FIELD RESULTS OF A SHORT SETTING TIME POLYMER PLACEMENT TECHNIQUE*

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INTRODUCTION

Newly drilled water injection wells in the Shell-operated Jordan University Unit in the Jordan (San Andres) Field of West Texas exhibited thin intervals of high permeability (and poor profiles) soon after injectivity began (Fig. 1). The wells had been selectively acidized (straddle packers were used to isolate each perforation while acidizing) with surface pressures of not more than 500 psi. Since fiberglass casing was cemented across the entire injection interval, the use of cement to squeeze off selected perforations (prior to reacidizing perforations not taking water) was not feasible because of its high density and hard set.

LOCATION MAP
JORDAN UNIVERSITY UNIT
AND RESPONSE AREA
JORDAN FIELD

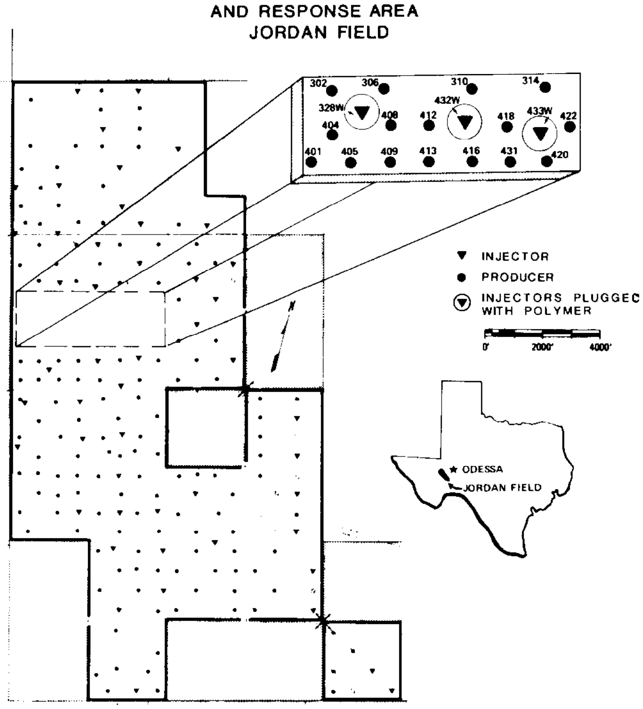

FIGURE 1

A plugging material with a low viscosity and a specific gravity approaching that of fresh water was needed in order to plug the rock matrix near the wellbore. A crosslinked polymer was used because its specific gravity and viscosity approach that of fresh water, and it is a nonparticulate. Therefore, the polymer could be used without hydraulically fracturing the rock or "plating out" on the wellbore face.

The use of polymers in injection well profile control has been well-documented in previous publications. [1,2,3] A different method of application of a crosslinked, stiff gel polymer (American Cyanamid Company AM-9 Chemical Grout) was successfully used to alter injection profiles in the three San Andres dolomite water injection wells.

Proven fluid design techniques were successfully used to premix a gel solution and a catalyst solution at the surface ("on the fly") for a downhole (3800 ft) setting time of approximately 20 min. at 90° F. The resulting solution had low viscosity pumping characteristics, yet rapidly increased in viscosity at the desired setting time. Consequently, the solution pumping characteristics were also similar to fresh water. In addition, an under displacement gel placement technique was utilized to assure that uncontaminated polymer was gelled in the pore network (within a radius of 6 to 8 ft) and back into the wellbore. The under displacement technique and

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reacidizing of old tight perforations were the keys to injection well profile change in the Jordan University Unit. Production history data from wells surrounding the three injectors reflect an increase of approximately 550 BOPD over an 18-month period. The increase in oil production is a direct result of injection well profile improvement. See Table 1 for an economic analysis of the cost of the three worked-over injection wells and of the production results associated with the 16 surrounding producing wells.

TABLE 1 ECONOMIC ANALYSIS - POLYMER PLACEMENT AND REACIDIZING OF THREE JORDAN UNIVERSITY UNIT INJECTION WELLS

INPUT	
Total cost of three jobs	$32,800
Crude value $/bbl	$ 8.22
Royalty %	12.5
Taxes and insurance $/bbl	$ 0.60
Direct Monthly Operating Cost	$13,700
(16 Producing and 3 Injection Wells)	
($800/mo/prod. well)	
($300/mo/inj. well)	
Production increase BOPD	550
Decline rate %/yr	8.0
Time period* yrs	1.7
(June 1974 to December 1975)	
RESULTS	
Additional recovery BO	313,400
Project payout (After Tax) yrs	0.06
Undiscounted profit (After Tax) $	891,000

*Does not consider increase prior to June 1974 or additional increase noted after July 1975.

Did not consider inflation or overhead.

NEED FOR NEW SEALING METHOD

Many types of formation-sealing materials have been used for treating thief zones in waterflood injection wells, the object being to cause highly permeable, "water drinking" sections to be sealed off and the injection water to enter other unswept zones. Portland cement, plastering agents, emulsions, resins, etc., have all been tried with some degree of success. The limited successes were probably due to a lack of effective vertical permeability between the thief zone and adjacent unswept sections.

True fluids, however, have been the most successful sealants of high permeability. They do not contain undissolved solids; consequently, they enter the formation unrestricted and go where any watery solution would go. This deep penetration is necessary to let the matrix provide strength to the seal beyond normal wellbore distortions and disturbances. Cement will sometimes "scab off" at low pressure input near the wellbore and fail in tension when a pressure differential is exerted from the wellbore.

SOUND FLUID DESIGN

A powdered sealing material marketed by American Cyanamid Company under the trademark AM-9 has true-fluid characteristics when in solution. AM-9 contains two organic monomers (acrylamide and N,N′ methylenebisacrylamide) and readily dissolves in water to yield a solution of low viscosity. Normally, the catalyst system is composed of an initiator AP (ammonium persulfate), usually 8% by volume, while the activator DMAPM (diamethylaminopropionitrile), and an inhibitor (where needed) KFe (potassium ferricyanide), are preblended with the AM-9 solution, usually 92% by volume. With the monomer mixture, typically 10% AM-9, and the catalyst blended and ready for use, the *activated* sealant viscosity is 1.2 cp. The sealant density is typically 8.5 lb/gal.

When reaction takes place, the polymerization causes the acrylamide to produce very long chain molecules in the aqueous solution. These long chain molecules *simultaneously* crosslink together, binding the water into an immobile three-dimensional network — a stiff, firm, rubbery, elastic gel. Gelling is almost instantaneous, in that the gel forms from the 1.2 cp, catalyzed solution in 5% or less of the preset gel time; preset gel time being the time interval in which a given blend of the AM-9 mixture and the AP catalyst will form a stiff gel after blending at a given average temperature. Gel time can be preset in a range from 10 seconds to 16 hours across an average prevailing temperature between 40°-200° F.

While other desirable products are on the market, the above-described polymer was used in the following field tests. AM-9 was selected because of its ability to gel when partly diluted, and its resistance to *any flow* when gelled in small capillaries even at high, sustained, differential pressure. Its stability in aging tests has indicated no evidence of gel deterioration for at least eight years. Another desirable quality of the gel is a complete lack of syneresis or exudation of water with time.[4,5]

PREVIOUS PLACEMENT METHOD

Until recently, placement of this and other fine, stable, firm gel-type polymers in high permeability sections was based on long setting times. The catalyzed solution was pumped into a zone to be sealed (not always isolated), overdisplaced with water, and the well then shut-in for a period in excess of the setting time (usually several hours).

REASONS PREVIOUS PLACEMENT METHODS FAILED

Dilution of the Mixture After Shut-In Time and Prior to Gel Time

Crossflowing (or pressure alignment) of fluids redistributed the catalyzed, ungelled treatment solution once surface pumping ceased. Consequently, the catalyzed material was diluted, moved away from the wellbore, and a weakened, ineffective seal resulted.

Improper Placement of the Sealant

The interval to be treated (target area) was not always isolated in order to place the solution exactly where it was needed. Instead, the catalyzed liquid was allowed to enter *all* porous or "taking"zones. This very often had a tendency to reduce permeability in some sections not needing to be sealed.

Overdisplacement of the Sealant

Overdisplacement is probably the cause of more failures in profile control than any other single thing. In the past, there existed a conflict in priorities as to what course of action should be followed when placing a sealing solution that became immobile with time. To assure that no gelling in the tubing took place, the sealant was overdisplaced *prior* to gel setting time. Therefore, channelling past the seal or no seal at all was the result.

NEW PLACEMENT METHOD DEVISED

One virtually unexploited and unique property of AM-9 type catalyzed solutions is their ability to be pumped or injected (catalyzing "*on the fly*") for much *longer* than the duration of a preset *short* gel time.

This technique was devised by R. H. Karol's Rutgers University group[5,6] while endeavoring to

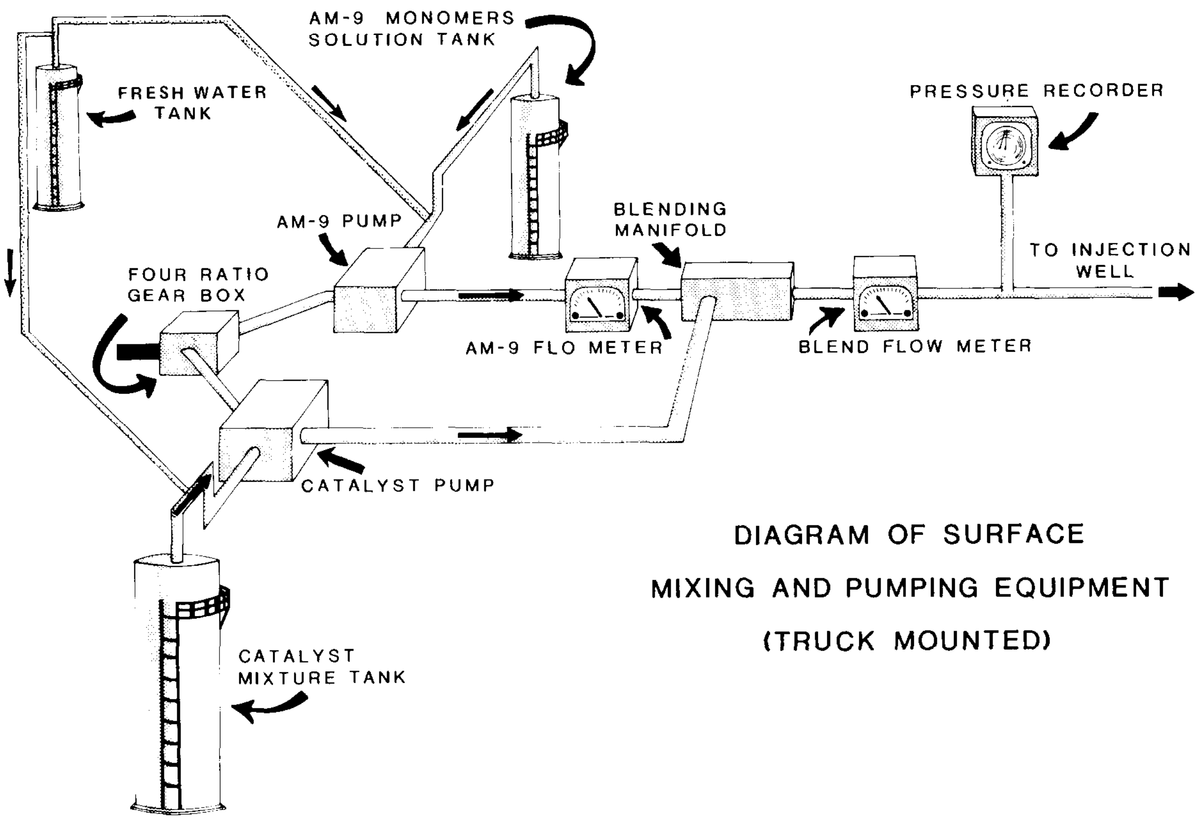


FIGURE 2

"grout-off" rapid flowing ground water through stratified soil sections with a minimum of grouting points.

The preset short gel time (long pumping time technique for injection well use) was then developed after careful study. A practical approach to profile correction was taken by the primary author after years of radioactive tracer surveying experience indicated a definite need for a new approach to the program. The transposition of R. H. Karol's ideas to oilfield problems was the result.

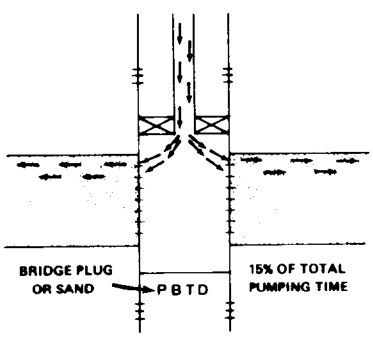
NEW PLACEMENT METHOD

The short gel-time versus long pumping-time technique was used at Jordan University Unit, Ector and Crane Counties, Texas.

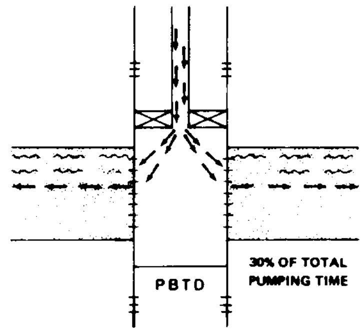
A portable unit consisting of tanks, pressure pumps and metering equipment, was designed to handle various volumes and ratios of the AM-9 system. One tank containing the AM-9 type monomer solution (approximately a 10-11% by weight mixture) and one containing the catalyst solution (approximately a 3-4% by weight mixture) are illustrated in Fig. 2. The two solutions are blended in predetermined proportions while being pumped into the well. The volumetric ratio is usually 92% monomer solution and 8% catalyst solution. This catalyzed mixture is pumped *into the formation* three to five minutes prior to gelling. After this preset gel time has elapsed, the polymer will start to form its stiff gel in depth in the formation and will *continue* to do so at the same rate it was being pumped when catalyzed (Fig. 3).

POLYMER PLACEMENT TECHNIQUE
JORDAN UNIVERSITY UNIT
JORDAN FIELD

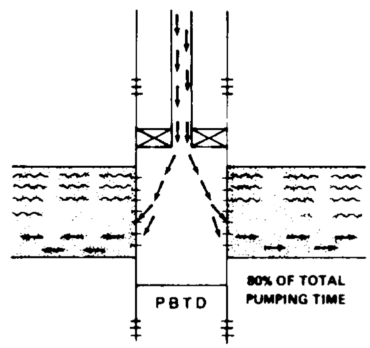
I. CATALYZED POLYMER INVADING HIGH PERMEABILITY ZONE



II. CATALYZED POLYMER BEGINNING TO GELL. HIGH PERMEABILITY ZONE INVADED AND POLYMER BEGINNING TO DIVERT TO OTHER ZONES



III. MOST CATALYZED POLYMER HAS GELLED AND HIGH PERMEABILITY ZONE IS SEALING



LEGEND:
CATALYZED FLOWING POLYMER (VISCOSITY – 1.2 CP)
GELLED POLYMER

IV. HIGH PERMEABILITY ZONE SEALED. UNDER DISPLACEMENT LEAVES GELLED POLYMER IN CASING

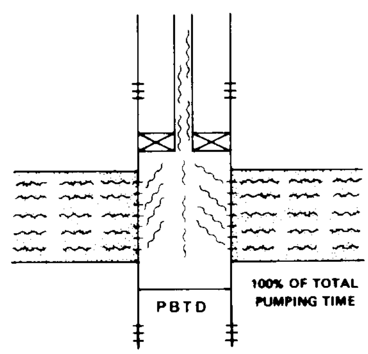


FIGURE 3

With this continuous gelling taking place in the thief zone during the catalyzing and pumping procedure, the injection pressure increases as the thief zone permeability is reduced, and subsequent diversion of the mixture to other "layers" of permeability in the isolated target zone will occur. As the polymer gels, and hence plugs the high permeability layer, a continuous, effective seal is achieved from the formation toward the wellbore when the catalyzed mixture is injected to refusal pressure (see Appendix). The resulting permeability seal is not considered to be deep enough in the matrix to be called a "reservoir treatment."

INJECTION WELL PROFILE CHANGES

The primary objective of the field tests was to reprogram injected water and, subsequently, improve oil recovery. This objective was accomplished in the Jordan University Unit by placing the polymer in thief zones and by selectively reacidizing zones of low injectivity.

A plugging material with a low viscosity and a specific gravity approaching that of fresh water was needed in order to plug the rock matrix near the wellbore. A crosslinked polymer was used because its specific gravity and viscosity approach that of fresh water, and it is a nonparticulate. Therefore, the polymer could be used without fear of hydraulically fracturing the rock or "plating out" on the wellbore face.

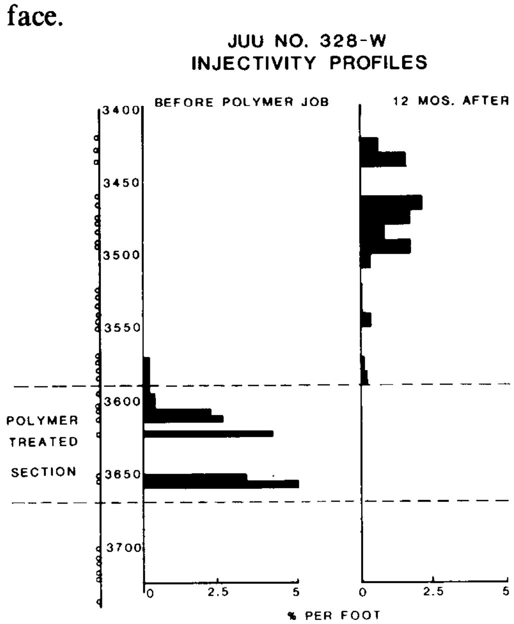


FIGURE 4

The resulting redistribution of injected water is illustrated in Figs. 4, 5, and 6. Most of the injection wells in this field are equipped with internally plastic-coated tubing, and recently drilled injection wells are equipped with fiberglass casing across the injection zone. A squeeze material that could be easily drilled out was required.

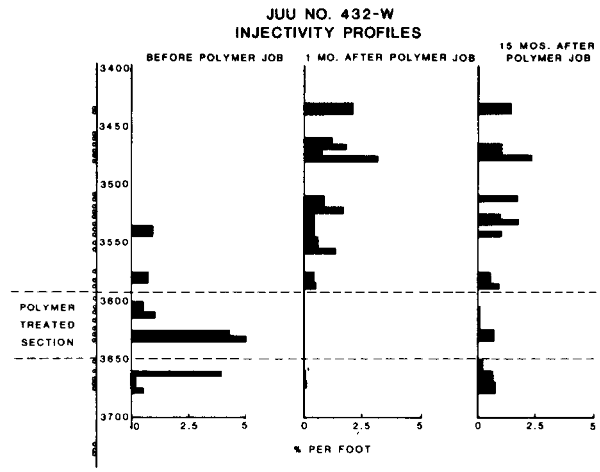


FIGURE 5

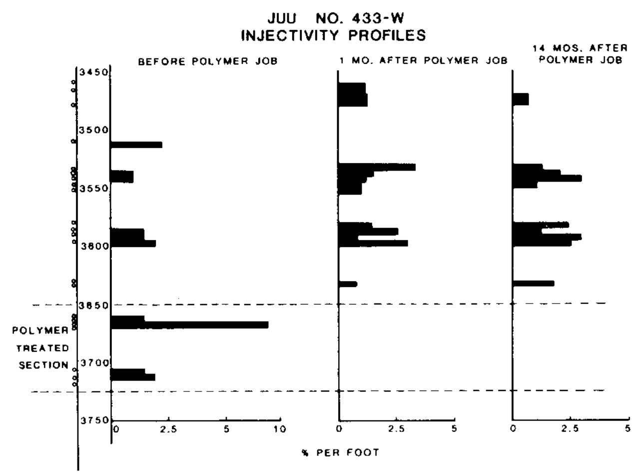


FIGURE 6

In all three wells, the thief zones were isolated by either plugging back with sand to the base of the thief zone and/or setting a packer above the thief zone. This assured the zonal isolation needed in order to accurately place the polymer. Control of acid entry in old perforations exhibiting poor injection profiles was accomplished by isolating sets of perforations with a packer and bridge plug.

Results indicate that while the polymer-squeezed perforations have been exposed to bottomhole injection pressures of about 2300 psi for over 24 months, only nominal volumes of injected water have entered the squeezed intervals. A complete summary of the well histories of the three treated wells is included in the Appendix. These results support data derived from tests conducted by the American Cyanamid Company in which sand and silt cores several inches in length effectively resisted gel extrusion at hydrostatic pressure of 2500 psi.

PRODUCING WELLS REFLECT PROFILE CHANGES

The 16 producing wells in the area surrounding the three subject injection wells have responded to the flood as illustrated in Fig. 7. The three injectors were drilled in mid-1972. Shortly after water injection was begun, oil production response in several of the offsetting producing wells was noted. The oil response was short-lived and production progressively declined. Water production, however, began increasing about three months after oil response was noted. The water production continued to increase at a rapid rate. Step-rate tests in the three injectors indicated the wells were not being fractured. Therefore, it was concluded that premature water breakthrough in thin, high-permeability streaks (based on available log and core data) was occurring. The results of the polymer treatments indicate an increase in oil production, in the response area, shortly after the polymer squeezes were accomplished. Water production continued to increase in the producing wells through 1974. In December, 1974, a sharp decline in water production in offsetting wells was noted. The rate declined from about 2000 BWPD to 1750 BWPD by April, 1975. The water producing rate has since increased to a stabilized level of about 2000 BWPD. Oil response is continuing to increase, and as of December, 1975, was approaching 1500 BOPD from the 16 producing wells surrounding the three worked-over injection wells.

RESPONSE AREA PRODUCTION
AND WATER INJECTION
JORDAN UNIVERSITY UNIT
JORDAN FIELD

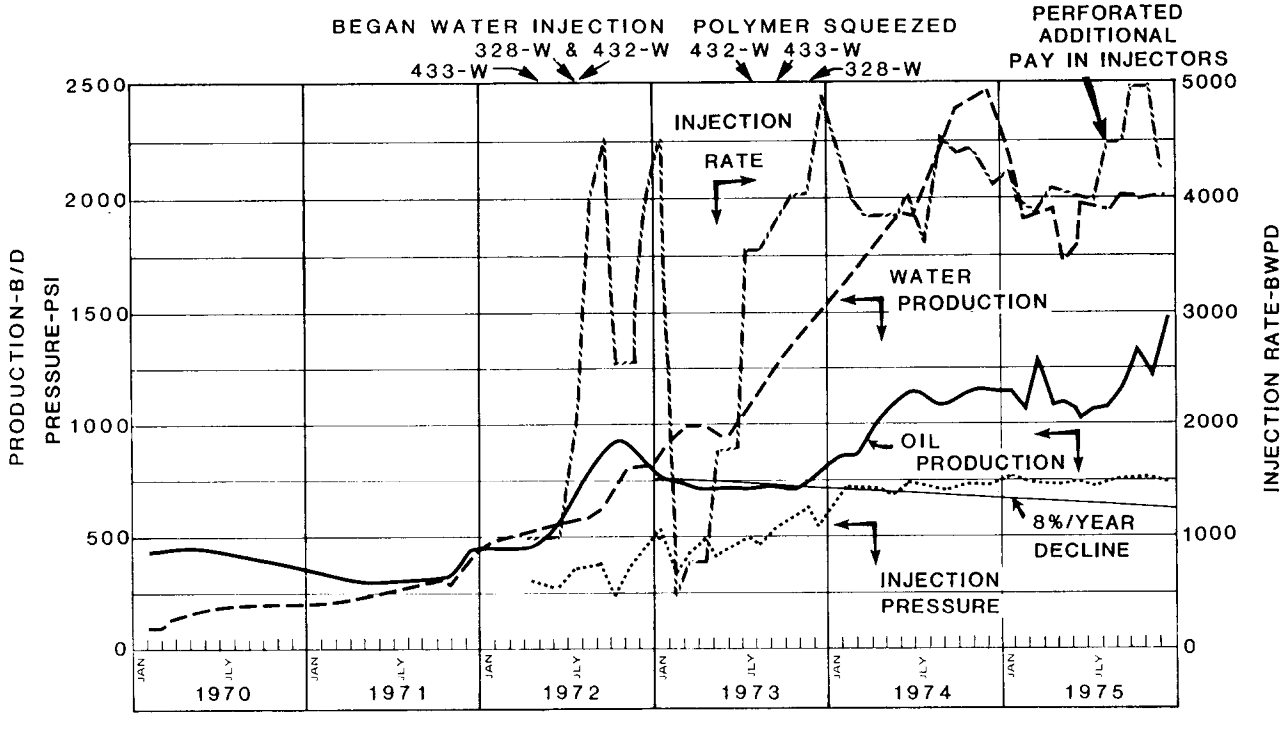


FIGURE 7

Injection rates in the three injection wells have fluctuated as reservoir fill-up is approached and as injection well pressure has been increased. In 1975, an additional zone of injection was opened, and an increase in injection rate was noted. The associated increase in oil production (September, 1975-December, 1975) was not included in the economical analysis as illustrated in Table 1.

Because of the significant cumulative injection volumes (440,000 + barrels of water per well) injected prior to the polymer squeezing, it was believed the continued increase of water production in 1974 was a result of "fill-up" water being produced from high-permeability, low-pressure, and low-residual oil saturated intervals.

Since 1974, water production has remained at a stabilized rate, and total fluid production has remained at about 80% of total water injected. While there must be some water bypassing occurring, the lease gas-oil ratio of approximately 300 cubic feet/BO indicates an excellent response condition. Therefore, it was concluded that the reservoir must be nearing a "hard" or "filled" system.

Because the offsetting producing wells are openhole, nitroglycerine-shot and fracture-treated completions, remedial efforts to reduce water influx have failed. Several plug-backs with hydromite have not reduced water production, and this fact is understandable when working in "shot" holes.

One well, Well No. 418, stands out as a significant example of the oil recovery possible in a previously watered-out producing well. In August, 1973, Well No. 418 was producing 35 BOPD and 63 BWPD and was being pumped-off. In September, 1973 the well had ceased to produce oil and had increased in water production to 95 BWPD with a pumping fluid level of 160 ft of fluid above the pump. As a result of this test, the well was shut-in on September 16, 1973. By April, 1974, the shut-in fluid level had increased 1200 ft in Well No. 418. The well subsequently was returned to production, pumping 102 BOPD and 277 BWPD. The production results are illustrated in Fig. 8. The programming of injected water by polymer treatments and the reacidizing of old perforations in Wells No. 432-W and 433-W resulted in a significant change in the producing characteristics of Well No. 418 and will result in substantial additional oil recovery at this location (Table2).

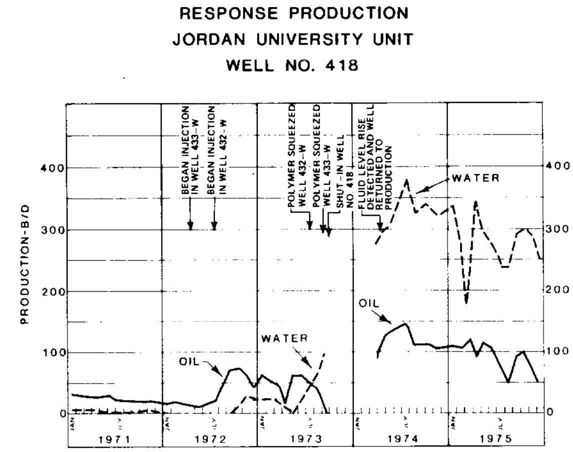


FIGURE 8

TABLE 2—ECONOMIC ANALYSIS - POLYMER PLACEMENT AND REACIDIZING OF TWO JORDAN UNIVERSITY UNIT INJECTION WELLS AND ASSOCIATED PRODUCTION RESPONSE IN WELL NO. 418

INPUT	
Total Cost of Two Jobs	$ 24,300
Crude Value $/Bbl	8.22
Royalty %	12.5
Taxes and Insurance $/Bbl	0.60
Direct Monthly Operating Cost	1,400
(1 Producing & 2 Injection Wells)	
($800/mo/prod. well)	
($300/mo/inj. well)	
Initial Production Increase BOPD	145
Decline Rate %/Yr	58
Time Period* Yrs	5.3
(Run to Economic Limit)	
RESULTS	
Additional Recovery BO	86,900
Project Payout (After Tax) Yrs	0.18
Undiscounted Profit (After Tax) $	234,000

*Does not consider increase prior to July, 1974.

Did not consider inflation, overhead or crude value changes.

CONCLUSIONS

1. The solution design technique of premixing separately and blending the gel solution and catalyst solution on the surface lends itself to flexibility and close quality control. Because of the short gelling and pumping time required, quality control of the catalyst is critical. The pump truck design is one key to solution quality control.
2. The placement techniques of isolating the targeted interval, pumping down internally plastic-coated tubulars, and under displacing *the blended polymer to gel in the pore network* within a radius of six to eight ft of the wellbore

are significant factors. In addition, *pumping the polymer to formation refusal* and gelling polymer in the wellbore maintains plug continuity and reduces the possibility of fluid channelling.

3. Reacidizing the old zones of low injectivity has aided greatly in the reprogramming of injected water in the example wells cited.
4. The absence of open, natural or artificially induced fractures in the Jordan University Unit wells mentioned certainly has increased the probability of success in placing polymer in the desired pore network, and reduced the chance of gel extrusion.

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APPENDIX

PROFILE ALTERATION OF JORDAN UNIVERSITY UNIT WELL NO. 328-W

Well No. 328W was drilled and completed as an infill water injection well in April, 1972. Injection was commenced on July 14, 1972, through 33 perforations over a 318-ft interval, at 1100 BWPD and 450 psi. Each perforation had been selectively acidized (using a cup-type packer assembly) with approximately 170 gal. of 15% NE acid at pressures of 0-500 psi. Care was taken not to exceed bottomhole parting pressure during completion operations. Thus, cement bond integrity and zonal isolation were achieved. By October, 1972, oil production in Well No. 306 (660 ft northeast) increased from 7 BOPD to 160 BOPD. By January 15, 1973, oil production had decreased to 21 BOPD and water production had increased from 17 BWPD (October, 1972) to 120 BWPD. A tracer survey run in Well No. 328W indicated "thief" zones existed from 3603 ft to 3656 ft. In order to eliminate or retard injection into the interval, Well No. 328W was selectively plugged and reacidized as follows:

1. Ran packer on tubing and set packer at 3561 ft. Resumed injection into high permeability zone perforations 3603 ft to 3656 ft at 1038 BWPD @ 505 psi (salt water).
2. Rigged up polymer truck and shut off plant injection, immediately began injecting fresh water (FW) through the pumps on the blending truck. The pumping rate was 44 gal./min. @ 590 psi.

   Note: A pressure increase, due to friction of surface equipment as well as reduced fluid head, was noted when switching from salt water to fresh water.

   a. Pumped in 2850 gal. FW preflush followed by 50 gal. of a blend (mixing while pumping) of 94% of an 11% AM-9 mixture and 6% of a 6.3% mixture of AP (ammonium persulfate) at 44 gal./min at 590 psi.

b. Reverted back to FW and pumped in 700 gal. FW at 44-50 gal./min @ 590-640 psi. Note: During the last part of this 600-gal. "test of flush", the pressure rose to 800 psi, at which time the rate was increased to 50 GPM. This was possibly caused by the 50-gal. test mixture trying to gel, possibly because the AP concentration was higher on the initial few gallons due to some unmixed AP in the area of the bottom of the tank. *Also*, with the well being shut-in prior to job, the bottomhole temperature may have been higher than anticipated.

c. Switched to the above-mentioned mixture of AM-9 and AP and pumped in 1530 gal. (setting time at approximately 17-18 min.) at a rate of 50 gal./min grading down to 44 gal./min; the pressure increasing from 610 to 620 psi while the last 300 gal. was being pumped at 44 gal./min.

d. Reverted back to FW and pumped in 270 gal. FW at 44 gal./min while the pressure rose from 620-630 psi.

e. Reduced the pumping rate to 27 gal./min and pumped in 150 gal. FW while the pressure rose from 540 to 550 psi (cumulative displacement = 420 gal.)

At 12 GPM pumping rate, pumped the following:

60 gal. FW - pressure rose from 500-520 psi
10 gal. FW - pressure rose to 540 psi
5 gal. FW - pressure rose to 560 psi
5 gal. FW - pressure rose to 590 psi
6 gal. FW - pressure rose to 700 psi
5 gal. FW - pressure rose to 900 psi
2 gal. FW - pressure rose to 1000 psi
3 gal. FW - pressure rose to 1200 psi
4 gal. FW - pressure rose to 1700 psi
(cumulative displacement = 520 gal.).

The capacity of the tubing string was calculated to be 580 gal., leaving 60 gal. gelled polymer in the casing and tubing.

3. Pulled tubing and packer.
4. Ran retrievable bridge plug and packer. Reacidized perforations 3460 ft - 3501 ft and 3420 ft - 3437 ft. Pulled tubing, packer and bridge plug.
5. Ran retrieving head on tubing. Cleaned out gel to 3580 ft.
6. Returned well to injection, cumulative cost of workover $8500. Figure 4 is a graphic record of before and after radioactive tracer surveys run in Well No. 328-W.

PROFILE ALTERATION OF JORDAN UNIVERSITY UNIT WELL NO. 432-W

Well No. 432-W was drilled and completed as an infill water injection well in May, 1972. Injection was commenced on July 14, 1972, through 37 perforations over a 298-ft interval, at 1350 BWPD and 200 psi. Each perforation had been selectively acidized (using a cup-type packer assembly) with approximately 200 gal. 15% NE acid at pressures of 0-500 psi.

Care was taken not exceed bottomhole parting pressure during completion operations. Thus, cement bond integrity and zonal isolation were achieved. By March, 1973, after injecting 240,000 BW in Well No. 432-W, water breakthrough was observed in Well No. 412, a producing well 600 ft east of Well No. 432-W (refer to Fig. 1). No appreciable oil bank preceded water breakthrough. A production log was run in Well No. 412 and water breakthrough was recorded in two zones. These two zones of water breakthrough correlated to water injection in Well No. 432-W from 3625 ft to 3634 ft and 3661 ft to 3676 ft. In order to eliminate or retard injection into the two intervals, Well No. 432-W was selectively plugged and reacidized in the following manner:

1. Plugged-back from 3759 ft to 3650 ft with sand.
2. Ran packer on tubing and set packer at 3566 ft. Resumed injection into high permeability zone perforations 3556 ft to 3634 ft at 1965 BWPD (salt water) at 510 psi.
3. Rigged up polymer truck and shut off plant injection, immediately began injecting fresh water (FW) through the pumps on the blending truck. The pumping rate was 42 gal./min at 530-575 psi.

   Note: A pressure increase, due to friction of surface equipment as well as reduced fluid head, was noted when switching from salt water to fresh water.

a. Pumped in 500 gal. FW preflush followed by 50 gal. of a blend (mixing while pumping) of 91% of an 11% AM-9 mixture and 9% of a 2.5% mixture of AP (ammonium persulphate) at 44 gal./min. @ 575 psi.
b. Reverted back to FW and pumped in 650 gal. FW @ 45.5 gal./min @ 580 psi. This procedure was followed as a check of mixture proportions to prevent a possible "flash set" when pumping the major volume of polymer.
c. Switched to the above mixture of AM-9 and AP and pumped in 1440 gal. (setting time at approximately 17 min) at an average rate of 43 gal./min at 570-600 psi.
d. Reverted back to FW displacement and pumped in 300 gal. FW at 42 gal./min as pressure rose from 595 to 610 psi (cumulative displacement = 300 gal.)
e. Reduced pumping rate to 20 gal./min and pumped in 140 gal. FW while pressure rose from 480 psi to 500 psi (cumulative displacement = 440 gal.)
f. Reduced pumping rate to 10 gal./min and pumped in 20 gal. FW while pressure rose from 470 to 480 psi (cumulative displacement = 460 gal.). At 10 gal./min pumping rate, pumped the following:

   10 gal. FW - pressure rose to 485 psi
   10 gal. FW - pressure rose to 490 psi
   10 gal. FW - pressure rose to 630 psi
   10 gal. FW - pressure rose to 1200 psi
   5 gal. FW - pressure rose to 1700 psi
   (cumulative displacement = 505 gal.)

   The capacity of the tubing string was calculated to be 540 gal., leaving 35 gal. gelled polymer in the casing and tubing.

4. Pulled tubing and packer. Cleaned out gel and sand to 3760 ft with a scalloped mill on tubing.
5. Reacidized perforations 3724-3732 ft, 3509-3556 ft, and 3434-3480 ft.
6. Returned to injection. Cumulative cost of workover $13,800.

Figure 5 is a graphic record of before and after radioactive tracer surveys run in Well No. 432-W.

PROFILE ALTERATION OF JORDAN UNIVERSITY UNIT WELL NO. 433-W

Well No. 433-W was drilled and completed as an infill water injection well in April, 1972. Injection was commenced on April 30, 1972, through 27 perforations over a 255-ft interval at 720 BWPD and 280 psi. Each perforation was selectively acidized (using a cup-type packer assembly) with approximately 220 gal. 15% NE acid at pressures of 0-500 psi. Care was taken to not exceed bottomhole parting pressure during completion operations, but communication between perforations was observed during acidizing. By September, 1973, after injecting 447,000 BW in Well No. 433-W, water breakthrough was observed in Well No. 418, a producing well between Well No. 432-W and Well No. 433-W. Well No. 418 responded to injection, but was producing 95 BWPD (no oil) with a pumping fluid level of 160 ft of fluid above the end and was shut-in on September 16, 1973. Since the same zones of injection were open in Well No. 432W and Well No. 433W, and premature water breakthrough occurred in Well No. 418, the analogy was drawn between Well No. 418 and Well No. 412 that water breakthrough was occurring within the same zones. In order to repair the injection profile in Well No. 433-W, a workover was performed as follows:

1. Ran packer on tubing and set packer at 3650 ft. Resumed injection into perforations 3660-3713 ft at 1800 BWPD at 570 psi.
2. Rigged up polymer truck and shut off plant injection, immediately began injecting fresh water (FW) through the pumps on the blending truck. The pumping rate was 49 gal./min at 620 psi.

   Note. A pressure increase, due to friction of surface equipment as well as reduced fluid head, was noted when switching from salt water to fresh water.

   a. Pumped in 500 gal. FW preflush. Changed over to a blend (mixing while pumping) of 93.5% of a 10% AM-9 mixture and 6.5% of a 3.1% mixture of AP (ammonium persulphate). Pumped in 50 gal. of this mixture at 59 gal./min at

635 psi.

b. Reverted back to FW and pumped in 750 gal. FW at 49 gal./min @ 635 psi. This procedure was followed as a check of mixture proportions to prevent a possible "flash set" when pumping the major volume of polymer.
c. Switched to the above-mentioned mixture of AM-9 and AP and pumped in 1520 gal. (setting time at approximately 21 min) at an average rate of 48 gal./min and 635 psi.
d. Reverted back to FW and pumped in 300 gal. FW at 46 gal./min @ 630 psi (cumulative displacement = 300 gal.).
e. Reduced pumping rate to 20 gal./min and pumped in 150 gal. FW while the pressure rose from 460 psi to 475 psi (cumulative displacement = 450 gal.).
f. Reduced pumping rate to 10 gal./min and pumped the following:

30 gal. FW - pressure rose to 430 psi
25 gal. FW - pressure rose to 440 psi
5 gal. FW - pressure rose to 450 psi
5 gal. FW - pressure rose to 490 psi
10 gal. FW - pressure rose to 570 psi
5 gal. FW - pressure rose to 650 psi
5 gal. FW - pressure rose to 750 psi
5 gal. FW - pressure rose to 850 psi
5 gal. FW - pressure rose to 1060 psi
5 gal. FW - pressure rose to 1340 psi
(Cumulative displacement = 505 gal.).

The capacity of the tubing-string was calculated to be 580 gal. leaving 30 gal. gelled polymer in the casing tubing.

3. Pulled tubing and packer. Cleaned out gel to 3783 ft with a notched collar on the bottom of tubing.
4. Ran straddle packer assembly on tubing and reacidized perforations 3458-3473 ft, 3533-3552 ft, 3580-3596 ft, and 3630-3634 ft.
5. Returned well to injection.
Cumulative cost of workover $10,500.
Figure 6 is a graphic record of before and after radioactive tracer surveys run in Well No. 433-W.