict the reservoir performance. A complete description of this technique can be found in Chapter 3 of reference 25.

APPENDIX B.
DERIVATION OF THE "RADIAL-SYSTEM-EQUIVALENT-RATE" (RSER) EQUATION

Since the mathematical model used in this study is for a linear system, there exists the problem of correlating producing rates for this system with those for a more real model: a radial system. In an attempt to resolve this conflict the following "radial-system-equivalent-rate" (RSER) equation was derived. While it is realized that this technique and the resulting equation are rather idealistic, it is at least a first attempt at a correlation.

From single phase, steady-state fluid flow, the producing rate is given by --

Linear system:

$$q_l = \frac{1.127\, A\, k\, \Delta p}{\mu L} \qquad \text{(B-1)}$$

Radial system:

$$q_r = \frac{7.07\, h\, k\, \Delta p}{\mu \ln \frac{r_e}{r_w}} \qquad \text{(B-2)}$$

where:
- q = flow rate (bbl/day)
- A = area (feet squared)
- h = thickness (feet)
- k = absolute permeability (darcys)
- Δp = pressure drop (psi)
- μ = viscosity (centipoise)
- L = length (feet)
- r_e = reservoir radius (feet)
- r_w = well bore radius (feet)

Now, let us define:

$$R_r = \frac{q_l}{q_r} = \frac{1.127\, A\, k\, \Delta p\, \mu \ln \frac{r_e}{r_w}}{7.07\, h\, k\, \Delta p\, \mu\, L} \qquad \text{(B-3)}$$

If we assume that the viscosity and permeability values are equal, and, also, that we wish the pressure drop in the two systems to be the same, we get:

$$R_r = \frac{.1595\, A \ln \frac{r_e}{r_w}}{L\, h} \qquad \text{(B-4)}$$

Equation B-4 expresses the ratio of the producing rates for a linear and a radial single phase, steady-state system.

As shown in the text, the predictions in this study were made with a reservoir length of 1000 feet and a cross-sectional area of 1000 feet squared. To keep a reasonable similarity between our radial and linear systems we should use r_e = 1000 feet and pick a reasonable value for r_w, say .333 feet. Substituting these values into B-4 we obtain:

$$R_r = \frac{.1595\,(1000) \ln \left[\frac{1000}{.333}\right]}{1000\, h} = \frac{1.275}{h} \qquad \text{(B-5)}$$

While the choice of .333 for r_w may seem rather arbitrary, notice that if $r_w = .5$, the numerator of equation B-5 would only change to 1.211. Obviously R_r is rather insensitive to the value of r_w.

Using equation B-5, Table B-1 was generated showing the relation between R_r and h.

Table B-1

h	R_r
5	.255
10	.1275
15	.0875
20	.06375
25	.510
30	.0425
35	.03643
40	.031875
45	.02833
50	.0255

APPENDIX C.

RELATIVE PERMEABILITY CORRELATION USED

In the basic equations to be solved the terms k_{ro}, k_{rg}, and k_{rg}/k_{ro} appear. Since this study was to approximate a "typical" sandstone reservoir, the decision was reached to forego using the relative permeability characteristics for any particular reservoir; it was decided to use some of the general correlations available in the literature.

To obtain k_{rg}/k_{ro} the following was used: (after Wahl, Mullins, and Elfrink[26])

$$\frac{k_{rg}}{k_{ro}} = \psi(0.0435 + 0.4556\psi) \qquad \text{(C-1)}$$

where:

$$\psi = \frac{1.0 - S_{wc} - S_{ge} - S_o}{S_o - S_{oir}} \qquad \text{(C-2)}$$

For obtaining k_{ro} an equation proposed by Pirson[27] was used:

$$k_{ro} = \left[\frac{S_o - S_{oir}}{1 - S_{wc} - S_{oir}}\right]^2 \qquad \text{(C-3)}$$

When k_{rg} is needed separately it is obtained as the product of the resulting values from C-1 and C-3.

TABLE I

RESERVOIR AND PRODUCTION PARAMETERS FOR RATE EFFECT STUDY

Property	Value
Length	1000 ft
Area	1000 sq. ft.
Porosity	0.15
Initial Oil Saturation	0.[illegible]
Equilibrium Gas Saturation	0.[illegible]45
Irreducible Oil Saturation	0.[illegible]
Permeability	10 md
Bubble Point	[illegible] psi
Minimum Well Bore Pressure	[illegible]0 psi

TABLE II

RATE EFFECT STUDY -- INITIAL RATE AND ULTIMATE RECOVERY INFORMATION

Rate (bbl/day) (1)	Initial Time Step Length (days) (2)	Ultimate Fractional Oil Recovery (approx. 10,000 days) (3)	Ultimate Fractional Gas Recovery (approx. 10,000 days) (4)	$\frac{(3)_i}{(3)_{30}}$ (5)	$\frac{(4)_i}{(4)_{30}}$ (6)
30	0.5	[illegible]420	[illegible]5011	1.000000	1.000000
15	1.0	[illegible]	[illegible]5506	1.00[illegible]	1.000[illegible]
10	1.5	[illegible]	[illegible]	1.00[illegible]	1.000[illegible]
5	3.0	[illegible]	[illegible]	1.00[illegible]	.999[illegible]
4	3.75	[illegible]016	[illegible]	1.00[illegible]	.999465
3	5.5	[illegible]	[illegible]206	1.00[illegible]	.999[illegible]
2	7.5	[illegible]	[illegible]	1.00[illegible]	.999[illegible]
1	15.0	[illegible]	[illegible]	1.00[illegible]	.998[illegible]
.5	30.0	[illegible]*	[illegible]*	1.00[illegible]	.998[illegible]
.1	150.0	[illegible]**	[illegible]**	.99[illegible]	.998[illegible]

* Was allowed to run to 25,000 days because of the low rate

** Was allowed to run to 60,000 days because of the extremely low rate

TABLE [illegible]

RATE EFFECT STUDY -- CONDITIONS AT ABANDONMENT (RSER) [illegible]

Rate (1)	Cumulative Fractional Oil Recovery (2)	Total Producing Time (days) (3)	Average Reservoir Pressure (psi) (4)	Cumulative Fractional Gas Recovery (5)	$\frac{(2)}{(2)_{30}}$ (6)	$\frac{(3)}{(3)_{30}}$ (7)	$\frac{(3)}{(3)_{30}}$ (8)
[illegible]	[illegible]*	[illegible]	[illegible]	[illegible]**	1.00000	1.00000	1.00000
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	1.00[illegible]	1.0[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	1.00[illegible]	1.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	[illegible]	1.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	1.0[illegible]	1.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	[illegible]	1.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	[illegible]	1.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	1.0[illegible]	2.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	1.0[illegible]	4.[illegible]

* [illegible]

** [illegible]

*** [illegible]

TABLE III

RATE EFFECT STUDY -- CONDITIONS AT ABANDONMENT (RSER) [illegible]

Rate (bbl/day) (1)	Cumulative Fractional Oil Recovery (2)	Total Producing Time (days) (3)	Average Reservoir Pressure (psi) (4)	Cumulative Fractional Gas Recovery (5)	$\frac{(2)}{(2)_{30}}$ (6)	$\frac{(3)}{(3)_{30}}$ (7)	$\frac{(3)}{(3)_{30}}$ (8)
30.0	[illegible]*	[illegible]	385.[illegible]	[illegible]**	1.00000	1.00000	1.00000
15.0	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	1.00[illegible]	1.05[illegible]
10.0	[illegible]	[illegible]	[illegible]	[illegible]	1.00[illegible]	.999[illegible]	1.1[illegible]
5.0	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	.99[illegible]	1.[illegible]
4.0	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	.99[illegible]	[illegible]
3.0	[illegible]	[illegible]	[illegible]	[illegible]	1.01[illegible]	1.[illegible]	2.[illegible]
2.0	[illegible]	[illegible]	[illegible]	[illegible]	1.0[illegible]	1.[illegible]	3.[illegible]
1.0***							
0.5***							
0.1***							

* Approximately 25% of total recoverable oil

** Approximately 91% of total recoverable gas

*** This initial rate is below the abandonment rate

TABLE V

INITIAL (BUBBLE POINT) FLUID PROPERTIES AND RESERVOIR CONTENTS

[illegible] (1)	Pressure (psi) (2)	Oil Formation Volume Factor (res. bbl/STB) (3)	Solution Gas-Oil Ratio (scf/STB) (4)	Gas Formation Volume Factor (res. bbl/scf) (5)	Oil Viscosity (centipoise) (6)	Gas Viscosity (centipoise) (7)	Oil in Place (STB) (8)	Gas in Place (scf) (9)
[illegible]	[illegible]	1.[illegible]	[illegible]	0.000[illegible]	1.[illegible]	0.0[illegible]	1[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	0.[illegible]	1.[illegible]	0.0[illegible]	1[illegible]	[illegible]
[illegible]	[illegible]	1.[illegible]	[illegible]	0.00[illegible]	[illegible]	0.0[illegible]	14,[illegible]	[illegible]
[illegible]	[illegible]	1.[illegible]	[illegible]	0.[illegible]	[illegible]	0.0[illegible]	14,[illegible]	[illegible]
[illegible]	[illegible]	1.[illegible]	[illegible]	0.00[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	1800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1[illegible]	[illegible]
[illegible]	[illegible]	1.[illegible]	[illegible]	0.00[illegible]	0.[illegible]	0.02[illegible]	12,[illegible]	1[illegible]
[illegible]	[illegible]	1.[illegible]	[illegible]	0.[illegible]	[illegible]	0.02[illegible]	10,[illegible]	1[illegible]

TABLE VI

ULTIMATE OIL AND GAS RECOVERY (AT 10,000 DAYS)

Oil	Total Oil Recovery (bbl)	Total Fractional Oil Recovery	Total Gas Recovery (scf)	Total Fractional Gas Recovery	Average Oil Saturation At Abandonment (fractional)
(1)	(2)	(3)	(4)	(5)	(6)
15-600	3051.7	0.224184	4,839,088	0.985666	0.47745
22-600	3903.9	0.230762	5,594,915	0.963758	0.44541
30-600	4188.0	0.290722	6,442,235	0.976523	0.40665
40-600	4262.6	0.297013	8,222,841	0.960123	0.39721
40-200	4428.5	0.255434	5,060,763	0.921070	0.49562
40-600	4262.6	0.297013	8,222,841	0.960123	0.39721
40-1000	3492.5	0.322757	11,752,220	0.977816	0.32837
40-1400	5545.2	0.343153	13,964,591	0.980677	0.27623

TABLE VII

MAXIMUM CONTRASTS ACROSS RESERVOIR

Oil	Maximum Pressure Contrast Across Reservoir (psi)	Normalized Maximum Pressure Contrast Across Reservoir	Maximum Saturation Contrast Across Reservoir (fractional)	Normalized Maximum Saturation Contrast Across Reservoir
(1)	(2)	(3)	(4)	(5)
15-600	1392.1	2812	1247	3657
22-600	970.2	2283	1135	3261
30-600	845.6	.2347	1035	2760
40-600	442.3	2527	.0996	2752
40-200	474.3	4623	1435	6283
40-600	442.3	2527	0996	2752
40-1000	432.9	1374	0439	2142
40-1500	460.4	1037	0740	1566

TABLE VIII

OIL COMPARISON CASES -- CONDITIONS AT ABANDONMENT (RSER) = 0.15/0.05 × 3.0 bbl/day

Oil	Cumulative Fractional Oil Recovery	Total Producing Time (days)	Average Reservoir Pressure (psi)	Cumulative Fractional Gas Recovery	Fraction of Total Recoverable Oil Recovered	Fraction of Total Recoverable Oil Recovered
(1)	(2)	(3)	(4)	(5)	(6)	(7)
15-600	.195366	1616.25	223.226	.939200	956725	.952650
22-600	222303	1664.50	172.978	.945239	963122	.960045
30-600	261454	2115.78	122.311	944339	969497	967021
40-600	289152	2320.86	96.112	940448	973531	971866
40-200	241541	3522.50	87.565	.855424	945610	926546
40-600	289152	2320.86	96.112	.940448	973531	971866
40-1000	314253	1968.44	96.516	954886	973652	977146
40-1400	336345	1647.02	98.820	961176	978734	982114

TABLE IX

OIL COMPARISON CASES -- CONDITIONS AT ABANDONMENT (RSER) = 20/0.05 × 40.0 bbl/day

Oil	Cumulative Fractional Oil Recovery	Total Producing Time (days)	Average Reservoir Pressure (psi)	Cumulative Fractional Gas Recovery	Fraction of Total Recoverable Oil Recovered	Fraction of Total Recoverable Oil Recovered
(1)	(2)	(3)	(4)	(5)	(6)	(7)
15-600	169704	850.00	975.692	741636	831133	.752421
22-600	197492	965.00	685.362	.784602	855807	797759
30-600	.246420	1205.00	424.105	768561	857933	807539
40-600	247475	1195.00	338.633	766242	.833213	.791471
40-200	.134550	610.00	341.173	344534	526751	422914
40-600	247475	1195.00	338.633	766242	833213	791471
40-1000	279134	1130.00	329.365	635952	864843	855617
40-1400	.308316	1065.00	349.636	645365	897172	.882415

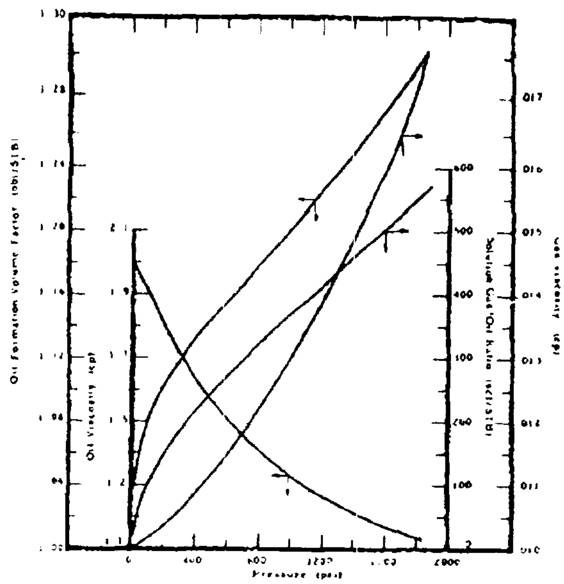


Fig. 1a--Various Fluid Properties for Rate Comparison Runs.

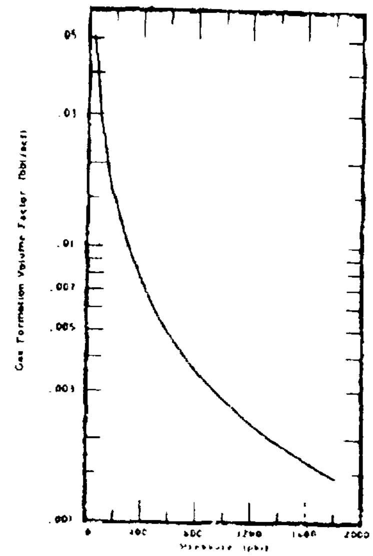


Fig. 1b--Gas Formation Volume Factor for Rate Comparison Runs.

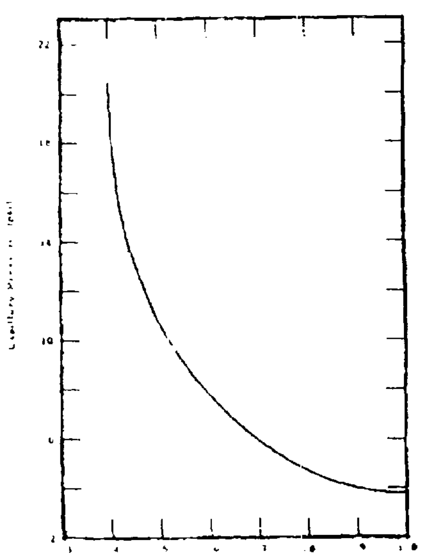


Fig. 2--Capillary Pressure Curve Used.

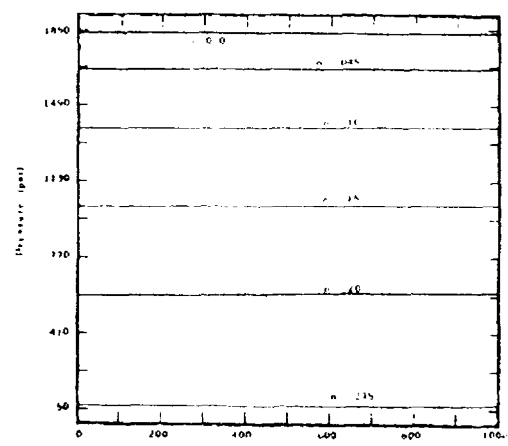


Fig. 3a--Reservoir Pressure Profiles Initial Rate = 0.1 B/D.

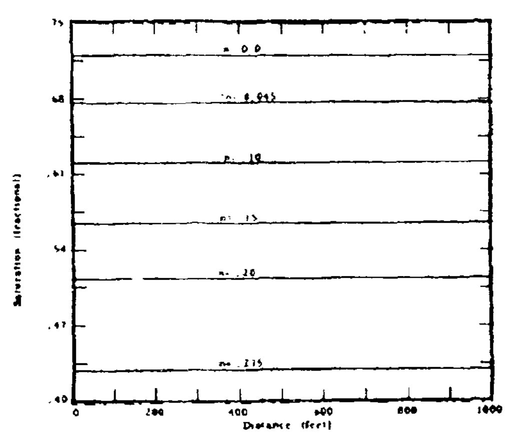


Fig. 3b--Reservoir Saturation Profiles Initial Rate = 0.1 B/D.

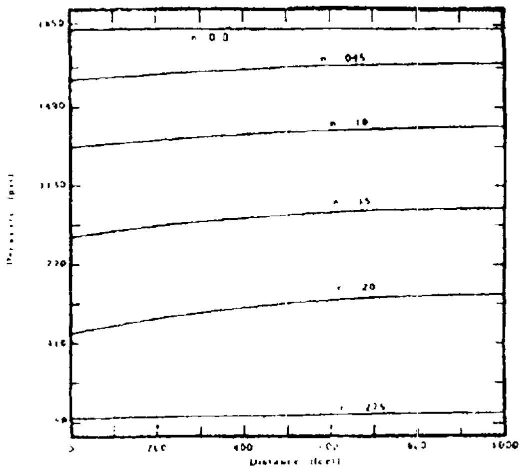


Fig. 4a--Reservoir Pressure Profiles
Initial Rate = 1.0 B/D.

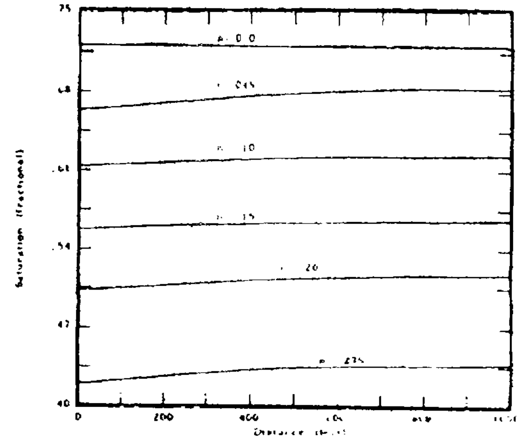


Fig. 4b--Reservoir Saturation Profiles
Initial Rate = 1.0 B/D.

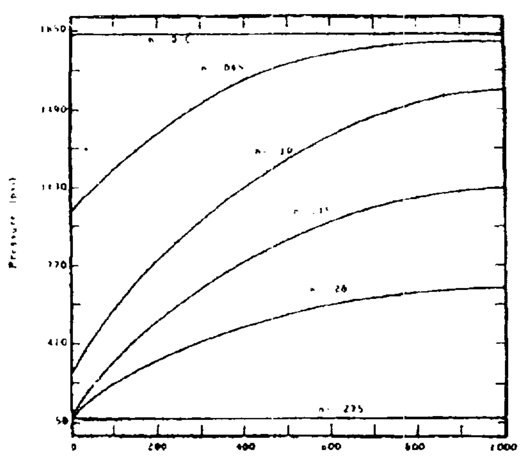


Fig. 5a--Reservoir Pressure Profiles
Initial Rate = 10 B/D.

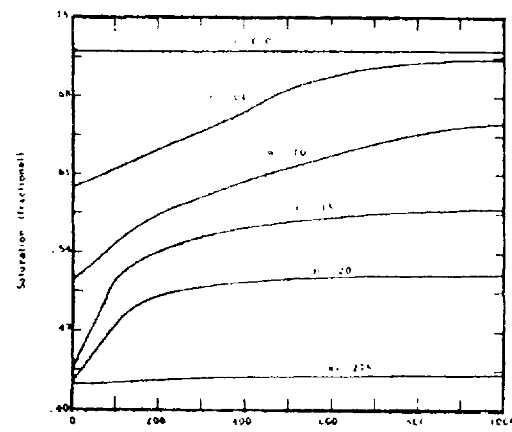


Fig. 5b--Reservoir Saturation Profiles
Initial Rate = 10 B/D.

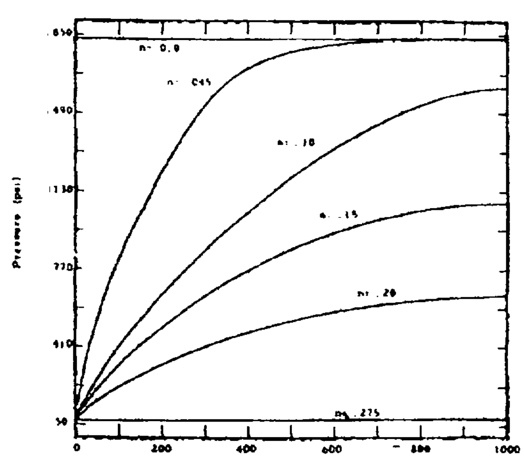


Fig. 6a-- Reservoir Pressure Profiles
Initial Rate = 30 B/D.

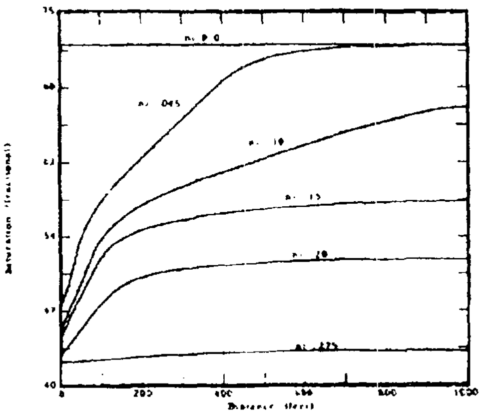


Fig. 6b--Reservoir Saturation Profiles
Initial Rate = 30 B/D.

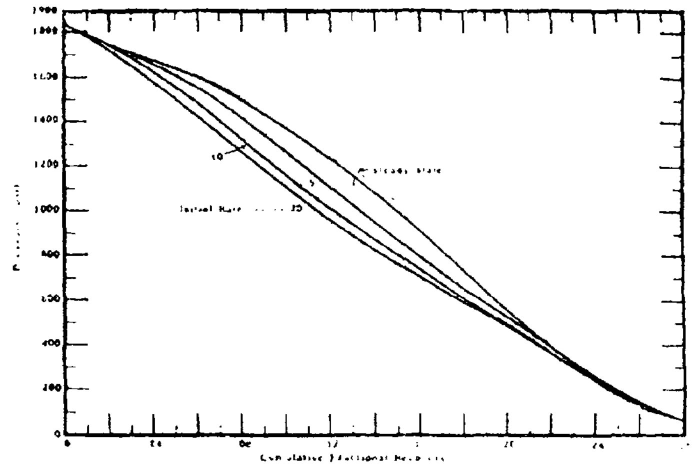


Fig. 7--Average Reservoir Pressure vs Recovery
for Various Initial Rates.

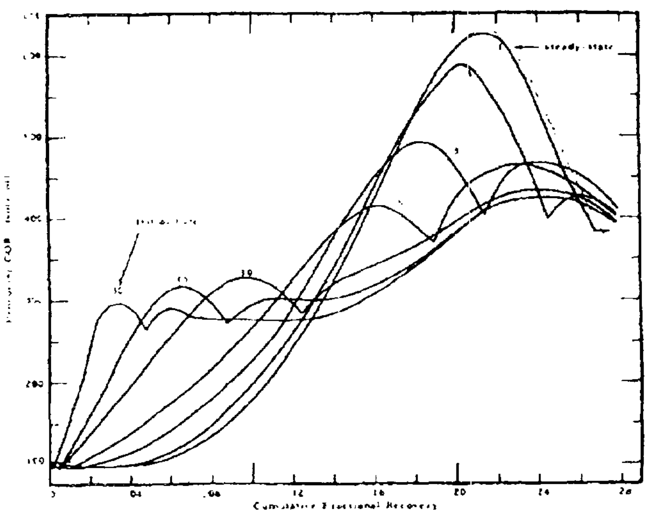


Fig. 8--Producing GOR Curves for Various Initial
Rates.

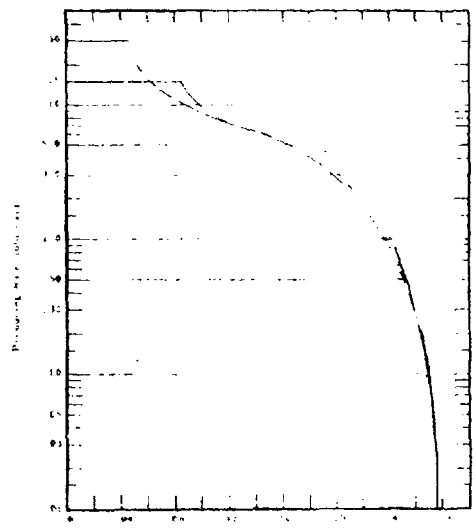


Fig. 9--Producing Rate vs Recovery for
Various Initial Rates.

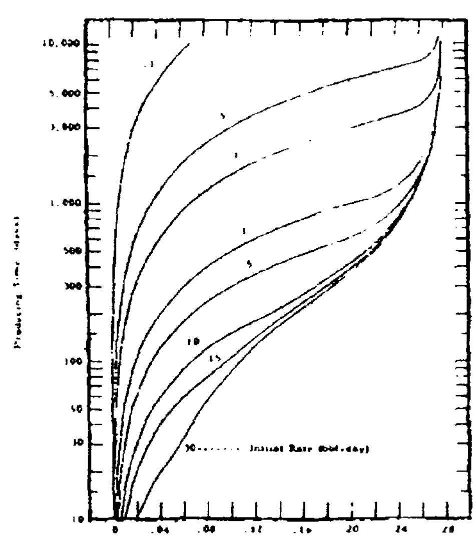


Fig. 10--Producing Time vs Recovery for
Various Initial Rates.

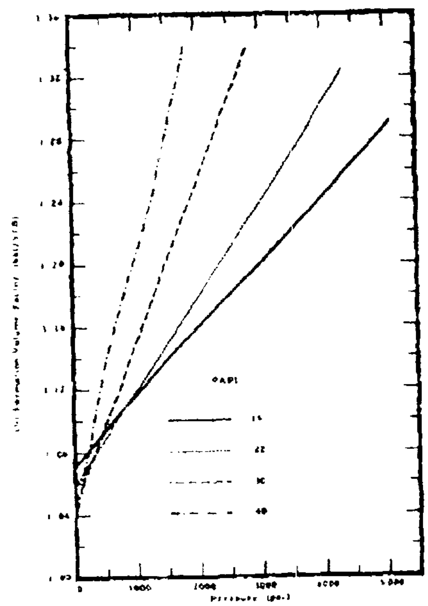


Fig. 16--Oil Formation Volume Factor for R_{sb} = 600 Oils.

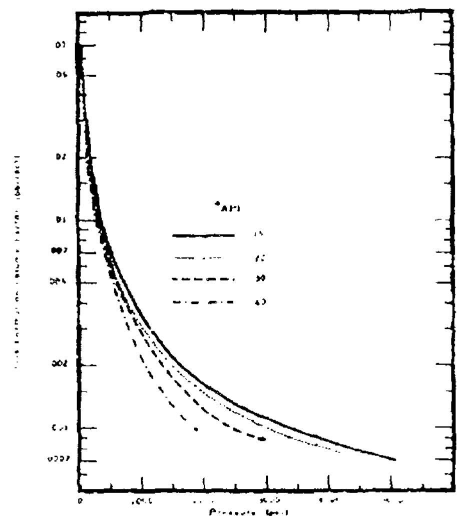


Fig. 17--Gas Formation Volume Factors for R_{sb} = 600 Oils.

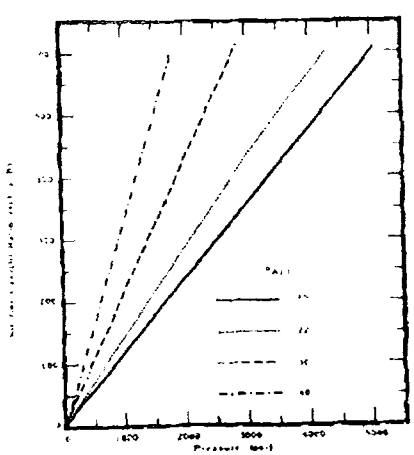


Fig. 18--Solution GOR for R_{sb} = 600 Oils.

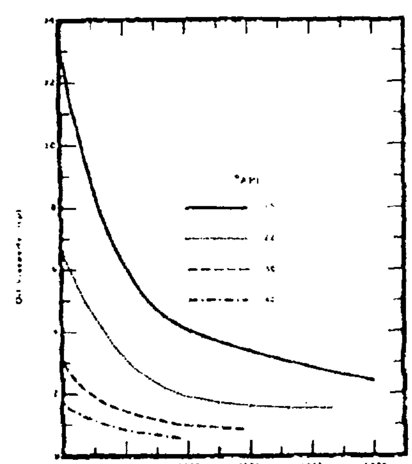


Fig. 19--Oil Viscosity for R_{sb} = 600 Oils.

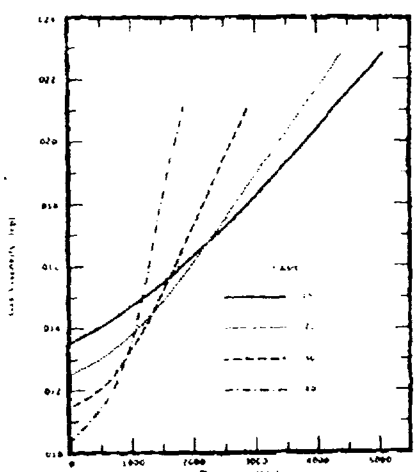
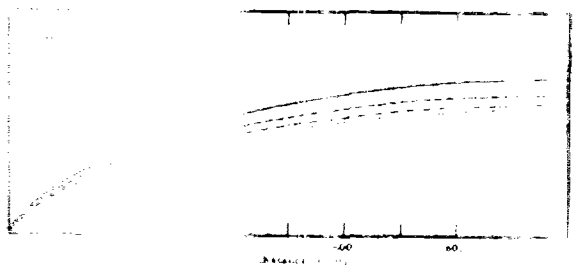
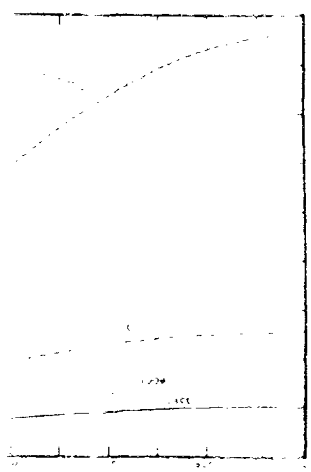
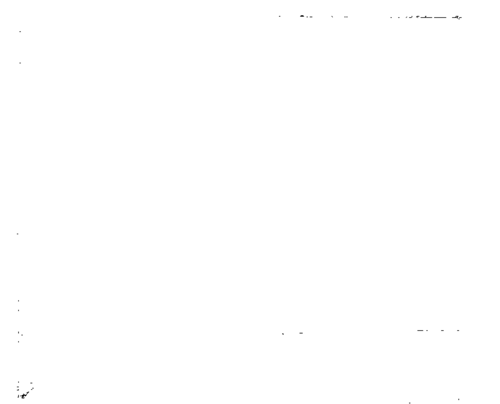


Fig. 20--Gas Viscosity for R_{sb} = 600 Oils.



...ximum Reservoir Pressu...
... 600 Oils.





...lized Maximum Reservo...
...les, 40° API Oils.

...ized Maximum Res...
...les, 40° API...

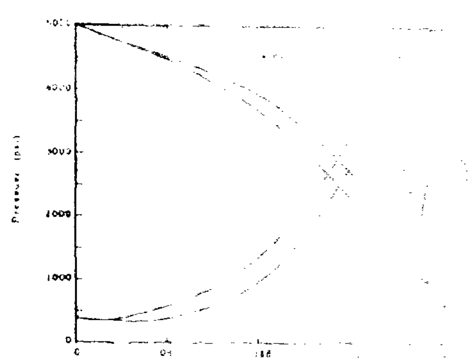


Fig. 23--A...g Pressure...
...urves, 15-...

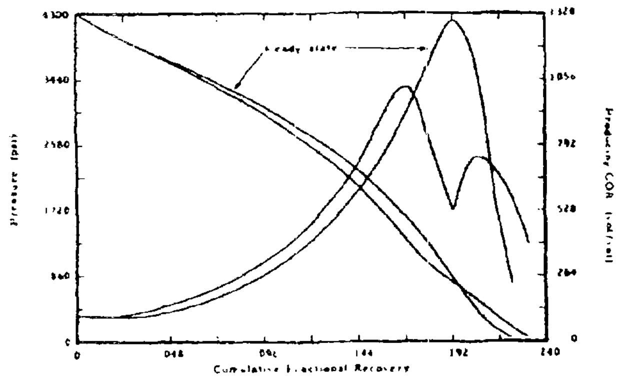


Fig. 24--Average Pressure and Producing GOR Curves, 22-600 Oil.

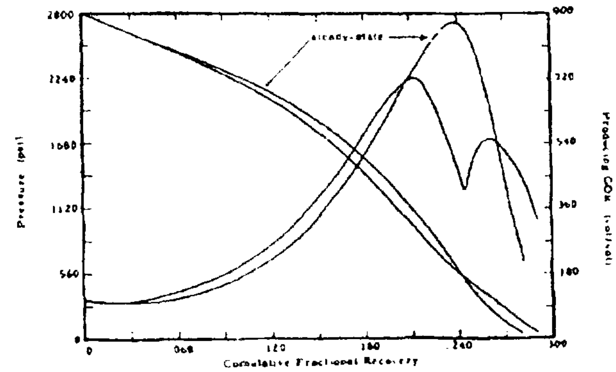


Fig. 25--Average Pressure and Producing GOR Curves, 30-600 Oil.

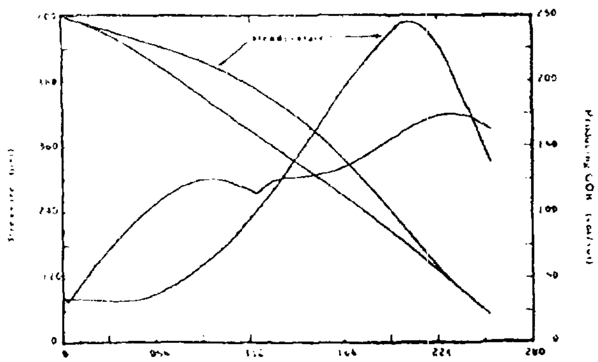


Fig. 26--Average Pressure and Producing GOR Curves, 40-600 Oil.

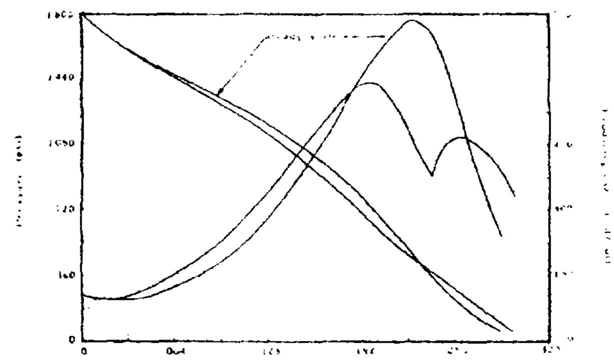


Fig. 27--Average Pressure and Producing GOR Curves, 40-600 Oil.

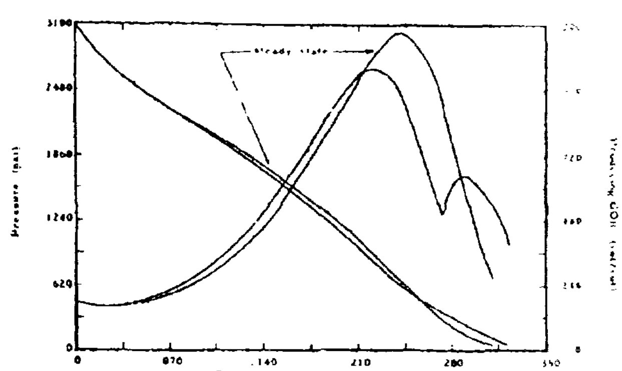


Fig. 28--Average Pressure and Producing GOR Curves, 40-1000 Oil.

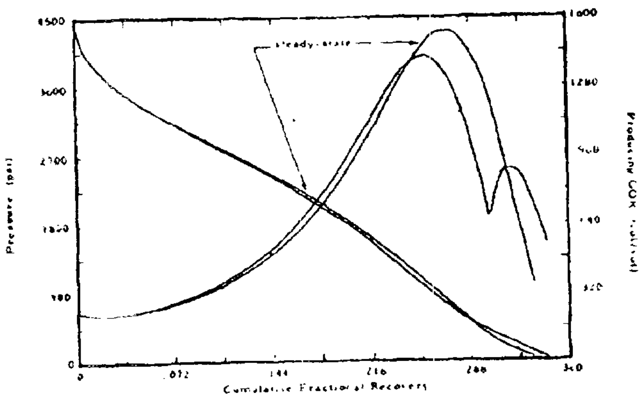


Fig. 29--Average Pressure and Producing GOR Curves, 40-1500 Oil.

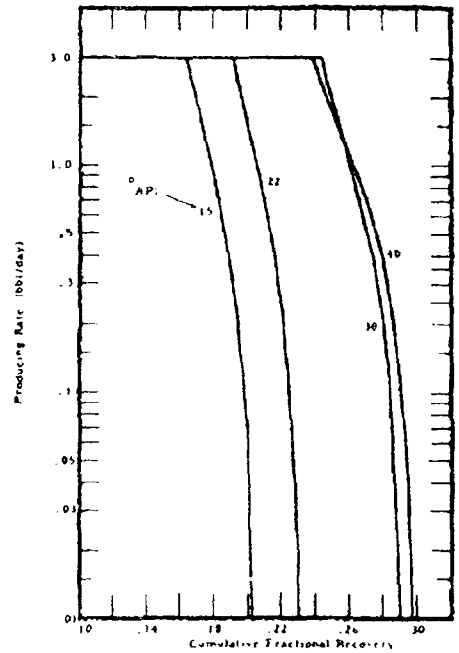


Fig. 30--Producing Rates vs Recovery R_{sb} = 600 Oils.

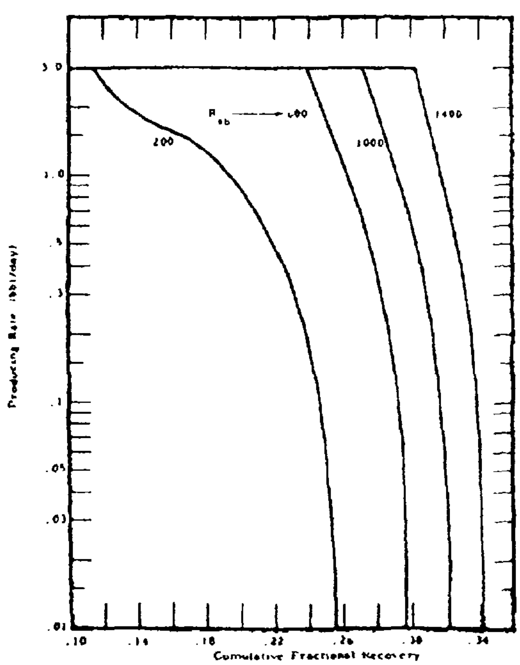


Fig. 31--Producing Rate vs Recovery 40° API Oils.