Spe 918

RESERVOIR
ENGINEERING

Predicting Waterflood Performance by the Graphical Representation of Porosity and Permeability Distribution

JARL P. JOHNSON
MEMBER AIME

KEWANEE OIL CO.
TULSA, OKLA.

Abstract

A simple tool for predicting the waterflood performance of stratified reservoirs has been developed using a variation of the familiar layer concept.[1,2] *The variation suggested allows consideration of non-uniform porosity development and mobility ratio.*

The procedure involves predicting both cumulative water injected and cumulative oil production in terms of per cent water cut using a permeability-porosity classification system.

The simplicity of the graphical approach to the cumulative oil recovery vs water cut prediction provides a convenient means of evaluating the areal as well as the vertical aspects of flood performance.

Introduction

A prediction technique, to be applicable to a heterogeneous reservoir, should provide a means for considering variation in volume as well as permeability. The presence of multiple rock types with different porosity-permeability relationships cause the common assumption of a uniform porosity to be impractical.

Further, the number of projects being evaluated in the prospect of a unitized operation make it desirable that a convenient means be provided to evaluate the lateral as well as the vertical aspects of porosity and permeability development.

A variation in the application of some familiar devices can provide the solution to both of these problems.

Premises

The premises necessary to the use of the procedure to be described are common to other methods with the following exceptions:

1. It is not necessary to assume a uniform porosity distribution or uniform water saturation.

2. It is assumed that in layers of equal permeability capacity, the advance of the flood front is inversely proportional to the mobile hydrocarbon volume of the layer.

3. A changing mobility ratio during the fill-up period is assumed.

Procedure

Rock Classification

To evaluate the effect of stratification on vertical sweep efficiency, reservoir permeability data from core analysis are classified according to a system similar to that proposed by Law[3] and demonstrated in Table 1. In addition to classifying the permeability data, the porosity of each sample is recorded. By listing both the porosity and permeability for each sample, it is possible to relate the porosity capacity and permeability capacity without the necessity of assuming that a uniform porosity exists or assuming a porosity-permeability relationship.

If sufficient data are available to estimate the water saturation for each permeability range, it[4] is possible to compute the hydrocarbon pore volume which can be substituted for the porosity capacity value, establishing a direct relationship between permeability and hydrocarbon volume.

The data are summarized at the bottom of each column, with the cumulative permeability capacity and corresponding reservoir volume shown as a per cent of the total as indicated in Table 1. For convenience, values are added from the highest toward the lowest permeability range. The example in Table 1 includes water saturation data and the cumulative hydrocarbon pore volume.

A plot of the cumulative permeability capacity vs the logarithm of the corresponding cumulative porosity capacity for four wells is shown in Fig. 1. Data from several wells in a single project were plotted on this graph to illustrate that more than one system is implied in each instance by the changing slopes and that there is some disparity between the plots representing different wells. Variations in rock type are responsible for the multiple systems, a common occurrence in carbonate reservoirs. Areal variation in porosity and permeability development account for the disparity between the curves.

It is often possible to combine the data from several wells as shown in Table 2 to provide a composite representation of the reservoir permeability distribution. It is important that the selection of data for a composite curve describes the vertical classification of the rock. For this reason it is suggested that individual curves representing several locations in the project be constructed prior to the

Original manuscript received in Society of Petroleum Engineers office July 28, 1964. Revised manuscript of SPE 918 received Sept. 24, 1965. Paper presented at SPE Annual Fall Meeting held in Houston, Oct. 11-14, 1964.

[1]References given at end of paper.

TABLE 1—PROJECT 1, WELL 1

	<0.1		0.1-0.4		0.5-0.9		1-1.9		2-3.9		4-7.9		8-15.9		16-31.9		32-63.9	
	k	φ	k	φ	k	φ	k	φ	k	φ	k	φ	k	φ	k	φ	k	φ
		5.0	0.2	10.3	0.5	5.7	1.0	21.3	2.0	9.3	7.2	15.4	12	16.1	[illegible]	18.1	50	23.4
		7.1	0.1	12.1	0.5	8.1	1.9	16.8	2.3	11.9	4.6	17.2	15	19.0	19	19.1		
		9.4	0.4	11.1	0.9	26.8	1.6	24.6	2.9	18.0	5.7	14.0	11	22.0	26	24.0		
			0.1	7.8	0.9	8.7	1.6	9.1	3.1	16.2	4.8	22.6	8.4	12.3	19	19.8		
			0.1	8.6	0.5	9.2	1.9	13.0	2.3	20.8	5.3	24.6						
					0.7	13.3	1.0	8.1	2.0	22.5	6.0	21.9						
					0.6	9.4	1.8	6.7	2.0	9.6	6.4	19.2						
					0.5	9.9	1.3	15.9	2.6	9.2								
					0.6	6.3			2.6	11.0								
					0.5	7.4			2.8	7.4								
TOTAL	0	21.5	0.9	49.9	6.2	104.8	12.1	115.5	24.6	135.9	40.0	134.9	46.4	69.4	87	81.0	50	23.4
Cumulative %	100	100.0	100.0	97.1	99.7	90.3	97.3	76.1	92.8	60.3	83.6	41.9	68.6	23.6	51.3	14.1	18.7	3.2
S_{w}		0.43		0.39		0.36		0.34		0.32		0.29		0.27		0.25		0.32
Cumulative % HPV		100.0		97.6		91.5		78.2		63.1		44.8		25.8		15.7		3.6

TABLE 2—PROJECT 1, COMPOSITE CLASSIFICATION FIVE WELLS

	<0.1		0.1-0.4		0.5-0.9		1-1.9		2-3.9		4-7.9		8-15.9		16-31.9		32-63.9		64-127.9	
Well	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh	kh	φh
1		21.5	0.9	49.9	6.2	104.8	12.1	115.5	24.6	135.9	40.0	135.9	46.4	69.4	87	81.0	50	23.4		
2		78.6	0.5	31.5	0.6	16.5			2.5	17.5	7.4	18.4			21	24.7				
3		19.1	1.2	42.5	1.4	28.0	18.4	193.8	21.7	133.5	9.4	24.8	34	55.0	34	38.8	322	168.1	173	43.1
4			4.0	140.8	3.1	49.0	16.2	133.3	12.7	83.1	18.0	54.7	10.2	22.8	47	45.7	208	111.2		
5			1.1	41.4	2.6	51.4	5.4	50.0	12.8	66.6	47.2	125.0	20.6	33.9	47	34.8	88	34.4		
TOTAL	—	119.2	7.7	306.6	13.9	249.7	52.1	492.6	74.3	436.6	122.0	367.8	111.2	181.1	236	225.0	668	337.1	173	43.1
Per cent Cumulative kh and φh	100	100.0	100.0	95.7	99.5	84.6	98.5	75.5	94.9	57.6	89.8	41.8	81.5	28.5	73.9	21.9	57.7	13.8	11.9	1.6

construction of a composite curve to provide a more accurate description of the reservoir and to determine what lateral changes in permeability distribution may exist. Where radical area changes occur, it will be desirable to group wells of similar rock classification and to treat each group as an independent reservoir. The performance of the various groups can be combined to provide a composite presentation of the predicted reservoir performance.

Reservoir Volume

An accurate estimate of the total reservoir pore volume should be made using the best data available. In the application of core and log data, the same cut-off limits should be used for porosity and permeability as were used in the classification of these data. The actual cut-off limits are not critical in most instances if the same limits are used throughout.

The reservoir mobile hydrocarbon volume is calculated as $(1 - S_{or} - S_{w}) \times PV$ with values of S_{or} and S_{w} determined in a normal manner.

The maximum amount of oil which can be displaced from the reservoir at 100 per cent efficiency is $(S_o - S_{or})\ PV$.

Cumulative Injection vs Water Cut

To predict the relationship between cumulative water injected and water cut, the permeability capacity-porosity capacity curve (Fig. 2) is divided into 10 layers of equal permeability capacity. The fraction of the total reservoir pore volume contained in each layer is read from the curve.

The mobile hydrocarbon volume of each layer is considered to be the displaceable volume, or volume of water

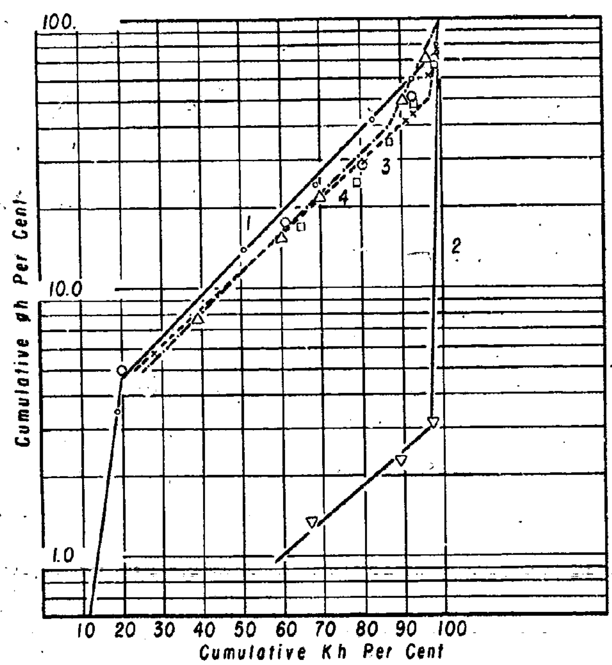

Fig. 1—Project 1 classification.

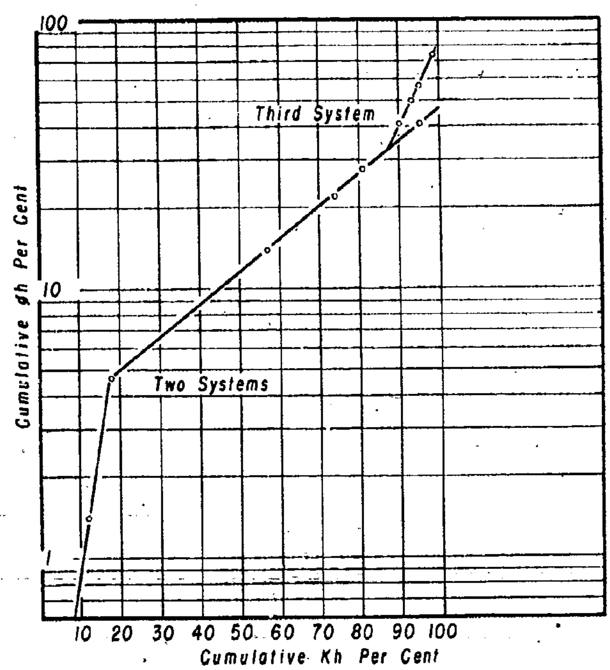

Fig. 2—Project 1 classification composite.

required to flood out that layer. This value is computed by multiplying the fractional volume in each layer by the total mobile hydrocarbon volume of the reservoir. These calculations are illustrated in Table 3. The layers will be flooded out in the order of ascending values of mobile hydrocarbon volumes. The surface water cut at the time each layer is flooded out is calculated from Eq. 1 as shown in Table 3.

$$\text{Water Cut} = \frac{M \times (5)}{M \times (5) \times [1 - (5)]}, \quad . \quad . \quad . \quad (1)$$

where M is the ratio of the mobility of the water phase to that of the oil phase and (5) refers to the value in Column 5 of Table 3 corresponding to the layer under consideration and is the fraction of the reservoir flooded at the time this layer is flooded out. This procedure is similar to the Stiles technique except for the use of varying mobility ratios during fill-up.

The mobility ratios during the fill-up period are assumed to vary because of the saturation changes occurring in the three-phase system. The relationship shown in Fig. 3, which has been used in the Panhandle field in Texas, was constructed by assuming the initial mobility ratio to be the mobility of water at residual oil saturation divided by the mobility of oil at initial oil saturation. The mobility ratio at fill-up is the ratio of the mobility of water in the water bank at residual oil saturation to the mobility of oil in the oil bank at connate water saturation as determined from laboratory core study.

A sample calculation for water cut would be as follows:

For Layer 1, a mobility ratio of 2 is used and the water cut is calculated to be:

$$\frac{0.1 \times 2}{0.1 \times 2 + (1 - 0.1)} = 0.182.$$

For Layer 3 (the next to be flooded), the mobility ratio used is 1.6 and the water cut is

$$\frac{0.2 \times 1.6}{0.2 \times 1.6 + (1 - 0.2)} = 0.286, \text{ etc.}$$

The apparent mobility ratio must be estimated on the basis of the assumed fill-up point. The value of the mobility ratio for the fourth layer was 1.2 and was 1.1 for the fifth and subsequent layers.

Water is assumed to enter equally into each layer until the first layer is flooded, as all layers by design have equal permeability capacities. Since one-tenth of the water enters each layer and a volume equal to its mobile hydrocarbon volume is required for flooding, the cumulative injection into the reservoir at the time the first layer has been flooded is 10 times the mobile hydrocarbon volume of Layer 1, adjusted for any losses from the reservoir.

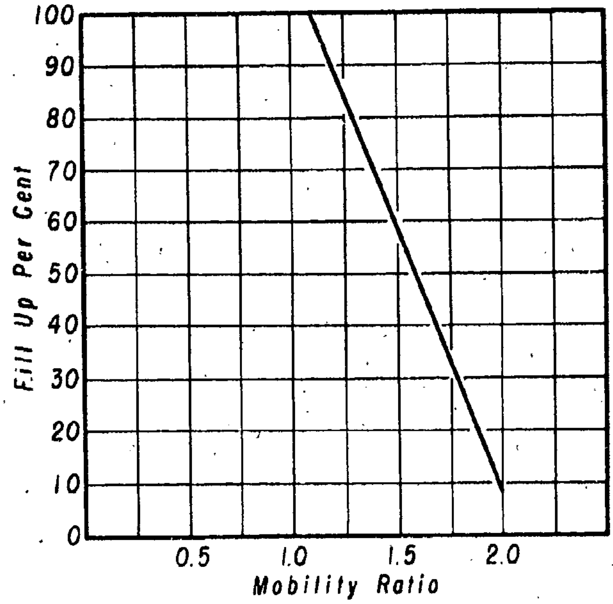

Fig. 3—Change in mobility ratio with change in fill-up.

For example, referring again to Table 3, a mobile hydrocarbon volume of 79,400 bbl has been attributed to Layer 1. Assuming an injection efficiency of 60 per cent, the cumulative water injected at the time Layer 1 is flooded out will be

$$\frac{79{,}400}{0.1 \times 0.6}, \text{ or } 1{,}323{,}000 \text{ bbl.}$$

After the first layer is flooded, the injection into that layer is proportional to the water cut. Injection into each of the other layers is equal to (1 − water cut) divided by the number of layers remaining to be flooded. This fraction, listed in Column 7 of Table 3, was calculated for Layer 3 in the lowing manner:

$$\frac{1 - 0.182}{9} = 0.091.$$

The total water required to flood Layer 3 is equal to its displaceable volume. Since 79,400 bbl have been injected into this layer, only the difference between the displaceable volumes in Layers 1 and 3 will be required. This value divided by the fraction of injection into this layer, plus the cumulative water injected to the flood-out of Layer 1 will be the cumulative injection to the flood-out of

TABLE 3—PREDICTING INJECTION SCHEDULE, PROJECT 1

(1) Layer No.	(2) Cumulative Fraction HPV	(3) Fraction HPV In Layer	(4) MHPV-Bbl In Each Layer (3) × (d)	(5) Cumulative kh Flooded Fraction	(6) Surface Water Cut (e)	(7) Fractional Injection	(8) Cumulative Water Injection (f)
1	0.009	0.009	79,400	0.10	0.182	0.10	1,323,000
2	0.049	0.040	352,800	0.60	0.623	0.095	6,316,000
3	0.065	0.016	141,100	0.20	0.286	0.091	2,453,000
4	0.087	0.022	194,000	0.30	0.375	0.089	3,144,000
5	0.115	0.028	247,000	0.40	0.444	0.089	4,437,000
6	0.150	0.035	309,000	0.50	0.525	0.093	5,548,000
7	0.200	0.050	441,000	0.70	0.720	0.094	7,380,000
8	0.270	0.070	617,000	0.80	0.814	0.093	11,034,000
9	0.400	0.130	1,146,600	0.90	0.908	0.098	20,041,000
10	0.550	0.150	1,323,000	0.95	0.954	0.092	23,237,000

(a) PV = 21,100,000 bbl
(b) PV_{swept} = 21,000,000 × 0.95 = 20,045,000 bbl — From Dyes, Caudle and Erickson
(c) HPV_{swept} = 20,045,000 × 0.7 = 14,031,500 bbl
(d) $MHPV_{swept}$ = 20,045,000 $(1 - S_{w} - S_{or})$ = 8,820,000
(e) Water Cut = $\dfrac{M \times (5)}{M \times (5) \times [1 - (5)]}$
(f) Fill-up occurs when 4,000,000 bbl have been injected. Assume 60 per cent efficiency.

Layer 3, or

$$\frac{141{,}000 - 79{,}400}{0.091 \times 0.6} + 1{,}323{,}000 = \quad 2{,}453{,}000 \text{ bbl.}$$

This procedure is repeated for each succeeding layer until the corresponding calculated water cut is at an economic limit. In the examples shown, the economic limit was set at a water cut of 95.4 per cent.

Note that an injection efficiency of 60 per cent was used in the Panhandle field examples. This value was obtained by comparing the produced and injected volumes in projects which are known to have passed the fill-up point. The injection efficiency is a difficult factor to evaluate for most projects and must be done by experience, taking into consideration possible thief zones, such as a gas cap or aquifer in association with the oil reservoir, or lack of confinement to the waterflood area if the water flood does not encompass the entire reservoir.

A curve illustrating the results of this procedure applied to the Panhandle field waterflood project is included as Fig. 4. The plot of the actual performance of this project indicates that there is excellent agreement between predicted and actual performance.

Cumulative Oil Production vs Water Cut

It is not surprising that there is a similarity between the permeability-porosity capacity plots previously described and a plot of the log cumulative oil recovery vs water cut for waterflood projects if you consider that one describes a relationship between storage capacity and permeability distribution and the other describes a relationship between recovery and water cut. This similarity has prompted the use of these curves as an approach to relating oil production and water cut. For highly stratified reservoirs, adjusting the slope of the permeability-porosity capacity curves for mobility ratio will produce a slope approximating the slope of flood performance curve.

The mobility ratio adjustment is made from the calculations previously performed to obtain the water cut. In the example in Table 3, the water cut at a *kh* value of 10 per cent becomes 18.2 per cent; that a 20 per cent becomes 28.6 per cent, etc. The effect of this adjustment on the curve previously shown as Fig. 2 is shown in Fig. 5.

When the mobility adjustment is made, the per cent ϕh corresponding to the water cut reflects the per cent of the mobile oil in the reservoir which will have been produced when the water cut has reached that level. The per cent ϕh is then converted to cumulative barrels by multiplying this value by the quantity $(S_o - S_{or}) \times PV \times$ Sweep Efficiency[4] and plotting as in Fig. 6. A comparison of the predicted performance and the actual performance is shown.

Both cumulative water injected and cumulative oil produced are now available in terms of water cut and can be related to each other and can be expressed in terms of time by estimating the injectivity of the input wells.

Figs. 7, 8, 9 and 10 are comparisons between the predicted and actual performance of two other projects. The same assumptions were used for these predictions as for Project 1. Note in Fig. 10 that there is not good agreement for the early life of this project. Premature water

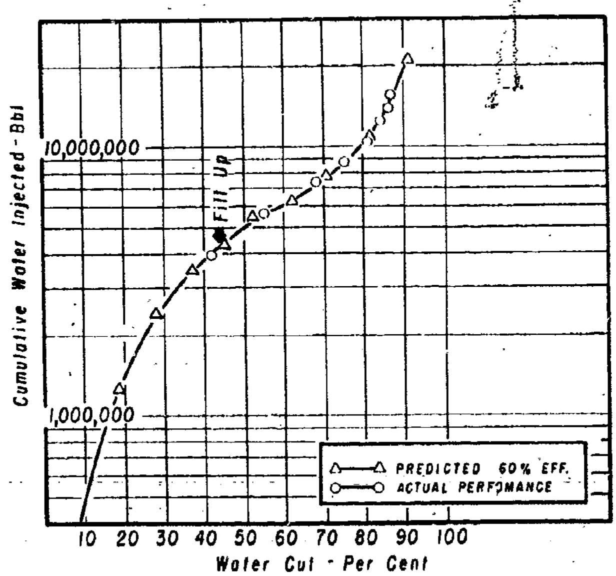

Fig. 4—Project 1 water-oil ratio vs cumulative injection.

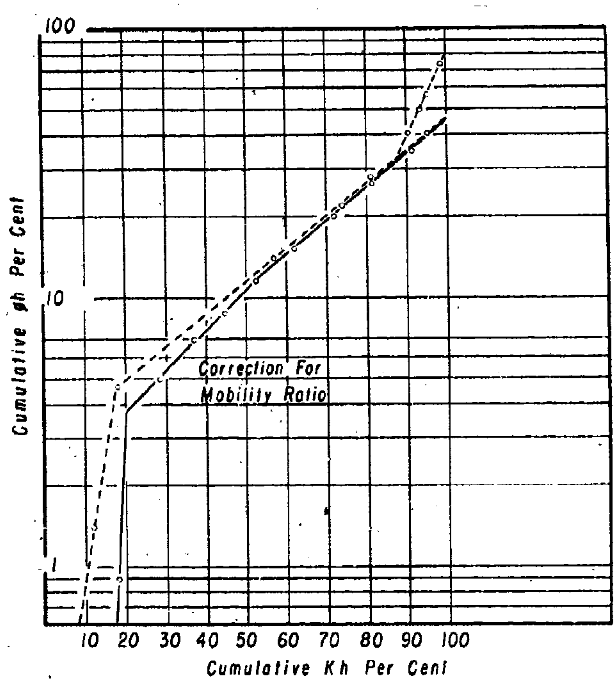

Fig. 5—Project 1 classification composite.

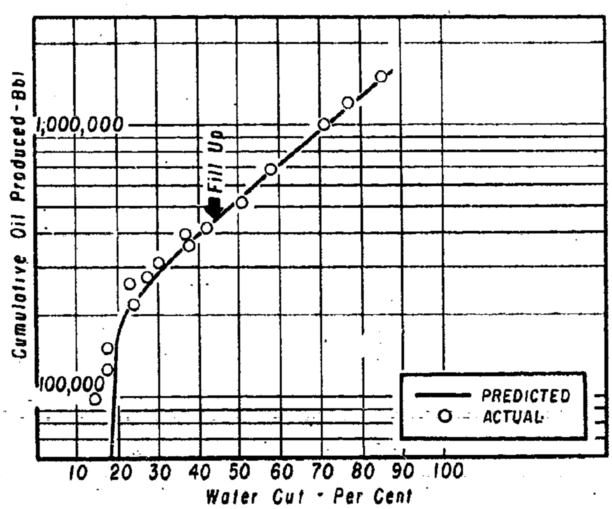

Fig. 6—Project 1 performance.

channeling occurred shortly after injection was initiated. Subsequent shutting-in of the offending producers is causing the project to conform closely to its predicted performance.

Areal Variations

The increasing number of unitized projects has created a need for a convenient means of evaluating the contribution individual tracts make to a total project. If a sufficient number of cores is available, it is a simple matter to plot the distribution curves and read the maximum recovery value as a per cent of the mobile oil from them. If the mobile oil volume is determined from production and volumetric data, the secondary recovery in barrels per acre-foot or other convenient units can be readily determined. This information can then be mapped to provide a useful parameter for unitization.

The representation of areal variation in permeability development is also useful in the design of injection patterns and in the planning of equipment size and location.

Necessary Precautions

Most projects have unique features which must be evaluated in any attempt to predict waterflood performance. Of particular concern is the existence of directional permeability or oriented fractures which will affect pattern efficiency or the existence of a gas cap, aquifer or other conditions representing potential loss of fluid from the project area.

The accurate determination of reservoir volume is essential. As previously noted, it is also important that the same limits of porosity and permeability be used in deter-

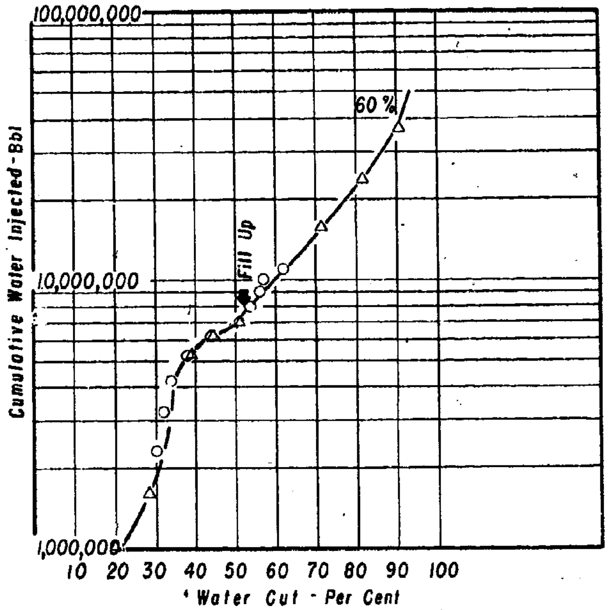

Fig. 7—Project 2 water cut vs cumulative injection.

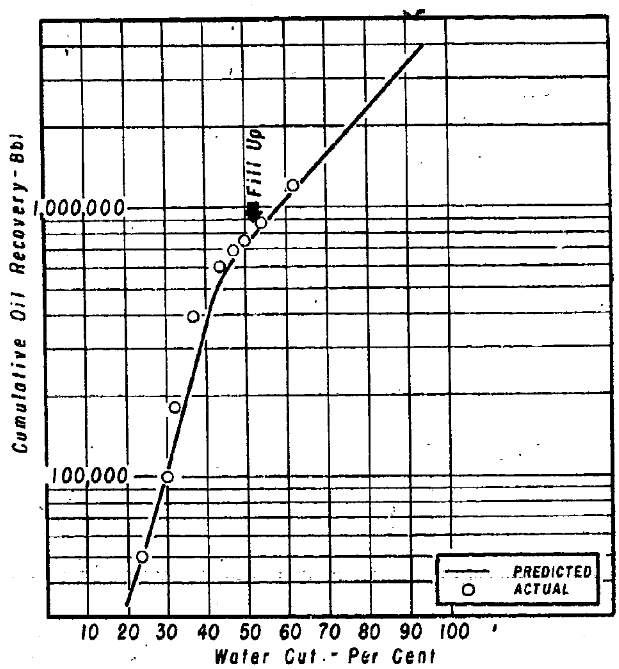

Fig. 8—Project 2 oil recovery vs water cut.

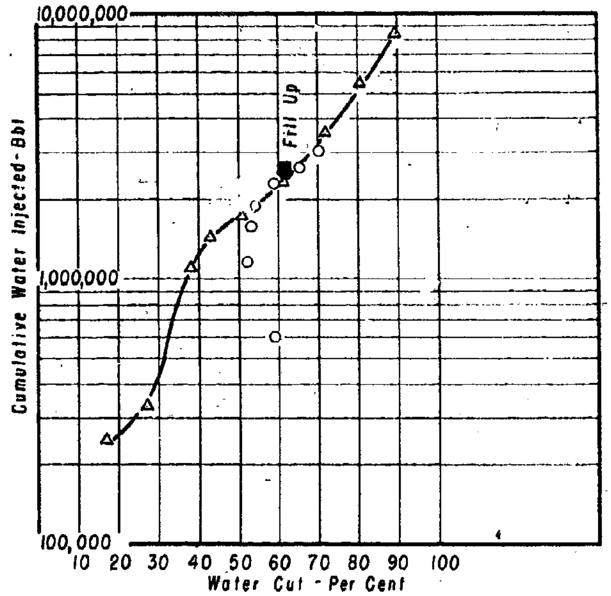

Fig. 9—Project 3 water injected vs water cut.

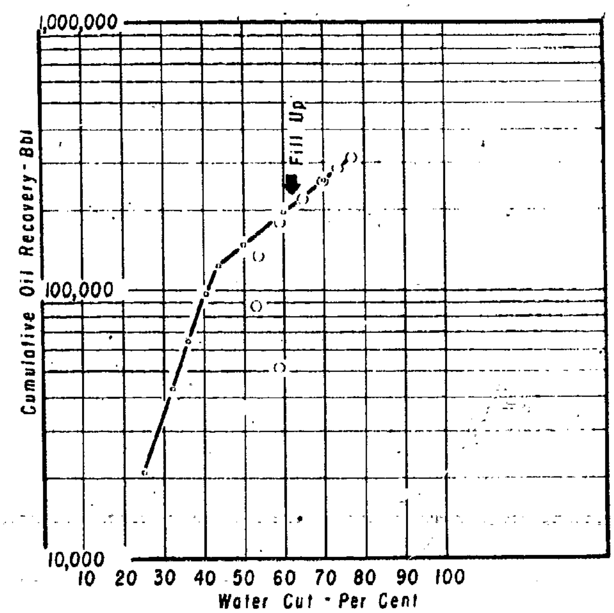

Fig. 10—Project 3 oil recovery vs water cut.

mining the reservoir volume as are used in the classification system. For example, no lower limit of porosity or permeability was set in classifying porosity and permeability for the projects described in this discussion; consequently, the entire oil section was considered to be a part of the reservoir volume.

Limitations

In common with the tools heretofore offered for predicting waterflood performance, this procedure cannot be applied to all reservoirs with confidence.

An examination of the commonly used prediction tools reveals that they depend upon the compensating effect of two or more unevaluated parameters and are, therefore, to a large extent empirical. The Stiles and Dykstra-Parsons' approaches, for example, describe flood movement as it is governed by stratification but do not evaluate crossflow, production behind the front, or variations in porosity which are factors that are often compensatory in sand floods.[5,6] The Craig technique relies heavily upon the offsetting effects of crossflow and stratification.

In stratified reservoirs where crossflow is negligible, each of these methods and similar approaches tend to result in optimistic predictions.

The success of the procedure that has been outlined also depends upon the compensating effects of un-evaluated parameters. In this instance, the graphical representation of the relation between permeability distribution and movement of the flood front is an oversimplification of the problem. Again, the effect of production behind the front has not been evaluated. In highly stratified reservoirs where crossflow is small, the effect of one of these factors offsets the other.

The use of this tool, then, is limited to stratified reservoirs such as the thick carbonate reservoirs in West Texas and in the Panhandle. However, properly applied, this simple technique can be a very useful tool in predicting the waterflood performance of these reservoirs.

References

1. Stiles, W. E.: "Use of Permeability Distribution in Waterflood Calculations", *Trans.*, AIME (1949) **186**, 9.
2. Dykstra, H. and Parsons, R. L.: "The Prediction of Oil Recovery by Waterflood", *Secondary Recovery of Oil in the United States*, Second Edition, API, New York (1950) 160.
3. Law, Jan: "A Statistical Approach to the Interstitial Characteristics of Sand Reservoirs", *Trans.*, AIME (1944) **155**; (1945) **160**.
4. Dyes, A. B., Caudle, B. H. and Erickson, R. A.: "Oil Production After Breakthrough as Influenced by Mobility Ratio", *Trans.*, AIME (1954) **201**, 81.
5. Katz, Marvin and Tek, M. R.: "A Theoretical Study of Pressure Distribution and Fluid Flux in Bounded Stratified Porous Systems with Crossflow", *Soc. Pet. Eng. Jour.* (March, 1962) 68.
6. Testerman, J. D.: "A Statistical Zonation Technique", *Jour. Pet. Tech.* (Aug., 1962) 889.

***

JARL P. JOHNSON *is chief engineer for Kewanee Oil Co., Tulsa. He holds a BS degree in petroleum engineering awarded by the U. of Tulsa in 1953. After graduation he joined Phillips Petroleum Co. and worked in Eastern Kansas and West Texas. In 1955 he joined Kewanee as a junior engineer at Crane, Tex., and subsequently served as senior, district and division engineer as well as district superintendent in West Texas. Prior to assuming his present position, Johnson was reservoir engineer at Tulsa.*