REMEDIAL CONTROL OF INJECTION WATER IMPROVES SWEEP EFFICIENCY

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INTRODUCTION

The economics of secondary recovery is certainly important to today's domestic oil industry. There is, however, another important consideration which must be taken, in view of present shortages of proven reserves—ultimate recovery of secondary oil.

In other words, can more of these known reserves now in place in reservoirs already drilled and under waterflood be produced economically? Obviously, no oil will be banked to a producer if no water is injected into the section containing the moveable oil saturation which remains after primary production is accomplished.

There are three common problems encountered in waterflooding which make it difficult—even impossible—to inject water into and through all of the reservoir containing the residual moveable oil:

1. Little or no response to injection due to *lack of confinement* to the section of interest
2. Premature water breakthrough due to zones of *high water saturation* or *extreme variations of permeability* within the section of interest
3. Water breakthrough due to *fingering* of *injection fluid* caused by *overinjection* and/or *directional permeability* within the section of interest.

This paper will consider only problems 2 and 3. Problem 1 was discussed by the author in a previous short course (1971).

Water breakthrough occurs rapidly in zones of high water saturation since injection always seeks the path of least resistance. High water saturations offer less resistance to the flood water because the relative permeability to water is greater.

Water breakthrough occurs rapidly in thin zones of high permeability for two reasons:

1. Most of the primary oil comes from the higher permeability, leaving high water saturation.
2. The extremely high permeability zones offer less resistance to the injection water anyway.

Water breakthrough comes soon when overinjection causes water to finger through to producers. Overinjection occurs when an optimum rate is calculated for a total section to be flooded and only a small zone accepts the injected fluid—again the path of least resistance.

Directional permeability simply offers the shortest distance between two points—in this case, between the injection and producing wells.

The paths of injection flow after breakthrough become even easier since they exhibit higher relative permeability to water.

MATERIALS

There are materials being used in an effort to alter the paths of injection water through reservoirs by attempting to control mobility ratio. Most of these materials are long chain polymers, usually acrylimides which are extremely shear-sensitive. Some are biopolymers which are shear-sensitive, but thixotropic. These pusher-type polymers probably do move more oil from the porosity they contact, but there remains reasonable doubt that they contact any more porosity than injection water.

This process of creating resistance to flow with small increases in viscosity of injection water to adjust mobility ratios has achieved some measure of success, but these results have been short lived and therefore, not profitable.

The material used to achieve the results presented here is a suspension of micron-size particles which are not shear-sensitive. The suspension possesses all the characteristics of water; the particles take on enough water to closely match the density of the carrier fluid (water) and, therefore, the suspension flows as water. These micron-size particles are small enough to penetrate and travel in the permeability paths taken by previously injected water. The suspension travels in paths until particles either seat in a constriction or deposit in the path due to reduced velocity. Once seated, the particle remains to restrict flow and divert the injection water to other paths.

When diversion is accomplished, the effects are permanent and reversible; permeability reduction in the direction of injection is maintained even when the well is flowed back.

PROBLEM DETERMINATION

The best approach to the solution of a problem is, of course, to locate, identify and define the extent of that problem.

The method used to pin down the injection troubles was a complete fluid movement analysis. This analysis required the running of radioactive velocity and tracer surveys and a decay series temperature survey to give the fullest picture of the pattern of fluid flow downhole. Each of the radioactive surveys shows the distribution of water in and close to the wellbore, while the temperature survey will show the zone of water collection.

This fluid movement analysis provides some of the data needed to calculate treatment volumes: (1) relative percentages of fluid loss and (2) thickness of zone.

Other needed data such as permeability ranges, formation type, production and water-oil ratios come from well files.

TREATMENT DESIGN

The work done during the past two years, using the particle suspension material, was carried out in more or less, a trial-and-error method. Original laboratory data was scaled up from core size to fit expected reservoir and borehole conditions, i.e.:

1. Surface area of core to surface area of wellbore
2. Length of core to some depth of penetration (100-150 ft)
3. Permeability of core (20-250 md) to some range of permeability in section.

These efforts produced values for treatment volume of 1200-2000 gal. per effective foot of major fluid loss as shown by the *fluid movement analysis* data. Adjustments were made for zones of much greater permeability, in some cases two to six times the calculated volume for 1 to 2.6 darcies.

Presently, engineering tests are being completed which already indicate that future treatments can be designed using computers.

PROCEDURE

All work performed to accomplish the following production results followed a simple procedure:

1. The logs were run on all wells.
2. The fluid movement analysis was made to define and correlate the problem.
3. The treatment was calculated.
4. The particles were formed by eduction of the standard chemicals into fresh water and suspended by agitation in a 2000-gal. stainless mixing tank.
5. Treatment was staged 2000 gal. at a time with normal injection between stages to allow for mixing the next stage.
6. Total calculated volumes were pumped and the wells returned to normal injection unless a premature change in rate or pressure was encountered.
7. When abnormal changes in pressure were observed, treatment was terminated and the well relogged to check results.
8. If no change in distribution was noted, treatment was completed.
9. All wells were relogged to check results for increased vertical distribution.

RESULTS

Two projects of significant size to evaluate the success of the particle suspension material have been performed over the past two years. Both projects indicated injection water breakthrough to producing wells due to fingering, high permeability, high residual water saturation or directional permeability.

The first project was a deep Springer sand reservoir in Grady County, Oklahoma. The project consisted of 13 wells which were treated in groups of two, four and seven wells. The groups of four and seven wells were not treated until response was obtained from previous treatments.

The problem was defined, by fluid movement analysis logs, as overdistribution into a relatively thin and highly permeable zone at the base of the Springer sand. The offending zone ranged in thickness from eight ft to 24 ft and represented only about 15% of the total section. Average permeability of the section averaged 58 md with a probable range of 20 to 280 md. Injection rates averaged 2500 BPD at pressures ranging from 0-2500 psi.

The work on the group of two wells was completed April 27, 1971; first response was noted in May. The production response in increased oil and reduced water was evaluated August 1, 1971 after 10,000 gal. of particle suspension diverting material. See Table 1.

The results from the treatment of well R-13 were gathered from seven offset producers; oil increase was 14,283 bbl and water decrease was 22,115 bbl.

The results from the treatment of well R-21 were gathered from six offset producers; oil increase was 20,205 bbl and water decrease was 61,130 bbl.

This represented a return of $121,094 on an inventment of $10,500 in logging and treatment costs during the three months of evaluation.

It is assured that equivalent results were obtained from the treatment of the other 15 wells and that the improvement persists even after two years. The unit is performing much better than expected.

The second project was performed in a shallow Healdton Sand Unit in Carter County, Oklahoma. Diagnostic logs were run on virtually all injection wells and the problems located in the third and fourth sands were attacked. (Fig. 1)

Treatment was accomplished in two phases around the periphery of the unit with two exterior wells.

Phase One involved 10 wells situated around the north end of the unit. *Phase Two* was done to close the south loop of the peripheral pattern and consisted of seven additional wells and three retreatments. Five wells were treated with a plugging stage prior to particle suspension jobs.

The 17 injection wells selected contained problems common to all—relatively thin, high permeability zones. The sections averaged 127 ft in thickness of which an average of 18 ft was accepting injection water, roughly 14.5%. Permeabilities ranged from 100 md to 2.67+ darcies. Injection rates ran from 825 BPD to 3200 BPD at pressures between 0-250 psi. Formation depths are 900-1400 ft.

Treatment volumes were calculated from the data gleaned from fluid movement logs and increased because of the much greater permeability present. Treatment volumes varied from 11,000-50,000 gal. See Table 1.

Some experimentation with treatments of high concentration particle suspension was done between Phases One and Two, again because of the extremely permeable zones. The results were doubtful and later laboratory data indicated an optimum concentration above which particles screen out on the face.

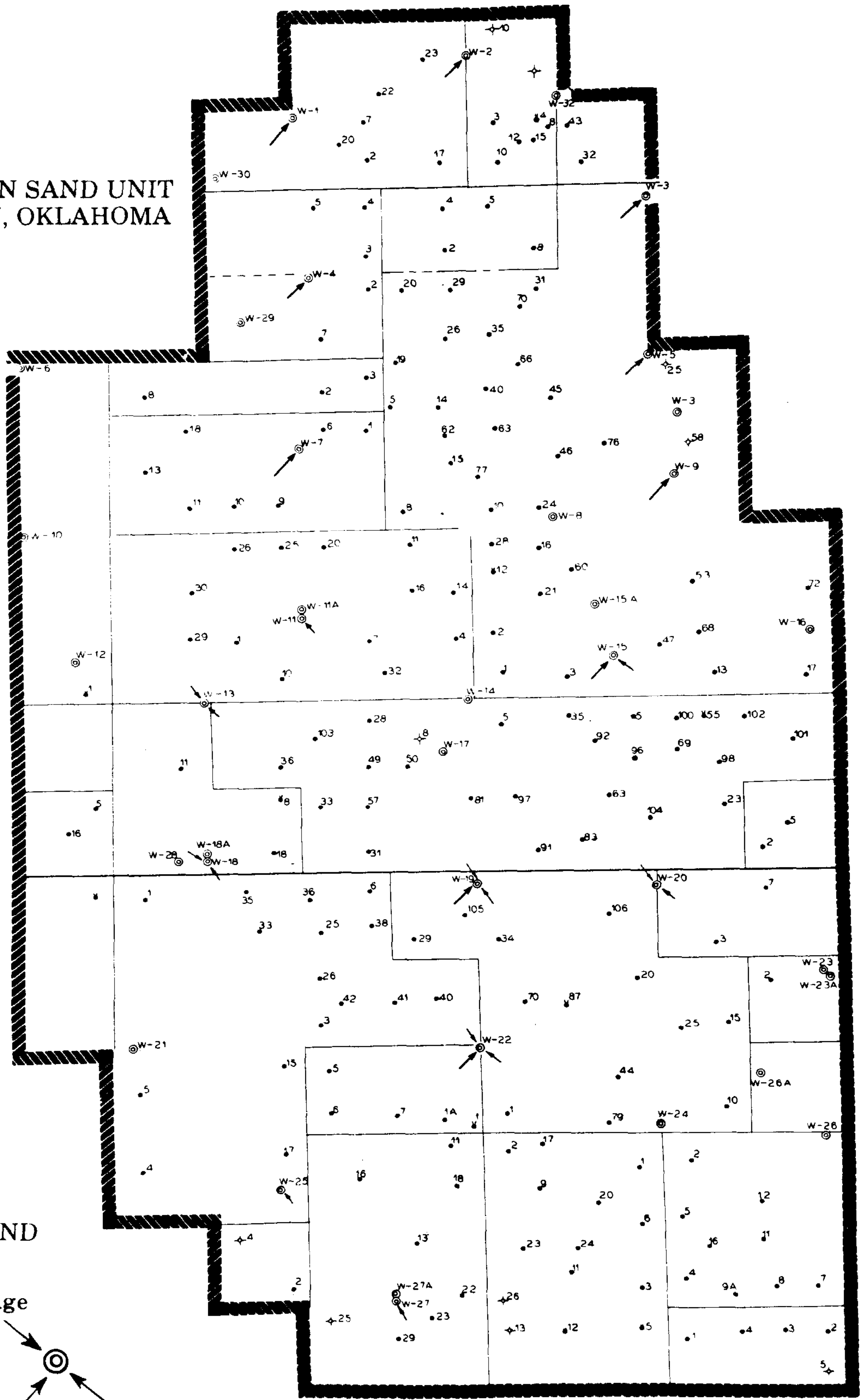
Figures 2 and 3 show conclusively that response began shortly after Phase One treatments were completed, March 25, 1972. Figure 2 indicates incremental oil produced above predicted and Fig. 3 describes the incremental water produced below predicted.

Thirty-five wells were tested to obtain these results and tests on January 5, 1972, showed an increase of 348 BOPD above predicted (131%) and 1631 BWPD decrease (28%).

It was thought for a while the results were not good, since total lease production remained the same, but the well tests showed Phase One performing better while the southern wells continued to water-out.

Figures 4 and 5 indicate the response gained from Phase Two treatments which were completed September 5, 1972. Figure 4 shows response immediately in oil increase over predicted production. Figure 5 shows a decline in water production below predicted starting in May, 1972, two months after Phase One was completed and another decrease after Phase Two in August.

FIG. 1—HEALDTON SAND UNIT
CARTER COUNTY, OKLAHOMA



LEGEND

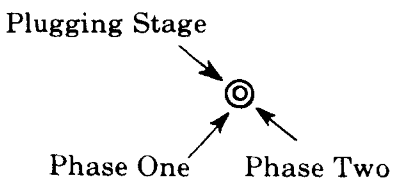


TABLE 1—TREATMENT DATA

Phase	Well No.	Date	Volume	(Type)	Loss Percent	Thickness Zone	Thickness Section	Pressure Before	Pressure After	Rate
PHASE ONE	1	3-14-72	20,000	(40)	100	23'	149'	175	215	2200
	2	3-15-72	16,000	(32)	100	18'	148'	200	280	2600
	3	3-20-72	18,000	(36)	83	14'	126'	230	275	825
	4	3-13-72	20,000	(40)				0	50	2200
		3-22-72	10,000	(60)	100	18'	193'	40	50	
		5-26-72	9,000	(60)				40	50	
	5	3-14-72	12,000	(24)	81	20'	206'	200	315	1750
	7	3-16-72	30,000	(60)	100	24'	210'	0	30	3200
		5-26-72	8,000	(60)				25	60	
	9	3-15-72	20,000	(40)	100	14'	100'	175	220	1780
	15	3-21-72	30,000	(60)	100	21'	108'	115	145	2200
	19	3-18-72	30,000	(60)				50	60	
		4-6-72	16,000	(60)	54	10'	80'	50	60	3000
		6-28-72	20,000	(306)				0	35	
	22	3-17-72	30,000	(60)				0	0	
		4-6-72	16,000	(60)	80	12'	82'	20	30	3000
		6-22-72	23,000	(323)				0	35	
PHASE TWO	11	8-24-72	14,000	(210)	95	20'	57'	50	60	2200
	13	8-28-72	1,250	(Plg)	86	12'	142'	20	100	2250
		8-31-72	50,000	(198)		12'		250	270	
	15	8-24-72	11,000	(67)		21'		190	245	
	17	8-25-72	12,000	(273)		4'		0	34	
	18	8-29-72	1,250	(Plg)	82	16'	200'	0	0	4600
		9-5-72	30,000	(154)				230	245	
	19	8-21-72	2,000	(Plg)		10'		0	200	
		8-30-72	36,000	(198)				90	125	
	20	8-28-72	1,250	(Plg)	78	30	60	0	30	1100
		9-1-72	50,000	(198)				120	170	
	22	8-21-72	2,000	(Plg)				0	100	
		8-29-72	20,000	(202)				110	120	
	25	8-24-72	12,000	(24)	100	24'		265	300	1680
	27	8-25-72	14,000	(140)	100	14'		120	140	815

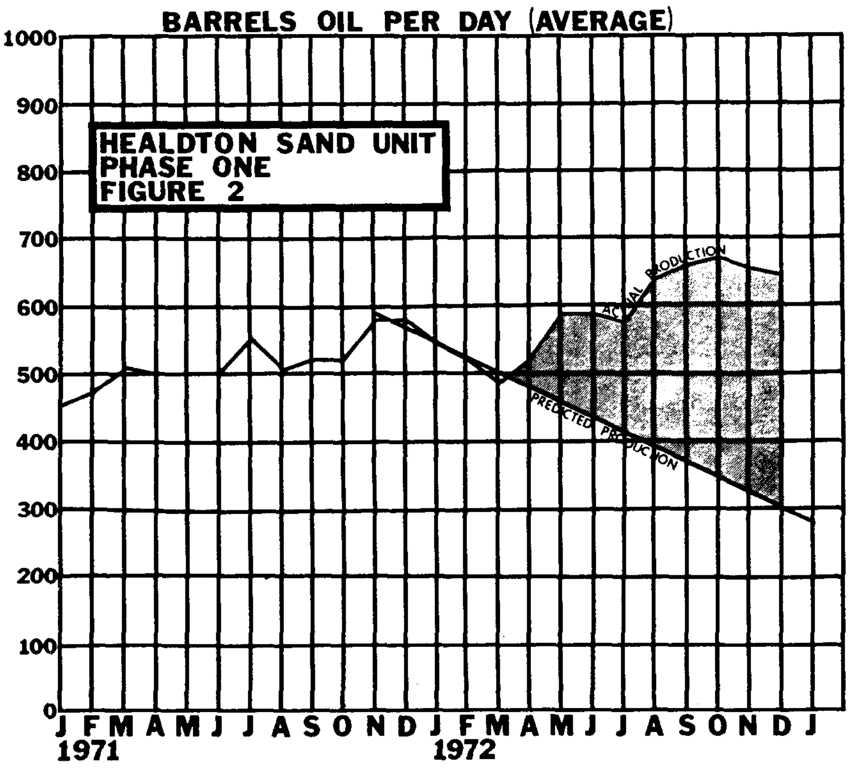


FIG. 2—HEALDTON SAND UNIT—
PHASE ONE

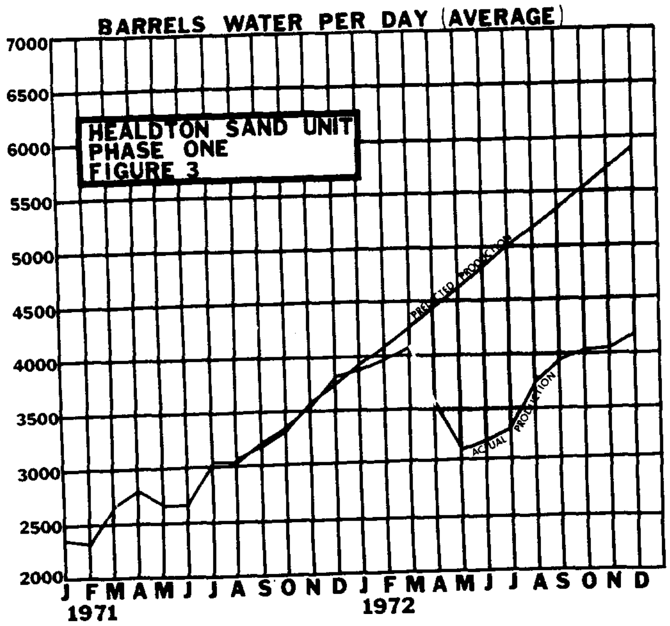


FIG. 3—HEALDTON SAND UNIT
PHASE ONE

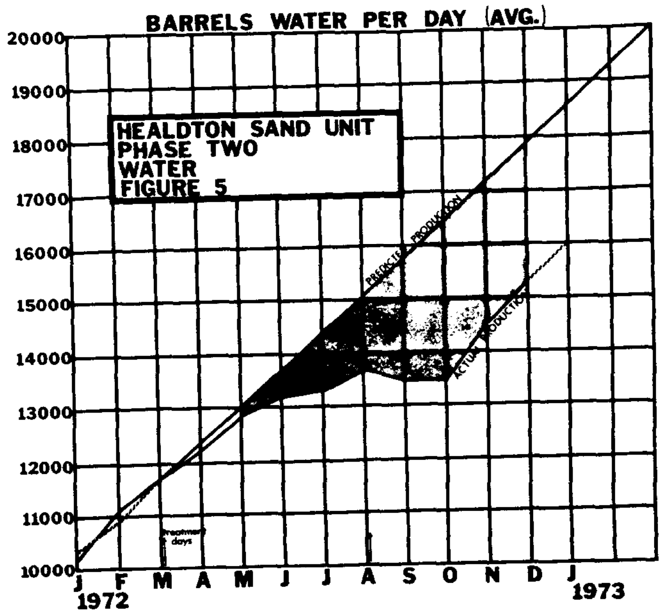


FIG. 5—HEALDTON SAND UNIT
PHASE TWO WATER

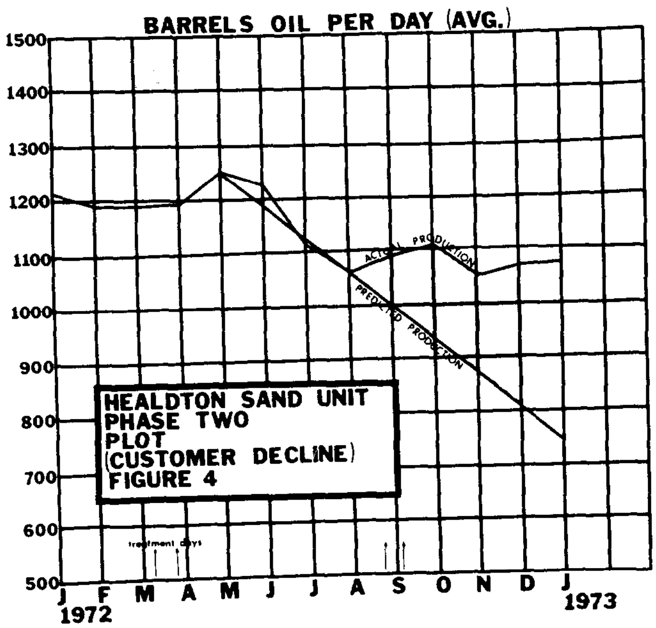


FIG. 4—HEALDTON SAND UNIT
PHASE TWO PLOT (CUSTOMER DECLINE)

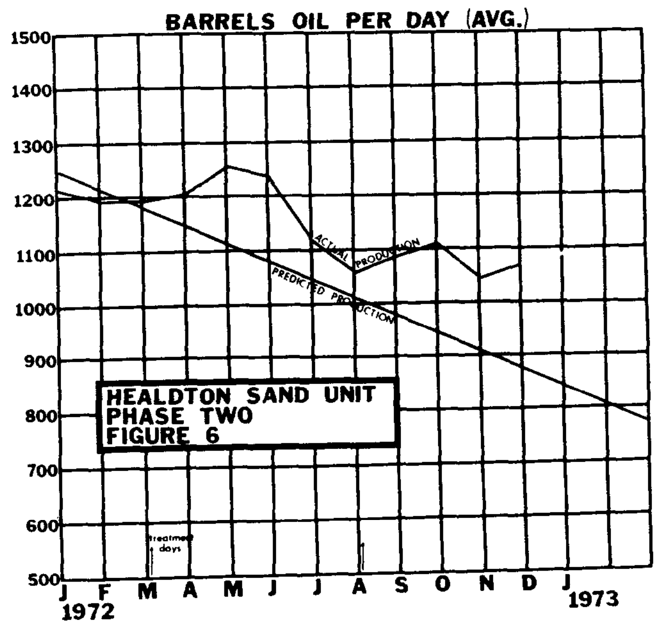


FIG. 6—HEALDTON SAND UNIT
PHASE TWO

The 54 wells monitored for Phase Two results indicate an oil increase of 328 BPD (44%) and 2600 BWPD reduction.

Figure 6 has been included to show that a logically selected, but flatter decline curve for Phase Two indicates a significant response in oil production from Phase One.

The total project payout was no more than five months and based on current tests, oil increase only, the profit should be about $6000 per day.

CONCLUSIONS

Particle suspension diverting treatment can be utilized to alter the path of injection water to improve oil production and reduce water breakthrough.

Response to such diversion of injection water is rapid in thin zones of high permeability with high injection rates.

The improvement effected is long lasting.

The economics of particle suspension treatments are good.

Treatment should be projected to closed patterns to reduce the effects of interference between wells.