When Should Polymer Treatment Be Started on Waterfloods?

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INTRODUCTION

In April of 1969, J. E. Kastrop of "Petroleum Engineer" wrote a strong editorial—WILD CATTING IN OIL RECOVERY—in which exploration risk factors and reservoir engineering risk factors were compared. The point being that with present recovery efficiencies running less than 33 per cent, why go out looking for "new" oil when over two-thirds of what has already been found is simply waiting for the know-how to produce it?

Polymers applied at the right time and under the right conditions, can improve oil recovery efficiencies by 5 to 15 percentage points. Although reservoir rock characteristics and fluid properties are important, the data presented here clearly point to timing as an overriding consideration when it comes to producing "polymer oil" at a good profit.

Fifty-six polymer projects are grouped in accordance with the producing water-oil ratio in effect at the start of treatment:

Group	Projects	Producing WOR
I	10	Less than 4
II	9	4 to 8
III	10	8 to 16
IV	27	Greater than 16

Although the number of projects varies, each group received about the same total polymer treatment tonnage.

Figure 1 shows how polymer oil recovery is a function of the producing water-oil ratio in effect at the time treatment is started. WOR's are the weighted average of evaluated projects in each group. All polymer which went into evaluated projects was used in figuring polymer oil per pound. This rule applied even when the project was rated "no response" due to mechanical or special reservoir problems that could not be helped by polymer treatment.

Techniques used to evaluate projects are illustrated by Line Numbers 12, 19, 37 and 43 (shown in Tables 1-4). (Individual projects are identified by a Line No. rather than by operating company or field.) In addition to covering three of the four water-oil ratio groups, these projects represent sand, lime, conglomerate and fractured reservoir conditions.

POLYMER OIL

Group IV

Twenty-seven projects with WOR's greater than 16 are shown in Table 1 along with pertinent reservoir and fluid properties. The size of individual polymer treatments ranged from less

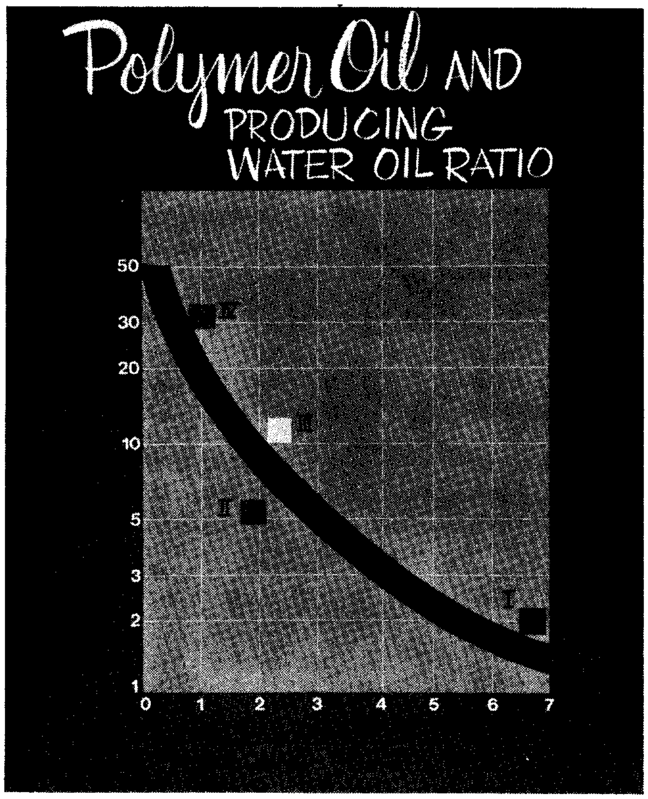

FIGURE 1

Polymer Oil & Producing Water Oil Ratio

than 1000 lb to over 20,000 lb. Fifty-two per cent of the polymer injected produced extra oil. Of the remaining 48 per cent, it is yet too early to evaluate 29 per cent, and 19 per cent went in on projects rated "no response". Further study of the "no response" category shows that one-third had mechanical or special reservoir conditions outside any possible benefit from the polymer.

Group III

Ten projects with WOR's between 8 and 16 are shown in Table 2 along with the reservoir and fluid properties. Treatment size varied from 2600 lb to 25,000 lb. Sixty-four per cent of the total polymer injected produced extra oil. For 27 per cent of the total polymer injected, it is yet too early for evaluation and 9 per cent of the polymer is rated "no response". All the "no response" polymer went on one project that never enjoyed net positive input rates before, during, or after treatment.

Group II

Table 3 covers projects with WOR's between 4 and 8. Treatment size ranged from 500 lb to over 80,000 lb. Ninety-four per cent of the polymer injected under these conditions is producing extra oil. As yet, 4.8 per cent cannot be evaluated and two small projects (1.2 per cent) gave no response. In one of these two cases (Line No. 1) the "no rseponse" on the production side was due to the nature of the test, the object being to

TABLE 1

Line Number	Formation Type	WOR	Average Permeability	% of Total Group Polymer	Barrels Polymer Oil	Number Inputs	Acres/ Producing Well	% Sweep at Breakthrough	Oil Viscosity
4	Sand	50	33	0.23	No response	1	20	15	NA
5	Lime	34	90	0.22	No response	1	20	NA	> 8
6	Sand	>16	NA	0.58	No response	1	20	NA	NA
7	Sand	30	216	0.72	No response	8	20	NA	2.6
9	Sand	20	41	1.08	No response	1	20	< 10	2.5
11	Lime	49	90	2.69	No response	1	20	6	> 8
13	Sand	63	80	2.16	15,000	1	10	10	3.7
14	Conglomerate	> 20	200	4.85	4,500	1	40	NA	1.5
16	Sand	40	135	1.34	No response	3	10	25	NA
18	Sand	47	460	2.33	3,750	1	2	21	17.8
20	Sand	42	25	1.79	No response	1	10	35	3.5
21	Sand	18	90	5.38	No response	1	10	34	1.2
22	Sand	30	200	17.80	12,000	4	40	< 25	6.8
24	Sand	30	12	0.90	1,200	1	5	NA	>10
25	Sand	30	170	3.60	16,000	1	40	21	1.6
26	Sand	>50	500	2.24	Too early	1	5	< 5	40
32	Sand	20	70	21.50	Too early	2	20	15	6
33	Sand	32.5	1000	10.78	1,500	3	10	14	1.5
36	Sand	>16	20	0.44	Too early	1	2	NA	16
37	Sand/Lime	23.8	40	9.39	20,000	24	20	8	5
40	Sand	>16	10	0.43	500	4	2.1	5	NA
41	Sand	50	NA	0.07	No response	1	2	NA	NA
46	Sand	>16	NA	1.08	Too early	1	10	< 15	NA
47	Sand	20	NA	2.16	Too early	1	10	< 15	NA
48	Sand	>16	50	1.34	Too early		20	NA	6
50	Sand	30	80	4.03	No response	2	20	NA	3.7
51	Sand	50	NA	0.87	No response	1	20	NA	NA
27				100.00	74,450				

pin down any wellbore damage that might result from polymer treatment concentrations up to 1 lb/bbl. Pressure fall-off tests on this well (which was set through and perforated with two feet open) showed no skin effect during or after the 30-day treatment interval.

Group I

Ten projects with WOR's less than 4 are shown in Table 4. Treatment size ranged from 3400 lb to over 30,000 lb. Sixty per cent of the polymer injected has produced or is now producing polymer oil. The remaining 40 per cent

Line Number	Formation Type	WOR	Average Permeability	% of Total Group Polymer	Barrels Polymer Oil	Number Inputs	Acres/ Producing Well	% Sweep at Breakthrough	Oil Viscosity
8	Lime	10	90	2.46	20,805	1	10	23	7.5
10	Sand	10	1200	7.00	85,000	1	20	15	2.5
12	Conglomerate	9.8	200	23.55	18,000	4	40	15	1.5
15	Sand	11.0	72	3.12	1,800+	1	10	30	NA
30	Sand	11.0	150	8.98	No response	1	20	< 5	4.0
34	Sand	15	400	7.47	15,000	2	6	NA	NA
35	Sand	> 8 & < 16	25	13.20	12,000	4	10	10	> 5
43	Lime	13	90	7.75	35,500	2	20	20	7.5
44	Sand	15.6	20	9.47	Too early	3	40	NA	4.2
54	Lime	10	90	17.00	Too early	2	40	20	7.5
10				100.00	188,105				

TABLE 2

Line Number	Formation Type	WOR	Average Permeability	% of Total Group Polymer	Barrels Polymer Oil	Number Inputs	Acres/ Producing Well	% Sweep at Breadthrough	Oil Viscosity
1	Sand	5.1	135	0.35	No response	1	40	NA	4.7
2	Sand	7	235	1.22	7,570	3	10	15	6
19	Sand	6	1,200	29.20	60,000	8	20	15	2.5
27	Sand	4	> 500	3.10	25,000	1	5	<5	50
29	Sand	6	>2,000	0.83	No response	1	5	<5	50
42	Sand	4>& < 8	NA	4.60	Responding	1	20	NA	15
45	Lime	6	NA	55.30	Responding	6	20	NA	NA
49	Sand	4>& < 8	NA	3.17	Too early	1	20	NA	NA
56	Sand	9	NA	2.23	Too early				
9				100.00	92,570				

TABLE 3

is going in on four projects that are not far enough along for a good response picture.

SPECIAL PROJECTS

Line No. 12 (Group III), shown in Table 2, is a conglomerate reservoir in North Texas. Half the field, 4 inputs, was put on polymer treatment while the rest of the field was used as a control. Figure 2 shows monthly oil and water producton for five years preceding polymer treatment and two and one-half years since. An increase in the WOR after the polymer treatment interval, followed by a steady decrease is typical of Group III projects. Note that both better oil production and less water contributed to the drop in WOR.

Line No. 43, (Table 2), a Lansing Kansas City Lime flood in Western Kansas is another Group III project which illustrates input side changes to be expected from polymer treatment. Figure 3 is a Hall Plot[1] of input Well WI-1 before, during, and after polymer treatment. Figure 4 shows input profiles for this same well before and after treatment. An increase in slope of the Hall Plot is a sign of better volumetric sweep. An improved input profile is also a sign of better volumetric sweep. When these two changes take place in the same well at the same time they are a strong argument in support of the principle that polymer treatment reduces

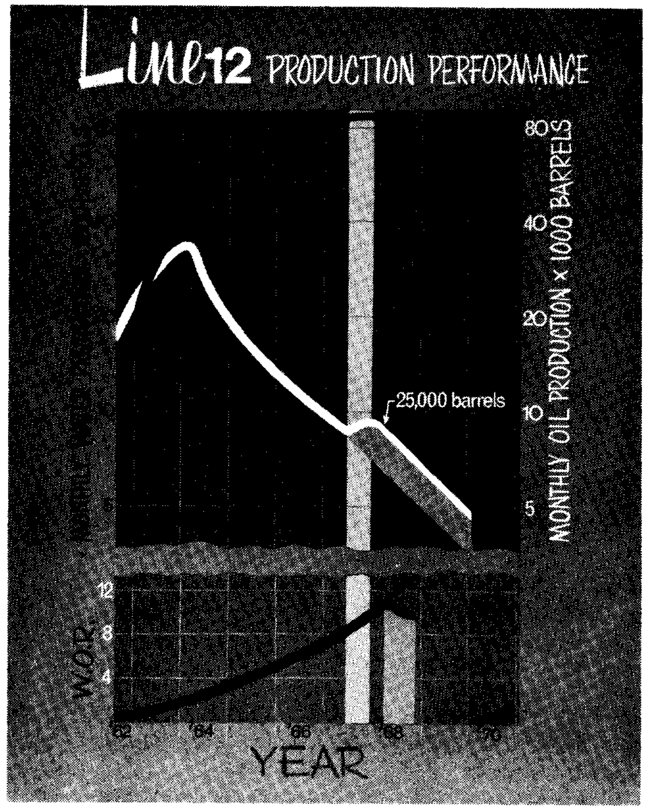

FIGURE 2

Line No. 12—Production Performance Before, During and After Polymer.

Line Number	Formation Type	WOR	Average Permeability	% of Total Group Polymer	Barrels Polymer Oil	Number Inputs	Acres/ Producing Well	% Sweep at Breakthrough	Oil Viscosity
3	Sand	1.5	4.3	4.39	52,500	4	5	31	3
17	Sand	2	NA	5.96	6,300	2	20	25	< 2
23	Sand	< 1		17.44	Responding			NA	
28	Sand	3.5		26.14	Responding	7			
31	Sand	1.2	75	3.00	5,400	5	15	12	>10
38	Sand	1.5	350	3.23	Too early	1	10	28	>10
39	Sand	3.1	>150	3.44	65,000	1	40	10	8
52	Lime	<0.5	15	21.94	Too early	4	40	NA	1.5
53	Sand	<0.1	<10	10.27	Too early	4	40	NA	5
55	Sand	3.5	30	4.19	Too early	1	10	15	3
10				100.00	129,200				

TABLE 4

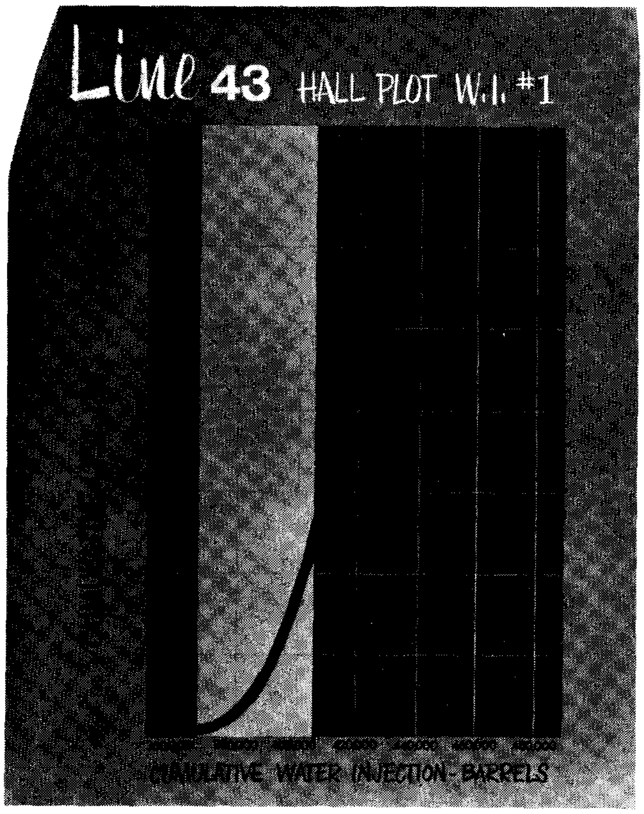

FIGURE 3
Line No. 43—Hall Plot W.I. #1.

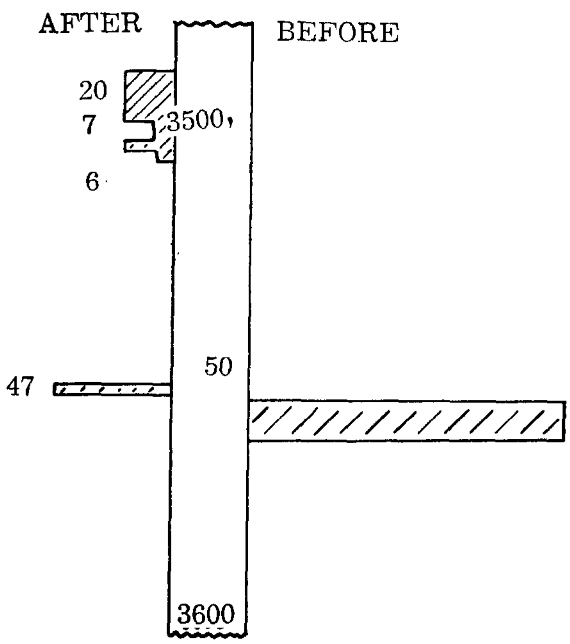

FIGURE 4
Line No. 43—W.I. #1 Input Profiles Before & Before and After Polymer Treatment.

permeability to water and at the same time proves conformance. Better volumetric sweep on this flood after polymer treatment should produce more than 4 bbl of "polymer oil" for each pound of polymer injected.

Line No. 19, (Table 3), a Strawn Sand flood in Group II uses WOR versus cumulative oil recovery curves (Fig. 5) to measure extra oil production due to polymer treatment. Inputs on this flood were treated with polymer one at a time after water had broken through to offset producers. Operating experience made it possible to estimate the water-oil ratio reversal point, and schedule well tests so that good production data were on hand when the effect of each input well polymer treatment was under study.

Experienced waterflood polymer users place top priority on regular, reliable producing well tests. When a test result appears out of line, the well is promptly retested. When pipeline runs and metered produced water volumes do not reflect well test totals, efforts are made to find out why.

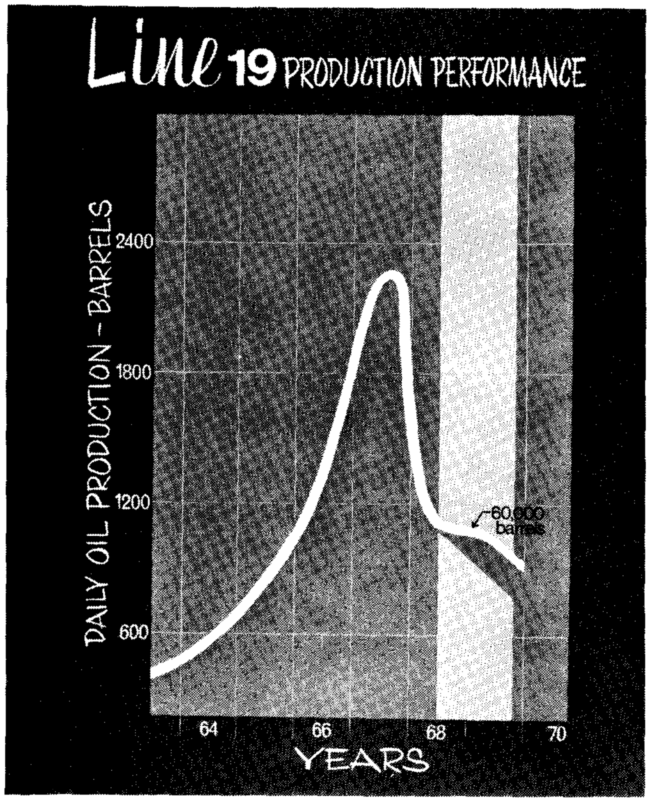

FIGURE 5
Line No. 19—Production Performance Before, During and After Polymer.

The oil industry's investment in, and ability to measure "results" of "oil recovery" type wildcatting will have a tremendous bearing on the acceptance of new production technology. Just as many early exploratory wells missed good pay zones, many new oil recovery processes have "missed" documented payouts!

Line No. 37, (Table 1), a Group IV project producing from the Aux Vases in Illinois, displays the common and often very necessary problem of changing more than one reservoir variable at a time. In this case four previously choked input wells were opened wide when polymer treatment was stopped and three producing wells were shut in six months after treatment began.

The flood was started April 14, 1967. By September of that year, production had peaked. The rapid response to fresh water injection plus the fact that no produced water was ever reused made it possible to correlate both produced water chloride content and producing WOR's. Operating management recognized the value of chloride tests early and developed excellent data. A suspected fracture condition was confirmed in August, 1967 when chloride values of producing well bleeder samples ranged from true Aux Vases water (33,700 mg/1) to 10,500 mg/1 or better than two-thirds fresh injection water. Figure 6 shows the steady increase in WOR's and decrease in chloride values for two years before polymer treatment. The expected WOR drop and chloride ion increase during and after polymer treatment are clearly seen.

Chloride ion values were determined from samples taken while wells were on test. Each chloride was then weighted according to the volume of produced water the well test showed. Results were totaled and divided by monthly water production to come up with a true weighted averaged chloride value.

With response to initial water injection showing up at some producing wells in less than six weeks, reservoir reaction to polymer treatment was also expected in about six weeks. This happened. While injection rates were increasing during the first three months from 62,200 bbl

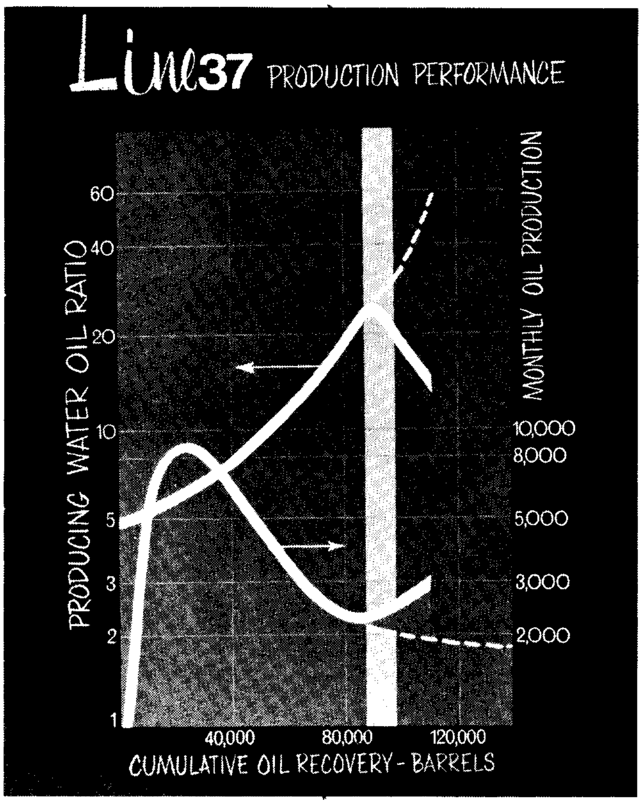

FIGURE 6

Line No. 37—Produced Water Chloride Content and WOR.

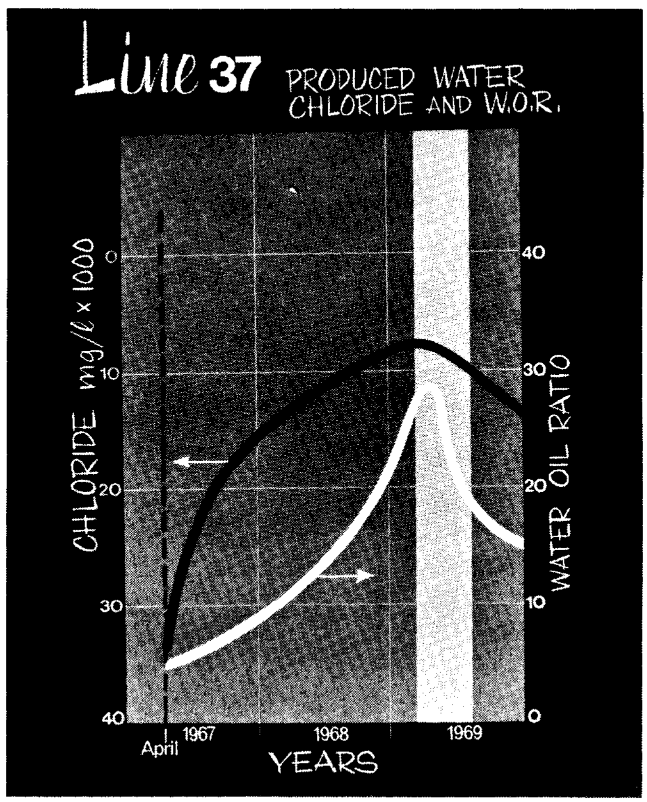

FIGURE 7

Line No. 37—Production Performance Before and After Polymer.

in April to 70,300 bbl in June, produced water volumes dropped from 72,000 bbl to 56,800 bbl. An increase in net injection is further evidence that polymer treatment improves volumetric sweep.

Figure 7 has WOR's and monthly oil production plotted against cumulative oil recovery. Although most of the WOR drop came from reduced water production, actual oil production for the six full months following polymer treatment (May through October) totaled 15,125 bbl, 870 bbl more than the total for the six full months before starting polymer. Present projections show that Line No. 37 will produce over 2 bbl of "polymer oil" for each pound of polymer injected even though treatment was started very late in the WOR life of the project.

Much as election night "returns" shift every few minutes, "returns" from polymer projects included in this study will change from month to month as production performance unfolds. However, the trends developed during this four-year period should stand the test of time and further critical evaluation.

The "wildcatting phase" of polymer oil recovery is over. Now that we know what measurements best reflect reservoir response to polymer it will be much easier to document success and show results in the form of a good dollar payout. The future holds orderly development and increasing use of the process.

CONCLUSIONS

1. Polymer treatment started early in the life of a flood will produce more polymer oil than the same treatment started later.
2. When volumetric sweep has been very poor, polymer treatment can be started late (WOR greater than 16) in the life of a flood with profitable results.
3. Performance measurements during and after polymer treatment, no matter how carefully they are made and recorded, have little value unless they can be compared with reliable pre-polymer production data or accurate recovery predictions.

REFERENCE

1. DeMarco, Michael: Simplified Method Pinpoints Injection Well Problems, World Oil, April, 1969, pp. 92, 97-100.

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