PETROLEUM TRANSACTIONS

Improved Secondary Recovery by Control of Water Mobility

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ABSTRACT

Certain high molecular weight synthetic polymers in very dilute solutions decrease water mobility in porous media 5 to 20 times more than would be expected from the solution viscosity. This indicates that increasing water viscosity to reduce adverse mobility ratios in water floods is economically feasible in many situations.

Laboratory results are consistent with accepted theory with respect to improved areal sweep, permeability distribution and displacement efficiencies as would be predicted from the solution mobility measured in the core.

The laboratory results have been confirmed by field pilot floods which recovered 80 per cent and 100 per cent more oil than comparative waterflood pilots in fields containing 16 cp and 130 cp oil respectively. Economic analyses based on pilot data indicate the method to be profitable.

INTRODUCTION

The desirability of improving the water-oil mobility ratio in waterflooding operations has long been appreciated, especially for high viscosity crudes. Methods of reducing the oil viscosity by application of heat, gas resaturation and miscible drives have met with some success. Conversely, it has been generally conceded that increasing the water viscosity would also be effective, but the amount of thickening agent required to effect an appreciable increase in viscosity is discouragingly high. The use of such materials as glycerin, sugar, or glycols is completely out of the question economically, so that considerable attention has been given to the use of the much more efficient synthetic water-soluble polymers as viscosity improvers; but even these materials are not economically attractive.

If increased water viscosity could be economically realized, marked improvements in areal sweep efficiency, as discussed by Caudle and Witte[1] and others, would be realized in field operations. Similarly, the improved mobility ratio would bring about increased recoveries by correcting permeability distribution problems as discussed by Stiles[2] and Dykstra and Parsons,[3] and improvements in displacement efficiency would be obtained as recognized by Buckley and Leverett[4] and Welge.[5]

LABORATORY STUDIES

THE RESISTANCE EFFECT

In the course of research to develop a more efficient water-soluble polymer viscosity builder, we discovered that a very few types of water-soluble polymers exhibited a most unusual and very interesting property not previously observed. Among the earliest materials showing such activity were polymers containing acrylamide. Fig. 1 shows a typical plot of the solution viscosity vs concentration for one of these polymer solutions as determined in an Ostwald viscometer. As usual, such a plot is an approximate straight line on semilogarithmic paper. Now, an inspection of Darcy's law,

$$q = \frac{k\,\Delta p\,A}{\mu L}, \quad \ldots\ldots \quad (1)$$

shows that a viscosity value can also be determined in a formation sample if the pressure, flow rate and permeability are known. If the core permeability is previously determined with water or brine, then the viscosity of another aqueous fluid may be determined from the equation. The viscosities so determined for glycerin (glycol or polyvinyl alcohol solutions, for example) agree with the viscometer determinations. However, in the case of the water-soluble polymer solutions in which we are interested, the viscosities measured in the formation sample depart very markedly from the viscometer values. A typical relationship for a polymer solution is also shown in Fig. 1.

This unusual departure from the expected response is referred to as a resistance property of the polymer and is quantified as "resistance factor". Since the resistance factor R can best be determined in a core under study, the term has been defined on the basis of the ratio of the brine mobility to the polymer solution mobility at residual oil saturation so that:

$$R = \left(\frac{k_w}{\mu_w}\right) \Big/ \left(\frac{k_p}{\mu_p}\right) = \frac{\lambda_w}{\lambda_p} \quad \ldots\ldots\ldots \quad (2)$$

where μ_p is the apparent viscosity of the polymer solution in the core.

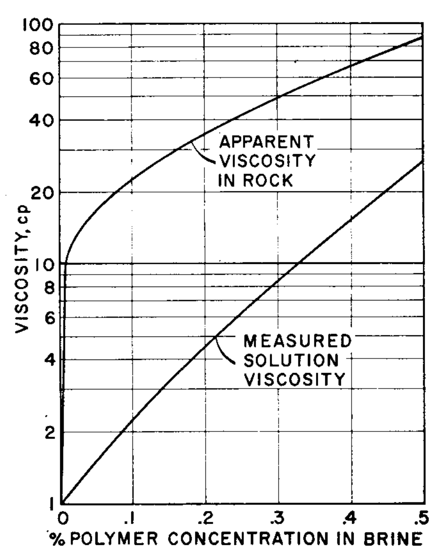

FIG. 1—POLYMER RESISTANCE EFFECT IN 250-MD BEREA SANDSTONE

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Discussion of this and all following technical papers is invited. Discussion in writing (three copies) may be sent to the office of the *Journal of Petroleum Technology*. Any discussion offered after Dec. 31, 1964, should be in the form of a new paper. No discussion should exceed 10 per cent of the manuscript being discussed.

[1]References given at end of paper.

There is the assumption here that the permeability is constant, and in fact there is no permanent loss of permeability resulting from polymer flow. In any case, the mobility parameter must be treated as an entity since there is no way of separating the apparent viscosity variable from a hypothesized temporary reduction in permeability.

The potential economic effect of this unexpected departure is easily seen in that it requires only a small concentration of polymer in the injection brine to accomplish important improvements in the water-oil mobility ratio.

This polymer property can be observed by a simple experiment. A 2 per cent NaCl solution is passed through a 1-in. diameter by 1-in. long Berea or other core of about 250-md permeability at a rate of about 10 ml/min. Then a 500 ppm polymer solution in 2 per cent NaCl solution which has been filtered through a medium grade diatomaceous earth filter is passed through the same core at the same pressure. Although the viscosity of the polymer solution may be only 1.5 cp, the flow rate will drop to 0.5 to 1 ml/min and come to equilibrium at this value. Thus, at constant pressure

$$R = \frac{q_w}{q_p} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (3)$$

Conversely, at constant flow, the injection pressure rises correspondingly:

$$R = \frac{\Delta p_p}{\Delta p_w} \quad . \quad . \quad . \quad . \quad . \quad . \quad (4)$$

The effect is not a core-plugging problem since the system does come to equilibrium. The extent of departure from the measured viscosity value is most pronounced at low concentrations. At higher concentrations the effect is approximately proportional to the solution viscosity.

This unusual effect is a property of only a few select water-soluble polymers, among which are the extensive family of acrylamide polymers and copolymers. The exact flow mechanism which causes this resistance factor has not been established but it does appear to be a complex combination of several factors. Although polymer solutions are generally highly non-Newtonian, this is not the only factor. The resistance factor is substantially constant over normal field fluid advance rates as shown in Fig. 2, which also shows the slope line and range of the viscosity-shear rate data from 4.8 to 960 sec^{-1} determined with a Fann viscometer. Since the shear rate in cores is not precisely determinable, this slope line is plotted on an arbitrary scale. At more rapid advance rates, the resistance factor increases, but the point of departure from constancy depends on rock properties. Accordingly, rapid laboratory flooding rates should be avoided.

The effect is not due to surface plugging because it does take place in depth, as can be shown by following the pressure profile in taps located along the length of a long core. It is evident in tortuous passages only and does not appear in straight capillaries as small as the spaces between compressed, parallel 7-micron glass fibers. It is qualitatively present in all sands and cores, but is quantitatively influenced by the type of core, permeability, clay content, the type of water or brine and oil saturation. For these reasons each reservoir must be evaluated in the laboratory to determine the proper chemical type and concentration to be used.

This unexpected reduction of water mobility by very dilute polymer solutions as determined in reservoir rock samples has been demonstrated beyond any doubt. It now remains to be seen if this reduction in mobility produces a proper and corresponding influence in oil recovery. The three reservoir efficiency factors of areal sweep, permeability distribution and displacement efficiency were studied independently to determine whether the recoveries would be improved according to the solution viscosity or according to the resistance-factor measurement.

AREAL SWEEP EFFICIENCY

Studies on the effect of mobility ratio on areal sweep were made in models using compressed glass wool as the porous media with colored water solutions of glycol of different viscosities adjusted to represent mobility ratios. Although the polymer solutions exhibit resistance factor in this type of porous medium, the simpler solutions were used for experimental reasons.

The models consist of a sandwich-like structure composed of a steel plate on the bottom, a thin rubber sheet membrane, then a layer of ½-in. fiberglass insulation mat which is sealed on the edges with latex. The organic binder is previously burned off in an annealing oven. A ¾-in. plexiglass sheet top is bolted through the steel which compresses the mat to about 1/16-in. thick. The porous medium has a uniform permeability in the order of 2 to 4 darcies. Uniform compression of the mat is maintained by a 6-ft hydraulic head applied to the space between the steel and rubber membrane.

The model is flooded through simulated wells drilled in the transparent sheet and the progress of the flood is recorded with a time-lapse movie camera and a still camera. Areal coverage values at a mobility ratio of one check well with the theory. Quantitative results on the effect of mobility

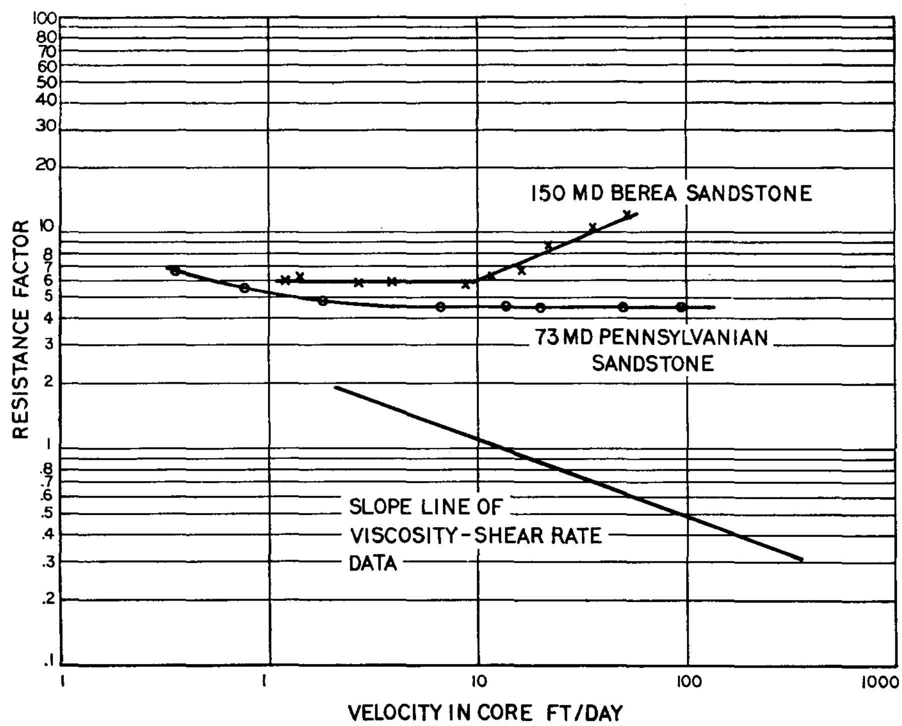

FIG. 2—EFFECT OF FLOODING VELOCITY ON RESISTANCE FACTOR.

ratio on areal sweep in five-spot models are shown in Fig. 3. This modeling technique has been used to study situations as complex as an existing 52-well field and will be described in a later paper.

PERMEABILITY DISTRIBUTION

To demonstrate the effect of the polymer solution on oil recovery where permeability distribution problems exist in isolated zones, a simple two-core experiment can be described using parallel sand-packed tubes.

Two 1-ft long tubes having inside diameters of 1.4 and 2.64 cm were packed with fine, clean sand and a sand-fireclay mixture having air permeabilities of 5,900 and 400 md, respectively. The tubes were connected to the flow lines in parallel, flooded with brine and then saturated with oil. A relatively low-viscosity oil of 6 cp was used to obtain reasonably sharp oil-water interfaces in each core. The results of the floodout are shown in Fig. 4. In the case of the water flood, the water breakthrough occurred after 10 ml of oil had been produced. The water cut then rose rapidly to a high value during production of oil from the less permeable core. With the improved mobility ratio due to the polymer solution, the oil produced at breakthrough was 50 per cent greater due to the extended period of simultaneous production from both cores. After breakthrough of the more permeable core, the water production from this core was restrained, permitting combined production at a lower total water cut. Similar experiments with 1.55-cp glycerin solutions show only a minor improvement over water.

DISPLACEMENT EFFICIENCY

The problem of displacement efficiency is concerned with the simultaneous flow of oil and water in the capillary pore structure. When the displacement efficiency is high, as for a low viscosity crude displaced by water, the saturation gradient is short and relatively sharp. Oil viscosities above 100 cp exhibit a very long saturation gradient which in some cases can reach from the injection well to the producing well.

Fig. 5 shows the results of a study involving the typical equilibrium-type experiment where a fixed water-oil ratio was injected into a core to equilibrium and the resulting saturation determined by radio tracer techniques according to Jennings.[6] A 1-in. diameter by 10-in. long sand pack mounted in plastic with a special mixing inlet end plate was flooded with brine and then saturated with crude oil containing radioactive ditolyl selenide tracer. The core was flooded with oil and brine or polymer solution at a fixed water-oil ratio at constant total flow rate supplied by two miniature 1/8 in. diameter plunger pumps equipped with variable speed and variable stroke. The two separate streams were mixed in the end plate.

The oil saturation in the core was monitored with a scintillation counter equipped with a discriminator to increase the signal-noise ratio. The core could be traversed across the 1/4-in. lead collimator to scan for uniform saturation. The effluent water-oil ratio was also brought to equilibrium with the feed before the oil saturation was measured.

As indicated on the ordinate, the water-oil ratio is numerically equal to the flowing mobility ratio at any saturation. Then, by definition, the resistance factor is equal to the ratio of the water and polymer mobility ratios at any one oil saturation. The oil mobility is constant so that:

$$\left(\frac{\lambda_w}{\lambda_o}\right) \Big/ \left(\frac{\lambda_p}{\lambda_o}\right) = \frac{\lambda_w}{\lambda_p} = R \quad . \quad (5)$$

With this type of curve, an increase in the water viscosity will shift the curve parallel and downward in the ratio of the mobility decrease. The dashed line shows the expected improvement to be obtained using a 1.55-cp water. However, when a very dilute solution of polymer having the same viscosity is used, the downward shift is much greater than would be expected. A curve of the resistance factor vs oil saturation can be obtained by plotting the ratio of the water-oil ratio values against saturation. This variable R factor complicates the picture; so for simplification,

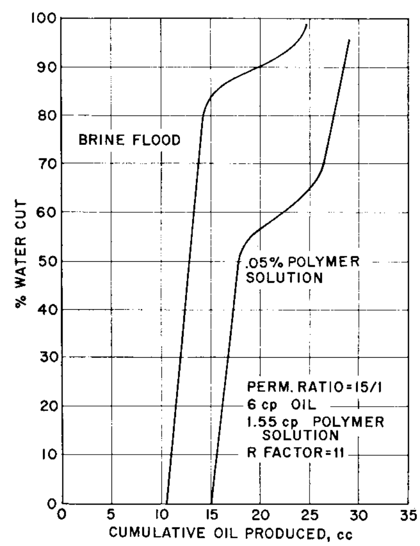

FIG. 4—EFFECT OF POLYMER ON PERMEABILITY DISTRIBUTION IN TWO PARALLEL CORES.

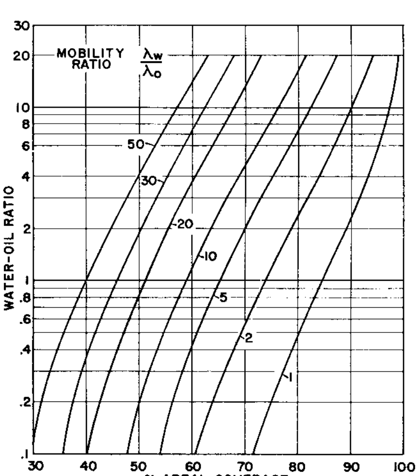

FIG. 3—AREAL SWEEP EFFICIENCY FROM MODEL DATA.

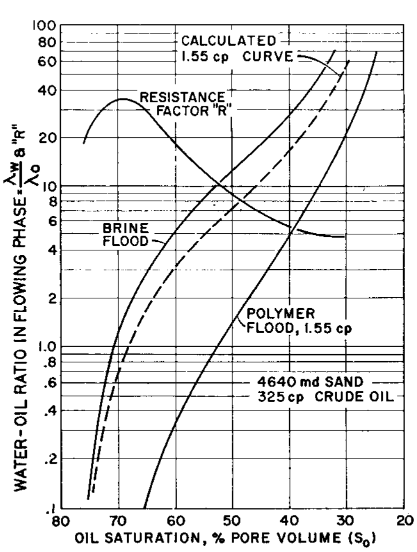

FIG. 5—EQUILIBRIUM DISPLACEMENT EFFICIENCY OF POLYMER SOLUTION.

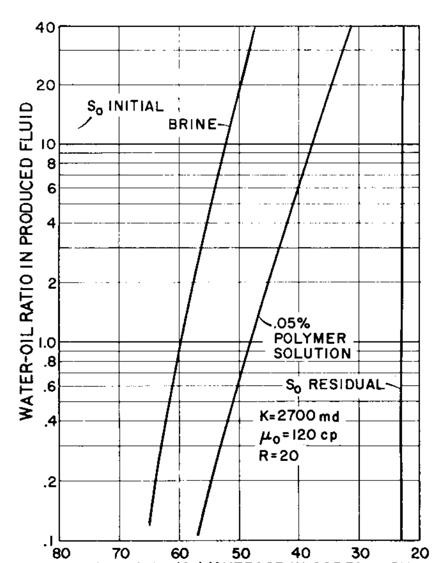

FIG. 6—POLYMER FLOODOUT COMPARISON.

R factors normally referred to are measured values at residual oil saturation unless otherwise stated.

An interpretation of these data shows that a water flood would reduce the oil saturation to 60 per cent at 84 per cent water cut while the polymer flood would reduce the saturation to 40 per cent at the same water-cut value. Correspondingly, at 60 per cent oil saturation, the water flood would produce at 84 per cent water cut while the polymer flood would be producing at 25 per cent water cut. Thus, the polymer solution will produce much more oil at a lower water cut.

CORE FLOODOUT TESTS

As one would expect, this improvement in displacement efficiency is reflected in a floodout test. Fig. 6 shows the results of such a test on a 1-in. diameter by 1-ft long unconsolidated core from a Louisiana field, using field fluids. According to the simplified form of the Buckley-Leverett theory, this test represents a linear model of the field on a pore volume basis. Thus, this core performance can be considered as a partial representation of the expected field performance.

The determination of the resistance factor value by comparing water-oil ratio values at a given saturation is not as straightforward as in Fig. 5 because the saturations represent average values for the entire core. Furthermore, the saturation gradients are not the same so that *R* values determined from over-all flow and pressure measurements may not correlate with the numbers obtained from the ratio of the water-oil ratio values.

All laboratory experiments consistently reveal that oil recoveries are indeed a function of the mobility ratios as determined on the basis of the resistance factor concept. The question then remains as to whether these increased efficiencies would actually be obtained in field operations. Accordingly, a series of pilot flood tests were run.

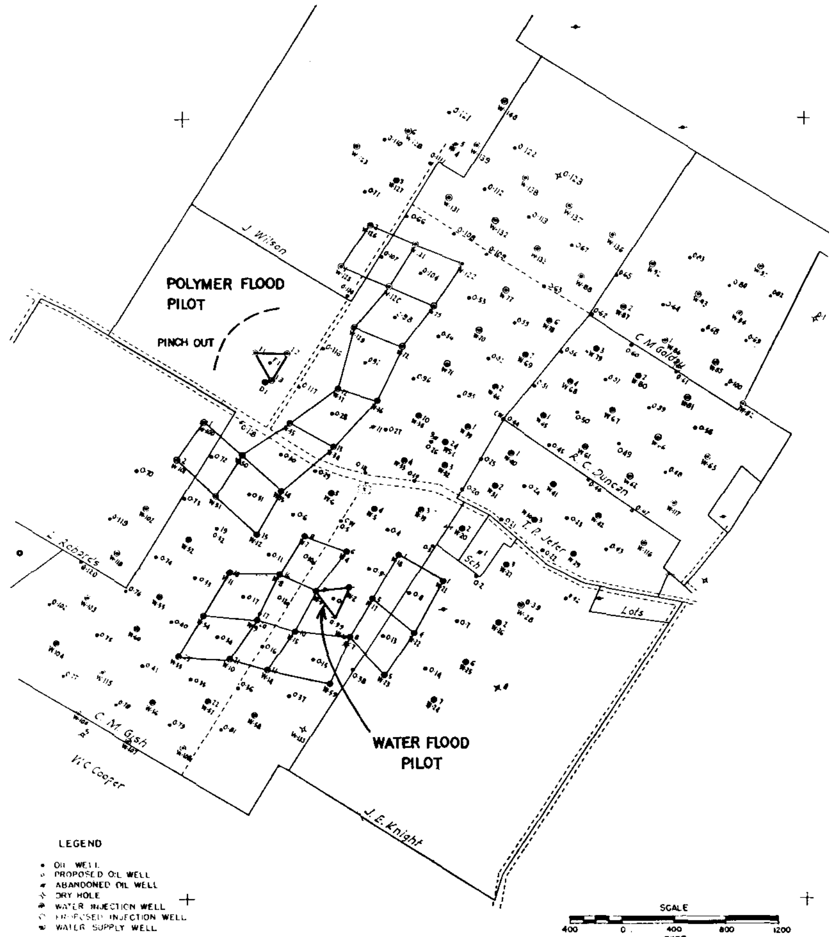

FIG. 7—NIAGARA PILOT FLOOD AREA.

PILOT FLOOD TESTS

NIAGARA PILOT FLOOD

In 1959 a 0.6-acre four-spot polymer flood pilot was run on the edge area of the 300-acre Niagara field near Henderson, Ky. This field had been under water flood for about 4 years following a waterflood pilot which had been run in 1954. The polymer pilot was drilled in the peripheral area near a pinchout as shown in Fig. 7, where the 750 ft deep Pennsylvanian formation was 10 ft thick and averaged 20 md. The 16 cp oil and a relative permeability of water at residual oil of 0.09 resulted in a 1.4 unfavorable mobility ratio for the water flood.

The oil in this sand is accounted for by a structural high with gentle relief and permeability development. The initial iso-water cut lines showed that the reservoir quality varied from zero initial water cut in the structural high in the area of the waterflood pilot to over 50 per cent in the north end of the field. Initial water cuts in the polymer flood pilot area were 20 to 30 per cent. Similarly, individual pattern waterflood recoveries varied from about 100 bbl/acre-ft in the north to about 300 bbl/acre-ft in the structural high. The polymer flood area was of average quality for the field.

A 1.35-cp polymer solution was injected continuously over a period of 33 months into the four-spot polymer pilot. The presence of the polymer solution, which exhibited a resistance factor of 8 in this reservoir rock, converted this flood to a favorable mobility ratio of 6. The water-cut performance of this pilot is shown in Fig. 8, where it is compared with the performance of the eight immediately adjacent waterflood patterns. This curve also shows the correspondence with predictions by a modified Stiles[3] method. All of the reported oil production values have been reduced to 70 per cent of the actual value due to unbalanced pressure regions outside of the pilot triangle. This correction factor was determined from the areal sweep models previously described by constructing and operating an actual scale model of this area of the reservoir.

The corrected polymer flood pilot performance was compared with the adjacent waterflood performance by scaling up the pilot area, volume, permeability and injection pressure factors resulting in a comparative performance as shown in Fig. 9. A detailed study of core analyses indicated that the adjacent waterflood patterns as shown in Fig. 7 were reasonably represented by the pilot reservoir so that the comparison appeared justified.

To further check the comparison method, the original waterflood pilot performance was similarly extrapolated to eight adjacent waterflood patterns with results as shown in Fig. 10. This degree of correspondence of the waterflood comparison indicates that the polymer flood comparison is probably not within the limit of error of the extrapolation method.

In this full polymer flood, the injection rate finally decreased to about

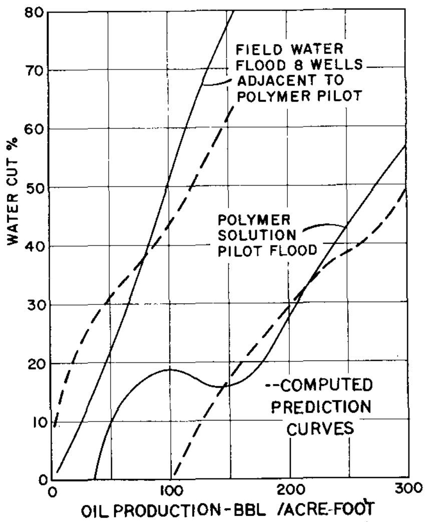

FIG. 8—NIAGARA PILOT FLOOD PERFORMANCE.

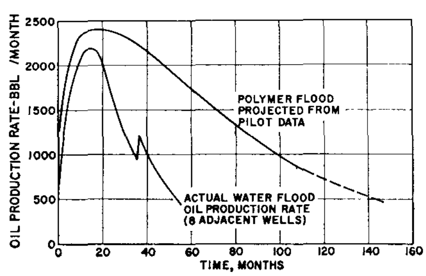

FIG. 9—COMPARISON OF WATER AND POLYMER FLOOD IN EIGHT WELLS ADJACENT TO POLYMER PILOT.

20 per cent of the initial rate as would be expected from the decrease in water mobility. In spite of this the oil production rate remained higher throughout the flood life due to the increased recovery efficiency. However, when only partial pore volumes of polymer solution are used, as would be dictated by economic considerations, the loss in injection rate is very much less due to the return to brine injection before the injection rate has been materially decreased. The presence of the low mobility water in the center of the field has little influence on the injection rate since the pressure drop is mainly at the wellbores.

The improvement in water usage efficiency is shown in Fig. 11, which compares the ratios of water injection to oil production. This curve demonstrates rather pointedly how an injection fluid costing many times more than water can be economic.

Since the area immediately adjacent to the pilot represented the average reservoir conditions of the entire field, the polymer flood pilot performance was scaled up to the full field basis so that an economic comparison with the actual waterflood operation could be made. A summary of this comparison is shown in Table 1.

THE TEXAS PILOT FLOODS

For further verification, a series of pilot floods were run in Starr County, Tex., in a small 4-acre reservoir containing about 7 net ft of 600 md sand, 85 ft deep. The five-spot patterns as shown in Fig. 12 were drilled on a spacing of 50 ft between like wells, and each pattern included four offset producers to balance the field pressures and insure definition of the pilot area.

TABLE 1—ECONOMIC PROJECTION OF KENTUCKY FIELD

	Water Flood	Polymer Flood
Oil Recovered at EL	172 bbl/acre-ft	310 bbl/acre-ft
Gross Oil Produced	1,390,000 bbl	2,428,000 bbl
Operating and Development Cost	$1,718,000	$2,941,000
Total Oil Cost/Bbl	$1.24	$1.19
Discounted Cumulative Net Income (6%)	$906,437	$1,621,890

The effectiveness of this means of insuring the definition of the pattern area had been previously demonstrated by the areal sweep model system. Since these offset producers are kept pumped off, they establish a pressure high line coinciding with the square pattern boundary lines and cause the pattern to flood as if it were one pattern in a fully developed five-spot field. Production data from the central producer only are used for evaluation. While this system requires four extra wells it helps avoid the need for correction factors.

The 130-cp oil viscosity resulted in an unfavorable water-oil mobility ra-

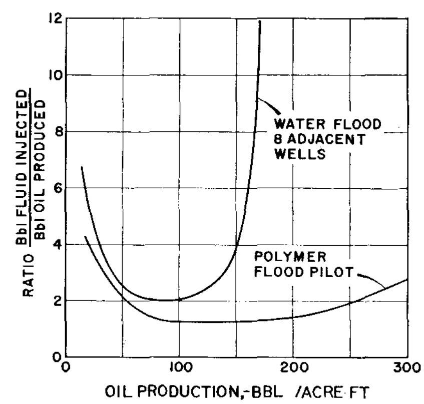

FIG. 11—INJECTION EFFICIENCY, NIAGARA FIELD.

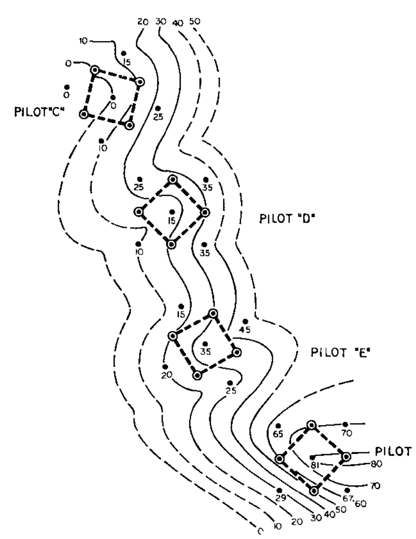

FIG. 12—ISO-WATER CUT MAP OF TEXAS PILOT FLOODS.

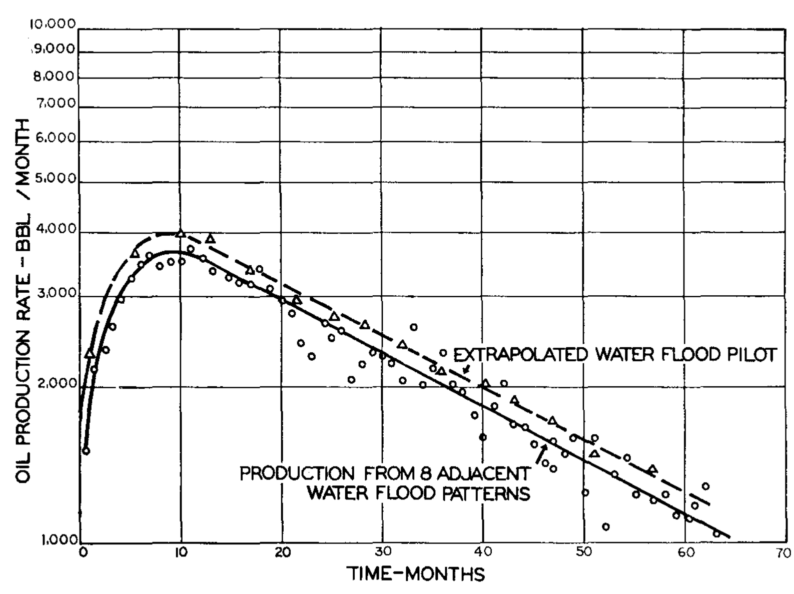

FIG. 10—COMPARISON OF WATERFLOOD PILOT AND PRODUCTION FROM ADJACENT AREA.

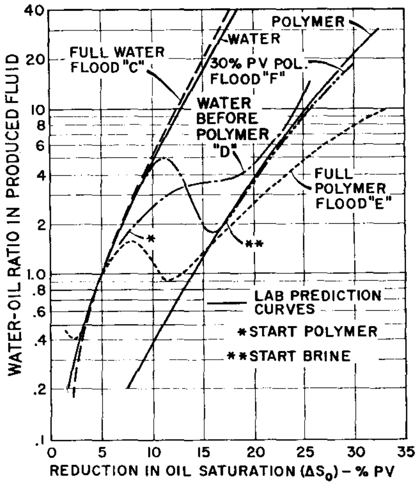

Fig. 13—Performance of Texas Pilot Floods, Albrecht Field.

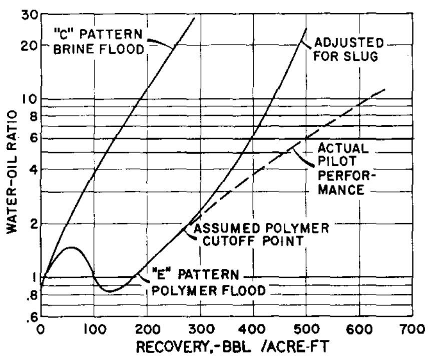

Fig. 14—Adjusted Pilot Performance for Economic Comparison.

tio of 40, but the average laboratory value for the polymer solution resistance factor in this formation of approximately 8 reduced the unfavorable mobility ratio to 5 for the polymer floods.

There was some variation in the quality of the several patterns with respect to water saturations, as shown by the iso-water cut lines of Fig. 12, so the best, or C, pattern was used for the water flood. D pattern was a flood which was started on brine and then was followed by the polmer solution. E pattern was used to demonstate the use of polymer solution continuously throughout the life of the flood to determine just how much oil could be recovered. F pattern was a modified polymer flood wherein a partial pore volume of polymer solution was injected and then followed by brine.

The results of these floods are shown in Fig. 13, where the actual performance curves are overlain on the prediction curves for water and polymer solution. The correspondence

TABLE 2—ECONOMIC PROJECTION OF ALBRECHT FIELD

	Water Flood	Polymer Flood
Gross Oil Produced	275 bbl/acre-ft	501 bbl/acre-ft
Initial Development Expense	$274,000	$301,000
Gross WI Income	$5,538,000	$10,075,000
Total Operating Cost	$2,081,000	$2,938,000
Cumulative 6% Discounted Net Income	$1,420,000	$4,312,000
Average Cost/NWI Bbl	$1.48	$1.01
Surface Area	500 acres	
Pay Thickness	20 ft	
Porosity	30%	
Well Spacing	20 acres	
Acquisition Cost	$1,204,000	

of the performance with the prediction curves is reasonably good. In all cases, the initial performance starts out along the waterflood curve since the polymer solution miscibly displaces the connate water, and then the performance moves over to the polymer curve and follows this trend.

This same water-cut flat or dip was also observed in the Niagara pilot flood. In the cases where considerable mobile water is present at the start, the floods started on the waterflood curve at an elevated water-oil ratio value.

Fig. 14 shows the actual performance data for the water flood and the E pattern polymer flood with the water flood adjusted to match the initial 50 per cent water cut to give a fair comparison between the two pilot patterns. For purposes of economic consideration, it was assumed that the polymer injection would be limited to 30 per cent of a pore volume and at this cut-off point the curve was adjusted upward to correspond with the slope indicated in Fig. 13.

To obtain a feel for the economic value of the process, a calculation was made based on the assumption that the relative performance of Fig. 14 could be extrapolated directly to a 500-acre field with a 20-ft pay thickness at 1,000-ft depth. An acquisition cost of 50 cents/bbl of waterflood reserves was assigned to the acreage and all development costs were included. Operating costs applicable to the area where assigned and the chemical costs included. An economic summary of the projection is presented in Table 2 and the 6 per cent discounted cash flow curve is shown in Fig. 15 for the two floods. It can be seen from this information that the resulting production gains far override the cost of the polymer. Further economies can be expected from the fact that the polymer solution was produced intact and suitable

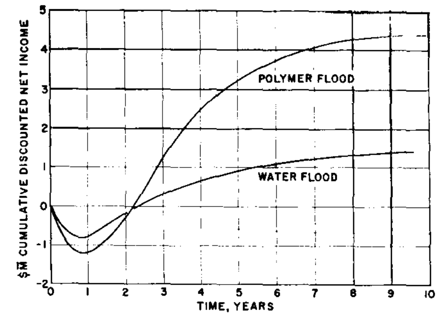

Fig. 15—Projective Comparative Economics, Albrecht Field.

for re-use in a closed brine system, although this was not actually done in those pilot tests.

CONCLUSIONS

In view of the laboratory and field experimental data obtained up to this time, as well as satisfactory results from several other commercial pilots presently under way, this process appears to hold promise to the oil producing industry as a means of increasing recovery, reducing production costs and increasing oil reserves.

NOMENCLATURE

q = Flow rate, cc/sec
k = Permeability, darcies
Δp = Pressure drop, atm
A = Area, sq cm
μ = Viscosity, cp
L = Length, cm
R = Resistance factor
λ = Mobility

SUBSCRIPTS

o, p, w = oil, polymer solution and water.

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