POLYMERS: AN IMPORTANT TOOL IN RESERVOIR MANAGEMENT

Bharat G. Mody
Oil Water Ratio Control, Inc.

ABSTRACT:

The purpose of reservoir management is to improve recovery and economics of producing properties. As oil prices go through wild price swings, economics of high water producing properties change from marginally profitable to a losing proposition. In this environment, a concentrated effort to decrease water production has paid off by reduction or elimination of water handling costs.

Use of polymers, to decrease water production, has helped many wells remain active. This paper presents various techniques of applying polymer to decrease or block water production. An increase of oil production is experienced, in many cases, as a byproduct. Further modification of the technique has resulted in the elimination of cement for complete plugging of selected pay intervals and casing leaks.

INTRODUCTION:

In recent decades, oil prices have experienced unprecedented upward and downward swings, from more than $40/bbl to less than $10/bbl then back up to $25/bbl and down again to $15/bbl. It has claimed many companies and forced others to merge. The number of oil industry personnel in the U.S. has declined considerably. This is due to a relatively higher cost of producing high water-oil ratio (WOR) wells. It is of utmost importance for the U.S. oil industry to adopt new ideas and revolutionary thinking for survival.

The recognition of the existence of reservoir heterogeneity (variations in permeability), in almost all reservoirs, is a major factor in initiating improved reservoir fluid management programs.[1] In many reservoirs, the degree of heterogeneity is sufficient to cause early water breakthrough, leaving behind an excess of 90% of oil in place.[2] As production continues, WOR of a producing well increases rapidly towards a 90-95% water cut. It is at this time that a large cycling of water in a water-flood project occurs. A similar phenomena occurs in a bottom water drive reservoir and is known as "water coning".

Once water breakthrough occurs, additional oil recovery is achieved with higher and higher water cycling. As water cycling increases, operational costs of oil production increases rapidly. The yearly cost of water handling at various production levels is shown in Figure 1. During the period of low oil prices, economic decisions claim the life of many producing wells. The State of Texas alone has lost at least 100,000 wells in the last five years. Engineers and managers are recognizing that by decreasing water cycling alone, the economic life of producing property can be extended. Many producing well polymer treatments have resulted in increased oil production and continued economic benefits.

The use of polymers to decrease water cycling, has progressively increased, since the mid 1980's. Both production and injection wells are treated using a delayed cross-linked polymer. Recently, many selected pay and casing leaks have been plugged, using modified techniques, where repeated attempts with cement failed. The true fluid nature and change of phase, due to chemical reactions, assists in achieving in-depth penetration and holding back water production. The following sets out procedures required to successfully maintain acceptable water-oil ratios.

Recognizing Major Factors

(1) Reservoir Heterogeneity

Petroleum reservoirs are composed of various strata containing wide ranging porosity and permeability. The variation of permeability occurs in vertical as well as horizontal directions in the reservoir. This variation in permeability is measured by degree of heterogeneity. The permeability variation coefficient (Γ) is equal to -0- for completely homogeneous reservoirs, and is equal to 1 for completely heterogeneous reservoirs. For water-flooding and enhanced recovery processes, the variation of reservoir permeability is a major cause for early fluid breakthrough. The source of extraneous fluid can be from an injection well, edge water or bottom water from an aquifer below an oil bearing pay zone. The presence of reservoir heterogeneity along with natural fractures, decreases recovery of oil, considerably, and increases cycling of drive fluid. The magnitude of lower recovery and increased cycling of fluid, is directly related to the permeability variation coefficient, Γ, defined as:[2]

$$\Gamma = \frac{k_{84.1\%} - k_{50\%}}{k_{50\%}} \qquad (1)$$

for a log-normal distribution

where:

Γ = Dykstra-Parson permeability variation coefficient
$k_{84.1\%}$ = Permeability of 84.1% of the reservoir samples, md
$k_{50\%}$ = Mean permeability, md

Most reservoirs have a permeability variation coefficient in the range of 0.6 to 0.8. Reservoirs with a permeability variation coefficient greater than 0.9 are considered highly heterogeneous or fractured.

Another factor causing early water breakthrough and poor reservoir sweep efficiency, is the adverse mobility ratio inherent in viscous oil reservoirs and reservoirs that are preferentially oil wet. The mobility ratio for water displacing oil is given by:[2]

$$M = \frac{k_{rw} \times \mu_o}{k_{ro} \times \mu_w} \tag{2}$$

where:

M = Mobility ratio
k_{rw} = Relative permeability of water
k_{ro} = Relative permeability of oil
μ_w = Viscosity of water
μ_o = Viscosity of oil

A mobility ratio where $M > 1.0$ is considered adverse.

As the water front moves from the source, it takes the path of least resistance to the producer via high permeability streaks, fractures, or channels. When the water front approaches the producing well, its movement, from the source to the producer, increases rapidly. In some cases it essentially waters-out the producing well. When this condition occurs, fluid withdrawal often increases without an increase in oil production.

The data extracted from the literature,[2] presented in Figure 2, shows how a combination of high permeability variation ($\Gamma > 0.6$), and adverse mobility ratio ($M > 1.0$), can result in low recovery factors at breakthrough caused by very poor volumetric sweep efficiency.

(2) Polymers

Polymers are used in many different areas of petroleum production. They have been applied as additives in drilling fluids, fracturing fluids, acid and cementing compositions. Because of their use, the term "polymer" is heard many times in the oil field and is very seldom given a qualitative description. The word polymer is derived from "poly" meaning many, and the "mer" meaning units. A polymer consists of a repeating chemical unit joining to form an extremely large molecule. A typical polymer may have several thousand to hundreds of thousands repeating units linked together. Polymers are also known as "macromolecules". As polymer molecules get longer and longer, it is virtually impossible to obtain all macromolecules absolutely uniform in size. Thus, the molecular weight of a polymer is an averaged quantity relative to the molecular weights of its individual macromolecules.[3] A polymer with the same average molecular weight may have a different molecular weight distribution (MWD), as shown in Figure 3. A polymer's MWD substantially effects its selective nature of flow through the pore spaces. The larger size of the polymer molecules makes it difficult for it to enter certain smaller size pore throats, thus minimizing its effect in tighter permeability sections of the pay.

The control of molecular weight distribution and various arrangement of monomer units attaching themselves to form macromolecules, defines the chemical and physical behavior of the polymers. A schematic representation of various polymer structures is shown in Figure 4. The most desirable polymer structure for flow through porous media is a linear polymer. Cross-linking increases molecular weight of a given polymer. Thus, the same name and molecular weight polymer can have entirely different chemical and physical properties. This is one of the fundamental distinctions of a polymer from a low-molecular weight substance, because the latter has an absolutely definite value of its molecular weight. This relates to both natural and synthetic polymers.[3]

Three types of water soluble polymers used extensively in the oil industry are:

1. Polyacrylamides
2. Polysaccharides
3. Cellulosics

Each one has an application in particular situations. The single most characteristic of these polymers is that they enter into the formation as a true (solid-free) fluid. The polyacrylamide polymer (PAM) also has a characteristic to adsorb on formation surfaces, thereby, affecting physical size of the pore space. Flow characteristics of oil and water through porous media is altered due to presence of a strong hydrophilic group in the PAM. Hence, PAM plays an important role in improving oil recovery and controlling water production.

WATER CONTROL PRACTICES:

The need for control of production and injection water has been recognized as one of the most important aspects of oil production.

Many different products and techniques have been developed to control water movement in the reservoir. Each has its own advantage. One of the earlier methods proposed and still being practiced today, is use of cement slurries. The following alterations in cement slurry compositions have been used.

1. Low fluid loss cement
2. Diesel oil cement
3. Low to micro-fine particle size cement
4. Pumping of solid-free reactive fluid ahead of cement

Each of the above approaches have had its own success and place in controlling water production. However, one of the major disadvantages of cement slurries is, it is a mixture of high concentration of solids and liquids.[4-7] The amount of liquid used is directly proportional to particle size of cement. When this mixture is placed against a porous matrix, it loses fluid and increases solid concentration further. As loss of fluid is experienced, cement slurries become a mass of immovable solids packed together, thus, controlling depth of penetration into the formation matrix. This is only possible if the porous matrix is large enough to accept the larger size of solid particles in the cementing slurries. This was documented by Mr. Shryrock in an experiment conducted using a 6/9 mesh gravel bed. <u>Neat cement slurry penetrated less than two inches into the gravel bed</u>, before dehydration, causing complete bridging.[8] In general, depth of penetration can not be increased beyond a few inches by decreasing particle size and/or fluid loss control. It is an accepted practice that cement particles do not enter the formation matrix. Use of <u>cement slurries does have limited application, in highly fractured formations, if applied properly</u>. During the application of cement, one needs to be completely aware of hydrostatic pressure and formation fracturing pressure.[9-10] In many instances cement slurries exert higher hydrostatic pressure than that required for fracturing the formation. When this occurs, control of fluid placement is lost and formation parting occurs. At this time, any additional attempt to pump more cement will result in extending the fracture length, yet, not providing the required squeeze. Cement slurries can provide a solution to control water, only if the source of the water problem is near the wellbore.

If the water problem is due to reservoir heterogeneity, alteration of fluid flow path, deep within the reservoir, is required. This can only be achieved by use of a true solution so a large volume can be injected. Many organic and inorganic materials are available on the market.[11-13] Each of these products have their use in controlling water production. One of the most effective products is the high molecular weight PAM. PAM polymer, containing a long straight chain of molecules (Figure 4A) and a narrow MWD (Figure 3), having a better injectivity, is most preferable. This PAM polymer solution can be cross-linked with relative ease to enhance its viscosity. The mechanism of cross-linking and increasing viscosity can be accomplished many different ways as follows:[13-19]

1. PAM in high saline water
2. Combinations of anionic and cationic polymers
3. Polymer and cross-linker alternate slug process
4. Delayed cross-linked process

PAM polymer used in all these processes is generally partially hydrolyzed. The degree of hydrolysis varies from 5-30% and is generally called "Partially Hydrolyzed Polyacrylamide" (HPAM). When HPAM is dissolved in water, viscosity of water increases. The magnitude of viscosity increase is related to the salinity of the water and degree of hydrolysis. As water salinity increases, polymer solution viscosity decreases. Also, HPAM has two important properties, they are; adsorption on mineral surfaces and mixture of molecular sizes. Adsorption of HPAM helps in reducing the subsequent flow of water, while larger molecular sizes aid in containing the polymer solution to the higher permeable area. Dissolving HPAM in water of higher salinity than the reservoir's, facilitates placement of the solution into the path of the least resistant at a lower viscosity. Once in-place, salinity of the polymer solution decreases to match the reservoir's, and the polymer solution viscosity increases.[14] In this process, polymers with high adsorption numbers are used. This particular technique has a good chance of success in relatively uniform matrix-like Sandstones. In naturally fractured Carbonate reservoirs, effectiveness of this technique is highly questionable, as viscosity increase is very limited.

The second polymer technique uses two polymers of opposite ionic charges.[16] The first slug of polymer, having high affinity to the reservoir rock, is pumped. This causes the first layer of polymer adsorption on reservoir rock surfaces. It is followed by an opposite ionic charged polymer slug which attaches itself to the first polymer layer, thus, reducing the size of the pore channel. These steps of alternate polymer injections are repeated until the desired reduction in injectivity is achieved. One of the drawbacks, however, is it assumes all fluid injection occurs in a confinement of high permeability and in the same flow path. Its effectiveness is experienced in a relatively uniform matrix such as Sandstone. The changes in large natural fracture systems, as a result of this technique, is not significant. Thus its use is limited.

The third method is known as "In-situ Cross-linking" or "Sequential Polymer Cross-linker Injection Technique".[13,16] This is very similar to the above technique. In this process, a low viscosity polymer solution is injected, followed by subsequent injection of a cross-linking agent. Injection is repeated several times to attain the desired changes in reservoir permeability to water. This process is known to provide an in-depth (50-75+') permeability reduction similar to the previously discussed techniques. In many cases, three to six weeks may be required to treat a single well. In cases where large volumes of fluid movement from an injection well to a producing well exists, this type of treatment has a high risk of failure. Large volumes of polymer water injection, required over a long period of time, makes it more suitable to treat injection wells, rather than production wells. This process is known to give better results in a relatively uniform formation matrix rather than in naturally fractured formations.

The fourth technique is known as "Delayed Cross-linking", "Surface Cross-linking" or the "Bulk Gel Process".[4-7,20,21] It utilizes a polymer solution of 10-30 centipoise (cps) viscosity. After injection it changes to a very high viscosity of several thousand centipoises to almost semisolid. The solubility of cross-linked polymers can be controlled by the amount of polymer and degree of cross-linking. The depth of penetration can be controlled by molecular weight of the polymer, adsorption characteristics, and length of gelation time. The effect of dilution, reservoir fluid interference to cross-linking time and other characteristics, needs to be understood for proper placement and success. This process has a wide application in injection as well as producing wells. If properly designed, this technique can be used for matrix treatment as well as for treating naturally fractured formations.

In certain cases, combinations of all of the above techniques can be utilized to achieve desired results. In many cases, the inability to properly characterize individual well parameters dictates that one be prepared to change the planned well treatment during actual well treatment. Therefore, it is critical that qualified trained personnel, with the ability to design and analyze treatments, be available on location during treatment application.[4-7]

Even though this author has used all of the above methods and a few others not mentioned, It is his belief that the majority of water control problems are better addressed using the delayed cross-linking of HPAM technique. This method provides a wide range of latitude for adjustment of treatment. It is generally more economical and treatment time is no more than two days in most cases. This technique requires blending of all necessary chemicals on the surface, prior to pumping, thus eliminating the necessity of mixing two or more fluids within the reservoir. Expected reaction occurs down hole within the reservoir with a higher degree of certainty. Additionally, use of a higher viscosity seems to help in achieving better confinement of the treatment into the zone of interest. All cases presented in this paper have utilized the delayed cross-linked HPAM system.

SELECTION OF CANDIDATE & TECHNIQUE:

As stated earlier, most reservoirs are heterogeneous, causing nonuniform fluid movement from pressure source to pressure sink. In many cases, recovery of up to 30% of original oil in-place is experienced.[15] If one looks closely, he will find an area, or a few wells in any field, that has produced less than 5-10% of allocated reserves. These types of wells are wells advocated to be investigated for an initial trial. It should be noted that all high water producing wells are not necessarily good candidates for decreasing water by polymer use. In many cases, a regular cement squeeze or a modified cement squeeze can yield similar results. It is also important to remember that a delayed cross-linked polymer squeeze is the only way to reach beyond the wellbore to effectively alter fluid flow path deep within the reservoir.[6-7] A candidate selected for water control treatment will generally have many of the following characteristics:[4-7]

1. <u>Production Well</u>
    a. Good initial productivity with low water cut
    b. High dynamic fluid level
    c. Poor recovery efficiency
    d. High structural well
    e. High lifting and disposal cost
    f. Limitation of fluid handling facilities
    g. Fractures extending into the water zone
    h. Channeling from injector
    i. Bottom or edge water encroachment
    j. Temporarily abandoned due to high water cut
    k. Presence of micro-annulus above or below pay zone
2. <u>Injection Well</u>
    a. Presence of thief zones
    b. Fracture leading out of injection zone
    c. Dissolution of reservoir rock
    d. Early water breakthrough
    e. Poor recovery efficiency
    f. Excessive injection rate at relatively low pressure
    g. Adverse fluid-in to fluid-out ratio

The technique of treatment considered and advocated in this paper is only the delayed cross-linked polymer system. In this system, by changing polymer concentration ionic characteristics, molecular weight, and degree of hydrolysis, cross-linked polymer gel characteristics can be altered. By changing the cross-linking agent, the characteristics of gel can be altered. The chrome redox reaction is preferable for economic and improved control of the cross-linking reaction. The reduction step from chromium +6 to chromium +3 provides better reaction control. Thus, from initiation to final gelation, reaction progresses much more smoothly over an extended time period. The gradual changes in polymer characteristics provide time for treatment adjustment to match the well response for optimizing treatment benefit. As treatment progresses, rate and pressure data are acquired for manipulation, analysis and interpretation. Analysis and interpretation are the most critical part of the whole system. It requires working knowledge of fluid flow in the porous medium, and complete chemical knowledge of interference of the cross-linking reaction in the presence of reservoir fluids. Therefore, for a successful application of water control treatment, a versatile, qualified technical person is required on the job.

TREATMENT DESIGN:

Theoretically, effective water control treatment requires about a 50% drop in differential pressure between the well bore and reservoir. A typical graph showing the relationship of depth of penetration, percent pressure drop, and radial pore volume is given in Figure 5. The treatment volume requirement increases as a square of radial distance from the well bore. Thus, fluid volume requirement for effective water control is large. Experience dictates that recommended treatment volume be at least 100 bbls for any well. This is because in any treatment, the leading and tail-end of polymer is going to have some dilution. As depth of treatment penetration increases, length of transition zone also increases, so consideration of dilution is a critical factor which needs to be incorporated in the overall plan.

Treatment design should also include selection of a specific polymer suitable for the reservoir. The polymer selected must be stable under reservoir water salinity and temperature. Polymer concentration is generally higher in an injection well treatment, towards termination, compared to a production well treatment. Post flushes for injection and production wells are different. Recommended treatment volume should be utilized as a guide only, knowing final treatment volume will be dictated by on-the-job well analysis and interpretation. This is a major reason why water control treatment cannot be engineered from the office, as a successful treatment requires flexibility during actual application.

Application of Treatment

Once the decision to treat a well is approved and work-over is commenced, it is recommended that tubing be pulled and inspected for the possible presence of scale, paraffins, and asphaltenes. All water control treatments are recommended to be performed under a packer. For improving injectivity and adsorption of polymer to reservoir rock, it is important that a preconditioning treatment be performed. Overall, the complete treatment can be divided into three major parts:

1. Gel-analysis
2. Preconditioning
3. Polymer treatment

It should also be emphasized that drinking quality water be used for treatment. The amount of water required should be stored in a clean tank on location, prior to job initiation. Generally, these treatments are performed over a two day period.

Gel-analysis

Once on location, the most important thing to check is the physical and chemical quality of water. All chemicals and their compatibility with reservoir fluid needs to be evaluated. Polymer solution is prepared with various chemical and cross-linker concentrations. These samples are brought up to reservoir temperature for determination of gelation time and gel quality. These results are used, during polymer treatment, to alter composition of polymer solution as treatment progresses and well analysis dictates. Typical gel analysis results are shown in Figure 6. This procedure also eliminates the need for secondary evaluations of central laboratory data and reduces the possibility of misinterpretation.

Preconditioning

All candidate wells should be preconditioned prior to pumping polymer. This step provides injectivity data which is utilized to select optimum polymer injection rate for the treatment. Prior to preconditioning, a step rate test should be conducted to determine the well's ability to accept fluid.

Preconditioning of a well is performed by pumping 300-500 gallons of acid with appropriate additives. In many cases, use of a mutual solvent or xylene are recommended to remove near wellbore damage. The main purpose of acid is to clean tubing and perforations. The cross-linking of polymer is adversely effected by presence of scale, iron sulfide, rust, and corrosion inhibitors. To control possible bio activity, a small biocide slug is injected, followed by a relatively high concentration of cross-linker. The strong surface active nature of cross-linker, promotes increased adsorption of polymer on the formation face. All of these fluids are over-displaced, past perforations, and allowed to soak overnight. If no surface injection pressure is observed during preconditioning, a bottomhole pressure measurement tool with surface readout is recommended.

Polymer Treatment

Actual polymer treatment begins the day after preconditioning of the well, by first establishing injectivity into the well with water. Polymer blending and injection begins, while continuously monitoring and analyzing injection rate and pressure data. Small batches (15-25 bbls) of polymer solution are prepared and pumped continuously at a constant rate. The chemical compositions of various batches are altered in accordance with results of continuous monitoring and analysis.

Treatment of a production well is performed with the reduction of water production as the primary objective. Therefore, during treatment, special care is taken to prevent total plugging. It is logical to expect changes in productivity, relative to changes in injectivity. Various plots are generated to continuously monitor changes in the injectivity and rate of pressure increase. A "Modified Hall Plot" and the "First Derivative" obtained by differentiation of the Modified Hall Plot is utilized as one of the tools. The First Derivative of the hall plot is indicative of injectivity changes within the treated formation. When desired changes in injectivity are achieved, treatment is terminated. The control of polymer placement is monitored using the Modified Hall Plot.

Treated producing wells are over-displaced with lease crude, and treated injection wells are over-displaced with noncross-linked polymer solution followed by fresh water. The over-displacement of producing wells (by lease oil) helps to reestablish oil saturation near the wellbore, while driving polymer solution away from the wellbore. When the specified volume of post flush fluid is pumped, the well is shut-in for 48 hours. To minimize injectivity decline in injection wells, it is often advisable to over-displace the injected polymer solution with water or noncross-linked polymer solution.

In special cases, where total plugging is desired, very fine inert solids are incorporated into the polymer. Once solid laden fluid reaches perforations, significant pressure increases are observed. At this point, injection rate and pressures are closely monitored so that injection pressure is always below formation parting pressure. It is very critical to displace solid laden fluid with viscous fluid to minimize fingering.

CASE HISTORIES:

Cases presented in this paper are typical of several hundred well treatments. Over the past decade, more than 750 wells have been treated or supervised by this author. Most of the wells treated in the past five years were production wells, while prior to that, most the wells were injection. Today's technology is a result of experience gained from treating injection wells that has been translated into production well application. Continuous monitoring was introduced in the early 1980's but utilization in the field began when production well treatment interest intensified. The idea of incorporation of solids has been advocated and practiced in the past 2-3 years. In specific cases of low fracture gradient wells, this idea was tried and has performed very well, particularly where repeated efforts to squeeze with cement had failed. The low (8.4 ppg) density of polymer solution compared to cement slurry, and flexibility of adjustment of polymer fluid properties has played a major role in achieving success over the use of cement. In a few cases, polymer squeezes were tested with positive pressure of over 500 psi. In general, it is recommended that a swab test be performed to check plugging of water entry into the well rather than positive pressure test.

Reservoir and production data for five selected cases are presented in Tables 1 and 2. These are all producing wells treated with and without isolation. Each is unique in itself.

Case 1

This well is located in Fisher County, Texas. It was producing through the Swastika Sand. It was classified as a loosely packed, easily friable, high permeability conglomerate type pay. Production was from 3947' perforated interval, with gross pay thickness of 38'. The average porosity, permeability, bottomhole pressure, and temperature is reported in Table 1. Upon initial completion in 1987, it produced 127 BO and 3 BW. Approximately a year later, this well's production changed to 8 BO and 110 BW with WOR of 14. Polymer treatment was performed without isolation or a production survey for water entry. It was treated with a total of 375 bbls of delayed cross-linked polymer. The Modified Hall Plot and First Derivative Plot is shown in Figure 7. Proper analysis and interpretation of data, dictated that treatment should have been terminated around 100 bbls. The well experienced complete plugging after the polymer application. After several stimulation treatments and over a 3-4 month period, production stabilized at about 13 BO and 35 BW. This well has been the lowest water producing well on the lease since treatment. An important point to remember about this treatment is that after several stimulation treatments, an increase of water production was not experienced, and the longevity of treatment has been over three years, yet this well is holding steadily.

Case 2

This well is located in Garfield County, Utah. It was producing from the Kaibab Formation. Pay consisted of dolomitic grain and packed stones. It had an active water drive from bottom. Production was from perforated intervals at about ±6700′ with gross pay thickness of 41′. Average reservoir properties are listed in Table 1. Initial production from this well was 847 BO and 330 BW in 1967. In late 1990, well production was 27 BO and 1800 BW with a WOR of 67. This well was treated with 700 bbls of polymer. The Modified Hall Plot and First Derivative Plot are shown in Figure 8. Analysis of these plots suggest this well required more polymer than was economically feasible. Yet, after treatment, the pumping fluid level was decreased by approximately 600′. Initially, water production decreased by 1000 bbls/day. After 22 months of production, this well now produces 700 bbls less water/day at a WOR of 55. Another polymer treatment is recommended and after that, if necessary, small acid jobs can aid in revitalizing the well's oil production.

Case 3

This well is located in Alberta, Canada. It was producing through the Slave Point Formation. It was classified as a carbonate/limestone type reef. It had a very active water drive from bottom. Production was from perforated intervals at about 5500′ with gross pay thickness of 38′. The average reservoir properties are listed in Table 1. Initial production was 169 BO and 24 BW in late 1984. In early 1989, the well was shut-in due to high water production. The average production, prior to treatment, was 6 BO and 194 BW. The well was treated with 325 bbls of polymer. The Modified Hall Plot and First Derivative Plot are shown in Figure 9. Analysis of these plots suggest this well treated in a textbook manner. Daily production, after treatment, has been 80 BO and 203 BW for the past 15 months. The WOR changed from 31 to 2.5 as a result of polymer application.

Case 4

This well is located in Ector County, Texas. It was producing from the Clearfork Formation. It was classified as dolomitic with a distinct presence of zonation. The well was on a lease under active water-flood. Production was from open-hole completions at a depth of 5500′. It was diagnosed as having early water breakthrough causing it to lose production. Initial production after completion in 1950 was 554 BO and 117 BW, while in December 1987, just prior to temporary abandonment, production was 1 BO and 660 BW, a WOR of 660. Recommendations were made to cover the bottom pay with sand and treat the upper pay with delayed cross-linked polymer for complete plugging. The polymer treatment progress is shown in Figure 10. Approximately 225 bbls of polymer was pumped and displaced by noncross-linked polymer. Production, 14 months after treatment, is 25 BO and 515 BW. The change in WOR from 660 to 21 is a result of polymer application.

Case 5

This well is located in Lea County, New Mexico. It was producing from the Grayburg Formation; classified as a highly vagular dolomite. A reservoir engineering study of the water-flood revealed that a certain area in the reservoir contained a highly permeable zone, causing large water cycling from injection to production well. Due to this, effective flooding of other zones was not possible. A decision was made to isolate and squeeze-off the high permeability zone. Several techniques were tried on various wells, with limited success. A proposal to squeeze with polymer was accepted with a contingency that if polymer did not give an effective seal, cement would be used. The well was treated with about 350 bbls of polymer. Polymer concentrations were altered as high as 11,000 ppm, and gelation time was changed utilizing continuous monitoring techniques. The Modified Hall Plot and pressure response, during treatment, are shown in Figure 11. Initial injection rate of 42 GPM at 637 psi changed to a final injection rate of 20 GPM at 1711 psi. The final 50 bbls of polymer contained lightweight, finely divided solids up to 5-10 lbs/bbl. Swab testing of the polymer treated zone revealed complete plugging. An interesting point to note is just 5-10 lbs/bbl of solid loading increased injection pressure from 900-1700 psi. Also, desired total plugging was achieved using delayed cross-linked polymer.

CONCLUSION:

1. Delayed cross-linked polymer treatment decreases water production.
2. Isolation requirement is not absolutely necessary.
3. Candidate selection is important.
4. HPAM polymer solution has selectivity.
5. On-site analysis and flexibility in treatment design is an absolute requirement.
6. Subsequent acid or oxidizing treatment can be performed without altering the effectiveness of treatment.
7. Effectiveness of treatment is several years.
8. Complete plugging can be achieved by cross-linked polymer.

REFERENCES:

1. Thakur, G.C.: "Waterflood Surveillance Techniques - A Reser-

voir Management Approach," SPE Distinguished Author Series, JPT (Oct. 1991).

2. Craig, Forrest F., Jr.: The Reservoir Engineering Aspects of Waterflooding, Henry L. Doherty Series, Dallas, SPE Monograph Vol. 3, copyright 1971 by AIME.

3. Kulezner, V.N. and Shershnev, V.A.: The Chemistry and Physics of Polymers, Translated from Russian by G. Leib, MIR Publishers (1990), Moscow.

4. **Mody, B.G.**, McKitric, R.S., and Shahsavari, D.: "Proper Application of Cross-linked Polymer Decreases Operating Costs," paper SPE 17288 presented at the 1988 Permian Basin Oil and Gas Recovery Conference, Midland, March 1988.

5. **Mody, B.G.**, McKitric, R.S., and Lambillotte, J.D.: "Precision Casing Leak Squeeze Using Cross-linked Polymerlamide," paper present at the 1988 Southwestern Petroleum Short Course, Lubbock, April.

6. **Mody, B.G.**: "Profile Control Technology With Cross-linked Polymer Improves Sweep Efficiency and Decreases Operating Costs," paper presented at the 1988 9th Exploration & Production Conference, Cairo, Egypt November.

7. **Mody, B.G.**, and Dabbous, M.K.: "Reservoir Sweep Improvement With Cross-linked Polymer Treatments," paper presented at the 1989 SPE Middle East Oil Technical Conference & Exhibition, Manama, Bahrain, March.

8. Shryock, S.H. and Slagle, K.A.: "Problems Related to Squeeze Cementing," paper SPE 1993 presented at the 1967 SPE 38th Annual California Regional Meeting, Los Angeles, October 26-27.

9. **Mody, B.G.** and Saunders, P.: "Design Criteria and Operational Considerations to Remedy Casing Leaks," paper presented at the 1980 Southwestern Petroleum Short Course, Lubbock, April.

10. Smith, D.K.: Cementing, Henry L. Doherty Series, Dallas, SPE Monograph Volume 4, copyright 1976 by AIME.

11. Smith, C.W., Pugh, T.D., and **Mody, B.G.**: "A Special Sealant Process for Subsurface Water Production," paper presented at the 1978 Southwestern Petroleum Short Course, Lubbock, April; and SPE 7176 presented at the 1978 Rocky Mountain Regional Meeting, Cody, May.

12. Syndansk, R.D.: "Acrylamide-Polymer/Chromium (111)-Carboxylate Gel for Near Wellbore Matrix Treatments," paper presented at

the 1990 SPE/DOE EOR Symposium, Tulsa, April 22-25.

13. Cole, R.C., **Mody, B.G.**, and Pace, J.: "Water Control for Enhanced Oil Recovery," paper SPE 10396.1 presented at the 1981 Offshore Europe Conference in conjunction with the Aberdeen Petroleum Section of SPE of AIME, Aberdeen, September 1981.

14. Zaitoun, A., Kohler, N., and Guerrini, Y.: "Improved Polyacrylamide Treatments for Water Control in Producing Wells," paper presented at the 1989 SPE International Oil Field Chemistry Symposium, Houston, February 8-10.

15. Schurz, G.F., Martin, F.D., Seright, R., and Weiss, W.W.: "Polymer-Augmented Water Flooding and Control of Reservoir Heterogeneity," paper presented at the 1989 Centennial Symposium Petroleum Technology into the Second Century at New Mexico Tech, Socorro, October 16-19.

16. Moffitt, P.D.: "Long Term Production Results of Polymer Treatments on Production Wells in Western Kansas," paper presented at the 1991 66th Annual SPE Symposium, Dallas, October 6-9.

17. Zaitoun, A., Rahbari, R., and Kohler, N.: "Thin Polyacrylamide Gels for Water Control in High-Permeability Production Wells," paper presented at the 1991 66th Annual SPE Symposium, Dallas, October 6-9.

18. Tan, H.C. and **Mody, B.G.**: "Laboratory Study of Polymers to Improve Conformance Control," paper presented at the 1986 Southwestern Petroleum Short Course, Lubbock, April.

19. Schoeling, L.G., Gree, D.W., and Willhite, G.P.: "Introducing EOR Technology to Independent Operators," SPE (Dec. 1989) 1344-50.

20. Liang, J., Lee, R.L., and Seright, R.S.: "Placement of Gels in Production Wells," paper presented at the 1990 SPE/DOE EOR Symposium, Tulsa, April 22-25.

21. Seright, R.S.: "Placement of Gel to Modify Injection Profiles," paper presented at the 1988 SPE/DOE EOR Symposium, Tulsa, April 17-20.

22. Hall, H.N.: "How to Analyze Waterflood Injection Well Performance," World Oil (Oct. 1963) 128-130.

23. Hearn, C.L.: "Method Analyzes Injection Well Pressure and Rate Data," Oil & Gas Journal (Apr. 18, 1983) 117-120.

24. Goolsby, J.L.: "A Proven Squeeze-Cementing Technique in a

Dolomite Reservoir," paper SPE 2473 presented at the 1969 SPE Permian Basin Oil Recovery Conference, Midland, May 8-9.

25. Carter, L.G., Harris, F.N., and Smith, D.K.: "Remedial Cementing of Plugged Perforations," paper SPE 759 presented at the 1963 California Regional Meeting, Santa Barbara, October 23-25.

26. Boice, D. and Miller, J.: "A Better way to Squeeze Fractured Carbonates," Petroleum Engineer (May 1970).

ACKNOWLEDGEMENTS:

My personal appreciation is extended to Mrs. Holly Spencer for typing this manuscript. I also appreciate the constructive criticism provided by Mr. Bernard J. Mahony, Sr.

Table 1
Reservoir Data

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5
Formation	Swastika	Kaibab	Slave Point	Clearfork	Grayburg
Type	Sand	Dolomitic	Carb-Lime	Dolomitic	Dolomitic
Depth	3947′	6920′	5568′	5569′	3852′
Gross Pay	38′	41′	38′	310′	±200′
Completion	Perforated	Perforated	Perforated	Open Hole	Open Hole
Porosity	20%	21%	7%	12%	10%
Permeability	>300 md	10-135 md	>1000 md	0.1-10 md	10-20 md
BHP	1100 psi	680 psi	2030 psi	1600 psi	800 psi
BHT	110°F	150°F	140°F	104°F	85°F
Spacing	40 AC	40 AC	160 AC	20 AC	40 AC
Drive	Bottom Water	Bottom Water	Bottom Water	Water-flood	Water-flood

Table 2
Production Data

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5
Formation	Swastika	Kaibab	Slave Point	Clearfork	Grayburg
Completion	Jul. 1987	Sept. 1967	Oct. 1984	Mar. 1950	May 1936
Initial Prod.	127/3	847/330	169/24	554/117	N/A
Current Prod.	8/110	27/1800	6/194(Apr.'89)	1/660(Dec.'87)	N/A
WOR	14	67	31	660	N/A
Fluid Level	1500'FS	5140'FS	131'FS	2475'FS	2100'FS
Treatment	Jul. 1988	Mar. 1990	Oct. 1990	Nov. 1990	Oct. 1991
Method	No Isolation	No Isolation	No Isolation	Isolation	Isolation

Current Status 1992

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5
Production	10/35	20/1100	80/203	25/515	N/A
WOR	2.7	55	2.5	20.6	N/A
Fluid Level	3800'FS	5700'FS	4265'FS	3000'FS	N/A
Months Since Treatment	43	22	15	14	4

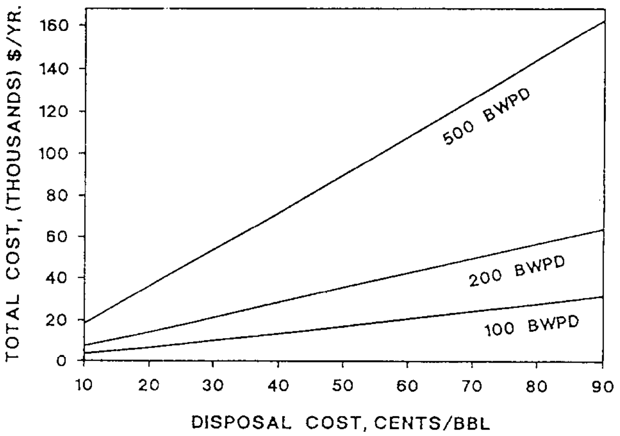

Figure 1 - Costs of water handling

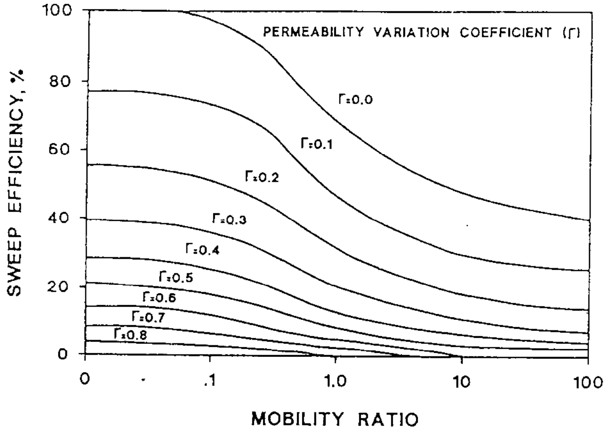

Figure 2 - Sweep efficiency vs. mobility ratio

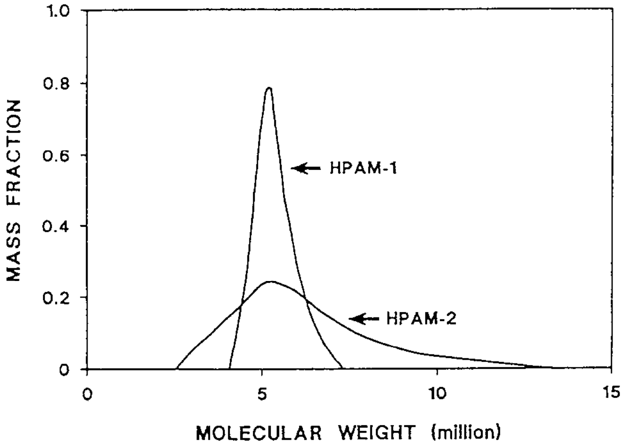

Figure 3 - Molecular weight distribution (MWD)

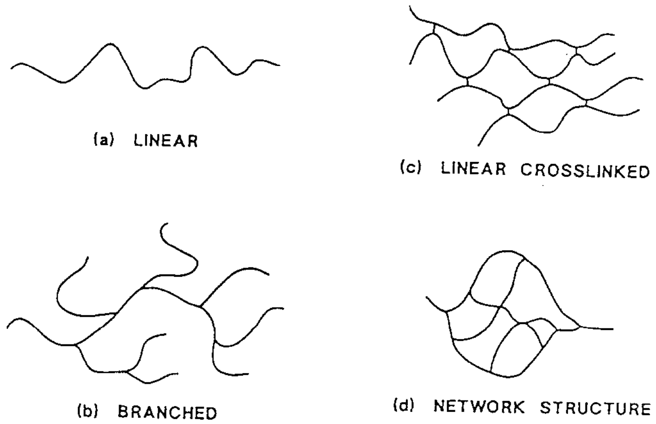

Figure 4 - Schematic representation of polymer

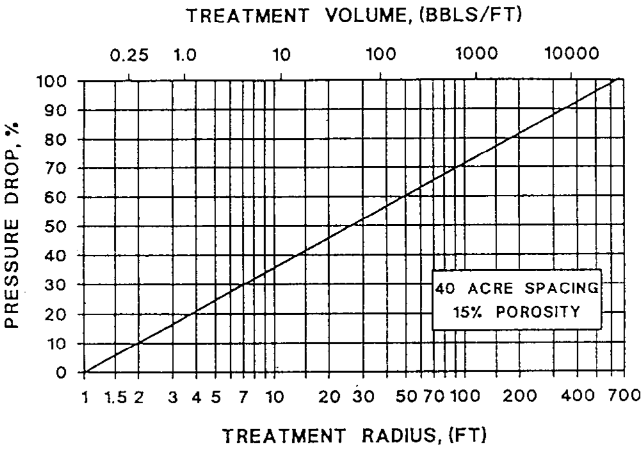

Figure 5 - Polymer treatment design parameters

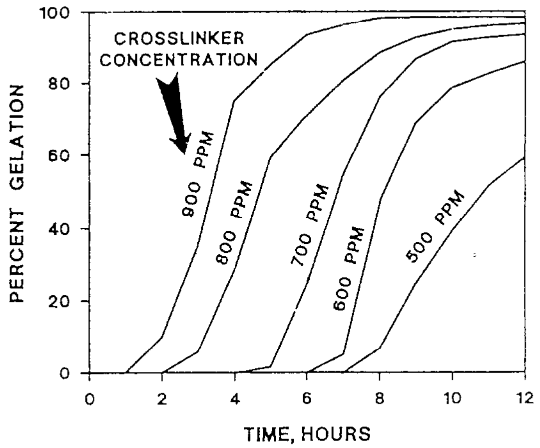

Figure 6 - Typical gel analysis at BHT

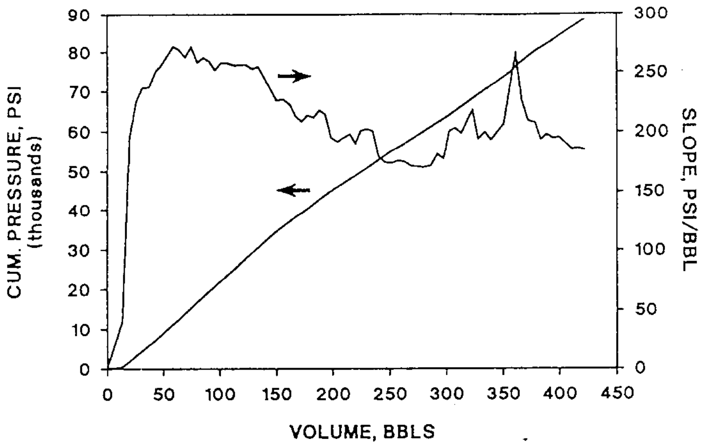

Figure 7 - Well response during treatment, Case - 1 well

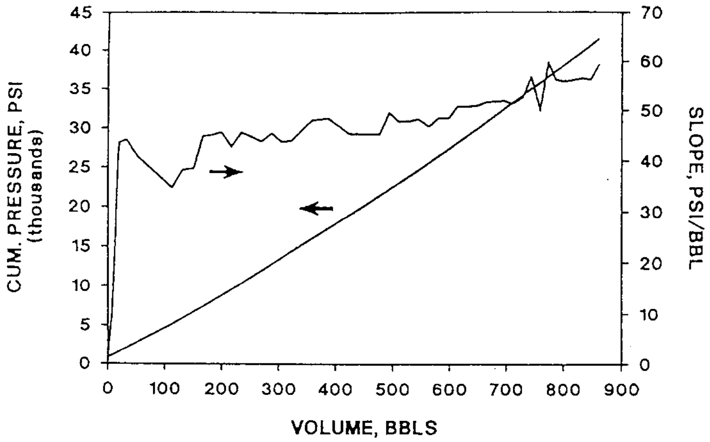

Figure 8 - Well response during treatment, Case - 2 well

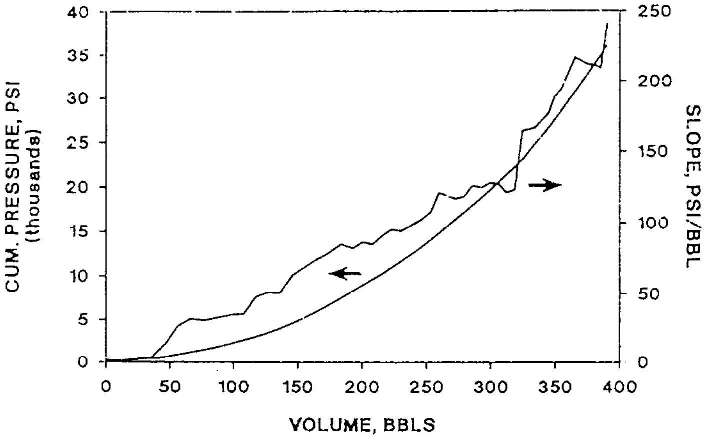

Figure 9 - Well response during treatment, Case - 3 well

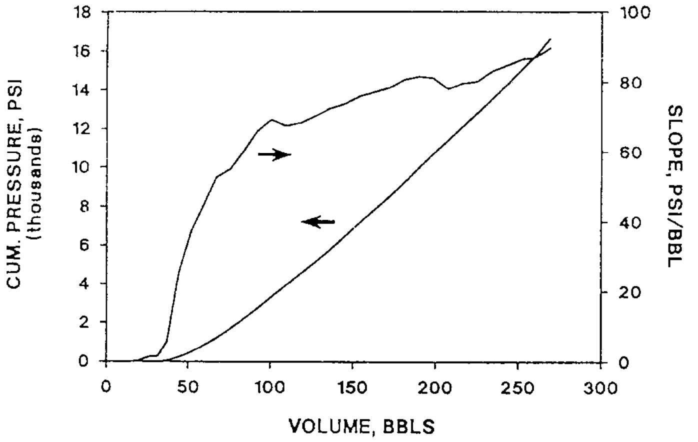

Figure 10 - Well response during treatment, Case - 4 well

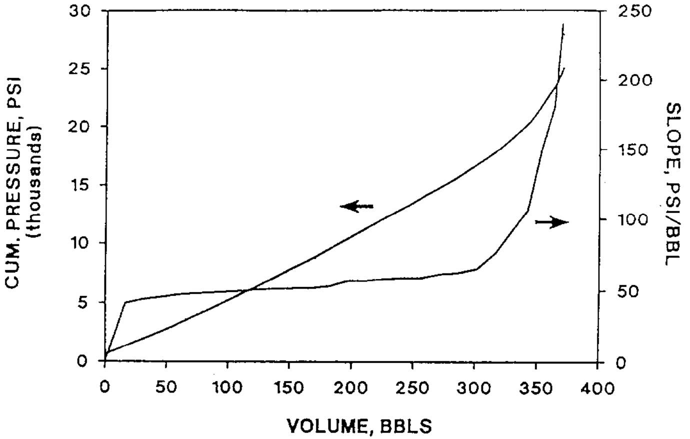

Figure 11 - Well response during treatment, Case - 5 well