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The Effect of an Initial Gas Saturation on the Performance of a Waterflood

H. Dykstra, Consultant
SPE Member

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ABSTRACT

The behavior of a waterflood is affected, among other factors, by the initial gas saturation at the start of injection. To illustrate this effect on oil rate and on the water-oil ratio (WOR), calculations were made with the Dykstra-Parsons(1) layered system model. Two cases were chosen, one for a high gravity oil with a low mobility ratio, and one for a low gravity oil with a relatively high mobility ratio.

The factors that effect the recovery of oil are described.The ideal situation for calculating a waterflood performance, would be that the values of all of the parameters to be used in the model correctly define the reservoir and fluid properties and the displacement process. The more closely the parameters define the system, the greater will be the confidence in the predicted results. If production history is available, a history match can be made. Certain parameters can then be adjusted to obtain a better match with actual performance before predictions are made of future performance. Examples are given for two waterfloods.

The fluid properties and saturation data used in the analysis were based on pressures obtained from depletion calculations to establish initial conditions prior to the start of the waterflood. For Case 1, a 40 deg API oil having an initial bubble point pressure of 3500 psia at 220 deg F was depleted down to a gas saturation of 30 percent. For Case 2, a 20 deg API oil having an initial bubble point pressure of 1500 psia at 130 deg F was depleted down to a gas saturation of 12 percent.

The results of the study show a substantial decrease in maximum oil rate and a substantial rise in the level of the WOR-recovery curve with increase in initial gas saturation.These types of results, showing the effect of an initial gas saturation, have not heretofore been published.

INTRODUCTION

A considerable number of papers have been published on methods of calculating waterflood oil recovery. Numerous references to these methods are given in a Monograph by Craig (2).

They can be categorized into four groups:

1. As layered systems accounting for reservoir heterogeneity.
2. Well patterns that account for areal sweep efficiency.
3. Empirical methods based on actual performance.
4. Numerical methods using reservoir simulators.

Several of the references cited by Craig(2) show a comparison between actual results and results obtained by different methods. Unfortunately, only one of the references gave sufficient detail to compare calculated oil rates and recoveries with actual rates and recoveries. None gave sufficient information to calculate WOR, or to determine reasons for the difference between calculated recovery and actual recovery.

This paper reviews the information needed to make a calculation of waterflood recovery. Equations for the Dykstra-Parsons(1) method will be described and applied to determine the effect of an initial gas saturation on the performance of a waterflood. For the one reference with sufficient data, a comparison between actual recovery and recovery calculated by the Dykstra-Parsons method will be presented.

The results will be of help to an engineer in making decisions regarding the timing of a waterflood, the well spacing, or the rate of injection, which in turn is related to the well spacing. An engineer can also apply the method to an ongoing waterflood to determine the economics of increasing the water injection rate.

PARAMETERS THAT AFFECT RECOVERY

In calculating the performance, or in matching the history of a waterflood, using the Dykstra-Parsons method, the following parameters are required:

1. Initial oil saturation at start of flood. Can be obtained from core analysis data, logging measurements, or from material balance calculations. The last requires a knowledge of the reservoir fluid properties and prior history of reservoir pressure and production data.
2. Residual oil saturation as a function of the initial oil saturation, oil-water viscosity ratio, and pore volumes of water injected. The lower the initial oil saturation, the lower is the residual oil saturation from water displacement(1-3). However, many predictions have been made using a residual oil saturation obtained after a large number of pore volumes of throughput, when in actuality only from one to two pore volumes of water are required to flood out a reservoir.
3. Initial gas saturation, which is a function of the stage of depletion. It can be obtained as for initial oil saturation.
4. Residual gas saturation, a function of initial gas saturation and increase in pressure during the waterflood process. Residual gas saturations can be obtained from laboratory flood tests(4). Calculations can then be made based on an increase in reservoir pressure, to determine how much of the gas will go back into solution.
5. Permeability distribution from core analysis data. The average should be based on a vertical distribution not on a volumetric distribution.
6. Porosity.
7. Relative permeability to oil and water from laboratory tests. The permeability to oil is at the start of a waterflood, with or without a residual gas saturation as determined from Item 4 above. The permeability to water is at the end of the flood test.

8. Areal sweep efficiency, a function of type of pattern, mobility ratio, and pore volumes of water injected. Can be obtained from published information on the various well patterns(2,5-8).

9. Oil formation volume factor at start of waterflood.

10. Oil viscosity at start of waterflood. It may be necessary to account for gas going back into solution. Calculations should be made to determine if there is a significant effect.

11. Water viscosity, a function of temperature and salt content.

12. Mobility ratio which in turn is a function of relative oil and water permeabilities as determined above and of oil and water viscosities.

13. Injection rate and effectiveness of the injection. The injection rate can be based on the relative water permeability measured at the end of a laboratory flood test, or it can be obtained from well injectivity tests. The effectiveness factor is more of a problem especially at the start of a waterflood. It is a function of the increase in reservoir pressure and can be calculated from compressibility data by means of a material balance relation. For a peripheral flood it would require an estimate, or a calculation, based on the size of the aquifer connected to the reservoir. If performance data are available, it can be estimated from the relation between gross reservoir producing rate to injection rate and extrapolated into the future.

14. Reservoir area, or pattern size, and thickness determined from structure maps and isopach maps. If the parameters vary considerably over a reservoir, then the calculations can be applied to separate parts of the reservoir. Usually, however, for an initial calculation of recovery, satisfactory results can be obtained by treating the reservoir as a whole, or if faults are present, by dividing the reservoir into fault blocks.

The ideal situation would be that the values of all of the parameters correctly define the reservoir and the displacement process. Then a good match would be obtained between calculated and actual performance. In real life, however, this does not happen because many of the parameters have an uncertainty about them. Thus in a history matching procedure, some of the parameters can be varied in order to obtain a good match, while other parameters known with more certainty, can be kept fixed. An example of this will be described.

THE DYKSTRA-PARSONS METHOD

The Dykstra-Parsons method(1) for calculating waterflood recovery was originally presented in 1948. The basic assumptions were as follows:

1. The reservoir consists of isolated layers of uniform permeability with no cross flow between layers.
2. Piston like displacement; that is only one phase is flowing in any given volume element.
3. Flow is linear.
4. The fluids are incompressible.
5. The pressure drop across all layers is the same.

In order to make the calculations, whose results were given in a set of coverage charts, it was necessary to make the following additional assumptions:

1. Layer permeabilities have a log normal distribution.
2. The thickness, porosity, and initial saturations were the same for each layer.
3. The mobility ratio was the same for each layer.
4. No initial gas saturation.

None of the additional assumptions are

required if the calculations are made on a layer-by-layer basis. As shown by Felsenthal, et al(9), variations in porosity among layers, and an initial gas saturation can be accounted for. Further, as shown by Reznik, et al(10), variations of initial saturations and of mobility ratio in layers can also be included in the Dykstra-Parsons method. These authors have shown that the method can be used for either a constant pressure drop across the system or for a constant rate. Lastly, as was indicated in the original paper and by Felsenthal (9), it can also be applied to a non-linear system, such as a 5-spot pattern, by including an areal sweep efficiency factor for the given mobility ratio of the system. (In the original paper the sweep efficiency term was C1).

Thus it can be seen that the Dykstra-Parsons method can be broadly applied to any proposed waterflood, or to make a history match of an ongoing waterflood. It has a big advantage over a reservoir simulator in that it requires only a modest amount of data. A reservoir simulator, on the other hand, may require up to several orders of magnitude more data than are required for the layered system model. Furthermore much, if not most, of the data for a simulator are obtained by interpolation between known data points, or by assumptions regarding the trend of the data.

It should be mentioned here that a misconception has existed regarding the Dykstra-Parsons method that was, in part, a result of a paper by Johnson(11). The correlation given in Fig. 11 of the original paper, as used by Johnson, was never meant to be used to calculate waterflood recovery except as a first estimate of potential recovery. It was mentioned in the original paper that no reports in the literature at that time gave all of the factors necessary to calculate recovery. Hence, the correlation was developed from laboratory data in order to provide an engineer with a rough estimate of waterflood recovery.

The derivation of the basic equations that relate the flow at breakthrough in a given layer to the flow in all other layers is given in the original paper. The resulting equations were used to calculate a coverage, C, or vertical sweep efficiency, and a corresponding WOR. Though not shown in the original paper, the recovery could have been calculated from the relation

$$Np=VrCEa(Soi-Sor)/Bo \qquad (1)$$

This was pointed out by Mobarak(12) who showed the difference that can occur in calculated recovery between the use of the correlation of Fig. 11 and the above equation when initial and residual oil saturations are available.

For a complete analysis of a waterflood, it is also necessary to relate recovery to cumulative injection and time. A complete set of equations that relate all of the factors is given by Reznik, et al(10). Their equations allow for variation of layer properties, but apply only to zero initial gas saturation.

The equations for calculating recovery and corresponding WOR are given in the original paper for no initial gas saturation and by Felsenthal(9) for the presence of an initial gas saturation. What remains to be given are equations to calculate cumulative water produced, cumulative water injected, time, and oil and water producing rates. In order to calculate time it is necessary to specify a rate of injection, or to input a table of rate and time. For the example calculations on two fields as given below, one was with a constant injection rate and one was for a variable rate.

The cumulative water produced is given by the area under the WOR-Np curve. For this calculation it is assumed that the WOR remains constant during the period between breakthrough in successive layers. In actuality, as shown by Reznik, et al(10) it does not remain constant except for M=1.0. However the error in this assumption becomes quite small with increasing number of layers.

The area under the WOR-Np curve, or the cumulative water produced for any layer, J, of breakthrough is

$$Wp(J)= \overset{J}{\underset{2}{\ }}\ WOR(j)[Np(j)-Np(j-1)] \qquad (2)$$

If an initial gas saturation is present, the water of fillup is given by

$$Wf(J)=OD(J)(Sgi-Sgr)/(Soi-Sor) \qquad (3)$$

where OD is oil displaced and is given by

$$OD(J)=PV(Soi-Sor)Ea\ \overset{N}{\underset{1}{\ }}\ Xw(n) \qquad (4)$$

and the summation for Xw is for each J. The cumulative water injected then is

$$Wi(J)=Wp(J)+Wf(J)+OD(J) \qquad (5)$$

For a constant injection rate, time in years is

$$T(J)=Wi(J)/365iw \qquad (6)$$

For a variable injection rate, a rate-time table is needed from which cumulative injection can be calculated as a function of time. Linear interpolation is then used to obtain the time for each Wi(J) that was calculated for breakthrough of each succeeding layer. Rates are calculated as follows:

$$qo(J)= \frac{Np(J)-Np(J-1)}{T(J)-T(J-1)} \qquad (7)$$

$$qw(J)= \frac{Wp(J)-Wp(J-1)}{T()J-T(J-1)} \qquad (8)$$

It was assumed that the layers have equal thickness, porosity, mobility ratio, initial water, oil, and gas saturations, and residual oil and gas saturations. To consider variation in properties between layers is rarely justified(9) because of lack of information on individual layer properties. In addition, the effect of an oil-gas front on the mobility of the region ahead of the water-oil front was not considered in the analysis. The mobility of the region ahead of the oil-gas front is usually not known with certainty.

RESULTS OF THE CALCULATIONS

The data used in the calculations to determine the effect of an initial gas saturation are shown in Table 1. A constant injection rate was used to flood out a 5-spot pattern. A depletion calculation using the method described by Tracy(13) was first made to deplete the reservoir down to a low pressure. This was done in order to determine the gas saturation as a function of pressure. The oil formation volume factor of the reservoir fluid was taken at the pressure corresponding to the selected gas saturations. The oil viscosity was based on correlations by Beal(14) and by Chew and Connally(15). The PVT data were based on the correlations of Standing(16).

Relative permeability data and residual oil saturations, that were used in the calculations, were determined from water displacement tests on cores selected from three different wells that had been cored in an oilfield. The results of the tests were summarized and averaged to provide relative oil and water permeabilities as a function of water saturation. The residual oil saturations as a function of initial oil saturation and of oil-water viscosity ratio were taken at 1.5 pore volumes of water injected. Similar tests could be conducted on cores from a reservoir of interest with varying initial gas saturations. The tests should be done with an oil-water viscosity ratio that is essentially the same as that in the reservoir. Residual oil saturations determined at 1.5 pore volumes can then be plotted against initial oil saturation to obtain the required relation.

The relative permeability data were combined with the oil-water viscosity data to obtain the mobility ratios. It was assumed that the pressure increase during the waterflood would result in some of the gas going back into solution and causing a decrease in oil viscosity. It was also assumed, for simplicity, that the residual gas saturation was zero to give the maximum effect on recovery. For a proposed waterflood, calculations should be made to determine the effect of a planned increase in pressure. The sweep efficiency was obtained from average curves based on published data(2,5-8), and is a function of mobility ratio.

For the light oil of Case 1, five initial gas saturations were selected, and for the heavy oil of Case 2, four initial gas saturations were selected. The calculated results for Case 1 are shown in Figs. 1 and 2 and for Case 2 in Figs. 3 and 4. Oil rates as a function of time are shown in Figs. 1 and 3, whereas the WOR values as a function of cumulative recovery are shown in Figs. 2 and 4. As can be seen from Figs. 1 and 3, the peak oil rate is lower and is delayed with increasing gas saturations. For the maximum initial gas saturation in Case 1 the peak oil rate is delayed until 2-1/2 years after injection was started. For Case 2 the peak oil rate is delayed for about one year after start of injection.

Figs. 2 and 4 indicate that the WOR curves versus recovery for the different gas saturations are nearly parallel to each other. The curves show an increasing level with increasing initial gas saturation. In fact the WOR after breakthrough in the first layer for the maximum initial gas saturation in both Cases 1 and 2 starts above 1.0.

A summary of the total recoveries, waterflood plus depletion, is shown in Table 2. The maximum total recovery for Case 1 occurs at zero initial gas saturation and for Case 2 at 4 percent initial gas saturation. It appears that for a high shrinkage oil, water injection should be started as soon as possible after development of the field is completed, or at the time when the bubble pressure will be reached. For a low shrinkage oil, water injection can be delayed until a gas saturation develops and production data are obtained for a more complete picture of the reservoir. In any event, calculations of recovery for several stages of depletion should be combined with economic calculations to determine the optimum time and well spacing for the waterflood. It may very well be possible that with the lowering of reservoir pressure a considerable saving of injection costs could be achieved.

A COMPARISON OF CALCULATED AND ACTUAL RECOVERY

As mentioned above, almost no information has been published on the actual performance of a waterflood where all of the required information to make a prediction has been included. A paper by Guerrero and Earlougher(17), however, did present enough information such that calculations could be made but only of oil recovery and rate. The paper compared five methods of predicting waterflood recovery, one of which was the Dykstra-Parsons method. The authors did not include the results of calculations on a layer by layer basis to account for an initial gas saturation. Instead they assumed that all of the gas would be displaced prior to the time that the effect of injection was felt. The results of their study were given in plots showing oil rate versus cumulative recovery and oil rate versus time. Water production rates were not given.

Permeability distributions and pertinent data were given for each flood. Ninety two k values were given for Flood 1 and 46 for Flood 2. It was necessary to smooth the data for Flood 1 because several k values were identical. The equations cannot be applied to layers of equal permeability because they become indeterminate.

The data used to make the recovery calculations were obtained from Table 1 of Guerrero and Earlougher(17). One can note that several values were given for oil and gas saturation data. None of the combinations of the various initial saturations totaled to 1.0. In particular for Flood 1, the sums for Soi=0.33 were less than 1.0 and for Soi=0.51 they exceeded 1.0. A similar problem also occurred for Flood 2. Therefore it was assumed that Sgi=1-Sw-Soi. A summary of the data incorporated into the Dykstra-Parsons method is shown in Table 3. Four sets of data were used for Flood 2 to show what can be done in order to obtain a history match with actual performance. A comparison of calculated recovery with actual recovery is shown at the bottom of Table 3.

The calculated recovery for Flood 1 at WOR=40 was 747 mbbl showing excellent agreement with the actual recovery of 753 mbbl. A plot of oil rate versus cumulative recovery is shown in Fig. 5. Also shown is the actual rate-cumulative recovery curve given by the authors in their Fig. 2. As can be seen there is reasonable agreement between calculated rate and actual rate. A plot of oil rate versus time is not given because of a large disagreement between calculated time and actual time. The calculated rate reached a maximum in about 6 months whereas the actual rate reached a maximum in about 20 months.

It should be mentioned here that the recoveries of over 1740 mbbl calculated by the authors (their Fig. 2 and Table 16) for the methods that they used, other than the empirical method, are highly unreasonable. The calculated recoveries exceed the ultimate recovery at 100 percent volumetric sweep efficiency of 1374 mbbl (Table 12 of their paper and Table 3 of this paper). With any method, the calculated recoveries should be less than the ultimate recovery for the same basic data. It is not known why the discrepancy is so large.

The first calculation for Flood 2 using the permeability data shown in Table 11 of Guerrero and Earlougher, resulted in not being able to calculate a WOR at breakthrough in layer 1. The reason for this was that the 558 md of layer 1 was so high, that layer 2 with a permeability of 273 md had not yet reached fillup at water breakthrough in layer 1. As a result the denominator in the WOR equation was zero. To get around this problem, the permeability data were plotted on probability paper and extrapolated to a permeability of 380 md for layer 1. This was close to the 384 md shown by the authors in their Table 8 permeability distribution that they used for the Stiles method.

The calculated recoveries for Flood 2 are shown in Table 3. Cases 2A and 2B had initial oil saturations of 0.40 and 0.47, respectively. The calculated recoveries at WOR=25 were 1291 and 1790 mbbl, respectively, which values are considerably lower than the reported recovery of 2000 mbbl. The calculated recoveries were limited by the total amount of water available for injection, as derived from Table 7 of the authors' paper, such that the calculated WOR values did not go beyond 25.

In an attempt to obtain a better match, the correlation of Lynch(18) was used to estimate a mobility ratio, M, of 1.2 for the oil-water viscosity ratio of 5.7 shown in Table 3. This is in contrast to the M of 1.9 derived directly from the relative permeability and viscosity data given in the authors' Table 1. In addition the areal sweep efficiency was also increased in line with the published information mentioned above. The resulting calculated recoveries for Cases 2C and 2D, as shown in Table 3, were 1512 and 1995 mbbl. The change in mobility ratio and corresponding sweep efficiency has now resulted in an excellent agreement between calculated recovery for Case 2D and actual recovery. It illustrates what can be done in order to obtain a good match with actual recovery.

Plots of rate versus time and of rate versus cumulative recovery for the Cases 2A to 2D are shown in Figs. 6 and 7, respectively. Also shown are the rate curves given by Guerrero and Earlougher in their Figs. 3 and 4. As can readily be seen the results for Case 2D come the closest to matching the actual rate performance.

If water production rates had been given, it would have been possible to calculate a WOR. A plot of WOR versus cumulative recovery could then also be used for additional adjustments in the input parameters in an attempt to obtain a better history match. In addition, it would been possible to compare the injection rate with the gross production rate to determine the effectiveness of the injected water. It is rare that the injected water is 100 percent effective throughout the life of the flood.

CONCLUSIONS

1. The parameters required for the calculation of a waterflood performance are listed and discussed. Comments are made regarding methods of arriving at the values of the parameters.
2. Equations for calculating water produced, water injected, time, and oil and water producing rates are given for the calculation of performance on a layer by layer basis. An initial gas saturation is included.
3. The equations were used to calculate oil rates and WOR performance as a function of the initial gas saturation for a high gravity oil and for a low gravity oil. The maximum oil recovery, depletion plus waterflood, was obtained at zero initial gas saturation for the high gravity oil and at an initial gas saturation of 4 percent for the low gravity oil.
4. The WOR versus cumulative recovery curves for each case showed an increasing level with increase in initial gas saturation, or decrease in initial oil saturation, at start of flood.
5. The Dykstra-Parsons method was applied to two water-floods for which published data were available. For Flood 1, excellent agreement was obtained between calculated and actual recoveries, but essentially no agreement was

obtained for rate versus time. For Flood 2, there was essentially no agreement for rate or recovery, until changes were made in the value of two of the input parameters, about which there was some doubt. Excellent agreement was then obtained for cumulative recovery and very good agreement for rate versus time. It illustrates what can be done to match history.

NOMENCLATURE

Bo = oil formation volume factor
C = vertical coverage
Ea = areal sweep efficiency, dimensionless
WOR = producing water-oil ratio
iw = water injection rate, bpd
j = any layer
J = layer of water breakthrough
M = mobility ratio
Np = cumulative oil recovery, bbls
n = number of permeability values
OD = oil displaced, reservoir bbls
PV = pore volume per layer, bbls
qo = oil rate, bpd
qw = water producing rate, bbls
Soi,Sor = initial and residual oil saturations
Sgi,Sgr = initial and residual gas saturations
T = time in years
Vr = reservoir pore volume, bbls
Wf = water of fillup, bbls
Wi = cumulative water injected, bbls
Wp = cumulative water produced, bbls
Xw = fractional distance traveled by water-oil front

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TABLE 1

ROCK AND FLUID PROPERTIES

ALL CASES

Area, acre	40
Thickness, ft.	50
Porosity, fract.	0.25
Connate water sat'n	0.25
Inj. rate, bpd	1000
Perm. variation	0.6
No. of layers	49

CASE 1	A	B	C	D	E
(40 API oil)					
Pressure, psia	3500	2947	1924	1636	597
Oil viscosity, cp	0.333	0.360	0.394	0.481	0.753
Form. vol. fact.	1.572	1.485	1.404	1.295	1.158
Saturations					
Initial oil	0.75	0.675	0.60	0.525	0.45
Residual oil	0.282	0.264	0.245	0.229	0.218
Initial gas	0	0.075	0.15	0.225	0.30
Residual gas	0	0	0	0	0
Mobility ratio	0.51	0.62	0.68	1.01	1.67
Sweep efficiency	0.99	0.985	0.975	0.955	0.92

CASE 2	A	B	C	D
(20 API oil)				
Pressure, psia	1500	1300	1027	277
Oil Viscosity	15.0	15.4	16.5	27.4
Form. vol. fact.	1.113	1.102	1.086	1.046
Saturations				
Initial oil	0.75	0.71	0.67	0.63
Residual oil	0.457	0.435	0.416	0.416
Initial gas	0	0.04	0.08	0.12
Residual gas	0	0	0	0
Mobility ratio	4.4	5.2	6.2	10.1
Sweep efficiency	0.845	0.835	0.82	0.785

TABLE 3

AVERAGE FLUID, ROCK, AND OTHER DATA
GUERRERO AND EARLOUGHER FLOODS ALONG
WITH CALCULATED AND ACTUAL RECOVERIES

	Flood 1	Flood 2 A	B	C	D
Area, acres	270	206			
Thickness,ft.	20.5(a)	25.5			
Porosity	0.20	0.21			
Form. vol. fact.	1.00	1.05			
Viscosity, cp					
Oil	8	4.0			
Water	1	0.7			
Ratio	8	5.7			
Water saturation	0.35	0.32			
Oil saturations					
Initial	0.33	0.40	0.47	0.40	0.47
Residual	0.17	0.10			
Gas saturations					
Initial(b)	0.32	0.28	0.21	0.28	0.21
Residual	0.05	0.04			
STOIP, mbbl	2834(c)	3252(d)	3831		
Ultimate, mbbl	1374(e)	2531(f)	3141(f)		
Relative perm.					
Water	0.1	0.1			
Oil	0.5	0.3			
Mobility ratio	1.6	1.9	1.9	1.2	1.2
Areal sweep	0.9	0.90	0.90	0.94	0.94
Inj. rate, bpd	8000		variable		
Recovery, mbbl					
Calculated	(g)747	(h)1291	1790	1512	1995
Actual	753	2000			

(a) Of the oil sand only
(b) From the relation Sgi=1-Sw-Soi
(c) From G&E Table 12
(d) From G&E Table 13
(e) From G&E Table 12, based on Soi-Sor=0.33-0.17=0.16
(f) Calculated from Soi-Sor. G&E Table 23 shows 2439
(g) At WOR=40
(h) At WOR=25

TABLE 2

SUMMARY OF CALCULATED RECOVERIES
TO A PRODUCING WATER-OIL RATIO OF 50

Case	Depletion Recovery mbbl	Waterflood Recovery mbbl	Total Recovery mbbl
1A	0	1103	1103
B	88	1010	1093
C	193	900	1093
D	278	753	1031
E	344	545	889
2A	0	779	779
B	113	684	797
C	221	569	790
D	278	352	630

Fig. 1 Oil rate vs time - 40 Deg API oil

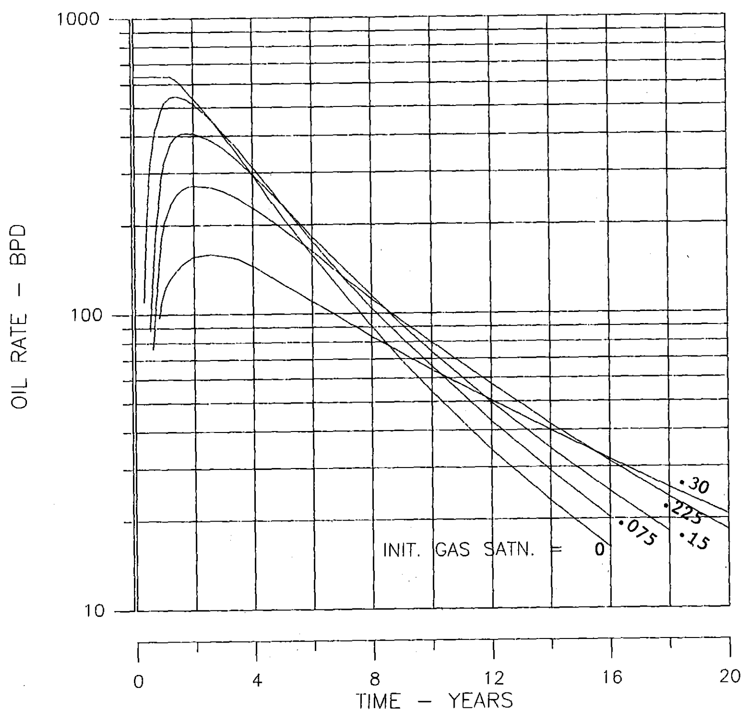


Fig. 2 WOR vs cumulative recovery - 40 Deg API oil

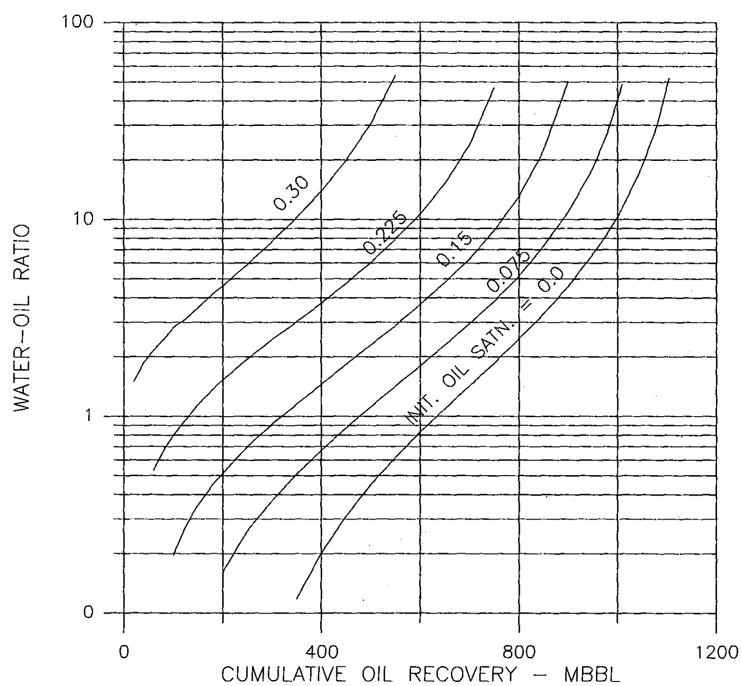


Fig. 3 Oil rate vs time - 20 Deg API oil

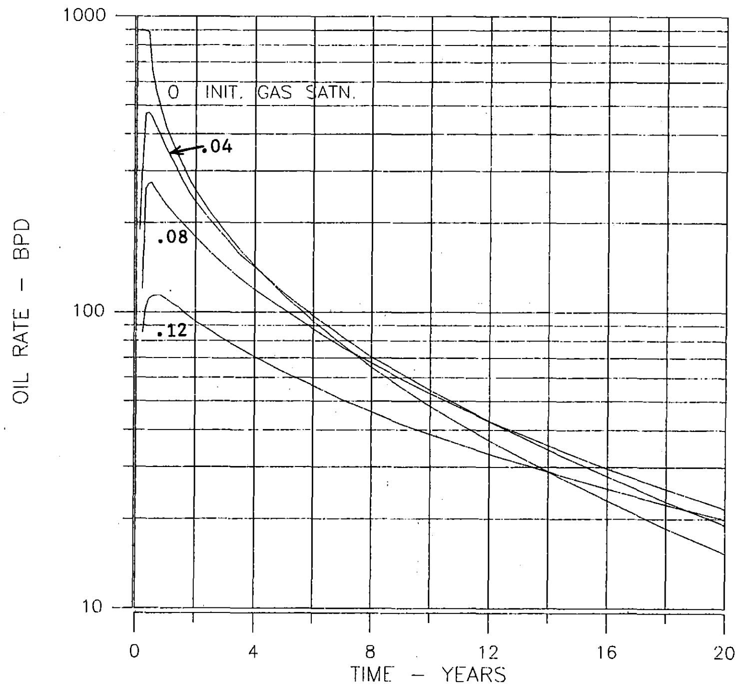
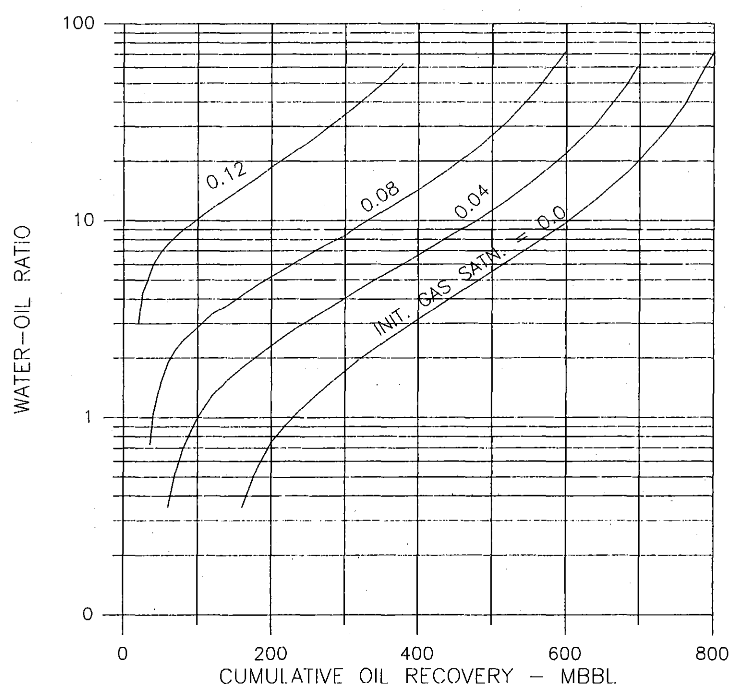


Fig. 4 - WOR vs cumulative recovery - 20 Deg API oil



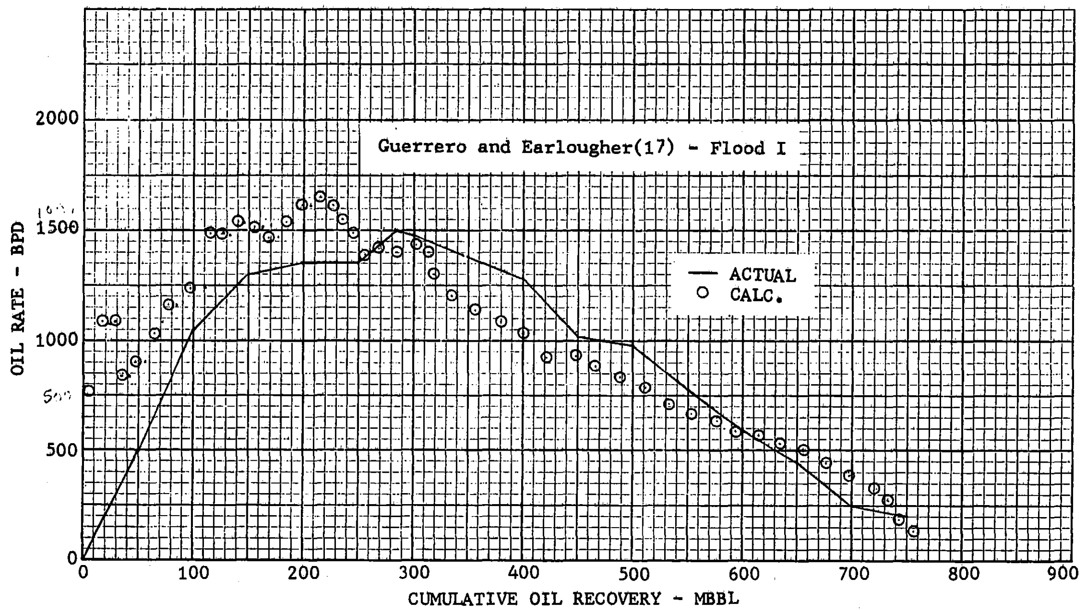


Fig. 5 - Oil rate vs cumulative recovery

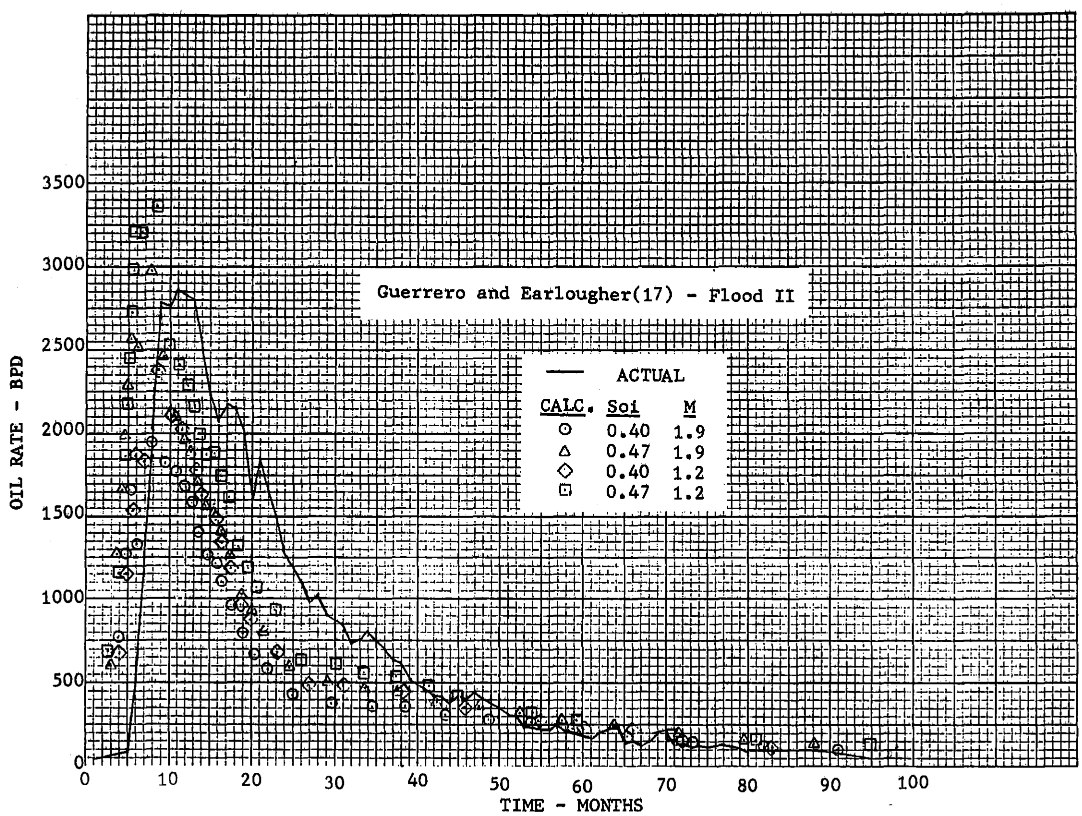


Fig. 6 - Oil rate vs time

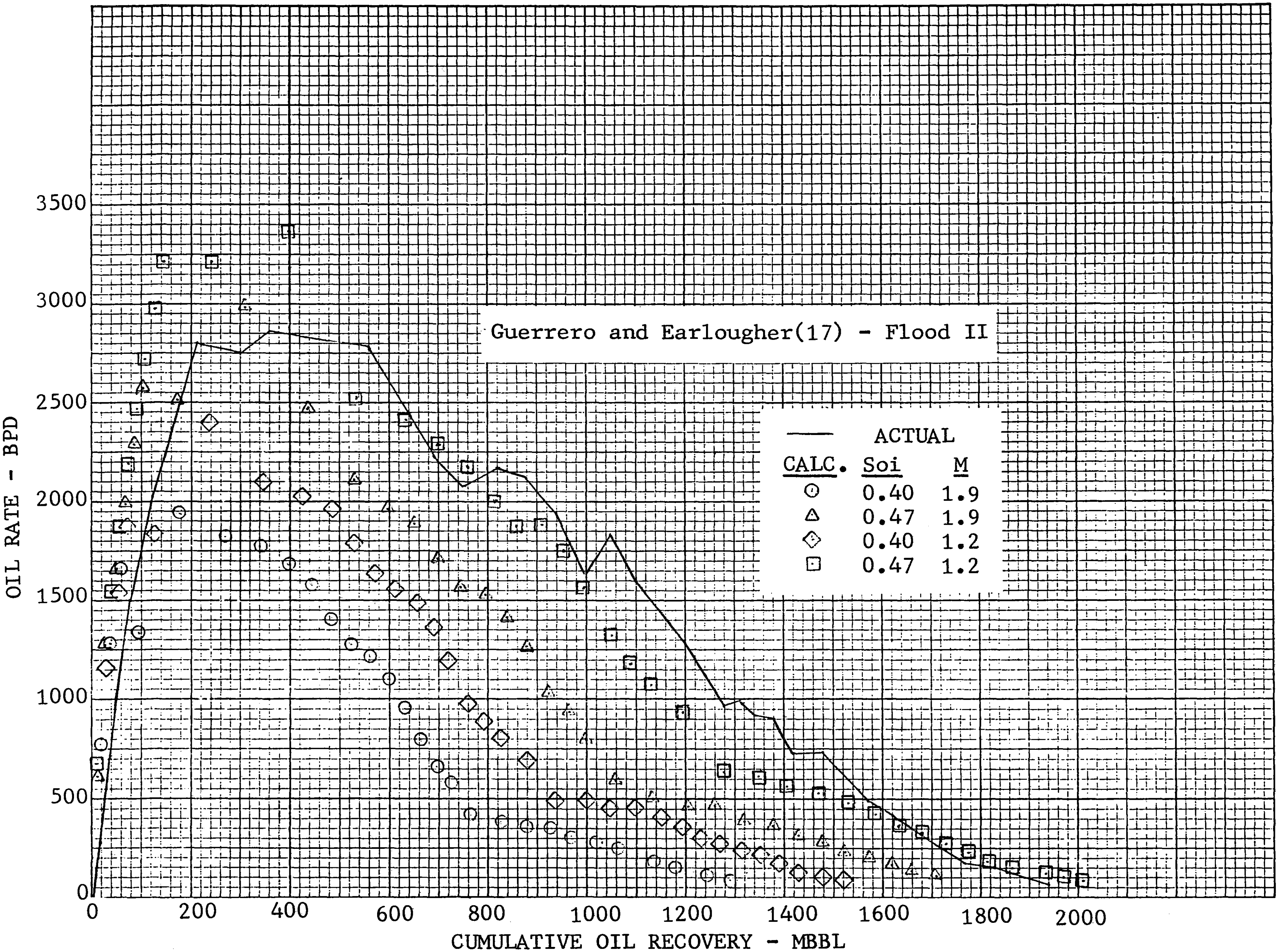


Fig. 7 - Oil rate vs cumulative recovery