LABORATORY STUDY OF POLYMERS TO IMPROVE CONFORMANCE CONTROL

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ABSTRACT

Typically, channels or streaks of high permeability develop after a period of time in CO_2 injection programs. To help prevent injected CO_2 and water from bypassing recoverable oil, polymer is injected which alters permeability to permit injected CO_2 and water to contact previously bypassed oil-bearing formation.

With the development of the laboratory apparatus described in this paper, significant improvements have been made in analyzing and designing polymer injection strategies to improve conformance control. The apparatus consists of a parallel series of cores of varying permeability to simulate variations in formation permeability. These cores are subjected to sequential injection of CO_2 and water, followed by polymer injection. Effects of polymer injection on formation permeability are then evaluated. Results of studies conducted using this laboratory apparatus have led to findings regarding:

1. Selection of a nonionic organic crosslinked polyacrylamide polymer which is stable in the low pH environment of supercritical CO_2.
2. Determination of an optimum treatment size to preferentially alter permeability to improve conformance control.
3. Long term effects of the CO_2 environment on stability of injected polymer.

INTRODUCTION

Injection of carbon dioxide (CO_2) to improve oil recovery actually began as early as 1952, although use of CO_2 enhanced oil recovery (CO_2-EOR) processes did not become widespread until after 1972 when rising oil prices, coupled with declining domestic oil production, caused an intense interest in EOR processes in general. In 1984, oil produced by various EOR methods represented 5.3% of total U. S. daily oil production. Of the total amount of oil produced by these EOR methods, 6.9% was produced by CO_2 injection projects. From 1982 to 1984, CO_2-EOR production increased to 31,300 BOPD,[1] and the total of 40 CO_2 projects represented a 43% increase.[1] A trend toward increased CO_2-EOR activity is expected in the future; recent completion of CO_2 pipe lines from New Mexico and southeastern Colorado to the Permian Basin in West Texas should provide a further boost to the growth of CO_2-EOR projects.

One severe drawback in the CO_2 process is the problem of poor conformance caused by the presence of channels, fractures and/or high permeability streaks in the formation, especially in carbonate reservoirs. Presence of these high permeability areas is further aggravated by the low viscosity of CO_2 gas, which can allow CO_2 to flow directly from an injection well to a production well, resulting in premature CO_2 breakthrough. If CO_2 breakthrough occurs, injected CO_2 and water can bypass recoverable oil, thus limiting future production potential. Another consequence of CO_2 breakthrough is large volume CO_2 gas production. Produced CO_2 must be separated and processed for reinjection, a process which requires expensive cleanup and recycling facilities and causes severe economic impact on CO_2 projects.

A nonionic, organic crosslinked polyacrylamide (NOCP) polymer was introduced to (1) modify CO_2-water injection profiles, (2) reduce channeling problems, and (3) help improve CO_2 conformance. To evaluate polymer treatment design and effectiveness, a laboratory apparatus was developed to simulate a formation with variable permeability, and a laboratory study was started which proceeded in two phases:

1. The initial phase was aimed at determining an optimum treatment size, and consequently improving treatment effectiveness under simulated CO_2-water injection conditions.
2. When the second phase is completed, the polymer will have been stored under supercritical conditions for a period of two years to study the long term effects of the CO_2 environment on stability of injected polymer.

CURRENT TREATMENT TECHNIQUE

Several methods are available for improving injection profiles. One common practice is mechanical installation of downhole profile control equipment;[2] however, the success of profile control equipment is limited by (1) degree of stratification of the reservoir, (2) cost of the equipment, (3) cost of wireline services required to place downhole profile control equipment, and (4) scale and corrosion problems.

Cement squeeze techniques are also commonly used to shut off channels or fractures. Generally though, squeeze cementing is most effective in the immediate vicinity of the wellbore, not necessarily extending into channels and fractures in the formation.

Foamed CO_2 processes have also been tested to control channeling problems,[3] but the results of those tests indicate CO_2-foam is limited mostly to the application of mobility control in CO_2 flooding.

Recently, one of the most common treatment methods employed has been injection of a metal crosslinked, anionic polyacrylamide which gels in-situ to block high permeability streaks. In cases where severe channelling and fractures are present however, this kind of treatment has not been found to provide long term effectiveness.[3] Even if initially successful, the anionic polymer treatment would be expected to last for only a few cycles of CO_2-water injection for the following reasons:

1. In most CO_2 injection projects the "Water Alternating with Gas" (WAG) flood method is used to control mobility problems. The anionic polyacrylamide crosslinked with metal cation (i.e. chrome, aluminum or zicronium) has been observed to be chemically unstable under the acidic environment created by CO_2 and water (when CO_2 dissolves in water, it forms carbonic acid). The crosslinking step of polymer and metal cation is very pH sensitive.

2. The gel formed by crosslinking polymer with metal cation is firm but may not be strong enough to resist flow in channels and high permeability streaks, and may be leached out by water and CO_2 as they are alternately injected behind the polymer.

NONIONIC ORGANIC CROSSLINKED POLYACRYLAMIDE POLYMER

The in-situ polymerization concept to improve waterflooding conformance control has been discussed extensively elsewhere in the literature.[4-6] This treatment technique involves pumping a catalyzed acrylamide monomer solution at a concentration in a range of 40,000 to 50,000 ppm, which does not polymerize until after it is pumped into the target formation (i.e. an in-situ polymer gel). By employing this process, the polymer solution is placed within the formation without the problems caused by injecting a viscous solution through flow restrictions. Mixing problems which can be encountered when dissolving high molecular weight polymers are also avoided. Polymer viscosities in excess of 600,000 cps can be created in-situ to provide conformance control in waterflood operations.

Application of this process has now been extended to CO_2-EOR projects for conformance control. Results of polymer aging tests under a CO_2 supercritical environment (at 110°F and 2500 psi) indicate that nonionic polymer is chemically stable in the low pH CO_2 environment.[3] Strength and stability of the polymer are enhanced by an organic crosslinking system which is incorporated as part of the in-situ polymerization. Unlike the metal crosslinker, the organic crosslinking process is not pH sensitive. By varying the organic crosslinker concentration, polymer viscosity can be controlled to yield a rubbery, insoluble polymer of over 4 million cp that has enough gel strength to help shut off channels between injectors and producers, and divert injected CO_2-water to previously unswept zones.

APPARATUS AND PROCEDURE

Dolomite Pack Preparation

Three dolomite packs having permeabilities in the range of less than 100 md to greater than 3 darcies were prepared in three stainless steel chambers. Each chamber has a diameter of 4.4 cm and is 27.6 cm long. Permeability variation was achieved by packing the chamber with differing mesh sizes of dolomite grain. The San Andres dolomite core sample was crushed and ground through a core grinder. Dolomite grains passing through the 325 mesh screen were formed to make the tightest pack. The remainder of the ground dolomite left on the 25/35 mesh screen was used to form the highest permeability pack to simulate formation channels and fractures. Each pack was consolidated with 10% cement and was packed in the chamber by hand. The interior of the chamber was coated with epoxy sand. The dolomite pack was prepared while the epoxy was still wet to bond the pack to the steel wall. Properties of these three cores are summarized in Table 1.

Supercritical CO_2 Gas Generation System

Supercritical CO_2 gas (approximately 1600 psi and 100°F) was generated with the system shown in Fig. 1. A laboratory feed pump having a plunger size of 6 mm and gear ratio of 15:1 was used to transfer the CO_2 liquid from the CO_2 cylinder to the CO_2 reservoir, and to pressurize the CO_2 to 1600 psi. The pump was equipped with a cooling coil on the intake side to precool the liquid CO_2 in order to maintain prime. This was achieved by circulating antifreeze at 32°F through the cooling coil with a submersible pump. A CO_2 reservoir was stored in a temperature bath at 100°F to vaporize the CO_2 liquid to supercritical CO_2 gas at 1600 psi and 100°F conditions, then CO_2 gas regulated to the desired test pressure with a high pressure regulator.

Linear Flow Multi-Core Holder Flow Equipment

A schematic of the linear flow, multi-core holder flow equipment is shown in Fig. 2. The three core holders were connected in parallel to represent three zones of widely different permeability being flooded at a constant rate of injection. Stainless steel high pressure fittings, valves, and tubing were used in the flow system to prevent CO_2 corrosion and to withstand a working pressure of over 2000 psi. The flow system was set up such that water and CO_2 flow rates through each individual core could be determined. Temperature was maintained at 100°F with heating tapes and a temperature controller. A 200 psi differential pressure transducer was used to monitor the differential pressure between inlet and outlet points. Pressure of the system was maintained at 1400 psi by a back pressure regulator. The back pressure regulator and gas flow regulator were submerged in a temperature bath at 120°F to compensate for heat loss due to expansion of CO_2 by the Joule-Thompson effect. Effluent gas was regulated with a precision gas flow regulator to the desired constant test pressure and was passed through a liquid gas separator, a drying chamber, and a mass flow meter. The three water flow rates were measured simultaneously, all data were collected continuously by a computer.

Experimental Procedure

Laboratory design parameters for this study are summarized in Table 2. All cores were saturated with a synthetic brine (Table 3) at 100°F and then saturated with oil (Table 4) from a West Texas formation. Following this, the cores were flooded with injection water until residual oil saturation was achieved. Supercritical CO_2 gas was injected through the system at a pressure of 1500 psi and 100°F. Flow rate of CO_2 through each individual core was determined. Water was injected through the system until stable flow was established at a differential pressure of 10 psi to determine the effective permeability to water before treatment.

A preflush of 400 ml of 6% KCl containing an oxygen scavenger was injected through the system at 10 psi differential pressure. The three cores were then treated simultaneously with the catalyzed monomer solution. A control sample of the treatment solution was stored in a water bath at 100°F to determine the properties of treatment solution. After treatment the chemical solution was flushed from the lines to the face of dolomite pack, and the cores were shut in for five days at 100°F to allow the monomer solution to polymerize.

After shut-in, water injection was resumed by slowly increasing differential pressure to a maximum of 25 psi. Water flow rate through each individual core was then determined. Alternating CO_2-water injection was continued to evaluate the treatment results. For each cycle, three pore volumes (approximately 1000 cc each) of CO_2 and water were flowed through the system. Three flow tests with different treatment sizes of 0.1 pv, 0.3 pv, and 0.5 pv of the treatment performed. Treatment size was based on the pore volume of the core No. 1 having the highest permeability.

Polymer Aging Test

For the second phase of this laboratory study, one liter of nonionic organic crosslinked polyacrylamide polymer (NOCP) was stored in a stainless steel reservoir and kept in contact with CO_2 at 1500 psi and 100°F conditions. A portion of the sample has been taken once a month to compare the polymer properties (i.e. solubility and viscosity) with a control sample. The aging test was scheduled to last for two years to study the long term effect of the supercritical CO_2 environment on the polymer.

RESULTS AND DISCUSSION

A summary of the CO_2 conformance control flow test results is given in Tables 5, 6, and 7, and Figs. 4, 5, and 6. During the test, water and supercritical CO_2 gas were alternately injected to simulate CO_2-WAG projects; however, since the water flow rate data were more reliable and accurate than CO_2 flow rate data, water flow rates and permeabilities to water before and after treatment were used to evaluate treatment performance.

Viscosity of the catalyzed acrylamide monomer solution during treatment was about 1.5 cps; as with water, it followed the path of least resistance into the highest permeability area (in this case core No. 1, permeability greater than 3 darcies). The ratio of the amount of treatment solution flowing into each core was proportional to the ratio of their permeabilities. The majority of the treatment solution was observed to flow into core No. 1 indicating the in-situ polymerization treatment technique could eliminate the need for zone isolation during treatment, and thus reduce the treatment expense.

Core No. 1, which had the highest permeability and consequently took the most treatment solution, was observed to have the highest permeability reduction after treatment. In three tests with three different treatment volumes the permeability reduction on core No. 1 remained over 90% for four to five cycles of CO_2-water injection (approximately 18 pore volumes of water). After four or five cycles, the permeability of core No. 1 was observed to rapidly increase. It is believed that at that point the polymer slug was removed from the highest permeability area in core No. 1 because the polymer was dissolved by the injected water. After the polymer slug was removed a continued permeability reduction effect was observed, though not as great as previously attained, because of polymer adsorption in the matrix. The larger the initial treatment size, the longer the permeability reduction remained and hence, the effectiveness of the treatment. In the case of 0.1 pv treatment the polymer volume injected was not sufficient to show a change in permeability in core No. 1, which regained its original permeability soon after the polymer slug was removed. With 0.5 pv treatment, the permeability reduction continued to remain at over 70% until completion of 15 to 16 cycles of CO_2-water injection (about 48 pv water), even after the polymer slug was removed.

As shown in Fig. 9, before treatment, 91% of the injected fluid flowed into core No. 1, thus exhibiting a very poor injection profile. After the NOCP polymer treatment and one cycle of CO_2-water injection, the injection profile was greatly improved. After the fourth cycle of CO_2-water injection, 30% of the injected fluid flowed into core No. 1, 50% into core No. 2, and 20% flowed into core No. 3. The injection profile improvement remained through 15 cycles of CO_2-water injection even though the change of injection profile was not revealed immediately after the treatment.Since all three cores were treated simultaneously, a small amount of catalyzed monomer solution invaded into the lower permeability cores (No. 2 and 3). After treatment, the permeabilities of these cores were also reduced and thus, the injection profile was not observed to be improved immediately after the treatment. However, as the test progressed the small amount of polymer in these cores was readily dissolved by injected water and the permeabilities of these cores regained their original values after one or two cycles of CO_2-water injection, whereas the high permeability reduction in core No. 1 remained. A limitation of the flow test apparatus is that the direction of flow is restricted to a linear path, whereas in actual formation conditions it would be assumed that injected fluids could establish new flow paths in areas of lower resistance, i.e. permeability.

Based on the results of these tests, it is believed that permeability reduction in a formation by a polymer treatment is controlled by two mechanisms:

1. Polymer gel strength is resistant to CO_2-water flow in channels, fractures, and high permeability areas.

2. Polymer adsorption in the formation matrix causes a lasting permeability reduction.

FIELD APPLICATIONS

Based on these laboratory test results, to obtain successful treatment to improve conformance in a formation with channels and fractures, the injected polymer should have the capability of developing enough gel strength to resist fluid flow in the channel, and the treatment should penetrate at least 50% of the offending area. It is recommended that the treatment be performed in two stages. The leading stage should contain a large amount of organic crosslinker to yield a stiff gel to seal off channels, fractures, and high permeability streaks. This stage should be designed to have a volume of at least 50% of the offending area. If severe channeling is present, the treatment pressure should be maintained low enough to minimize the highly crosslinked monomer solution flow into the lower permeability zones.

The second stage is used to treat the high permeability formation matrix instead of streaks or channels. The polymer solution injected in the second stage can be formulated to have either a small amount, or no crosslinker at all, to maintain its characteristic of solubility in water. Thus, when the second stage of chemical polymerizes it would still have enough viscosity (1) to divert water and CO_2 to previously unflooded zones, and (2) to act as a mobility control fluid to help improve areal and volumetric sweep efficiency.

Design Evaluation Technique

Another recommended aid to designing polymer injection treatments is to conduct tracer studies containing the chemical fluorescein on potential candidate wells to help determine treatment volumes. Though fluorescein dye is highly adsorbent on reservoir rock, it is most useful in identifying interwell channels and fractures where residence times are short because its presence is easily detected without elaborate equipment and/or techniques. In sunlight, it is visible in concentrations as low as 1 ppm; with the use of a "black light" it is visible at concentrations of only a few parts per billion.[7] Thus, problems normally associated with monitoring the offsets for breakthrough of the tracer fluid are essentially nonexistent. A detailed tracer design and evaluation technique was discussed by Terry, et al.[8]

A tracer survey which results in the breakthrough of a very small injected fluid volume, relative to the interwell pore volume, indicates the existence of an interwell open fracture, channel communication, or thin high permeability streak. Knowledge of the channel or fracture volume is important to sizing a remedial treatment. The tracer survey also allows determination of the extent of channeling present by the number of surrounding wells from which it is produced, thus indicating flow patterns between injectors and producers and further aiding treatment planning.

Treatment Technique

The treatment should be performed during the water injection stage of the WAG project. Prior to injecting the catalyzed monomer solution, a "pill" of tracer chemical should be injected, followed by a 50 bbl spacer of field water. Offsets should be monitored for breakthrough of the tracer during treatment. Offset producing wells that show presence of the tracer chemical during treatment should be shut in after the tracer arrives. After treatment, the injection well should be shut in for at least five days to allow the chemical solution to polymerize and develop maximum viscosity. All other offset producers should also be shut in at least one day to ensure that the treatment solution does not flow away from the wellbore.

CONCLUSIONS

1. Catalyzed monomer solution, when treated simultaneously into three cores representing three zones of widely different permeability, follows the same least

resistance path as normal injection water. This allows most of the treatment solution to be placed in the most offending area without the need of zone isolation.

2. After shut-in, NOCP chemical successfully polymerizes in-situ under CO_2 environment and reservoir conditions.

3. When NOCP is fully polymerized, the resulting gel exhibits sufficient viscosity to reduce flow into the highest permeability core and divert the CO_2 and water into the lower permeability cores, resulting in an improved injection profile.

4. Nonionic organic crosslinked polyacrylamide (NOCP) is chemically stable under acidic environment of supercritical CO_2.

5. Optimum treatment volume is 0.5 pv of the offending area. The offending area, which is the pore volume of channels, fractures, or high permeability streaks, can be determined in many cases by tracer survey before treatment.

6. Injection profiles are greatly improved after one cycle of CO_2-water injection.

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Table 1
Properties of Dolomite Packs for CO_2 Conformance Control Tests

Dolomite Core No.	Core Dimension Diameter (cm)	Core Dimension Length (cm)	Dolomite Pack Composition		Porosity (%)	Pore Volume (cc)
1	4.35	27.30	25/35 mesh dolomite Class H cement water	720 gm 80 gm 10 ml	31.83	130.7
2	4.40	27.62	25/35 mesh dolomite 325 mesh dolomite Class H cement water	378 gm 342 gm 80 gm 10 ml	26.5	111.4
3	4.40	27.62	325 mesh dolomite Okla. No. 1 sand Class H cement water	560 gm 160 gm 80 gm 10 ml	26.4	107.1

Table 2
CO_2 Conformance Control Laboratory Test Design Parameters

Flow System:	Multiple cores linear flow
Core Sample:	San Andres Dolomite Formation
Core Dimension:	Diameter: 4.4 cm Length: 27.6 cm
System Pressure:	1500 psi
Saturation Fluids:	Formation oil and water from a west Texas area
Flow Temperature:	100°F
Flow Pressure:	10 psi before treatment 1 psi during treatment 25 psi (max.) after treatment
Flow Fluids:	Water and supercritical CO_2
Treatment:	Nonionic organic crosslinked polymer
Treatment Solution Properties:	Viscosity (during treatment) = 1.5 cps Viscosity (after fully polymerized) = 1,000,000 cps Polymerization time = 12 hours

Table 3
Synthetic Injection Water Formulation

Component	Concentration (mg/liter)
$NaHCO_3$	1300
$CaCl_2 \cdot 2H_2O$	4000
$MgCl_2 \cdot 6H_2O$	5600
$NaCl$	3230
Na_2SO_4	1750

Table 4
Results of Oil Analysis

Paraffin Content:	2.52%
Asphaltene Content:	1.16%
H_2S:	Not detectable
Viscosity (at 72°F and 1 ATM):	6.0 cps

Table 5
Results of Laboratory Flow Test for CO_2 Conformance Control

Test No. 1
Treatment Size = 0.1 pv of core No. 1
Treatment Fluid = Nonionic organic crosslinked polyacrylamide polymer

Stage	Cumulative Flow of		Permeability to Water			Permeability Reduction			Percent of Flow		
	CO_2* (pv)	Water (pv)	Core No. 1 (md)	Core No. 2 (md)	Core No. 3 (md)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)
Before Treatment	0	0	3980	162.2	50.4	-	-	-	94.8	4.0	1.2
Waterflow											
After Treatment	0	3.29	1422	101.2	35.9	64.3	37.6	28.9	91.0	6.6	2.4
After 1st cycle of CO_2	2.92	6.21	792.0	97.8	35.1	80.1	39.7	30.3	85.6	10.6	3.8
After 2nd cycle of CO_2	5.89	9.16	562.3	97.4	36.3	85.9	40.0	28.0	80.8	14.0	5.2
After 3rd cycle of CO_2	8.83	12.28	450.7	117.1	42.8	88.7	27.8	15.0	73.8	19.2	7.0
After 4th cycle of CO_2	11.65	15.12	387.0	130.5	41.0	90.3	19.5	18.7	68.0	23.4	8.6
After 5th Cycle of CO_2	14.48	18.03	330.0	187.8	51.2	91.7	-	-	58.0	33.0	9.0
After 6th Cycle of CO_2	17.41	21.03	967.0	216.2	56.2	75.7	-	-	78.0	17.5	4.5
After 7th Cycle of CO_2	20.16	24.3	2523.0	250.1	61.4	36.6	-	-	89.0	8.8	2.2

* The pore volume of CO_2 at 100°F and 1500 psi conditions.

Table 6
Results of Laboratory Flow Test for CO_2 Conformance Control

Test No. 2
Treatment Size = 0.3 pv of core No. 1
Treatment Fluid = nonionic organic crosslinked polyacrylamide polymer

	Cumulative Flow of		Permeability To Water			Permeability Reduction			Percent Of Flow		
Stage	CO_2* (pv)	Water (pv)	Core No. 1 (md)	Core No. 2 (md)	Core No. 3 (md)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)
Before Treatment	0	0.0	3840.	284.0	50.3	-	-	-	92.0	6.8	1.2
Waterflow After Treatment	0	2.94	1099.	111.5	17.6	71.4	60.7	65.0	89.5	9.1	1.4
After 1st Cycle of CO_2	2.99	5.88	248.9	79.5	17.5	93.5	72.0	65.2	72.0	23.0	5.0
After 2nd Cycle of CO_2	5.97	9.08	120.6	140.1	29.9	96.9	50.6	40.6	41.5	48.2	10.3
After 3rd Cycle of CO_2	8.93	12.23	145.9	124.8	26.6	96.2	56.0	47.1	49.1	42.0	8.9
After 4th Cycle of CO_2	11.82	15.38	111.3	147.8	53.9	97.1	47.9	-	35.6	47.2	17.2
After 5th Cycle of CO_2	14.71	18.28	380.7	178.9	50.4	90.1	37.0	-	62.4	29.3	8.3
After 6th Cycle of CO_2	17.72	21.28	685.6	204.1	74.7	82.1	28.10	-	71.1	21.1	7.8
After 7th Cycle of CO_2	20.66	24.39	1007.6	225.8	62.9	73.8	20.4	-	77.7	17.4	4.9
After 8th Cycle of CO_2	23.62	27.05	1038.2	248.1	82.8	73.0	12.6	-	75.8	18.1	6.1
After 9th Cycle of CO_2	26.60	30.12	1343.2	253.7	100.8	65.0	10.6	-	79.1	14.9	6.0

* The pore volume of CO_2 was at 100°F and 1500 psi conditions.

Table 7
Results of Laboratory Flow Test for CO_2 Conformance Control

Test No. 3
Treatment Size = 0.5 pv of core No. 1
Treatment Fluid = Nonionic organic crosslinked polyacrylamide polymer

	Cumulative Flow of		Permeability To Water			Permeability Reduction			Percent Of Flow		
Stage	CO_2* (pv)	Water (pv)	Core No. 1 (md)	Core No. 2 (md)	Core No. 3 (md)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)	Core No. 1 (%)	Core No. 2 (%)	Core No. 3 (%)
Before Treatment	0	0	3500	250	93.1	-	-	-	91.1	6.5	2.4
Waterflow											
After Treatment	0	3.17	746.8	129.9	41.9	78.7	47.8	55.0	81.2	14.1	4.7
After 1st Cycle of CO_2	3.08	6.17	290.7	143.1	70.4	91.7	42.5	24.4	57.7	28.4	13.9
After 2nd Cycle of CO_2	6.10	9.18	205.4	174.0	98.8	94.1	30.1	-	42.9	36.4	20.7
After 3rd Cycle of CO_2	9.16	12.30	193.2	201.6	100.0	94.5	19.0	-	39.0	40.8	20.2
After 4th Cycle of CO_2	12.3	15.35	152.0	219.8	116.4	95.7	11.7	-	31.1	45.0	23.9
After 5th Cycle of CO_2	15.25	18.38	412.2	189.5	159.9	88.2	23.8	-	54.1	24.9	21.0
After 6th Cycle of CO_2	18.13	21.41	644.8	241.2	165.8	81.6	3.1	-	61.3	22.9	15.8
After 7th Cycle of CO_2	21.28	24.63	536.2	174.9	156.0	84.7	29.7	-	61.8	20.2	18.0
After 8th Cycle of CO_2	24.26	27.90	717.9	224.3	149.7	79.5	9.8	-	65.8	20.5	13.7
After 9th Cycle of CO_2	27.22	31.06	648.8	240.8	155.0	81.5	3.2	-	62.1	23.1	14.8
After 10th Cycle of CO_2	30.18	34.06	722.3	252.1	133.0	79.4	-	-	65.2	22.8	12.0
After 11th Cycle of CO_2	33.15	37.17	659.3	269.4	186.7	81.2	-	-	59.1	24.2	16.7
After 12th Cycle of CO_2	36.07	40.43	605.4	283.0	173.9	82.7	-	-	57.0	26.6	16.4
After 13th Cycle of CO_2	39.02	43.42	696.0	301.0	202.1	80.1	-	-	58.1	25.1	16.8
After 14th Cycle of CO_2	42.04	46.42	633.7	369.2	178.0	81.9	-	-	52.8	31.5	15.7
After 15th Cycle of CO_2	45.00	49.18	806.6	403.5	201.2	77.0	-	-	57.1	28.6	14.3
After 16th Cycle of CO_2	47.92	52.25	878.4	413.9	172.8	74.9	-	-	60.0	28.2	11.8
After 17th Cycle of CO_2	50.96	55.30	1208	392.7	203.6	65.5	-	-	67.0	21.8	11.2

* The pore volume of CO_2 at 100°F and 1500 psi conditions

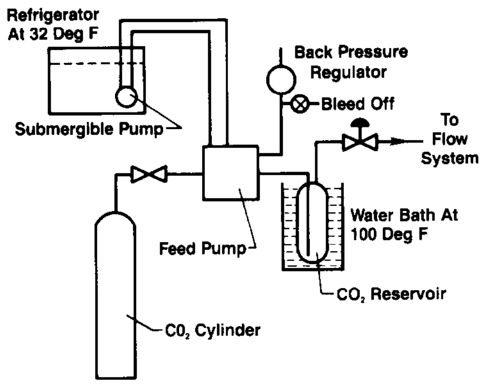

Figure 1 - Supercritical CO_2 gas generation system

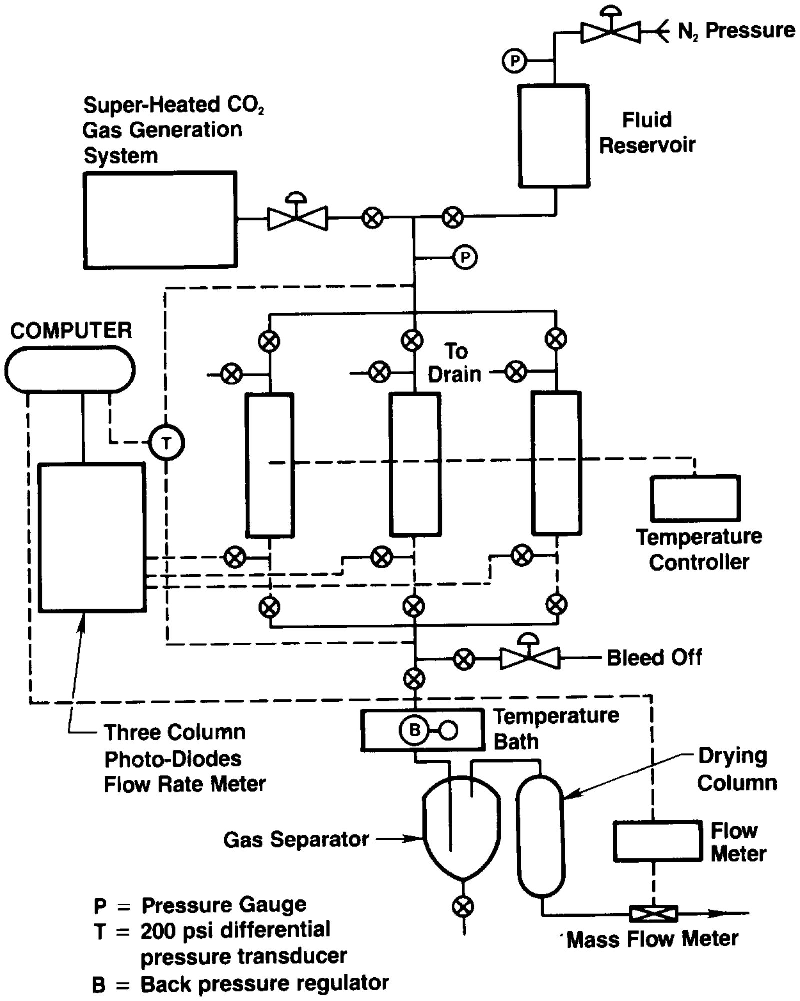

Figure 2 - Linear flow multi-core holder flow equipment

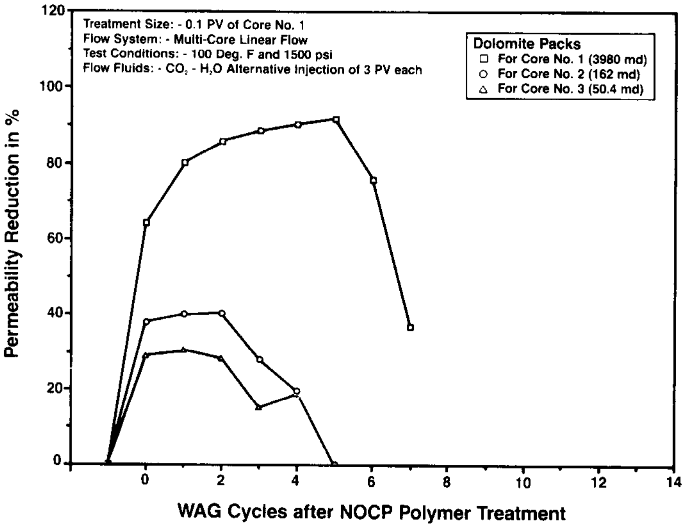

Figure 3 - NOCP polymer for CO_2 conformance control - flow test results

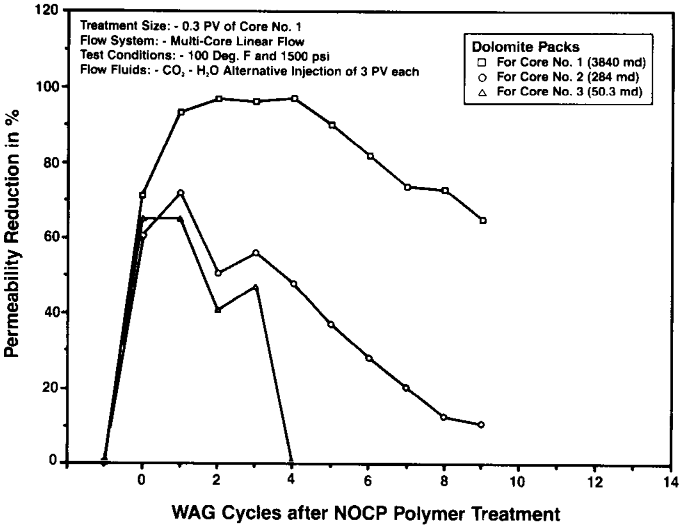

Figure 4 - NOCP polymer for CO_2 conformance control - flow test results

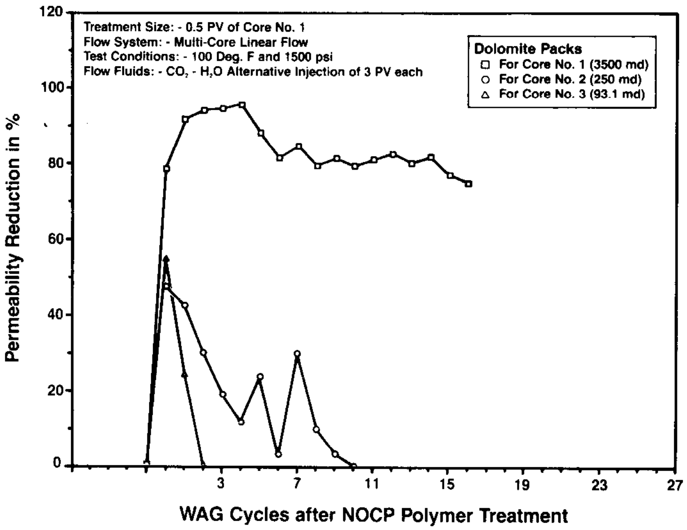

Figure 5 - NOCP polymer for CO_2 conformance control - flow test results

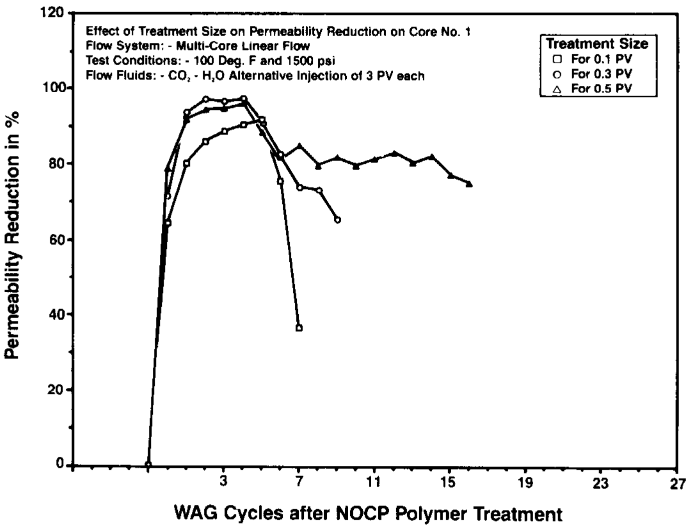

Figure 6 - NOCP polymer for CO_2 conformance control - flow test results

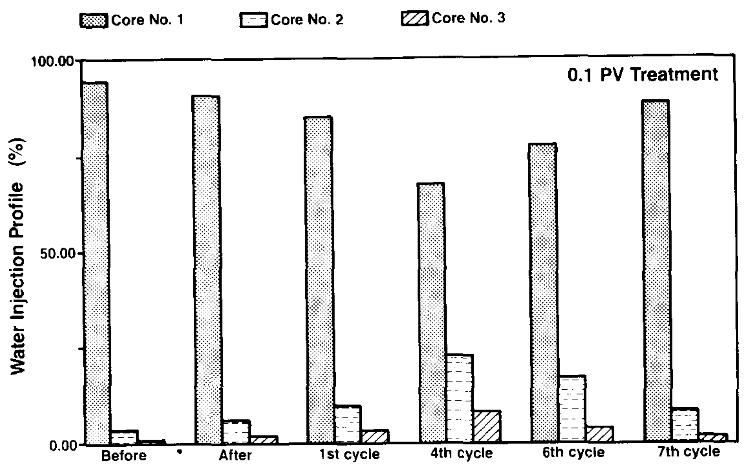

Figure 7 - Water injection profile for WAG cycles after NOCP polymer treatment

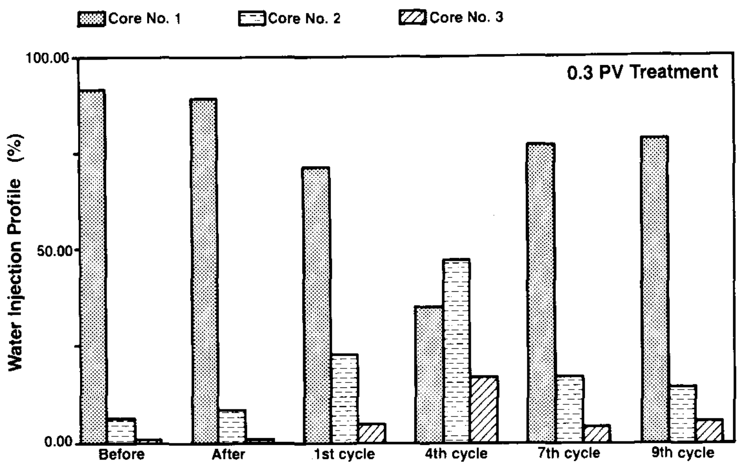

Figure 8 - Water injection profile for WAG cycles after NOCP polymer treatment

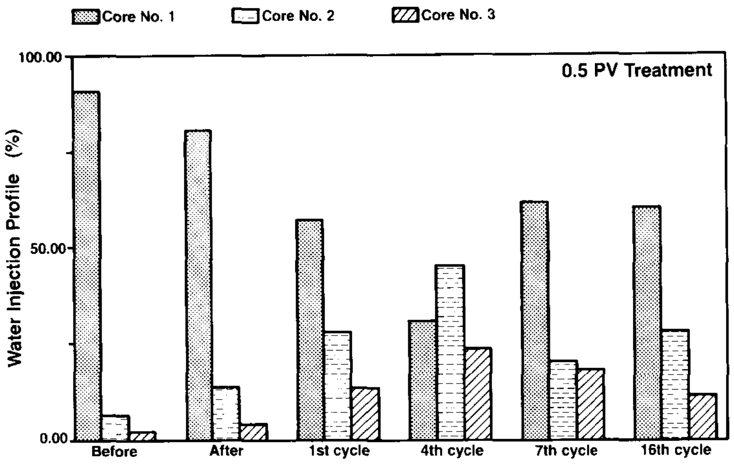

Figure 9 - Water injection profile for WAG cycles after NOCP polymer treatment