CONFORMANCE CONTROL IN OIL RECOVERY

by

Dwyann Dalrymple, David Sutton, and Prentice Creel

Halliburton Services

ABSTRACT

Once primary oil recovery from a reservoir has been accomplished, secondary and enhanced oil recovery techniques have been used to further the life of the field. Some of the most commonly occurring problems encountered with these techniques are:

1. Lack of confinement to the section of interest
2. Permeability variations in the producing zone
3. Early water breakthrough due to fingering of the injection fluid through the oil
4. Directional permeability from injection wells to producers.

All of the above situations may be lumped into one category termed "conformance control" problems. This paper discusses various techniques and methods currently being used to identify and correct conformance control problems in reservoirs such as those found in the West Texas/New Mexico region. Included are several "state-of-the-art" treatment methods and how they are being applied for various situations, along with some of the necessary remedial workover techniques involved.

INTRODUCTION

An oil reservoir could be described as porous rock filled with oil, buried deep beneath the earth's surface. Simply pumping oil out of holes (wells) placed into this rock and spaced 1/8 to 1/4 mile apart has historically left as much as 85 per cent of the initial oil in place.

Since the late 1920's operators have recovered significant amounts of additional oil by injection of water or gas into wells to sweep through the porous rock and push the oil into the wellbore of selected wells. Such secondary recovery processes are an integral part of today's reservoir engineering and have been discussed in many textbooks. The process of waterflooding almost always increases the per cent recovery, however, all too often, waterflood projects reach a point of producing mostly injection water and very little oil when a large per cent oil is still in the reservoir. Most of the unrecovered oil is simply bypassed when injected water sweeps through the high permeability layers and channels of the rock and breaks through into the producing wells (see Figures 1 and 2). Blocking off these "short circuit" paths so the oil can be swept out of the rest of the porous rock is the idealized and ultimate objective of conformance control.

The term "conformance" was first used to describe the vertical uniformity of a reservoir contacted by an injected fluid or gas.[1] When applied to secondary (waterflooding) and subsequent (polymers, immiscible, thermal, fire, etc.) recovery programs, "conformance control" embraces all actions taken to improve injection and production profiles. Conformance control activities are designed to (1) help the injected fluids flow through the desired area, (2) help limit the fluids produced to the desired area, and (3) help eliminate unwanted production. Any procedure intended to enhance recovery efficiency, improve wellbore/casing integrity, and satisfy environmental regulations could be classified as conformance control.

Justifying the expense of conformance control work is often difficult because of poor results realized in the past. In a survey of water control treatments by one operator, the best results were obtained from cement squeezes, and then only by a 50 per cent success ratio[2]. Other more exotic treatments had a much lower success ratio and were usually performed only in very severe cases or as experiments on wells that were nearly depleted or had no significant reserves. As Sparlin, et al pointed out,[2] most unsuccessful conformance control treatments may be the result of one or more of the following:

1. The source of the problem was not determined prior to the treatment
2. The wrong product or treatment procedure was used
3. The correct product was improperly used.

There is no "wide spectrum antibiotic" cure for all possible conformance control problems. Also, there is no "magic" product, nor will there ever be one. The mysticism must be removed from conformance control products and services in order to be able to know when one particular chemical treatment (or combination of products) is applicable and when it should not be used.

The most difficult part of a conformance control treatment design is the actual task of identifying the problem. Once that has been done, everything fits into place. Elements of information needed are:

1. What the treatment is expected to do
2. What conditions it must withstand
3. What volume is needed
4. If a combination of treatments are required.

Under the above definition, conformance control has three principal functions:

1. Identification of the problem

2. Vertical isolation of all active (or potentially active) productive or receptive formations penetrated by the wellbore and casing. In effect, the casing/borehole annulus generally should be sealed from the flood zone to the surface if economics and environmental considerations so justify. A profile correction program has little chance of success where, as an example, half the wells are producing 200 bbl of unwanted brine per day from another zone.

3. Identification and modification of the injection (or production) profile within the flood zone to improve the efficiency of the flood water in reaching more oil and sweeping it toward the production well.

DEFINITION OF CONFORMANCE CONTROL TERMS

These factors must be considered in any conformance control design:

1. Vertical conformance efficiency---the cross sectional area contacted by the injected fluid divided by the cross sectional area enclosed in all layers behind the injection front (Figure 1). The vertical conformance efficiency is a measure of the two dimensional (vertical cross section) effect of the reservoir nonconformities.

2. Areal conformance efficiency---in an areal sense, injection and production take place at individual points in the formation. As a result, pressure distributions and streamlines develop between injection and production wells. In symmetrical well patterns, a straight line connecting the injector and the producer is the shortest streamline between these two wells; the pressure gradient along this line is the highest in the field. Injected water moving along this streamline reaches the producing well before water moving along any other path. Consequently, only a portion of the reservoir area between the two wells is contacted by the flood water at breakthrough time (Figure 2). This contacted portion is the pattern areal conformance efficiency at breakthrough.

3. Volumetric conformance efficiency---the product of the pattern areal conformance and vertical conformance efficiencies, or:

   %Areal Efficiency X %Vertical Efficiency = %Volumetric Efficiency

4. Mobility ratio---mobility ratio is computed by the formula:

   $M = Kd\,\mu o / \mu\,dKo$

   where:

   Kd = Effective permeability of the formation to the displacing fluid.
   Ko = Effective permeability of the formation to the oil phase.
   μ_o = Viscosity of oil (cp)
   μ_d = Viscosity of displacing fluid (cp)

As a general rule, a mobility ratio greater than 1 is unfavorable; and a mobility ratio equal to or less than 1 is favorable.

CONFORMANCE CONTROL

In order to have any chance of success, conformance control programs require full knowledge of the problem, formulation of a viable plan, and proper execution of the treatment.

Problem Identification in Producing Wells

Investigation should begin with a review of the reservoir being produced. This should include:

1. Recovery mechanism

2. Permeability and porosity variations
3. Any directional permeability
4. Zone height
5. Reservoir dip
6. How soon water production began after well completion
7. If water production increased over time, how rapid was the increase?
8. Where was the original WOC?
9. Where are the perforations located?
10. What do bond logs indicate?
11. Are there shale breaks present and, if present, are they continuous from injector to producer?
12. What are the results of fluid entry or spinner surveys?
13. Do the core tests show natural fractures and/or high vertical permeability?

If the problem is early water breakthrough, well data should be examined to look for:

1. Undesired production from a channel behind the casing can occur any time in the life of a well, but it is most noticeable after initial completion or stimulation of the well. Unexpected water production at this time is a good indication that a channel exists. Temperature logs, pressure logs, etc. can verify this problem.

2. Perforation into water or too close to the water zone.

3. Stimulation job entered water zone or connected an injector and producer.

If the problem is water entry in a later stage of well life, the operator may expect one or more of these conditions:

1. Early water breakthrough or channel from a waterflood or natural water drive. High permeability streaks cause the water drive mechanism to displace the oil at various rates. Premature breakthrough causes the loss of energy required to sweep the lower permeability zones. Gradiomanometer and radioactive surveys may be used to detect the encroachment of the bottom water contact if a natural water drive is present. Tracers may be incorporated if the water encroachment is suspected from injection wells.

2. Bottom water coning---this is possible if the producing zone is located on top of a water zone. An excellent discussion on water coning along with equations to predict cone heights can be found in the work done by Muskat.[5]

3. Depleted reservoir---if this is the case, there is very little that can be done. Oil must be present to be produced.

4. Casing leaks---normally detected by an unexpected increase in water production. A water analysis is another good tool for determining the source of the extra water production. Temperature logs can also be used to locate the source of the leak.

Problem Identification in Injection Wells

These items of information should give many clues to the cause of injection well problems:

1. Injection pressures and rates may indicate the possibilities of fracturing the zone unintentionally.

2. Well logs such as bond, Gamma, SP, etc are studied.

3. Injection profiles are established by spinner and temperature surveys, radioactive tracer, etc. These tests may help find channels and establish vertical conformance problems.

4. Dye tracer checks for interwell communication help the operator estimate the portion of the reservoir being swept. By pumping dye into the injection well and timing its arrival at the producer, the operator can evaluate streamlines and other similar problems.

5. Pulse tests provide another method of checking the time required for water to reach the producers.

If the well data indicate an unfavorable injection profile, there are many possible causes which include:

1. Scale buildup
2. Bacteria
3. Debris
4. High permeability streaks
5. Crossflow in wellbore
6. Injection water incompatible with formation water.

If the injection water has no apparent effect on incremental oil recovery, possible problems include:

1. Injection well and producing well not perforated in the same zone
2. Water going out of zone
3. Existence of a gas cap
4. Fault between injector and producer
5. Mobility of fluids totally unfavorable
6. Fill-up not yet achieved
7. Producing wells not pumped off.

If there is a direct communication to the producer, possibilities include:

1. Fractures
2. Channels
3. Poor mobility ratio.

ISOLATION OF THE ZONE OF INTEREST

Some formations can be effectively treated for conformance control without remedial work to isolate zones or stop unwanted water flow, though most conformance control jobs would benefit from steps taken to limit the conformance work to the targeted zones. Operators recognize the need for zone isolation, but at times elect, in the interest of economy, to skip the zone isolation steps. The choice made will heavily influence the job design, which will be discussed later.

Analysis of the Problem

Many wells that are candidates for secondary and enhanced recovery operations were drilled 30 to 50 years ago. The production casing in many of these wells was cemented with just enough cement to extend a few feet above the top of the productive zone of interest.[4] This procedure has left as much as 2500 ft of uncemented casing between the TOC and the surface pipe.

Primary concern is caused by formations that originated from evaporation of sea water and are imbedded with salt and anhydrite. When contacted by water, the salt readily dissolves to form a highly corrosive solution that attacks the casing in the uncemented interval. Casing leaks result from the attack, and flowing brine migrates from zone to zone.

Flowing brine causing the problem can be from either producing formations or from waterflood projects underway in adjacent wells. The flow may take one or more of these paths:

1. Through a leak in the production casing and out the top of the casing

2. After entering the tubing/casing annulus, brine may corrode and produce through the tubing

3. Communication from one zone to another (crossflow) throughout the casing/wellbore annulus and flow out of an adjacent well that also has damaged casing

4. Communication to a fresh water zone via the production casing and contamination of the zone through another casing leak.[4]

Zones thought to be barren 30 years ago when the above mentioned cementing was done have become active in spite of initial evaluation or have changed due to inter-reservoir pressure from nearby waterflood programs in lower zones. Wells that were improperly plugged and abandoned can furnish the conduit for this inter-reservoir movement.

At the time of original drilling, no over-pressured zones existed and drilling and cementing programs used seldom subjected uncemented formations to pressure gradients as much as 11 lb/gal (0.57 psi/ft). Many of the formations would then, and will now fracture at a pressure gradient far less than the normal cement slurry density (14 to 15 lb/gal). Another condition complicating the analysis is that the reservoir condition may have been significantly altered from its original state, as listed below:

1. Formerly non-producing zones are now water saturated and capable of producing large volume of water or brine.

2. Zones which originally showed a fracturing gradient 0.70 psi/ft are now depleted and will fracture at gradients as low as 0.50 psi/ft.

Evaluation of Conditions

Two of the most important and useful items of information needed to design a successful zone isolation cementing job are (1) formation pressure and (2) fracturing pressures. Such information is useful (1) to avoid loss of large volumes of slurry into weak formations, (2) in the determination of a realistic column height for recementing jobs, and (3) to control backflow after cementing. If the well in question will hold a full column of fluid, this sort of information is easily obtained from pressure recordings made during injectivity tests and from analysis of shutdown curves.

If the well will not stand full, downhole pressure gauges are essential. These gauges include (1) self-contained wireline pressure devices, (2) pressure sensors on electric cable, and (3) echo meters.

If a program requires circulating cement into the open annulus, formation pressure data and a series of "rate-in, rate-out" circulation tests can be used to (1) evaluate perforation location, (2) determine realistic cement column height, and (3) determine the need for additional cleaning, foamed flushes, and the application of ultra light foam cements.

Squeezing for Zone Isolation

A high incidence of first squeeze failures has gone a long way toward elimination of the phrase "simple squeeze job" from the oil operator's vernacular. A squeeze job failure is essentially a failure to place enough slurry in the areas where it can be effective and hold it there long enough to form a permanent seal. Although there can be no guarantee of success most failures have one or two factors in common: (1) lack of knowledge about downhole conditions, and (2) overly optimistic expectations about the job results.

The most common contributors to squeeze job failure and field-proven methods of handling each one are discussed below.

1. Lack of fluid loss control. Poor fluid loss control and low placement rates can lead to a premature squeeze which can block an uncemented annulus and force the cement to the wrong area or prevent sufficient slurry from entering an injection zone to block vertical flow. Vertical flow must be stopped to accomplish zone isolation. Fluid loss control during squeeze jobs depends mostly on slurry compositions, namely fluid loss additives, gelation materials, foam content, and foam stability. Fluid loss can also be reduced by large pre-charge volumes and reactive flushes (precipitation or gelation type) pumped ahead of the cement.

2. Low placement rates. A low injection rate simply gives more time for a specific volume of cement slurry to lose fluid and become a solid mass. In effect, the placement rate supplies the time factor for fluid loss. Fluid loss additives can supply only so much control and some minimum rate is always needed for a specific slurry penetration distance.

3. No clear knowledge of where the slurry is needed or how to get it there. Some squeeze jobs are apparently run with little more knowledge than the approximate depth of the casing leak. If more than one formation is open in an uncemented annulus, the slurry will enter the formation with the lowest pressure parting gradient, which is very often not the formation which produced the brine causing the leak.

4. Poor injection point control. Slurry entrance into at least one formation is normally needed for a squeeze job success. Simply isolating a hole in the casing with packers does not ensure that slurry can be forced into the formation at that point. Some zones cannot be successfully squeezed without first blocking the uncemented annulus below the depth where the squeeze is needed.

5. Effect of bottom water. In controlling bottom water, problems occur where natural or induced fractures extend into lower zones. The goal is to block vertical permeability in the lower part of the zone while maintaining good horizontal permeability in the rest of the zone. One method of accomplishing this goal is to simultaneously inject clean fluids into the upper part of the zone while performing a cement squeeze in the lower part. A modification of this approach is to perforate into the lower zone and inject the squeeze fluids directly into the water.

   Another method of combatting bottom water is to inject a low viscosity temporary blocking material into the upper zone before squeezing the bottom zone. The success ratio of this type of squeeze job is greatly improved by using reactive silicate preflushes of the type described in Table 1. All jobs shown in the table were run after one or more single slurry cement squeeze jobs had failed.

6. High volume water flow in an uncemented annulus (often referred to as crossflow) can dilute a cement slurry to the point that it is no longer an effective sealing material. Controlling such conditions eventually requires squeezing off the brine producing zone. This means the producing zone pressure must be exceeded by significant pressure; if deep vertical permeability blocking is required, the pressure excess required may be as much as 0.33 psi/ft. If a weak zone is open in the same uncemented area, special techniques such as foam cementing as described by Garvin and Creel may be needed.[4] A multiple stage cement job with selective injection could also suffice if slurry injection points can be controlled.

7. Poor bonding to the formation is common in salt formations and the cure presents a dual problem. Saturated salt slurries are needed for good bonding, but such slurries have exceptionally long thickening and initial set times which can complicate squeeze procedures. The slurry must remain static during the time between placement and initial set. High pressure water can easily enter and disrupt the integrity of a cement during its transition from a fluid to a solid.[5]

8. Flow back into annulus of casing due to gel strength induced pressure loss after cementing (annular gas flow effect). When pumping is stopped, the downhole pressure is initially equal to the hydrostatic

pressure plus any remaining surface pressure. (If no squeeze pressure is obtained some formations will continue to "take slurry" until the hydrostatic is equal to the fracture extention pressure.) As the cement gels and fluid is lost from the slurry (to permeable formations) the pressure in the cement rapidly decreases. This pressure decrease allows gas or brine to enter the cement, migrating upward, mixing with the cement slurry and/or forming flow channels for the brine or gas.[3] Foam cement, plastic state expansion additives, thixotropic additives and compressible cements are often effective in controlling the phenomenon.

9. Multiple injection zones. Difficulties of squeezing more than one area with a single job are mostly self evident, however, treating multiple injection points or paths in a single zone is less understood. For instance, a reactive preflush or pad ahead of the slurry can result in a complete blockage of one flow path yet the following slurry meets very little additional restriction, and no squeeze pressure is evident. This condition is best solved with multiple stage squeeze jobs with an Externally Catalyzed Silicate System (ECSS) preflush ahead of each stage,[4] or by pumping a large volume of a Internally Catalyzed Silicate System (ICSS) solution which will react with the formation brine in addition to its time dependent set.

CONFORMANCE CONTROL MATERIALS

After determining the source of the problem and taking the necessary steps in isolation of the problem, the treatment can be designed. Four materials used to support conformance control programs are:

1. Internally Catalyzed Silicate System (ICSS)---for altering water injection profiles and water/oil ratios. The ICSS sealant is just what its name implies; it is a sealant. It is placed as a low viscosity (1.2 cp) solution which contains no solids. The internal catalyst allows a controllable pump time before the system sets to a stiff gel. The material does not have significant strength in its "neat" form (less than 15 psi). Its strength lies in the matrix sealing quality of the system. Laboratory tests on this type of material performed in a 1 in. diameter, 3 in. pack of Oklahoma No. 1 sand, ICSS has resisted extrusion even after 2000 psi hydraulic pressure was placed on the system.

   The sealant may be used alone or may form part of a combination of ICSS sealant-cement squeeze. Primary use of the material has been to prevent bottom water coning and to seal selected zones. The internal catalyst and low viscosity allows injection deep into the formation radially around the wellbore. A cement "tail-in" exercises a synergistic effect on the treatment: (1) the cement gives a high compressive strength material near the wellbore where the differential pressure is the greatest, (2) the cement gives a positive surface indication that proper displacement has taken place, and (3) the ICSS reacts with the cement to flash set the silicate near the wellbore and the cement begins hydration almost immediately.

After setting, the ICSS forms a firm gel that is a permanent treatment and relatively inert to most chemicals. It may be used to form a barrier to water zones below when no natural barrier previously existed. The system has also been used ahead of later acid treatments. The acid was prevented from contacting the water zone below by the ICSS barrier but performed as an acid matrix treatment of the producing zone.

Table 2 contains several examples of the use of this system.

2. Externally Catalyzed Silicate System (ECSS)---a two fluid, two-stage silicate system developed specifically for controlling subsurface brine flow in producing or injection wells. This system has seen extensive use in both flood operations and primary production for improving the oil/water ratio. The materials are relatively low cost with one survey showing a 29 day treatment payoff. A generalized treatment procedure follows:

   a. Hole is cleared to lowest point of interest and a retrievable packer is set at or above perforations.

   b. Injection rate and pressure are established with formation water or conditioned freshwater.

   c. Pump brine followed with a spacer.

   d. Pump ECSS solution followed by a spacer.

   e. Repeat steps "c" and "d" up to five times.

   f. Move packer above top perforations.

   g. Pump acid with surfactants and buffers appropriate for the zone treated.

   h. Displace and inject into the formation at a relatively slow rate.

   The advantage of this procedure is selective blocking of water production with minimal effect on oil production.

   As previously described, ECSS solution can also be used ahead of a cement squeeze. In a two stage operation, the initial or last ECSS solution forms a very stiff gel when it intermixes with a formation or synthetic brine. The gel forms a bridge or plug to block or divert the cement slurry. As cement slurry intermixes with the ECSS solution, a very stiff gel is formed which limits cement slurry entry into that area. Multiple stages may be required under some severe downhole conditions. In fresh water or low-brine concentrations zones, a reactive brine spear-head must be pumped into the problem zone to cause the lead ECSS solution to function properly.

   ECSS job results are shown in Table 3.

3. Monomer/Polymer Treatment (M/P)---this system helps improve oil displacement efficiency in injection wells by improving the vertical and areal conformance of the zone. To fully understand how this treatment works, one must fully understand what the words "monomer" and "polymer" represent.

The prefix "poly" means many and the prefix "mono" means one. The root "mer" is taken from the Greek and means units. Therefore the word polymer itself only means "many units." This is where the term "monomer" is important. A monomer can best be thought of as one unit. When many monomer units are tied together a polymer is formed. Figures 3 and 4 illustrate this point. In Figure 3 is a collection of beads falling through a funnel into a glass container. The beads represent monomer units traveling through a pore channel. Note that little injection resistance is expected in this operation. In Figure 4 the beads are tied together in the form of a chain to represent a polymer. Note that this "polymer" is going to have difficult time "flowing" through this pore channel.

In the above example, if one had analyzed the chemical one would see the same elements present, yet each exhibited extremely different flow and viscosifying properties. The extra viscosity polymers give their carrying fluids is the reason they are considered in EOR projects. Addition of polymers will increase the viscosity, thus helping improve the mobility ratio (see definitions) of the flooding fluid.

The M/P is mixed on the surface using conventional equipment; no specialized pumping skid units are necessary. All activaters, catalysts, and crosslinkers (if used) are contained in a single solution. When the material is placed it is a monomer with a viscosity of approximately 1.2 cp. The placement procedure is at the same rate and pressure at which the waterflood was being operated. Penetration of the M/P into the interval should be proportionately the same as the flood water since all the variables concerning relative permeability and injectibility are the same.

Once in place, the treated injection well and its offsets are shut in for a period of five days to allow for "insitu" polymerization. The size of the recommended treatment is usually 25-100 per cent of one daily injection volume. At every place the M/P is located, the solution contains the same quantity of catalyst and activaters. The M/P is placed as a one solution treatment.

The M/P system is placed as a monomer fluid into the formation while the fluid is of low viscosity. When the M/P polymerizes, its viscosity increases drastically. Since larger quantities of the monomer enters the highly permeable sublayers of the formation, more polymer will be formed in that area, influencing the permeable sublayers more than the tight sublayers of the formation. The goal of polymerization is diversion of the floodwater into portions of the zone which had not been taking fluid previously. Water invasion of these conformed formations will tend to be more uniform and efficient, and will help displace more oil toward the producing well.

Every point about the M/P system is a variable to be optimized for each particular situation. The viscosity of the final polymer, the solubility of the material, and the pump time are all controllable factors. Combining these factors gives more control over a job design than with any other chemical treatment.[6] It is a good practice to isolate thief zones so that the M/P solution may be placed in the offending interval, however, for reasons of economy and convenience it is common to treat the injection well without isolation.

Table 4 and Figure 5 contain examples of treatment results using the M/P system.

4. Sequential Polymer Treatment (SPT)---this treatment has been found effective in treatment of high permeability streaks in injection wells. It consists of pumping a dilute polymer (approximately 500 to 1500 ppm in the injection water) into the injector. After a spacer of injection water containing no polymer, a second stage consisting of a crosslinker is pumped. This crosslinker attaches to the polymer in the rock matrix. After another spacer, additional dilute polymer is pumped, and this polymer attaches to the crosslinker. This sequence results in a building effect in the pore channel. The high permeability streak is gradually plugged off and a resulting build up in the surface injection pressure is seen. When the pressure reaches a predetermined figure, the polymer sequence is halted and injection continues with water only. (See Figures 6-9.)

CONFORMANCE CONTROL DESIGN CONSIDERATIONS

When designing a conformance control project, the operator must consider the purpose of his program. The physical and chemical characteristics of the solutions he introduces into the formation must be compatible with immediate and future plans for the reservoir. Below is a guide to some common selections based on treatment purpose. In Tables 5 and 6 are stated problems and a selection of the treatments that may be applied to solve the problems.

1. If the project is designed for later enhanced oil recovery of a particular interval, do not use the ICSS. Use of ICSS will permanently seal the zone. Treatment should instead be made with systems such as the M/P system or other viscosifying chemicals which only restrict fluid entry into the interval.

2. Use of ICSS may be considered if the purpose of the program is pressure maintenance and direct channels are present or if injection out of zone is occurring.

3. If program's purpose is to pressure up for future CO_2 work, do not use an anionic polyacrylamide. Conduct the treatment with a system which will not be affected by the CO_2 injection, such as M/P or ICSS. However, if CO_2 is currently being injected, ICSS systems would have problems with premature gellation during placement.

CONCLUSIONS

As pointed out in this paper, conformance control problems must be approached in a logical fashion before the success ratio will ever be significant.

1. Determine the problem, do not assume the problem. Go through the steps in ferreting out the difficulty.

2. Isolate the zone for better wellbore integrity. The best treatment is a total waste of money if it does not go where you need it. To use an axiom, "don't step over a dollar to pick up a penny."

3. Choose what treatment or combination of treatments will best fit your problem.

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Table 1
Casing Leak Repair Jobs Using Externally Catalyzed Silicate System

Depth (ft)	Volume ECSS (gal)	Volume CMT (sks)	Pressure on SQUEEZE (psi)	Remarks
4,263	1,000	200	3,800	Drill out successful test
3,896	2,000	200	3,800	Open hole squeeze
4,085	2,500	250	1,000	Drill out successful test
6,478	2,000	200	2,300	Drill out successful test
7,125	4,000	175	2,000	Plug to abandon
8,550	2,000	50	600	Drill out successful test
12,480	4,000	150	500	Drill out successful test
12,576	4,000	150	1,750	Drill out successful test

Table 2
Internally Catalyzed Silicate System[4] Job Results

Formation	Amount of ICSS (bbl)	Sacks Cement	Production BWPD/BOPD Before	After	Time Period
Strawn Lime	100	50	200/1	71/86	30 days
Edwards Lime	54	0	994/7½	100/0	---
Ellenburger	100	300	44/68	176/0	---
Palo Pinto Reef	35	35 bbl ICSS Slurry	400/Trace	150/30	2 months
San Andres	60	60 bbl ICSS Slurry	81/1	50/23	---
Ellenburger	300	150	100/0	50/30	5 month
Ellenburger	400	100	60/60	0/150	3 month
Devonian	300	100	9/63	0/121	4 month
San Andreas	500	100	400/1	140/82	2 month
San Andreas	500	50	280/6	100/60	90 days

Table 3
ECSS Job Results[4]

Volume ECSS (gal)	Production Oil/Water Before	Production Oil/Water After
3,000	4/90	4/35
3,000	14/140	13/63
3,000	8/130	18/75
3,000	0/160	15/25
3,000	2/130	11/15
3,000	0/121	23/35
6,000	0/150	22/35
6,000	0/135	18/52
4,000	0/163	20/84
3,000	0/120	6/50
3,000	2/100	5/30
3,000	2/100	5/30
3,000	0/130	9/30
3,000	2/120	9/40

Table 4
M/P Treatment Examples

Well Number	Before		After	
	Pressure	Rate	Pressure	Rate
1	925	341	1200	220
2	825	285	1100	218
3	800	571	1200	200
4	825	417	1200	200
5	500	342	1200	280
6	900	219	1150	150
7	1000	195	1250	nil
8	900	292	1150	150
9	820	214	1200	150
10	1025	244	1200	160
11	300	500	600	200
12	300	700	600	200

Table 5
Production Well Problems/Solutions

Problem	Choice of Solutions					
	Cement Squeeze	ECSS	ICSS	ICSS Slurry	M/P	M/P X C(1)
Channel Behind Casing	X	X				
No Shale Barrier			X			X
Fracture Job Went to Water	X	X	X	X		X
Acid Job Went to Water			X			X
Channel From Injector				X		X
Early Water Breakthrough			X			
Bottom Water Coning			X			
High Permeability Streaks					X(2)	

(1) M/P X C is an extremely strong crosslinked polymer version of M/P.

(2) Lightly crosslinked

Table 6
Injection Well Problems/Solutions

Problem	Choice of Solutions							
	Cement Squeeze	ECSS	ICSS	ICSS Slurry	MP	MP X C	ECSS Squeeze	Acid Cleanup	Swab
Casing Leak	X	X					X		
Channel Behind Casing	X	X					X		
All Water Out Bottom	X	X	X			X	X		
High Permeability Streaks			X		X	X			
Skin Damage								X	X

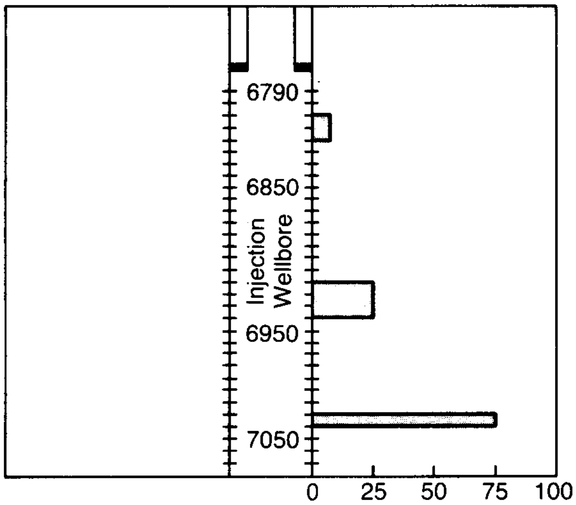

Figure 1 - Vertical conformance efficiency examples

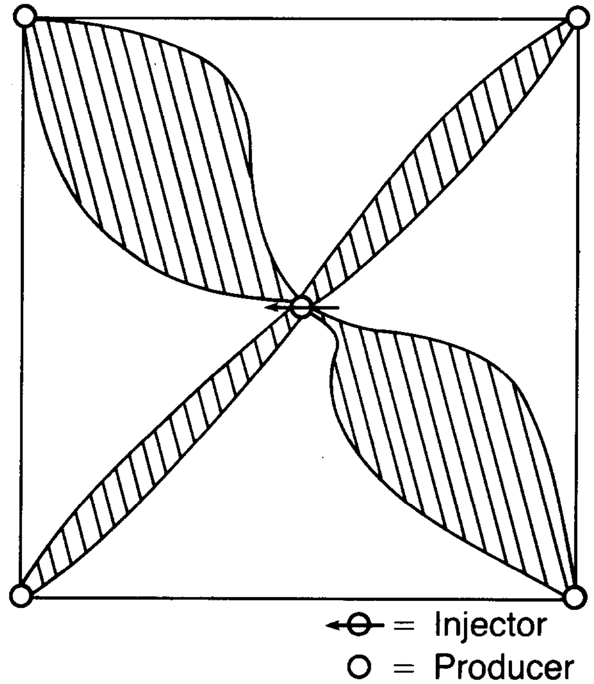

Figure 2 - Areal conformance efficiency example

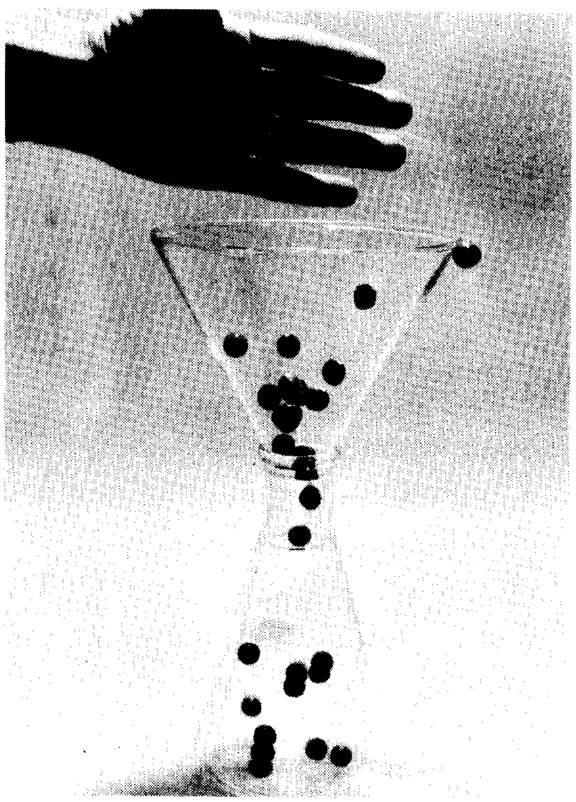

Figure 3 - Flow properties of a monomer

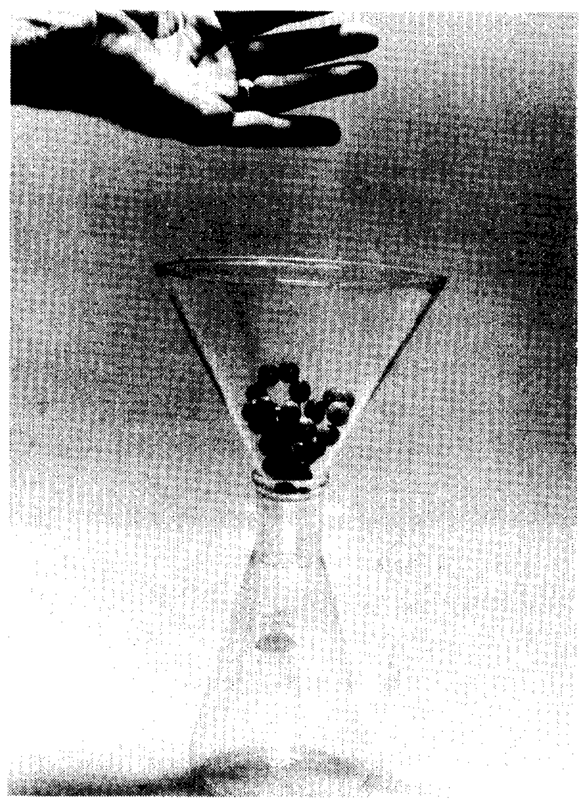

Figure 4 - Flow properties of a polymer

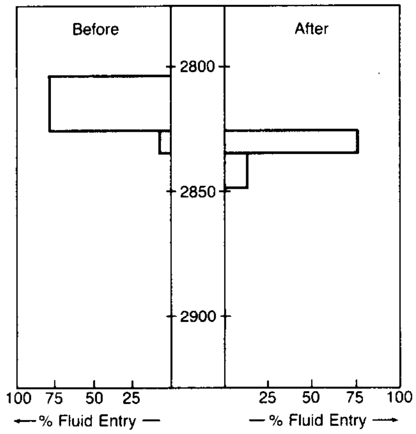

Figure 5 - Example conformance correction with M/P System

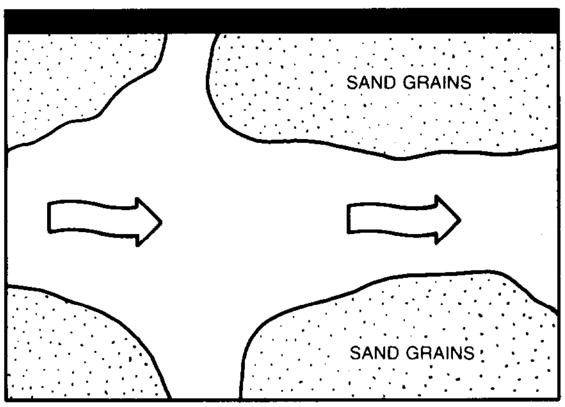

Figure 6 - Original fluid path in pore throat

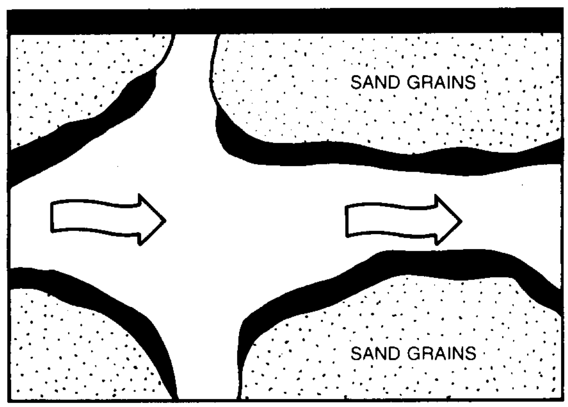

Figure 7 - Adsorption of first polymer stage on rock surface

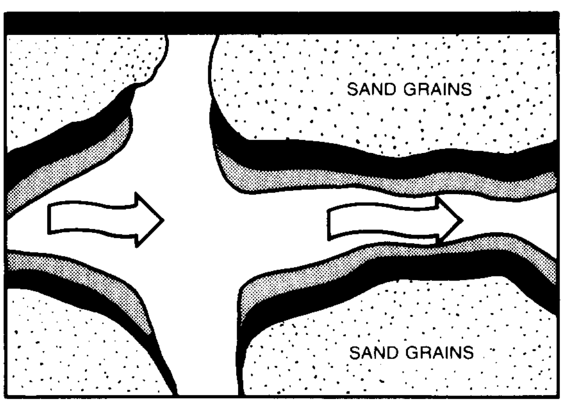

Figure 8 - Adsorption of crosslinker on polymer

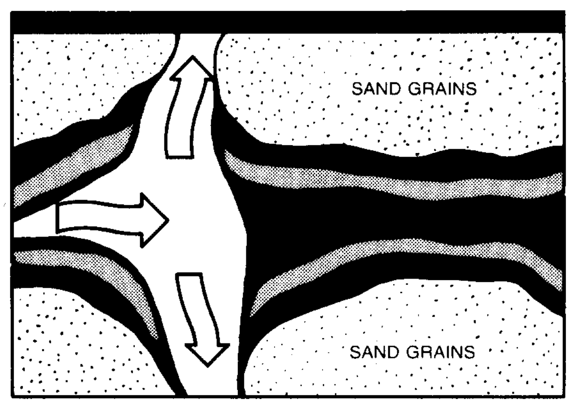

Figure 9 - Adsorption of polymer on crosslinker and resulting change in fluid path