New Applications of Polymer Flooding

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INTRODUCTION

Efficient oil recovery by waterflooding requires that certain fluid and reservoir properties lie in an appropriate range. The mobility ratio of the oil being produced to the water being injected is one such parameter which fortunately can be adjusted by one technique or another to obtain satisfactory recoveries. The most recent technique for adjusting the water oil mobility ratio is to dissolve small amounts of a water soluble polymer in the injection brine. It has been found that very small quantities of polymer greatly reduce the mobility of injection fluid thus increasing oil recovery. The increased recovery is due to a more effective sweep of the reservoir and can be quantitatively predicted in advance of the flooding operation. Laboratory and field tests of the process have previously been reported.[1,2] The present discussion concerns the new commercial applications of this process.

Method of Application

The use of polymer flooding requires essentially the same equipment as normal brine flooding. A flow sheet and equipment cost estimate for a 10,000 BPD flood have been presented by Schurz.[3] The additional capital above the cost of a normal waterflood plant amounts to $10,000. Capital expenditure for the process is therefore negligible and it is clear that the quantity and cost of the chemical used is the critical factor in any given application. These values are determined on the basis of laboratory core tests followed by calculation procedures to determine the economic optimum.

The laboratory studies consist essentially of measuring the pressure required to force brine through a core at residual oil saturation and then measuring the pressure required to force successively higher concentrations of polymer solution through the same core with flow rate and all other conditions held constant. The studies are conducted using cores and fluids from the field in question at field temperatures. When the correct polymer is used it is found that even at very low concentrations, considerable extra pressure is required to force polymer solution through the core. As the polymer concentration is increased, increasing pressures are required. The results of these tests are generally reported as a "resistance factor" which is the ratio of the pressure required to force polymer solution through the core to the pressure required to force brine through the core at the same rate. A typical plot showing the variation of resistance factor with polymer concentration is shown in Fig. 1. From such a plot the additional oil recovery corresponding to a given polymer use is calculated. The economic optimum point is selected and on this basis the most advantageous polymer injection program is recommended. Included in these calculations is, of course, the time rate of oil production; it is found that after an initial delay due to decreased injection rates, the oil production rate of the polymer flood exceeds that of the straight brine flood because of the increased efficiency of the displacement process.

PRIOR WORK

Theoretical justification has long existed for the belief that low mobility brine should give increased oil recoveries. Field tests showing such improvement have however only recently been published. Pye has reported field tests in two different reservoirs. One test involved a reservoir containing 16 cps oil; recovery was increased from 172 bbl/A ft on brine to an estimated 319 bbl/A ft using a 500 ppm polymer solution for the life of the flood. In another reservoir containing 130 cps oil the use of a 500 ppm polymer solution injected for 30 per cent of a pore volume yielded 501 bbl/A ft. The adjacent waterflood pattern yielded only 275 bbl/A ft.

In both of the tests described above Pye was able to show that the increased recoveries were predictable on the basis of the known reservoir parameters and the measured resistance factors.

Four additional field tests are reported by

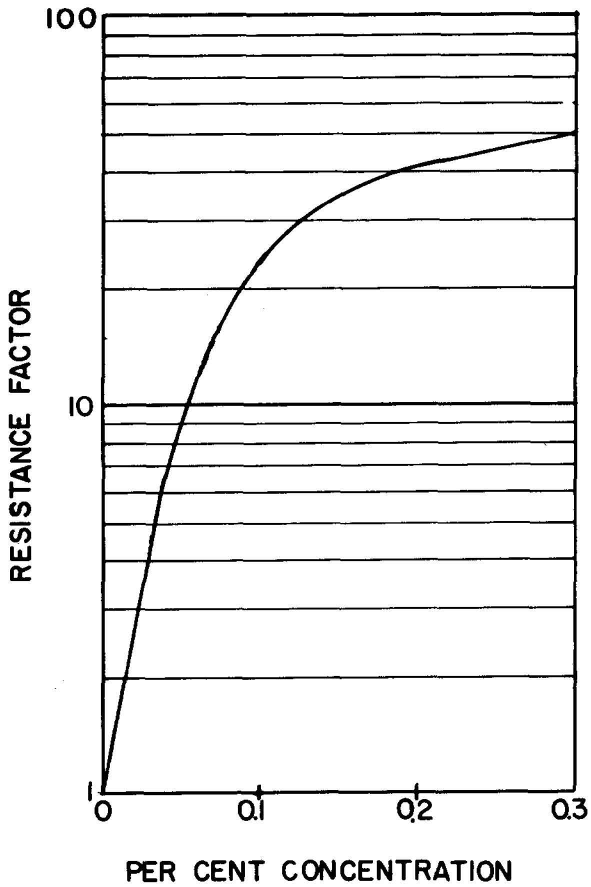

Figure 1

Sandiford. These tests were conducted in fields already under waterflood and involved the injection of relatively small volumes of concentrated polymer solution to see if this would produce a significant change in the waterflood performance.

One of the tests involved the injection into one well of 2600 lb of a partially hydrolyzed polyacrylamide dissolved in 2000 bbl of brine. Seven wells surrounding the injector showed increases in oil recovery and eventually a total of 95,000 bbl of additional oil was recovered. The oil viscosity in this case was 110 cps. A similar test in a 2.8 cps reservoir led to the production of 30,000 to 70,000 bbl of additional oil. Of the two other tests reported by Sandiford, one produced moderate quantities of additional oil; the other failed to change production. In this last test it was subsequently discovered that production wells in the vicinity produced poorly, if at all, from the zone of interest.

CURRENT EFFORT

Subsequent to the publication of the papers discussed above commercial application of polymer flooding has started in all of the important waterflood areas of the United States. Polymers, especially designed for use in this process, are now commercially available.

Table I lists field parameters for a number of fields in which polymer floods are now being conducted. As the results of these tests are published, a very complete picture of the useful range of polymer flooding should emerge.

TABLE I

TYPICAL RESERVOIRS NOW UNDER POLYMER FLOOD

Field	Depth, Ft.	Porosity %	K (Air)	° API	(cps)	Mobility Ratio (Brine:Oil)
A	1000	20	41	26.6	76	40.7
B	1020	19	100	29.1	26.4	10
C	1400	19.5	42	30.5	13	3.5
D	725	21.7	27	24.5	90.1	23.4
E	2200	30.6	92	30.6	12	4.2
F	2350	34	2300	14.5	36	15
G	6500	17	50	55	0.07	0.2
H	2200	36.5	1600	14	450	80.6
I	410	19.5	300	33.7	8.9	4.2
J	1930	34.2	230	24	54	22.6
K	2200	31	155	21.8	14	5.2
L	2695	25	2000	13.5	500	92
M	2800	19	1700	36.1	7.3	2.7
N	4450	26.3	390	16.0	80	32.4

N E HALLSVILLE FIELD TEST

Field G in Table I has been in operation for a long enough period so that the results of the test can now be assessed.

The Crane reservoir of the N E Hallsville Field is the zone of interest. This is a Pettit lime reservoir which was discovered in 1950 when gas wells penetrated the Crane zone as well as overlying gas productive strata in the upper Pettit lime. The upper Pettit porosity pinches out and does not appear above the central and western portions of the Crane reservoir. Gas production from the Crane reservoir was always observed high in fluid content and as the field was developing to the west starting in 1956, good oil production was obtained.

The ultimate development of the reservoir is shown in Fig. 2. Gas wells were developed on 640-acre spacing and oil wells were drilled on an 80-acre spacing.

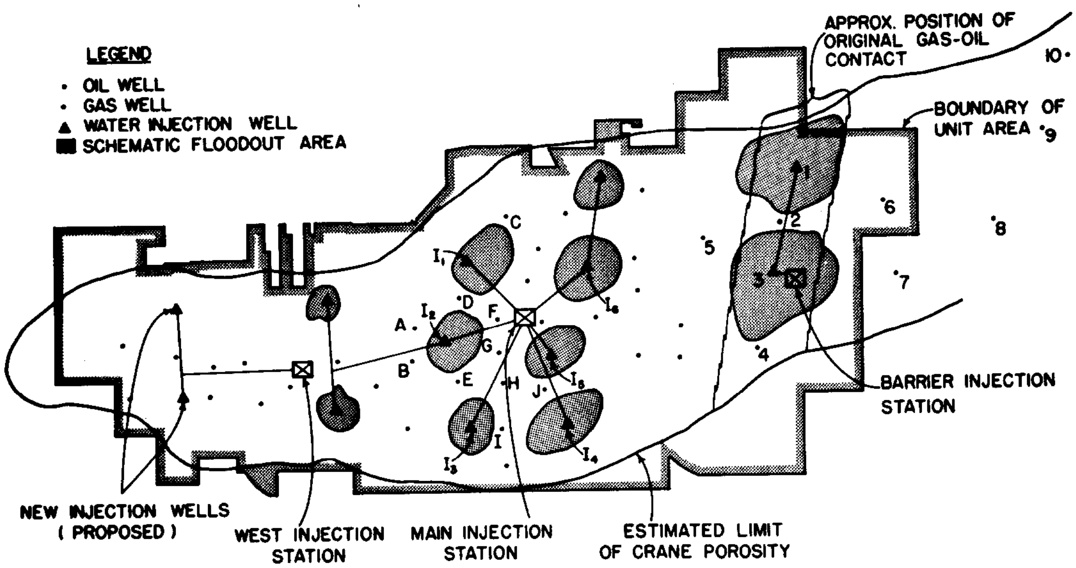

Figure 2

The reservoir defined by this development is a stratigraphic trap occupying 17,000 acres with an average thickness of 5.4 ft and a reservoir volume of 91,500 AF. Total Crane reservoir length is 16 miles with an average width of about 2½ miles. The reservoir dips to the west from about 6200 ft subsea to 6700 ft. The portion of the reservoir from —6700 to —6400 was oil bearing, the portion from —6400 to —6300 was a broad transition zone from oil to gas and the remainder of the reservoir was gas productive. Reservoir properties are shown in Table II and reservoir fluid properties are shown in Table III. Primary production and the accompanying pressure decline are shown in Fig. 3.

On the basis of this observed production-pressure decline relationship, it was calculated that a rather low primary recovery of perhaps 1,000,000 S.T.B. would be achieved or about six per cent of the original O.I.P. This low recovery is attributable to the high volatility of the crude with resultant high shrinkage and to the continuing withdrawals from the gas cap with consequent decline in field pressure.

As a result, repressuring techniques were considered early in the field operation. The large volume of the associated gas cap and continued gas production made such repressuring operations impractical by normal techniques. Careful study of the problem by Hunt Oil Company engineers, however, led to a novel proposal to isolate the gas and oil productive areas. It

TABLE 2

Average Reservoir Properties

Formation:	Crane zone	Pettit Lime
Volume:	Gas Cap -	56,000 A. Ft.
	Oil zone -	35,500 A. Ft.
	Total	91,500 A. Ft.
Porosity	-	17.0 per cent
Connate water	-	27.0 per cent
Permeability	-	50 md.
Original O. I. P.	-	17,400,000 S. T. B.
Gas	-	55,000,000 M.C. F. Std. Conditions
Temperature	-	229°F Oil Zone, 215°F, Gas Zone
Original pressure	-	3289 psi at 6600 Ft. subsea

TABLE 3

Reservoir Fluid Properties

Oil Gravity	-	57.1° A. P. I. (Stock Tank)
Oil μ	-	.072 cps (229°F saturated)
F. V. F.	-	2.4 at 3289 and 660 Ft. subsea
Original GOR		1325 ft.^{3}/S. T. B.

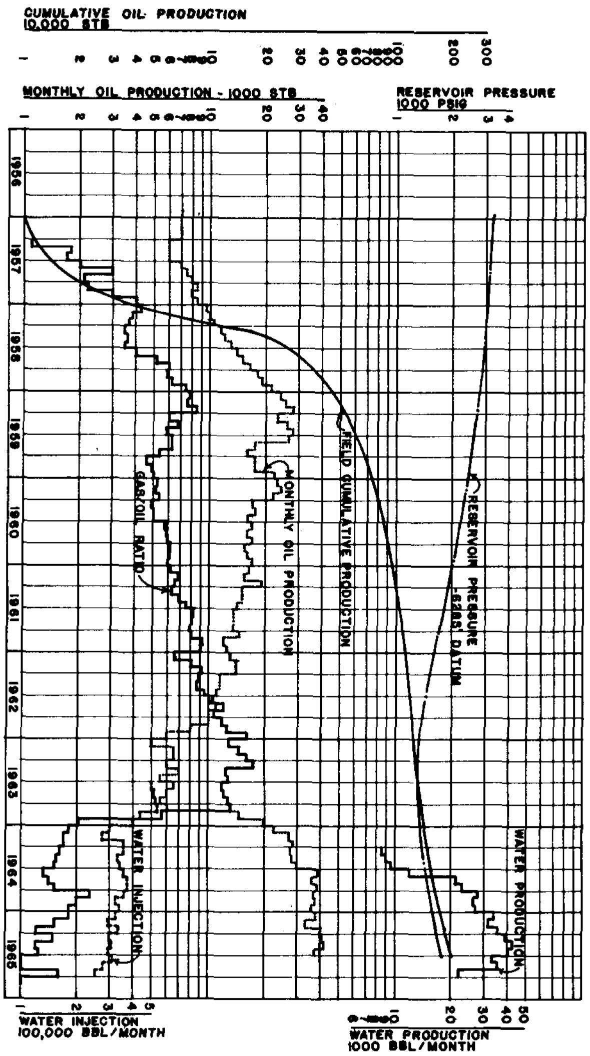

Figure 3

was proposed that the gas cap be isolated from the oil productive zones by the placement of a "barrier" zone of viscous water. This barrier would be placed at the intersection of the gas cap and the oil transition zone, thus separating the western oil zones from the gas cap in the eastern portions of the field. Such a barrier would effectively seal the reservoir, preventing transfer of fluid from the repressured areas to the lower pressure gas cap zone.

It was necessary, of course, that the barrier itself remain intact and not move too rapidly under the influence of the applied pressures. Two methods were planned to realize these conditions. First, production wells on both sides of the barrier would be carefuly controlled to minimize pressure differentials across the barrier. Second, it was proposed that the fluid used to form the barrier be a viscous fluid which once in position would be much more stable under the influence of any cross barrier pressures.

After a study of prior materials, Hunt engineers concluded that entirely new materials were needed for this use. Fortunately, the new polymeric materials especially designed for waterflood mobility control were just being developed at this time.

The materials of choice are the water soluble polymers which, when dissolved in injection fluids, greatly reduce the mobility of the aqueous phase, but exert no effect on the oil or gas flows in the reservoir. These materials have the solubility, stability, and other properties required for use in petroleum reservoirs. In Hallsville cores, one of these materials reduced the mobility of brine by a factor of four at a use concentration of 250 ppm. With this ability to produce a stable barrier, plans for the recovery program were completed.

The method used to establish the barrier is shown in Fig. 2. Injection wells 1 and 3 were used for the initial injection of the Pusher solution. At the same time, wells 2 and 4 were operated at maximum draw down to elongate the barrier as shown. With the barrier in place, there were two choices as to the most suitable secondary recovery method. The initial reservoir properties were very favorable to the use of miscible recovery program; however, because of those delays necessitated by formation of a unit and final establishment of a program, reservoir pressures had declined to a point where miscible recovery was no longer attractive and a straight waterflood was the most suitable recovery method.

Formation of the unit was completed and the unit became effective as of January 1, 1963.

The initial waterflood installation had two pumping stations. The barrier station equipment consisted of three triplex pumps designed to supply 600 BWPD at pressures up to 3000 psi. The main station had six inch pumps designed to supply 12,000 BPD.

Injection operations were started May 30, 1963, utilizing plain water. An injection test was conducted in August of 1963 to check the effect of the polymer solution on injectivity. Pressure increases from the addition of this material were modest and no decrease in injectivity was observed. Equipment for the continuous addition of the polymer powder was installed and the injection of polymer was started in October of 1963.

A very rapid response to water injection was observed. Field-wide average bottom-hole pressure was 1306 lbs in June of 1963. By September of 1963 the pressure decline had been arrested and, in fact, field-wide average pressure had increased slightly to 1309 psi; three wells D, I, and J in the central injection area had been affected by the substantially higher pressure in their area and had ceased to flow by natural gas lift because of the decreased G.O.R. These wells as well as others, which ceased to flow as the pressure wave reached them, were placed on artificial gas lift. With the increases in pressure, substantial increases in production were observed as shown in Fig. 3.

Bottom-hole pressures continued to increase and by June of 1964 it was apparent that the barrier had become an effective sealant for the reservoir. Pressures on both sides of the barrier were essentially identical indicating negligible fluid loss across the barrier. Pressure conditions at this time are shown in Fig. 4.

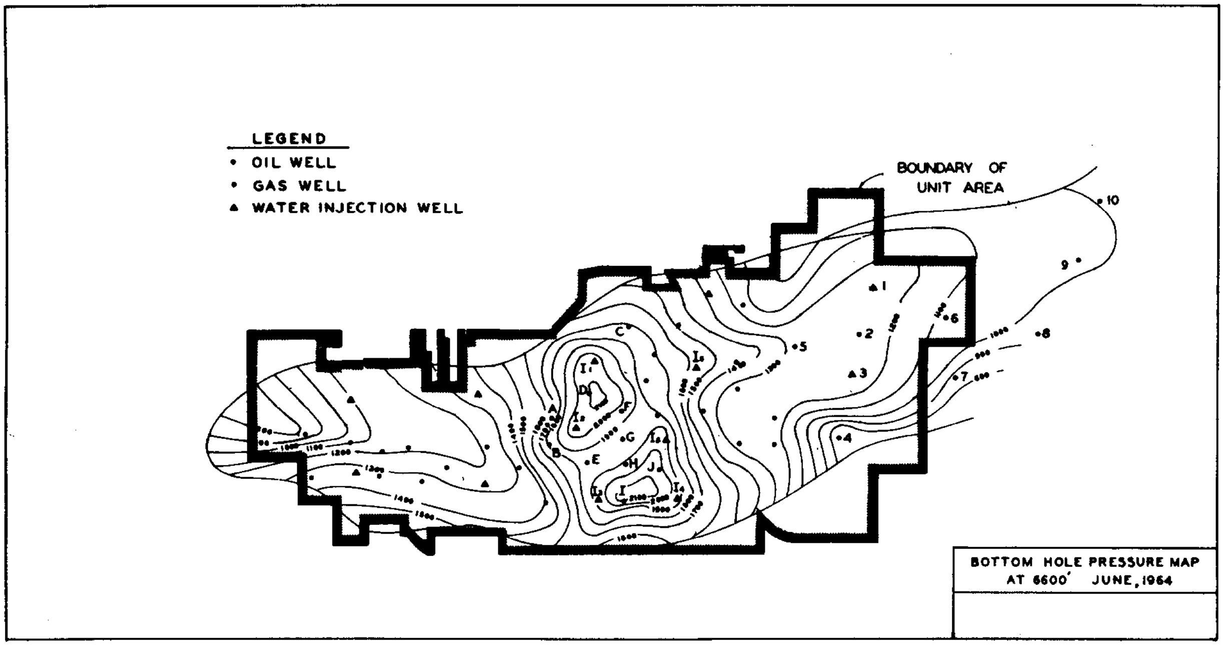

Figure 4

The pressure slope at the bottom of the diagram (Section 36) has negligible effect on leakage because of very low fluid transfer rates in this area. Well 4, in fact, produced so little fluid at this time that it was shut in. Well 2 on the other hand proved to be a prolific producer. When originally completed, the well was a gas producer as would be expected from its position in the reservoir. However, as pressures increased, this well became an oil producer and ultimately produced over 95,000 bbl of oil before being abandoned for production.

Two new wells were drilled during the development of the waterflood program. Core data from these wells were correlated with previously obtained logging information to indicate that the Crane sand in this reservoir was not one uniform body, but rather two separate zones. In the central field area these zones overlap and become contiguous. Away from this central area, these zones may be separated or non-existent as shown. The qualities of these zones differ greatly but on the average the A or upper zone is regarded as having about 5 md permeability while the B or lower zone averages 50 md.

Very high sweep efficiencies had been assumed for the reservoir because of the favorable mobility ratio under reservoir conditions. Water viscosity under these conditions was approximately 0.27 cps and oil viscosity was .072 to .09 cps depending on reservoir pressure. In practice, this high sweep efficiency was not borne out. Water breakthrough in many wells corresponded to sweep efficiencies of 50 per cent or less. It appeared likely that this was caused by the two-layer systems involved. In many cases, the breakthrough could be predicted by assuming that one of the two zones had been swept with a very high efficiency.

Because of this low sweep efficiency, it appeared that oil production would be substantially delayed or even lost if a more effective means of simultaneously sweeping both zones could not be devised. After a consideration of the methods available for such corrective action, it was concluded that the most economical method would be the injection of a wave of polymer solution which would initially invade the zone receiving the greater part of the injection fluid and hence, would reduce fluid flow in that zone to a greater extent, thus improving fluid distribution between the zones.

To test this proposal, a 70,000 lb wave of polymer solution was injected into wells 11, 12, 13 and 14 over an 80-day period starting July 1, 1964. This treatment might be expected to affect 13 wells in the immediate vicinity of the injection pattern; however, only ten of these wells had been placed on production gas lift prior to initiation of the test and of this ten, only five had a watercut and hence, an established decline prior to the polymer injection. Data on all ten of these wells are presented in Table IV and the cumulative production data from the five wells with a prior watercut are presented in Fig. 5.

There was no immediate effect on the reservoir, but about two months after the start of the polymer injection, impressive production changes occurred. The polymer injection simultaneously reduced the watercut and very substantially increased oil production in the five wells which had an established decline. While not as definitive, it is apparent that other wells in the area also enjoyed substantial improvements in production. Careful inspection of the data to date suggests that about 59,000 bbl of increased oil may have resulted from the polymer injection. In this respect, it should be noted that the five wells shown in Fig. 5 would have reached economic cut-off and would have been abandoned had it not been for the production increases attributed to the polymer injection. The timing of the production response is of interest in considering the mechanism of the action and the influence of other extraneous field activities on the production. From Fig. 5, it appears that the first effects of polymer injection appeared about two months after the start of injection, and these effects had become completely effective after five months. At this point, a new decline is established and the flood proceeds to completion.

Examining various wells, it appears that those wells which initially responded most quickly to water injection and which were nearest to a polymer injection responded most quickly to polymer injection.

Another interesting observation as to the

OIL/WATER PRODUCTION

Date	A	B	D	E	F	G	H	I	J	K
11-63			173/20					157/0	386	
12-63	100/0	65/0						172/0	372/0	190/0
1-64	100/0	66/3	125/60	70/7	166/0	68/0	258/0	63/41	184/37	190/0
2-64	47/20.9	NT	88/86	137/0	195/2	NT	369/0	48 /44	NT	NT
3-64	26/25	25/5	80/81	220/0	221/0	90/0	360/2	51/40	47/17	28/40
4-64	24/25	8/21	88/70	205/0	199/3	73/0	360/0	49/39	73/58	21/46
5-64	41/11	30/20	93/60	207/0	166/8	183/16	449/0	58/38	95/42	23/28
6-64	21/18	8/30	102/55	209/0	138/8	129/0	432/5	34/46	49/63	19/46
7-64	12/29	9/20	48/85	188/3	137/0	163/0	464/0	32/44	33/94	20/61
8-64	9/29-33/112 (1)	9/19-7/100 (1)	31/94	103/11	124/14	155/0	412/0	31/52	28/93	16/64
9-64	33/95	17/87	40/87	110/8	85/28	87/8	483/0	19/63	30/105	14/2
10-64	45/151	13/129	30/116	82/8	49/25	59/19	262/32	24/77	23/138	10/49
11-64	30/80	28/206	26/106	99/30	19/39	52/37	229/40	47/67	25/124	25/124
12-64	73/73	28/114	20/90	109/30	20/30	39/41	274/44	68/82	35/117	11/56
1-65	68/128	54/88	12/84	65/74	42/27	54/37	189/75	27/99	16/159	14/109
2-65	44/182	38/117	NT	77/7	NT	NT	NT	23/37	NT	NT
3-65	7/33	67/89	36/74	NT	30/45	73/33	167/132	NT	31/122	40/30
4-65	20/18	NT	NT	88/31	NT	NT	NT	30/171	NT	NT
5-65	10/50	NT	NT	NT	NT	-----	NT	NT	NT	NT
6-65	23/224	0/217	20/87	64/37	40/13	60/47	107/154	NT	12/37	57/107
7-65	31/110	120/84	10/124	66/40	20/40	NT	36/50	33/136	NT	15/47
8-65	NT	NT	NT	NT	52/20	43/27	27/0	15/48	NT	NT
9-65	NT	18/74	30/107	NT	104/43	NT	NT	NT	NT	27/194
10-65	34/	13/147	NT	144/32	67/27	27/43	33/17	7/28	NT	10/214
11-65				147/57	-----	50/61	30/110	NT	NT	

(1) - Wells A and B received 1000 gal. acid treatments August 10, 1964.

NT - No test.

Table 4

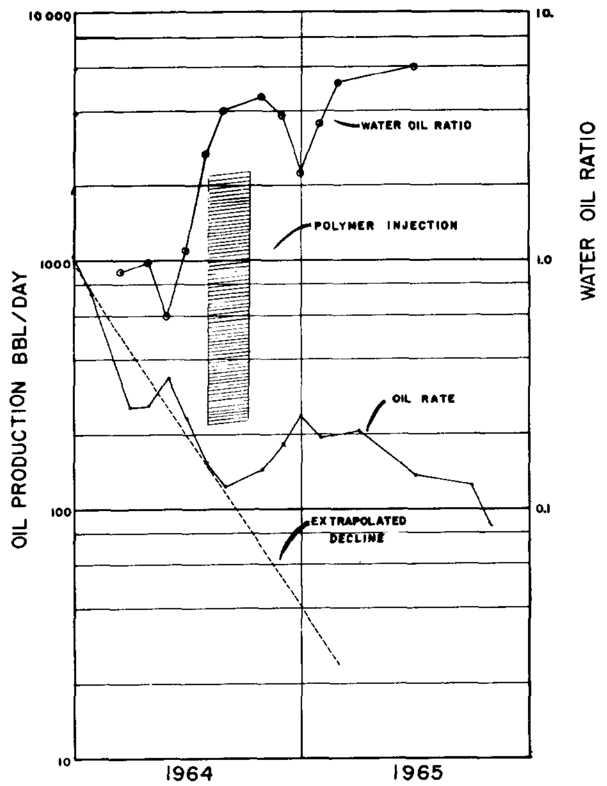

Figure 5

mechanism by which the polymer is effective in the reservoir was furnished by tracer studies performed throughout the course of the flood. These studies conducted by an independent consulting laboratory involved the injection and subsequent analyses of four independent tracers. Two of the materials used, SCN— and NO_3— were never detected. Rather than assuming that this represents some gross reservoir incongruity, it seems likely that at the elevated temperature of this reservoir, both SCN— and NO_3— are chemically active enough to be destroyed. This is confirmed by the fact that the other two tracers I— and tritiated water were detected every time they were injected.

The tracers in every case were injected after injection of from 300,000 to 500,000 bbl of water in the the injection well concerned. Two significant observations were made at production wells. One was the injection volume at the time of initial breakthrough; second was the additional volume required for tracer breakthrough.

The sweep efficiency was calculated by calculating the reservoir volume between a given injector and producer assuming a completely circular injection pattern and comparing this volume with the actual volume injected at breakthrough. Similarly, the volume injected between the addition of tracer and its appearance at the associated production well gave an indication of the channelling tendency in the reservoir.

We note in this connection that the void volume of a reservoir to tracer ions and to water as measured by water breakthrough, is different. Tracer ions enter all portions of the flooded zone except that portion occupied by residual oil. Hence, the maximum theoretical voidage to tracer is $\phi(1-S_{or})$. The water measured at breakthrough, however, was not differentiated as to being injection water, connate water, or some combination of the two. Hence, the maximum theoretical voidage to injection water is $\phi(S_{or}-S_{wc})$.

The sweep calculated on this basis is shown in Table V. At the time of breakthrough under these favorable mobility conditions from 34 to 100 per cent of the required water to give a perfect circular pattern just filling the volume between the injector and producer being studied had been injected. The sweep at breakthrough is obviously affected by the reservoir properties (in some places quality of the A and B zones is identical at other points they differ widely) and by the production operations. In the barrier area, for example, every effort was made to form an elliptical injection front accounting for the 34 per cent number in this area. A comparison of the breakthrough sweep with the sweep measured by the appearance of tracer at adjacent production wells shows the tendency of fluids to channel in the reservoir. The tracer in every case followed the injection of a large volume of injected water. In the pattern area, the tracer fluid and the injection fluid were identical in properties except for the tracer ions so the tracer was preceded and followed by fluid of unit mobility ratio. In the barrier area the tracer was injected in water, but was followed by polymer solution so the mobility ratio was 0.25. Column 9 of Table 5 shows this tendency for the injection fluid to channel as indicated by the injection volumes for water breakthrough compared to tracer breakthrough. As in many other reservoirs, tracer ions very quickly transfer from injector to producer under normal circumstances. The injection of the Pusher solution, however, eliminates this rapid transfer by filling high permeability channels with low mobility fluid. The tendency to channel as measured by the ratio in Column 9 varies from 4.0 to 8.3 at a unit mobility ratio.

TABLE 5

1	2	3	4	5	6	7	8	9
Injection Well	Production Well	Voidage to Water $\phi(1-S_{or}-S_{wi})$	Voidage to Tracer $\phi(1-S_{or})$	Injection Volume to Breakthrough	Injec. Vol. to Tracer Breakthrough	Sweep by Breakthrough (5/3)	Sweep by Tracer (6/4)	Channelling Tendency (7/8)
I2	A	616,000	963,000	443,700	118,000	.72	.12	6.0
I2	B	856,000	1,340,000	470,458	118,000	.55	.09	6.2
I2	E	781,500	1,220,000	590,181	232,000	.75	.19	4.0
I2	F	1,750,000	2,730,000	590,181	118,000	.34	.04	7.7
I4	J	395,000	617,000	429,184	57,000	1.08[1]	.13	8.3
3	2	2,325000	3,630,000	807,600	978,000	.35	.27	1.28

[1] It is possible that breakthrough of water in well J was due to injector I5. In this case, sweep by breakthrough would be 0.69 in better agreement with other wells. The tracer, however, had to come from well I4.

When a polymer solution follows the tracer, however, this ratio is dramatically reduced about four-fold to a value of 1.28. It seems most likely that this improved fluid distribution in all zones and all areas of the reservoir accounts for the improvement in oil rate and the decrease in water production observed upon injection of polymer.

Field operations at Hallsville were highly automated both for injection and production. After initial start-up, equipment has operated with a minimum of labor and has been essentially trouble-free during the entire operation. The production operations were initially centered in the central area of the unit. The main oil zone in the western edge of the field is just now being opened to production in accordance with the production allowables.

This new technique of isolating gas and oil zones with a viscous barrier has thus been proven in its first field trial affording a new technique for recovery in this type of reservoir.

It has also been demonstrated that reservoir defects resulting in channelling or bypassing in a reservoir can be corrected by the use of low mobility fluids. It is expected that these techniques should find wide application in future recovery programs.

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