ENHANCED OIL RECOVERY BY POLYMER FLOODING

(Final Project report)

Submitted for Partial Fulfillment of the

B.TECH. Degree (Applied Petroleum Engineering)

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CERTIFICATE

This is to certify that the Project Report on **"ENHANCED OIL RECOVERY BY POLYMER FLOODING"** submitted to University of Petroleum & Energy Studies, Dehradun, by **Mr. Abhishek Jadli & Mr. Siddharth Badoni** in partial fulfillment of the requirement for the award of Degree of **Bachelor of Technology** in **Applied Petroleum Engineering** (Academic Session 2003 – 07) is a bonafide work carried out by them under my supervision and guidance. This work has not been submitted anywhere else for any other degree or diploma.

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Executive Summary

Polymer flooding results in improved reservoir volumetric sweep efficiency and reduced water production, thus increasing oil recovery and eliminating the problem of wastewater from oil and gas production, therefore reducing its impact on the environment and simultaneously achieve economic benefits. In a conventional waterflood, if the mobility ratio is unfavorable, the water tends to finger by the oil and to move by the shortest path to the production well. This effect is amplified by reservoir geologic heterogeneities. A polymer solution moves in a more uniform manner. While flow still tends to be greatest in high-permeability zones and along the shortest path between the injection and production wells, the effect is damped because polymer solution mobility is less than water mobility. So, polymer flooding is a modification of waterflooding, in which a slug of high molecular weight, water-soluble polymer is injected during a waterflood. The polymer acts to improve sweep efficiency by both increasing viscosity and reducing water permeability, thus, in this process an attempt is made to alter the relative rates at which injected and displaced fluids move through a reservoir.

In both hydraulically and naturally fractured reservoirs, void channels often allow injected fluids to flow directly between injection and production wells, thus causes early breakthrough. As fractures, vugs, and similar void channels often cause excess water production and poor sweep efficiency in reservoirs. This problem is especially important for EOR projects, where high-value fluids are injected. In production wells, void channels often extend into an aquifer-thus accentuating water production. So polymer solutions and gels are often placed in oil production wells to try to reduce water production from the water bearing zone as after gel placement the water flow reduces considerably but oil flow does not. Gels have effectively mitigated channeling through fractures, fracture-like features, and voids. Gels have reduced channeling through fractures in waterfloods and gas floods. Gels also have reduced water production in wells where fractures, fracture-like features, and voids connect to an underlying aquifer.

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1.0 Introduction

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary. Primary production, the initial production stage, resulted from the displacement energy naturally existing in a reservoir. Secondary recovery, the second stage of operations, usually was implemented after primary production declined. Traditional secondary recovery processes are waterflooding, pressure maintenance, and gas injection, although the term secondary recovery is now almost synonymous with waterflooding. Tertiary recovery, the third stage of production, was that obtained after waterflooding (or whatever secondary process was used). Tertiary processes used miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process became uneconomical. The other name of tertiary recovery i.e. "enhanced oil recovery" (EOR) is the more accepted term in oil and gas industry than the term tertiary recovery. Generally there are three types of water control problems in water flooding systems:

1) Open flow paths-this kind of problems is associated with the presence of fractures or faults or to oil being confined to the rock matrix.

2) Fluid fingering or viscous fingering (edge water) is caused by post areal sweep which is common in heterogeneous reservoir.

3) Conning water or bottom water problem- where oil is being produced near the oil water contextures, too much water.

One of the upcoming techniques to improve recovery efficiency is polymer flooding. Polymer flooding can yield significant increase in percentage recovery when compared to conventional water flood projects in certain reservoirs. As, the addition of a polymer yields two benefits:

1) Reduces the total volume of water required to reach the ultimate residual oil saturation.

2) Increases sweep efficiency due to improved mobility ratio.

Many successful Projects have reported increased recoveries of 5-15%. However many unprofitable projects were the result of inadequate reservoir description or problems with the polymer system being used. In recent years the polymer gel flooding technology has been field tested extensively and can be classified as proven technology. Thus, in a polymer flooding, a solution of partially hydrolyzed polyacrylamide polymer in brine, at a concentration of a few hundred to several hundred ppm of polymer, is injected to displace oil (and associated water) toward production wells. The size of the polymer slug might be as much as 50 to 100% PV and might be varied in composition. That is, the highest polymer concentration used is injected for a period of time followed by slugs at successively lower concentrations. The final fluid injected is water or brine. The high viscosity attained by dissolving polymers in water makes oil displacement more efficient compared to conventional water injection.

More generally, efficiency can be enhanced by reducing the water production, which is worldwide an increasing problem for operators. In mature oil fields, as oil depletion induces a rise in the oil-water contact, water breaks through in the production wells at a certain moment. Breakthrough can also result from stimulation by water injection. Depending on the specific situation water production can be decreased by shutting off the bottom of the well or plugging certain water producing layers by using polymer gels or cements, the so-called water shut-off treatments. Other shut-off treatments involve disproportionate permeability reducers (DPRs), which are usually polymer solutions or gels. DPR working is based on the fact that adsorption of hydrophilic polymers can strongly decrease the permeability to water while having little effect on the permeability to oil. The DPR (Disproportionate Permeability Reduction) reduces water permeability more than oil (or gas) permeability and therefore, may be a method for water shutoff. DPR is most effective when used against water production caused by coning or in situations where the watered out layers are separated from the oil producing layers.

Enhanced Oil Recovery By Polymer Flooding

1.1 Screening Criteria for Polymer Flooding

1)Oil	Viscosity <200 cp at reservoir conditions Gravity> 18° API (oil viscosity is the more important parameter)
2)Water	Low salinity preferable but not critical
3)Lithology	Grossly vugular limestone to be avoided
3)Reservoir	Mobility ratio: upto 240 Permeability: > 10 md Heterogeneity factor: 0.5 - 0.85 Temperature: < 150° F (but some polymers are available at higher temperatures)
4)Favorable Factors	Good waterflood conditions High Øh High mobile oil saturation
5)Unfavorable Factors	Extensive fractures Strong water drive Gas cap High permeability contrast Highly saline formation water Severe injectivity problems High calcium and clay content
6)Laboratory Screening Tests	Oil analysis (gravity, viscosity, sulfur) Water analysis Laboratory displacement tests

1.2 Mechanism of Polymer Flooding

One of the upcoming techniques to improve recovery efficiency is polymer flooding. This can be achieved in two ways:

1.2.1 Polymer Augmented Waterflood

Many reservoirs are fractured and much oil remains in these fractured, carbonate oil reservoirs after water flooding or gas injection. The high remaining oil saturation is due to a poor sweep in fractured reservoirs. Sweep efficiency is an important factor in oil recovery, especially in fractured formation. Fractures systems generally have a broad distribution of fracture widths. The wide fracture will act as thief zones for the injected fluid and little of the injected fluid will reach the narrow fractures. Another reason for high remaining oil saturation in fractured oil-wet, carbonate formation is that the matrix will retain oil where the upward oil film flow path is interrupted by fractures. As a result, oil is retained in oil-wet pores by capillarity. The basic principle behind the use of flooding polymers as an oil recovery technique is to reduce the mobility of the injected water thereby reducing the tendon eye of water to. beak past the oil and assisting to give an even sweep through the reservoirs. The objective is to improve the total recovery of oil within a reduced time frame and improve the Produced oil/ water ratio. In the case of a reservoir that is non homogenous the effects of high oil viscosity are magnified. The more mobile water will tend to break rapidly via the zones of higher Permeability.

Thus, we increase the viscosity of water by the addition of polymer. The high viscosity attained by dissolving polymers in water makes oil displacement more efficient compared to conventional water injection. This is done to control mobility ratio. Mobility control is a generic term describing any process where an attempt is made to alter the relative rates at which injected and displaced fluids move through a reservoir. The objective of mobility control is to improve the volumetric sweep efficiency of a displacement process. In some processes, there is also an improvement in microscopic displacement efficiency at a specified volume of fluid injected. Mobility control is usually discussed in terms of the mobility ratio, M, and a displacement process is considered to have mobility control if $M<=1$.

Volumetric sweep efficiency generally increases as M is reduced, and it is sometimes advantageous to operate at a mobility ratio considerably less than unity, especially in reservoirs with substantial variation in the vertical or aerial permeability.

Mobility ratio can be modified by any combination of changes in the permeabilities of the rock to the displacing and displaced fluids and/or changes in fluid viscosities:

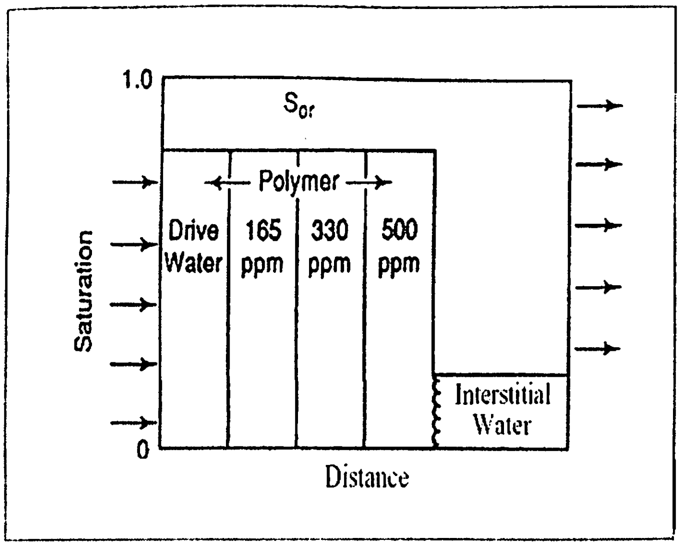
$$M=(k_{rD}/\mu_D)_{S_D}(\mu_d/k_{rd})_{S_d}$$

where krD=relative permeability of the displacing phase, krd=relative permeability of the displaced phase, μD=viscosity of the displacing phase, μd=viscosity of the displaced phase, SD=average saturation of the displacing phase in region behind the displacing-phase front. *Sd* =average saturation of the displaced phase in the region ahead of the displacing-phase front, and consistent units are used.

Most mobility-control processes of current interest involve addition of chemicals to the injected fluid. These chemicals increase the apparent viscosity of the injected fluid and/or reduce the effective permeability of rock to the injected fluid. The chemicals used are primarily polymers.

1.2.2 Process Involved:

High-molecular weight water-soluble polymers in dilute concentrations [on the order of a few hundred parts per million (ppm)] increase the viscosity of water significantly. Two types of polymers are commonly used for mobility control in waterfloods: partially hydrolyzed polyacrylamide and xanthan biopolymers. The mobility of polymer solutions containing polyacrylamide is reduced by a combination of increased solution viscosity and reduced rock permeability caused by polymer retention. In contrast, xanthan polymer solutions reduce the mobility of the injected solution by increasing the solution viscosity. When the initial mobility ratio is unfavorable for a waterflood, mobility control can increase the microscopic displacement efficiency at a specified WOR. In a polymer-augmented waterflood, polymer is injected continuously at the initial polymer concentration for a limited period. Reducing the polymer concentration systematically as more PV's are injected is the most cost-effective method to conduct a flood. After sufficient polymer has been injected, the polymer slug is displaced through the reservoir by injecting water. Polymer selection, injected concentration, polymer volume injected, and the method of reducing the polymer concentration with PV's of fluid injected are determined from data obtained in laboratory experiments and by simulating the polymer flood with computer models.



Injection schedule for a continuous polymer flood

1.2.3 In-Situ Permeability Modification: More generally, efficiency can be enhanced by reducing the water production, which is worldwide an increasing problem for operators. In mature oil fields, as oil depletion induces a rise in the oil-water contact, water breaks through in the production wells at a certain moment. Breakthrough can also result from stimulation by water injection. Depending on the specific situation water production can be decreased by shutting off the bottom of the well or plugging certain water producing layers by using polymer gels or cements, the so-called water shut-off treatments. Other shut-off treatments involve *disproportionate permeability reducers* (DPRs), which are usually polymer solutions. DPR working is based on the fact that adsorption of hydrophilic polymers can strongly decrease the permeability to water while having little effect on the permeability to oil. For an effective application of the above-mentioned technologies knowledge of polymer *flow behavior and retention behavior*, both in porous media, is indispensable. Apart from oil-related applications this field is important to many other industries and technologies, but nevertheless it is still not well understood. The main reason for this is the complex relationship between rheology and retention behavior. Both are depending on porous medium structure and are clearly different from bulk behavior. The aim in this work is to contribute to the understanding of this field, while focusing on systems based on aqueous polymer solutions. Even for Newtonian fluids in well-defined porous media, the prediction of dissipation is not straightforward at all as it is a complex function of wall and internal friction, velocity gradients and tortuosity, all strongly related to flow path geometry. Modeling a porous medium by a bundle of tubes is conceptually an improvement over the well-known capillary bundle model with straight tubes. The presence of diameter variations gives the possibility to account for elongation dissipation effects, which contribute to the measured permeability. *Experiments on coreflood by aqueous non-ionic Polyacrylamide (PAM) solutions in silicon carbide grain packs at low flow rates are done. PAM is the most frequently used system in polymer flooding- and water shut-off treatments.*

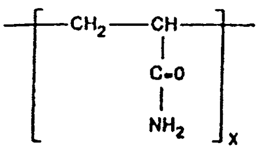
The experiments show that, above a certain concentration in the semi-dilute regime, the mobility reduction Rm does not stabilize during injection, as it does at lower concentrations in the dilute regime. This behavior seems to be related to the formation of adsorption entangled multilayer whose thickness can grow during injection. *The layer thickness is an important parameter as, together with the effective pore size, it determines the resulting permeability reduction and the magnitude of the so-called disproportionate permeability reduction (DPR) effect*

1.3 Properties of Polymers

1.3.1 Physical and Chemical Characteristics of Polymers

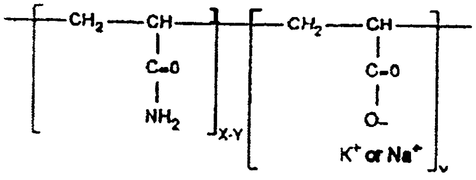
Polymer Types => Two types of polymers, often called macromolecules, are used widely in EOR processes: polyacrylamides and polysaccharides. Polyacrylamides can be manufactured by polymerization of the acrylamide monomer, shown here in the Figure shown below

Structure of Polyacrylamide



$$-\left[CH_2-\underset{\underset{\underset{NH_2}{|}}{C\text{-}O}}{\overset{}{CH}}\right]_X-$$

Structure of Hydrolyzed Polyacrylamide

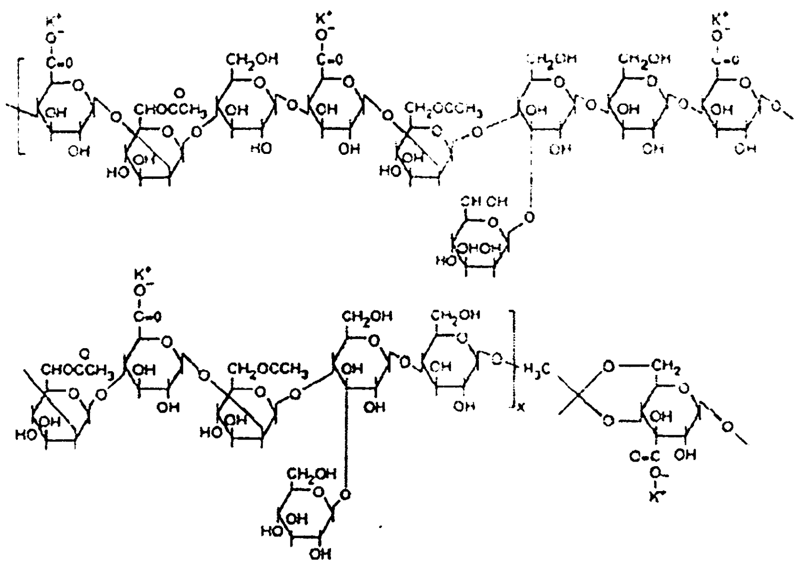


$$-\left[CH_2-\underset{\underset{\underset{NH_2}{|}}{C\text{-}O}}{CH}\right]_{X-Y}-\left[CH_2-\underset{\underset{\underset{\underset{K^+ \text{ or } Na^+}{O^-}}{|}}{C\text{-}O}}{CH}\right]_Y-$$

Polymerization produces macromolecules with average molecular weights ranging from 0.5 million to 30 million, depending on the extent of polymerization. Molecular weights commonly used range from 1 million to 10 million. Polyacrylamide adsorbs strongly on mineral surfaces. Thus, the polymer is partially hydrolyzed to reduce adsorption by reacting polyacrylamide with a base, such as sodium or potassium hydroxide or sodium carbonate. Hydrolysis converts some of the amide groups (NH2) to carboxyl groups (COO-), as shown above. The degree of hydrolysis is the fraction of amide groups that are converted by hydrolysis and ranges from 15 % to 35 % in commercial products. Polyacrylamide also is used in the "unhydrolyzed" form in some applications. Even "unhydrolyzed" polyacrylamide will have small amounts (2% to 4%) of hydrolyzed groups unless exceptional precautions are taken in the manufacturing process. Partially hydrolyzed polyacrylamides are also produced by copolymerization. Polyacrylamides are supplied as a dry polymer or as liquid emulsions with oil- or water external systems.

The most widely used polysaccharide is xanthan gum, which is a biopolymer produced commercially by microbial action of the organism ***Xanthomonas campestris*** on a carbohydrate feed stock.

Typical structure of the xanthan biopolymer is shown in Figure below



The polymer acts like a semi rigid rod and is quite resistant to mechanical degradation. Average reported molecular weights of xanthan biopolymers used in EOR processes range from 1 million to 15 million, depending on the method used to determine the molecular weight. The properties of a particular biopolymer depend to a large measure on the organism used to manufacture the polymer. There are many strains of *Xanthomonas campestris,* and different biopolymers consequently have been developed from these strains. Xanthan biopolymers are supplied as a dry powder or as a concentrated broth. Unless special precautions are taken in the manufacturing process, the biopolymer product contains cellular debris that must be removed by filtration before it can be injected into porous rocks. Dry xanthan biopolymers are also susceptible to formation of microgels, which have plugging tendencies. Other polymers have been developed for particular applications. For example, polyvinyl pyrrolidone was developed for high temperature applications in harsh environments where polyacrylamides and biopolymers were found not to be applicable.

1.3.2 Polymer Stability

The property that makes polymers useful for EOR applications is that small concentrations of polymer, on the order of a few hundred to a few thousand ppm (by weight), increase the viscosity of an aqueous solution significantly. For a polymer to be useful in EOR applications, it must be stable at reservoir conditions for the expected residence time in the reservoir rock. Because polymer can degrade under certain conditions , short-time laboratory tests can be misleading. Polymer stability at reservoir temperature and in the presence of reservoir brine is essential to EOR applications. It is well-established that both polyacrylamides and biopolymers are susceptible to oxidative attack by dissolved oxygen in the injected water. Degradation is detected by the loss of solution viscosity with time. At low temperatures, the reaction rate is slow and can go undetected in short tests. The degradation rate increases as temperature increases, which is consistent with chemical reaction kinetics. The oxidative degradation reaction is catalyzed by dissolved metal ions, such as Fe+ + + . Degradation by oxidative attack can be prevented or minimized by reducing the oxygen content of the water or brine to less than a few parts per billion. This usually is done by use of oxygen scavengers or deaeration. Sodium dithonite is used to stabilize polyacrylamides. A mixture of thiourea, isopropyl alcohol, and sodium bisulfate was found to retard oxidative attack on xanthan biopolymers at temperatures up to 207°F.Oxygen scavengers are not typically used in field applications because most reservoirs have a reducing environment and because dissolved oxygen is consumed rapidly after the injected fluid containing oxygen enters the reservoir.

The thermal stability of polymers (i.e., stability at higher temperatures) is a second important consideration. Laboratory tests indicate that the carbon/carbon backbone of polyacrylamides is stable in the absence of oxygen and divalent ions to temperatures up to 194°F.During incubation at high temperatures, however, polyacrylamides undergo hydrolysis by reaction of the amide groups with water. This is reflected in an increase in solution viscosity. The behavior of xanthan polymers at elevated temperatures is complex.Acetyl groups in this polymer are susceptible to base-catalyzed hydrolysis. For example, unbuffered xanthan solutions exhibit a decrease in pH when exposed to elevated temperatures. The increase in hydrogen-ion concentration is attributed to the generation of H+ when O-acetyl groups are hydrolyzed. The xanthan molecule has a helical structure that appears to take on different configurations, depending upon salinity divalent-ion concentrations, and temperature. Changes in structural configuration can be correlated in terms of a transition temperature. The transition temperature increases with salinity and divalent ion content.

It is usually necessary to prepare the injected polymer solution in reservoir brine. Reservoir brines often contain high concentrations of divalent cations, in particular Ca ++ and Mg ++. The solution viscosity of each polymer is affected by the presence of divalent cations. Both polyacrylamides and biopolymers are stable in high concentrations of divalent cations at low reservoir temperatures. Ferric ion (Fe ++) will cause gelation of polyacrylamide and must be excluded or chelated within reservoir brines. The presence of divalent cations causes stability problems for polyacrylamides at elevated temperatures. As the degree of hydrolysis increases as a result of polyacrylamide reaction with water, the solubility of the polymer decreases in the presence of calcium and magnesium. Polymer degradation also results from bacterial attack. Biopolymers are susceptible to biological attack resulting in the loss of solution viscosity from the destruction of the carbohydrate backbone, which can be rapid. For this reason, the polymer broth usually contains a bactericide, such as formaldehyde, to control bacterial growth. At one time, it was thought that bacterial attack would not be a problem in petroleum reservoirs because the organisms could not be transported through the porous rock. Unfortunately, bacterial attack has been observed in at least two field tests.

High concentrations of formaldehyde (1,500 ppm) successfully controlled the bacterial attack. When H2S is present, no known bactericide is effective. Polyacrylamides are perceived to be less susceptible to biological attack than biopolymers.

1.3.3 Rheological Properties :

1.3.3.1 Effect of Shear Rate

Aqueous solutions of polyacrylamides and xanthan biopolymers often exhibit non-Newtonian rheological behavior. A Newtonian fluid has a linear relationship between shear stress and shear rate .

The proportionality constant in this relationship is the viscosity of the fluid. For Newtonian fluid:-

$$\tau=\mu\dot{\gamma} \quad ....(1)$$

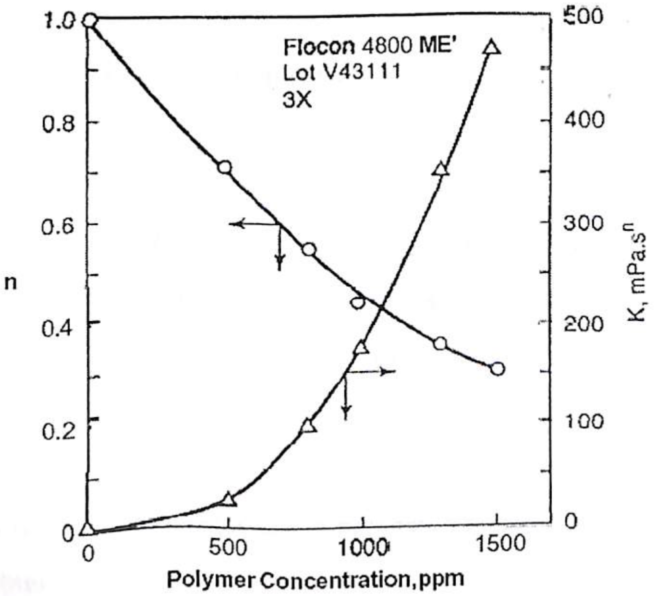
where r=shear stress, μ= solution viscosity, and γ=shear rate.
A more general expression relating shear stress to shear rate is:

$$|\tau=\mu_a\dot{\gamma} \quad ....(2)$$

The apparent viscosity varies with shear rate. Normally, the apparent viscosity of polymer solutions used in EOR processes decreases as shear rate increases. Fluids with this rheological characteristic are said to be shear thinning. The apparent viscosity decreases because the polymer molecules are able to align themselves with the shear field to reduce internal friction. Often it is possible to represent the rheological properties of a shear thinning fluid by the power-law model given by eq.3 which results from combining eq.1&2.The constants K and n depend on the concentration of the polymer.

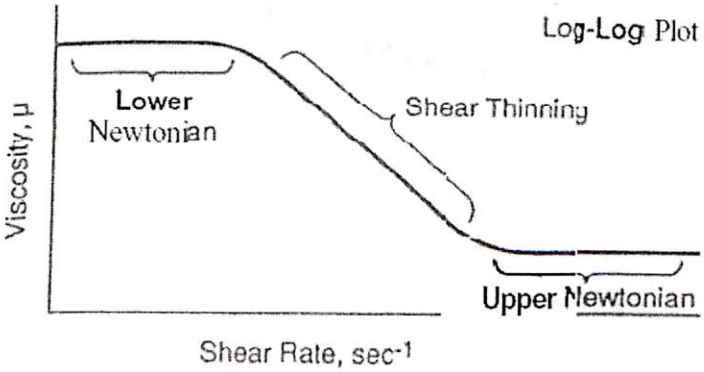
$$\mu=K\dot{\gamma}^{(n-1)} \quad ....(3)$$

where μ = apparent viscosity, K=power-law constant, n =power-law exponent, γ =shear rate, and consistent units should be used. The fig. shows the correlation of K and *n* with polymer concentration for a xanthan biopolymer.



Variation of power-law parameters with polymer concentration.

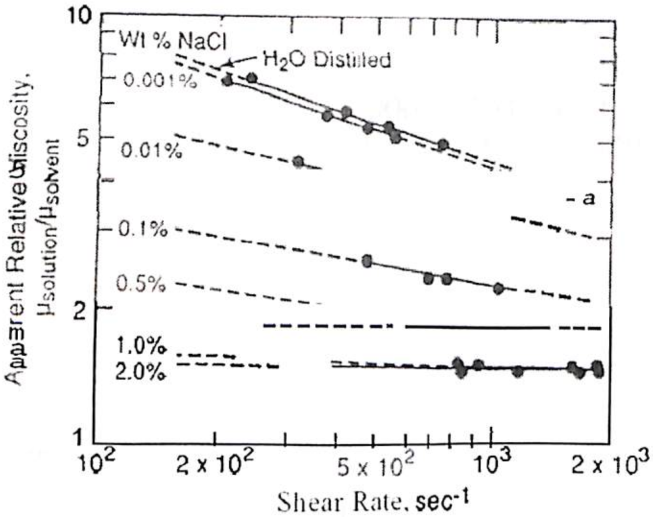
The shear-thinning behavior may encompass a wide range of shear rates and, in many cases, may be the only behavior that is measurable with available viscometers. However, shear thinning is often just one part of the rheological behavior. The given **Fig.** a plot of apparent viscosity vs. shear rate, represents a typical rheogram for a shear-thinning fluid. At low shear rates, the fluid behaves as a Newtonian fluid in that the apparent viscosity is constant. This region is called the lower Newtonian region. As shear rate increases, there is a another transition from shear-thinning behavior represented by the power-law model. At high shear rates, there is another transition from shear-thinning behavior to Newtonian behavior. This region is called the upper Newtonian flow region.



Rheology of shear thinning fluid.

1.3.3.2 Effect of Salinity

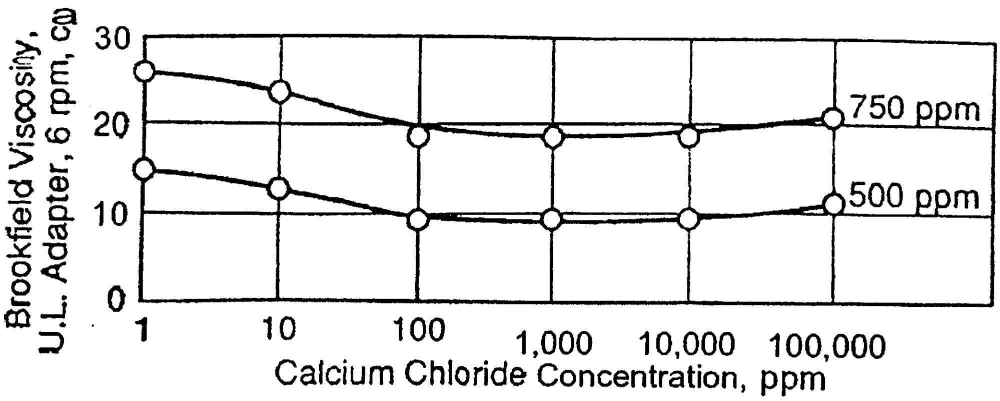
The rheological behavior of polymer solutions may also be affected by salinity and divalent-ion content. The effects are specific to polymer type, and the largest effects are observed with polyacrylamides. Because it is not possible to produce unhydrolyzed polyacrylamide commercially, the discussion concerning polyacrylamides refers to partially hydrolyzed polyacrylamides. Hydrolysis of polyacrylamide introduces negative charges on the backbone of the polymer chain that have a large effect on the rheological properties of the polymer solution. At low salinities, the negative charges on the polymer backbone repel each other and cause the polymer chain to stretch. Each polymer molecule occupies more space in solution, and the apparent viscosity of a dilute solution increases accordingly. For example, the apparent viscosity of a dilute solution (250 ppm) of Pusher 500 at a shear rate of 200 per seconds in distilled water is about seven times the viscosity of water. Larger differences are observed at lower shear rates. When an electrolyte, such as NaCI, is added to a polymer solution, the repulsive forces are screened by a double layer of electrolytes and extension is reduced. As the electrolyte concentration the extension of polymer chain decreases and the solution viscosity declines. Fig. illustrates the effect of salinity on the relative viscosity (apparent solution viscosity/solvent viscosity) of 250-ppm solutions of Pusher 7000, a partially hydrolyzed polyarylamide.



Variation in relative viscosity with salinity and shear rate for 250-ppm Pusher 700 solutions at 25°C.

Chain extension also is controlled by the degree of hydrolysis. Salinity has little effect on the relative viscosity of the "unhydrolyzed" polymer. Thus, much of the increase in solution viscosity anticipated from rheological data taken on polymer solutions prepared in distilled water is not attainable at salinities expected in reservoir brines. Divalent ions (Ca++, Mg++) bond readily to the negatively charged macro-ion in preference to a monovalent ion, such as sodium. The effect of divalent-ion concentration on relative viscosity is more pronounced than sodium-ion concentration because the divalent ions locate themselves in such a way as to screen the negative charges on the backbone more effectively.

Compared with solutions of partially hydrolyzed polyacrylamides, viscosities of xanthan solutions are much less affected by changes in salinity or divalent-ion content. Fig. illustrates this by plotting the solution viscosity at various shear rates vs. salinity and divalent-ion content.



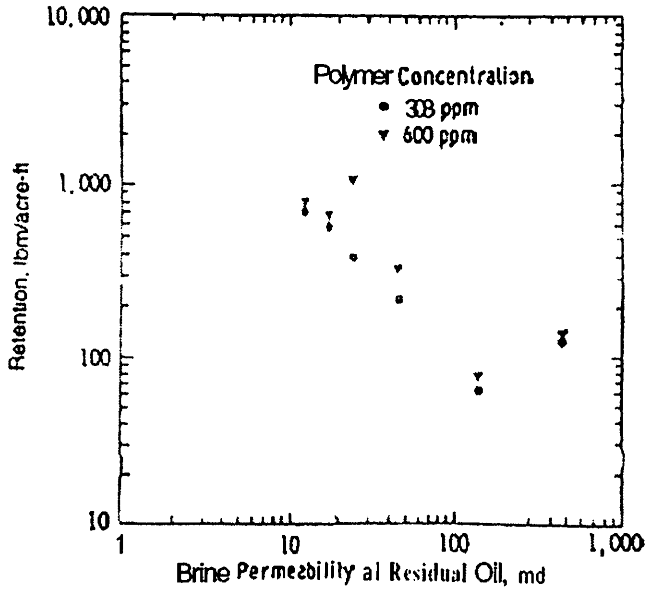
Effect of divalent-ion content on viscometric behavior of xanthan biopolymer

1.4 Flow Mechanics of polymers

1.4.1 Polymer Retention

When a polymer flows through a porous sandpack or rock, there is usually a measurable amount of polymer retention. Retention is caused primarily by adsorption on the surface of the porous material and mechanical entrapment in pores that are small relative to the size of the polymer molecule in solution. In most cases retention of polymers used in EOR applications is considered instantaneous and irreversible. This is not exactly true because small amounts of polymer can be removed from porous rock by prolonged exposure to water or brine injection. Usually, however, the rate of release is so small that it is not possible to measure the concentrations accurately. Retention also may occur when flow rates are suddenly increased after polymer has been injected at a constant rate until a steady state condition has been attained. This type of retention, called hydrodynamic retention, is characterized by expulsion of the polymer when the flow rate is reduced suddenly. The amount of polymer retained when a polymer solution is displaced through a porous medium must be determined by experimental measurement. If the porous material is unconsolidated and the permeability is on the order of 1 darcy or larger, polymer adsorption can be estimated with batch adsorption experiments In these experiments, a polymer solution of known concentration is contacted with a known mass of sand grains until no Further change in polymer concentration is detected. The concentration of the equilibrated polymer solution is determined, and adsorption is computed by material balance. Polymer retention in porous media is determined primarily by flow experiments.

The given Fig. shows the variation of polymer retention with brine permeability at ROS.



.V

The retention at low permeability is large and is probably a result of excessive mechanical entrapment of polymer molecules in small pores. Another possible explanation is high clay content. Retention of xanthan biopolymer depends on the effective permeability of the porous rock. Thus, Polymer retention increases as the effective permeability decreases. Polymer retention in porous media may be correlated by use of the Langmuir isotherm model, which is given by

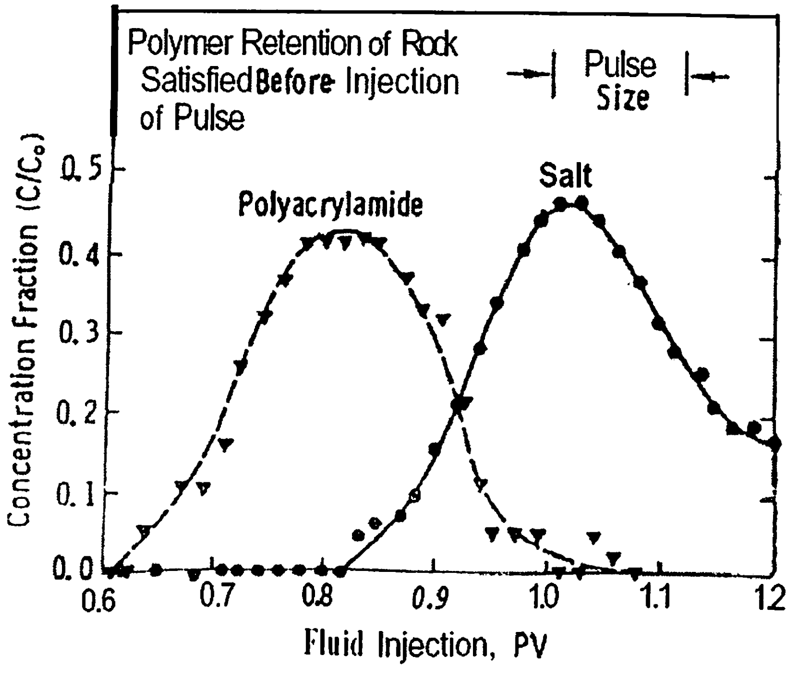
$$\hat{C} = a_1 b_1 C/(1 + b_1 C) \quad \text{........................} (1)$$

Where,

$\hat{C}$=polymer adsorption, C=polymer concentration in solution, and a_l, b_l =constants. The Langmuir model is an equilibrium relationship, and its application assumes retention is instantaneous. The constants a l and bl, are determined by fitting the data.

1.4.2 Inaccessible PV (entrapment)

Polymer molecules are larger than water molecules and are large relative to some pores in a porous rock. Because of this, polymers do not flow through all the pore space contacted by the brine. The fraction of the pore space not contacted by the polymer solution is called the inaccessible PV. The concept of inaccessible PV is illustrated from the results of an experiment shown in **Fig.**



Early arrival of polymer front because of inaccessible pore volume

In this experiment, a polymer solution containing 2% NaCl was displaced through a Berea sandstone core until no further polymer was retained. Then the polymer and NaCl composition of the injected fluid were reduced for a period to create a "pulse" change in NaCl and polymer concentrations. The concentration profiles shown in Fig. are effluent profiles of polymer and NaCI. The midpoint of the change in salt concentration is arrived at about 1 PV injected, as expected from displacement theory, assuming complete contact with the PV. The polymer pulse, however, arrived about 0.24 PV earlier than expected and thus did not contact all the PV in the core. About 24% of the pore space was not accessible to the polymer. Inaccessible PV has been observed in all types of porous media for both polyacrylamides and biopolymers and is considered to be a general characteristic of polymer flow in porous media. The magnitude of the inaccessible PV can range from 1 % to 2% to as much as 25% to 30%. depending on the polymer and porous medium. However a slight decrease in inaccessible PV with concentration is indicated by the polyacrylamide. The impact of inaccessible PV on polymer transport in porous rocks often is concealed by polymer retention. In displacement experiments where a constant polymer concentration is injected into a porous medium that has not been contacted previously by polymer, retention causes the effluent concentration to lag.

1.4.3 Permeability Reduction

Polymer retention reduces the apparent permeability of the rock. Permeability reduction depends on the type of polymer, the amount of polymer retained, the pore-size distribution, and the average size of the polymer relative to the pores in the rock. Permeability reduction is determined experimentally by first displacing polymer solution through a porous medium and then displacing the polymer with brine and measuring the permeability to brine after all mobile polymer has been displaced. It is convenient to describe the permeability reduction in terms of the initial brine permeability. In practice, this is done by defining the *residual resistance factor* as the ratio of the brine mobility before contact with polymer , to the brine mobility after all mobile polymer has been displaced from the pore space. Mathematically, the *residual resistance factor* is given by:

$$F_{rr}=\lambda_w/\lambda_{wp} \text{ ....(1)}$$

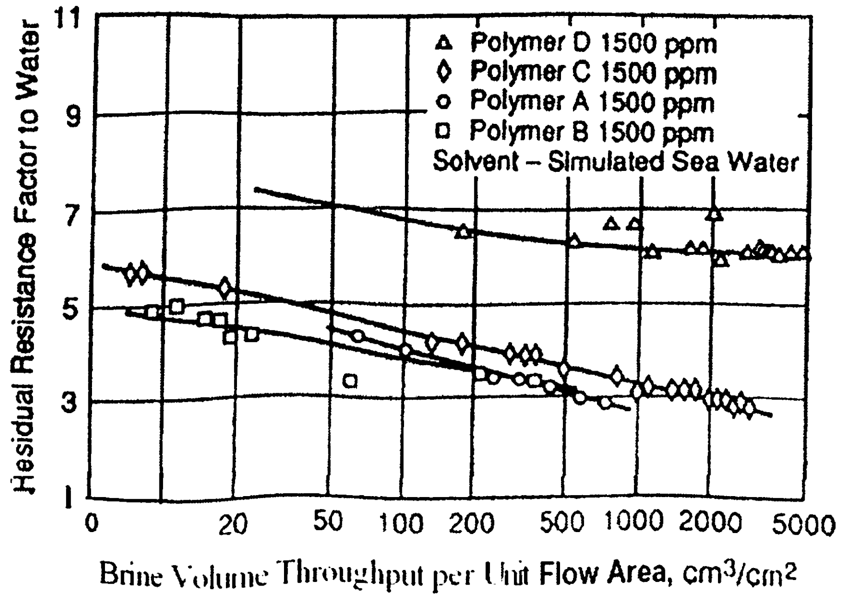
$$F_{rr}=k_w/k_{wp} \text{ ....(2)}$$

where Frr=residual resistance factor for the porous matrix after contact with a particular polymer solution, kwp =permeability of the porous matrix to brine after contact with polymer solution, kw=initial brine permeability, ?w=brine mobility before contact with polymer and ?wp=brine mobility after all mobile polymer has been displaced from the pore space.

Note; the permeability to brine after the mobile polymer has been displaced, *kwp* is assumed to be the same as the permeability of the porous medium to the flow of polymer,kp.

Retention of xanthan biopolymer is relatively small when bacterial debris are removed by filtration. Compared with xanthans, polyacrylamides usually cause larger reductions in brine permeability. At high salinities or divalent ion content, permeability reduction is decreased. *The permeability to brine after contact with polymer may be reduced from 10% to 30%.*

The permeability reduction usually persists for a large number of PV's of fluid throughput. In laboratory tests with relatively low fluid throughput, little change in brine permeability occurs. However, prolonged fluid injection eventually erodes the permeability reduction, as indicated in Fig., where the residual resistance factor declines markedly with PV's throughput.



Degradation of permeability reduction after prolonged brine injection

Prediction of the permeability reduction from properties of the porous rock and the polymer is not possible. Thus, experimental measurement with the rock and polymer of interest is necessary.

1.4.4 Polymer Mobility in Porous Media

Polymers are non-Newtonian fluids. Consequently, the flow characteristics in porous media for some polymers are related to the rhelogical properties For shear-thinning fluids with rigid structures, such as xanthan biopolymers, the flowing polymer exhibits Newtonian characteristics at low frontal-advance rates, a shear-thinning region at intermediate frontal-advance rates, and Newtonian characteristics at high frontal-advance rates. Because the shear-thinning region often includes the range of most reservoir frontal-advance rates , so most experimental data have been taken in this region. Data describing the flow of polymers in porous media can be obtained by conducting steady-state flow tests in core plugs or sandpacks over the range of frontal-advance rates anticipated in the bulk of the reservoir and in the vicinity of the wellbore. In these tests, polymer of a specific concentration is injected at a constant rate. Pressure drops are measured across the entire length of the porous medium and between measuring ports spaced along the porous medium, constant rate is maintained until the pressure drop reaches a steady state. A series of measurements of flow rate vs. pressure drop is taken to determine the flow properties of the polymer in the porous material.

The obtained data can be analyzed by assuming that Darcy's law applies to the flow of polymer in porous media:

$$u=\lambda_p(\Delta p/L) \text{.........................} (1)$$

where µ=Darcy velocity, ?p=mobility of the polymer in the porous rock, ?p=pressure drop, L=length over which the pressure drop is measured, and consistent units are used. The mobility of the polymer is defined by:

$$\lambda_p=k_p/\mu_p \text{..........................} (2)$$

where kp=permeability of the porous medium to polymer and µp =apparent viscosity of the polymer at the average shear rate existing in the porous medium.

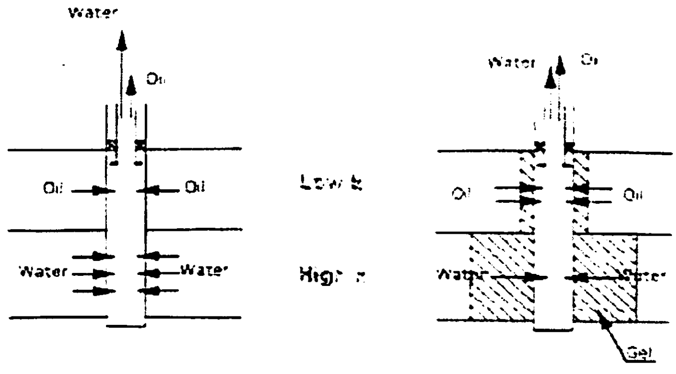
2.0 GEL POLYMER TECHNOLOGY

High water production is a major concern in mature hydrocarbon reservoirs. Almost all oil or gas reservoirs produce water. Since nature doesn't like vacuum, water usually replaces oil as hydrocarbon reserves decline in the field. In mature or old fields, most of produced fluid is water, with oil or gas representing a few percent of total production. Moreover, many reservoirs are submitted to water injection, which provides pressure maintenance and improves sweep efficiency. A continuous increase in water production is thus a normal behavior in the lifetime of a field. Often, water flow paths in the reservoir, especially close to the wellbore, are irregular, by-passing large hydrocarbon saturated zones and inducing undesirable high water-cut levels. The causes of excessive water production are multiple. Some of them are listed here whose order corresponds to increasing difficulty of treatment by gels:

1). Tubing/casing/packer leaks
2). Flow behind pipe
3). Layered reservoirs with vertical flow barriers
4). Individual fractures between injectors and producers
5). "2-D coning" through fractures
6). Channeling through naturally fractured reservoirs
7). 3-D coning or cusping
8). Layered reservoirs without vertical flow barriers.

In this list, cases 1 and 2 correspond to completion failures, a workover problem. Gels have the advantage over cements or mechanical plugs to be able to penetrate the formation over several feet, and thus create a deeper barrier. Moreover, they can easily be removed from the borehole by water recirculation. Let's consider a two-layer reservoir with a strong permeability contrast (for example 1/10) and a horizontal continuous barrier which prevents cross-flow. Since the high permeability layer is swept first, it has a tendency to overtake the oil production from the low-permeability layer. This situation calls for a treatment in future which intends to decrease water influx from the high-permeability layer, thus favoring low permeability layer production.

Costs of handling and disposing of water produced from oil reservoirs often shorten the life of a production well. For example, in well producing oil with an 80% water cut, the cost of handling water can be as high as $4 per barrel of oil produced. In some parts of the North Sea, water production is increasing as fast as reservoir oil rates are declining. As oil is produced from a reservoir, water from an underlying aquifer or from injectors eventually will be mixed and produced along with the oil. This movement of water flowing through a reservoir, into production tubing and surface processing facilities, and eventually extracted for disposal or injected for maintaining reservoir pressure, is called the *'water cycle'*. Oil producers are looking for economic ways to improve production efficiency, reduce operating costs and improve hydrocarbon production simultaneously. Thus, in order to reduce water production, polymer gels have been used to modify the mobility of water and oil in petroleum reservoirs, these are high-molecular weight water-soluble polymers or weak gels reduce selectively the relative permeability to water with respect to the relative permeability to oil or to gas and are known as "Relative Permeability Modifiers" (RPM's). This phenomenon is known as favorable DPR(Disproportionate Permeability Reduction). Reduced permeability to water can lead to decreased production of water, and sometimes increased production of oil, thereby prolonging the useful life of the reservoir. DPR is observed for both single polymers and crosslinked gel also DPR depends on the reservoir characteristics (e.g. lithology, pore size distribution and wettability). The usual method to study DPR is to saturate a porous medium with gelant, allow time for gelation to occur, and then inject oil and water to steady state conditions and determine permeabilities at 100% fractional flow of each fluid. However fractures, vugs and similar void channels often cause excess water production and poor sweep efficiency in reservoirs. In both hydraulically and naturally fractured reservoirs, void channels often allow injected fluids to flow directly between injection and production wells. This problem is especially important for EOR projects, where high-value fluids are injected. In production wells, void channels often extend into an aquifer-thus accentuating water production. In many cases, gels have effectively mitigated channeling through fractures, fracture-like features, and voids. Gels have reduced channeling through fractures in waterfloods and gas floods.



(a) (b)

Before treatment After treatment

Principle of DPR

2.1 DPR Mechanism

Adsorption in reservoir rocks of water-soluble polymers or gels induces a selective reduction of the relative permeability to water with respect to the relative permeability to oil or to gas. DPR working is based on the fact that adsorption of hydrophilic polymers can strongly decrease the permeability to water while having little effect on the permeability to oil. There are two main mechanisms one of which is relying on "fluid partitioning", whereas the other relies on "wall effects." The fluid partitioning theory claims that there are segregated flow paths for oil and for water inside the porous medium, and the gel tends to invade water flow paths, thus reducing water mobility preferentially. In the wall effect theory, the basic assumption is that after gel injection, a film covers the pore walls and changes dramatically two-phase flow properties by wettability, and lubrication effects. For the wall effects, there are two hypotheses, one assuming that the polymer/gel film is almost rigid, the other that the film can be squeezed by oil flow through pore channels. However, Due to hydration water, polymer adsorption increases the irreducible water saturation. Furthermore, for a formation producing both oil and water, a reduction of permeability to water induces automatically an increase in water saturation in the zone invaded by the RPM. The combination of these effects, both inducing an increase in water saturation, decreases oil permeability. Thus in practice it is very important to evaluate these unfavorable water saturation effects and to minimize them whenever possible. As a consequence, RPM treatments are more suitable in wells having zones with high oil saturation surrounding the wellbore than in wells where all zones produce at the same water cuts. Due to the reduction of both water and oil permeabilities, RPM treatments always induce a loss in the well productivity index. If this productivity loss is not counterbalanced by an increase in the drawdown on the well (by activation or by a lightening of the well fluid column), otherwise there is an obvious risk of losing oil production, even with the water cut strongly reduced. For fractured formations, due to the superficial invasion of the matrix blocks, RPM treatments have less impact on the well productivity index.

Furthermore, DPR is most effective when used against water production caused by coning or in situations where the watered out layers are separated from the oil producing layers. In situations with 2-phase flow a DPR treatment (even an idealized) will cause an increased pressure drawdown because of water saturation buildup in the treated zone. The producing WOR is in such situations the same as before the treatment.

However, the general understanding of the governing mechanism for DPR has not yet been reached. There are several suggested mechanisms. The most frequent proposed methods are:

- Polymer adsorption at the pore surface and the possibility to alter the wettability to more water-wet situation as well as some lubrication effects.
- Selective shrinking (or dehydration) and swelling of polymer and crosslinked gel-Segregated flow of oil and water.
- Balance between the opposing capillary forces and elastic confining forces.

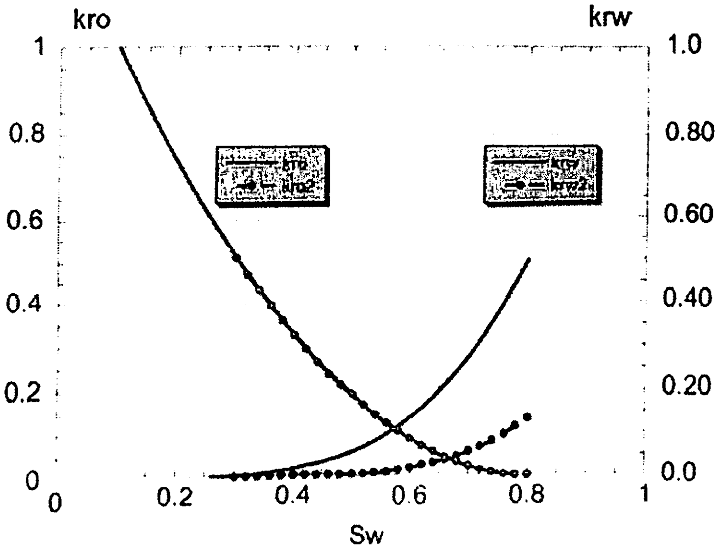
Finally, there are suggestions that there could be combinations of these mechanisms. One reason for the lack of consensus about DPR mechanisms may be that DPR is observed for both single polymers and crosslinked gel.

2.2 Process Involved

A DPR fluid is here a fluid with the ability to reduce the water permeability more than the hydrocarbon permeability. Here we discuss only oil permeability but the same arguments hold also for gas permeability. The most common DPR fluids are chemicals with the ability to form a gel in the pore space or chemicals retained in the pore space. Both mechanisms reduce the effective pore volume. Because of the segregated pathways the pore restriction is dominant for the phase in which the DPR fluid is soluble. In the following, different possibilities of obtaining DPR are demonstrated:

2.2.1 Saturation shift and wettability

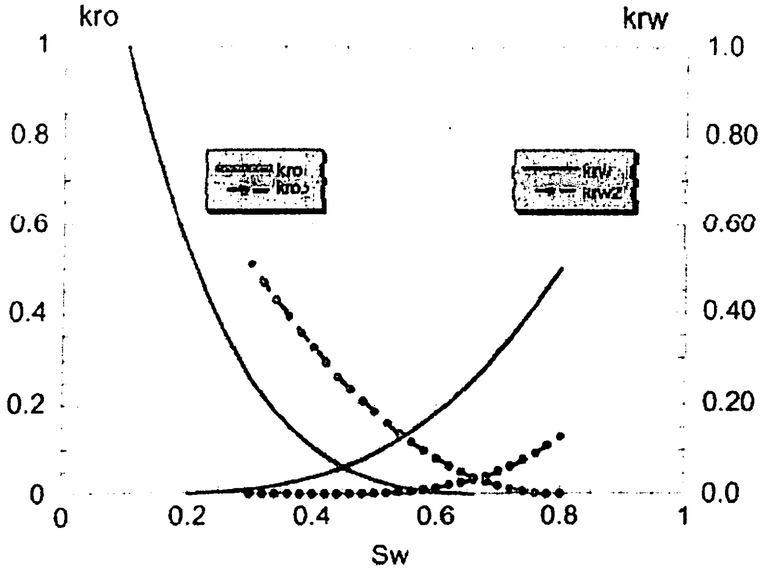
Assume standard relative permeability curves and injection of a fluid capable of reducing the available pore volume (porosity) for water by whatever mechanism (e.g. adsorption, retention, precipitation, filtration or gel formation). The reduction in porosity is expressed by an increase in the irreducible water saturation, Sw = Swi + ? S, Where ? S, is the shift in irreducible water saturation (i.e. the reacted DPR fluid act as immobile water). Because of the shift in saturation the relative permeability curves will be altered and may give rise to a DPR effect. As shown in Fig. , the endpoint water relative permeability is shifted downwards from krw = 0.5 before treatment to krw = 0.13 after treatment (RRFw=2 .60).



Relative permeability curves before and after injection of a fluid capable of reducing the water saturation, ? Swi=0.2.

As long as the residual oil saturation is not changed, the endpoint water relative permeability is reduced. The endpoint oil relative permeability is reduced as well from 1.0 to 0.51 (RRFo = 1.96), simply because the irreducible water saturation is increased. As a first approximation one may use the saturation shift and the asymmetry of the relative permeability curves to demonstrate a DPR effect. The same results can be obtained assuming the shift in the residual oil saturation.

Now, assume that the fluid injected alter the wettability. Then the water permeability is reduced more than the oil permeability, as shown in Fig.



Relative permeability curves before and after injection of a fluid capable of changing wettability

Thus, alteration of the wettability causes a shift in water saturation and may cause DPR. So the endpoint relative permeability reduction may give rise to a DPR effect, however small. This has been shown by only exploiting the slope of the relative permeability curves (wettability) and endpoint saturation's.

2.2.2 Pore size restriction

It is well known that both polymer and polymer gel have the ability to block the pores or restrict the pore size. There are at least two mechanisms for this pore size restriction. Polymer retention (which includes the terms adsorption, mechanical entrapment, precipitation, etc), typical for these retention mechanisms is that the permeability reduction increases with decreased initial permeability and with decreased pressure gradient. In this notation, adsorption is only one of several retention mechanisms. Gel formation. Gel is formed by cross linking of polymers into a 3D network. It is assumed that the gel behaves the same way in the porous media as in a bulk phase. As a first approximation we can assume that gel restricts flow considerably. As with polymer retention the permeability reduction increases as the pressure gradient decreases, but for most gel systems the permeability reduction increases with increasing permeability. A simple and frequently used model for a porous media is a bundle of capillary tubes. In this model an adsorbed layer at the surface of the water-wet tubes will reduce the pore space and reduce the permeability to water more than to oil. Segregated pathways can interpret this effect. Water flows close to the water-wet surface and will be restricted. The oil flows unrestricted in the middle of the pores as long as the thickness of the adsorbed layer is not too large. This flow behavior has been demonstrated theoretically both with regular pores and with more realistic pore size distribution. Experimental data have also been used to support the adsorbed layer as the DPR mechanism. The adsorbed layer model will, however, not work for oil-wet media. Therefore the adsorbed layer model is not a general model for the DPR mechanism. With adsorption on an oil-wet surface, the model should predict higher permeability reduction for oil permeability than for water, simply because oil is the wetting phase and will flow close to the surface and be restricted by the adsorbed layer. Nevertheless experiments, showing a DPR effect in what is claimed to be an oil-wet media using an adsorbing polymer have been interpreted with the adsorbed layer model. However, it is unlikely that a water-soluble polymer will adsorb at an oil-wet surface. It may be that the claimed oil-wettability is more of a mixed or fractional wettability where there still are some water-wet pathways, or that the claimed adsorption is not the governing retention mechanism.

It is well known that pre-filtration improves the injectivity of a polymer through a porous medium. Well-filtered polymer solutions show less permeability reduction than less filtered solutions. The adsorption level is, however, about the same. If polymer adsorption should be the governing retention mechanism, the following observation should be observed during the coreflood experiments: A pressure increase during the polymer injection until the adsorbed layer is established. The differential pressure should then level off corresponding to the mobility reduction (permeability reduction multiplied by the relative polymer viscosity). At the same time the produced polymer concentration should be equal to the injected concentration. The normal observation for DPR polymers is, however, a gradual increase in differential pressure (increases as the injected volume increases) without the differential pressure leveling off. The produced polymer concentration is lower than the injected. This indicates a filtration process rather than general adsorption. A study in micromodels using water-wet porous media supports this. The retained polymer was reported as polymer entanglement (which is essentially an adhering of polymer, forming a network on the pore surface that is constantly replenished from the flowing polymer solution) on the crevices between the grains.

2.3 Flow of oil and water through a geltreated media

For a rigid gel placed at residual oil saturation, no oil continuous pathways should exist. Therefore no oil should be able to flow through such a gel. For less rigid gels, experiments have shown the possibility of forcing oil through. It has been argued that an aqueous gel may swell in water and shrink in oil. However, this is chemically not possible. For an aqueous gel to shrink, water has to be extracted. There is to our knowledge no known mechanism by which oil can extract water from an aqueous gel nor has any been suggested. Nevertheless, this mechanism has been used to explain why oil is more easily flooded through a gelled media than water. If this mechanism is operative water has to flow through the gel by diffusion, which gives a strong permeability reduction. Because of gel shrinkage in oil, mobile water is separated. Oil may displace this water, and bypassing the gel giving a less permeability reduction. It has also been suggested that the flow of water is through the gel matrix, whereas the oil pushes its way through the gel in form of immiscible drops or filament with the flow characteristic controlled by the elasticity of the polymer gel. The oil flow will then open a channel through the gel matrix, resulting in a higher permeability. In corefloods where oil and water are cycled after placement of a strong gel, highest *RRFw* is measured in the first water cycle. In subsequent water cycles after an oil cycle essential lower *RRFw* is measured. This indicates that the open channels generated by the oil permanently destroyed some of the gel matrix. The gel is not repaired after the oil has forced its way through.. Results support the theory of permanent breakdown of gel after oil is forced through it. The interpretation is however, by a mechanism of gel dehydration. If oil is in place before treatment, especially if the oil is mobile, the oil will have easier pathways than through the gel and will, therefore, not necessarily need to break the gel.

However, in an ideal reservoir situation (single phase water production from the watered out layer and single-phase oil production from the oil producing layer) it may be an advantage if oil breaks the gel. Open pathways is created in the oil zone, while water is hold back from the watered out layer. This concept may be effective until water breaks through in the oil layer, but is not a real DPR situation. It is rather a selective gel placement concept, which competes with placement concepts where gelation in the oil zone is avoided. A balance between the opposing forces, capillary force and elastic confining force, might contribute to DPR. The capillary force should act to maintain a minimum droplet radius, which in turn opens a channel through the gel. The gel exerts an elastic confining force to close the channel. The final radius of the oil droplet and the size of the oil pathways depend on the balance between the two forces. The effective permeability to oil increases with increasing radius of the flow path around the droplet. The experimental data from corefloods , however, do not support such a mechanism.

It is our opinion that a balance between the capillary force and the gel elasticity is not a major DPR effect. However, if there is an effect one may speculate in which direction it will work. Consider an oil droplet at the entrance of a narrow channel through the gel. If the oil droplet is a rigid particle (i.e. high interfacial tension) it will tend to plug rather than to be transported through the gel. On the other hand, if the oil droplet is more easily deformed (i.e. low interfacial tension) the droplet may be transported through the channel. This consideration corresponds to higher oil permeability reduction for high interfacial tension. Nevertheless, it is well known that gel shrinkage may occur, but not selective for only one of the phases. It is also accepted that polymer will shrink or swell , because of electrostatic shielding, e.g. by variation of brine salinity. The polymer will then shrink giving low injecting viscosity and the polymer retention causes relatively low permeability reduction. If back produced with a less saline water, the retained polymer will swell giving an essential higher permeability reduction.

2.3.1 Segregated flow

Segregated pathways can, either be flow of one phase in a preferred set of channels or flow of one phase in defined parts of the channel. When in place in the pore network, a water-based DPR fluid will be distributed mainly in or between the pores in the same manner as water. Therefore the placement of the waterbased DPR fluid will to some degree be exchanged with parts of the water in place. To have an effect of the DPR treatment it is crucial that the oil pathways are continuous and not broken by the DPR treatment. If not, the treatment will cause blocking for both phases - blocked water preferred pathways and discontinuous oil preferred pathways. To illustrate this effect assuming that a strong gel is placed into a reservoir at residual oil . The remaining oil is immobile and will not flow without breaking the gel, and in practice no water will flow because of the gel. On the other hand, if the DPR fluid does not occupy all the available pore space (e.g. gel shrinkage or polymer retention in only a fraction of the volume), the oil preferred pathways are still intact with only minor flow restriction for the oil. By this segregated pathway model we are able to interpret DPR for the following situations:

2.3.2 Retention of polymer

In our opinion the so-called adsorption model is more a retention/entrapment model and the governing mechanism for permeability reduction is a result of entrapment. Since water soluble polymers will be trapped in the parts of the pores available for water, the flow restriction for water is stronger than the restriction for oil. In a water-wet situation, only water will flow in the smallest pore. In the largest pore both oil and water will flow, with water close to the wetted surface. A water-soluble polymer will flow as water. Retention is concentrated in the smallest pore throats and at the surface in pore channels as well as some adsorption at the bulk surface. After treatment oil will continue to flow only in the largest pores with minimum restriction. The water flow is restricted both in the smallest pores (and pore channels) because of the polymer and to some extent by the adsorbed layer. This will result in a DPR effect. If the core is oil-wet, only oil will flow through the smallest pore, with both water and oil in the largest pore. The polymer will not flow through the smallest pores and will not adsorb on the surfaces. Retention may however, occur in the pore channels (where both oil and water are able to flow) or in the small pore entrance. This will result in less water permeability reduction compared with the water-wet case. Trapping at the entrance to the smallest pore, may cause restriction of oil flow. However, since most of the flow is through the largest pores the oil permeability reduction should be limited. The permeability reduction for both water and oil should be limited in such a pore configuration, and it is not obvious that a general DPR effect is observed.

2.3.3 Adsorption

In situations where adsorption is the dominant retention mechanism, mainly regular pores and water-wet situations, a DPR effect will be observed according to the adsorbed layer model. Notice that this model is already included in the general segregated pathway model, saying that a polymer layer replaces the water film. When the adsorbed thickness, is essential smaller than the pore radius, (e.g. high permeability) the permeability reduction is low. Hypothetically if one assume an oil-wet pore , a polymer layer replaces the oil film and (ii) alter the wettability from oil-wet to water-wet one will have a situation qualitatively the same as in above Fig., where a DPR effect is found. Notice that the combination adsorbed layer and oil-wet pores after treatment will give the opposite effect of DPR, stronger flow restriction for oil than for water.

2.3.4 Weak Gels

Gel aggregates or flowing pre gelled systems will act similar to polymer entrapment. The aggregates will be trapped in the smallest porethroats. Most likely the permeability reduction for both oil and water will be higher than for single polymer, but may be controlled.

2.3.5 Strong gel placed in water-wet pores

Placed at residual saturation this will not be an effective DPR method since the oil continuity is broken. The only possibility for oil to flow is by breaking the gel , and permanently open a channel through the gel. Thereby there will be flow by oil, but also for water. The final DPR effect after some oil-water cycles will be less pronounced.

2.3.6 Strong gel placed in oil-wet pores

Recovery from oil-wet reservoirs causes a long tail-end production. Tail-end oil production is mainly the result of film flow at high water-cut. At true residual oil saturation the situation with strong gel in oil-wet pores is the same as for the water-wet case - strong blocking. However, for practical purposes the true residual oil saturation is not reached when the gelant is placed. This makes it possible to maintain some oil continuity and a better DPR effect than for water-wet situation. The entrance pressure for water may not be sufficient to penetrate the smallest pores, which remain open

2.3.7 Gel placed in mixed-wet media

This is more or less the same situation as for the oil-wet case. However, it would be even more difficult to reach the true residual saturation thus giving good possibility of maintaining oil continuous pathways.

2.3.8 Gel shrinkage

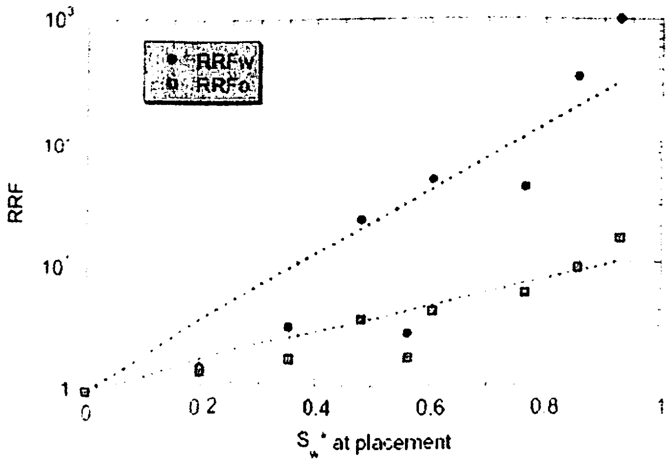
Shrinkage of the gel after placement can be a benefit, since the possibility of oil continuity will increase. To some extent, the polymer to crosslinker ratio may control the shrinkage but not selectively for only one of the phases. When the gel shrinks, an amount of excess water may form a continuous channel that may be accessible to both water and oil. In accordance with the arguments the gel will most probably start to shrink at the gel-oil interface. In a water-wet situation, where oil droplets are placed in the middle of the largest pores, the droplets will be surrounded by an excess water layer, which may lead to continuity. Then a DPR effect will be observed. In oil-wet situations the gel is placed in the middle of the pore with an oil film close to the surface. Here the excess water is located between the oil film and the gel may be seen as isolated droplets in the middle of the pores. Again a DPR effect will be observed. Through these simplified situations we have established a basis for the DPR mechanism, which assumes segregated flow on the pore scale. In a reservoir situation the wettability will not be straight water-wet or oil-wet. It will be some water-wet pores and other oil-wet. Nevertheless, it is still possible to demonstrate the DPR effect with the segregated flow model for both oil-wet and water-wet pores. The only requirements are oil continuity and water based DPR fluid restricting the pore size.

2.4 Optimal DPR system

When used in a layered reservoir DPR is an alternative to selective placement, where gel is formed in the watered out zone and no gel is formed in the oil zone. A DPR system should preferably give larger permeability reduction in the high permeability zone than in the low permeability zone. Likewise an optimal DPR system should have no permeability reduction for oil and a significant permeability reduction for water. In practice there will always be some reduction in the oil permeability. This reduction should, however, be minimized. There are several criteria regarding oil permeability reduction:

- Minimum reduction in oil permeability measured at the same saturation (excluding the effect of shift in saturation) .
- Minimum reduction in endpoint oil permeability, (including the shift in saturation).
- Maximum endpoint permeability reduction ratios .

It should be quite obvious that the permeability reduction depends on the saturation at placement or the volume occupied by the DPR fluid. At Sw* = 0, there should be no permeability reduction for both phases and maximum reduction at residual saturation (Sw* = l). The saturation at placement of gel systems is calculated by volume balance. For single polymer systems the water saturation at placement may be interpreted as the endpoint water saturation after treatment. Fig. Shows a set of permeability reductions



RRF versus normalized saturation at placement.

RRFw and RRFo are plotted versus the normalized water saturation at placement. As can be seen the permeability reduction for both oil and water increases as the water saturation increases. Most of the DPR systems will show a similar trend. Having a DPR fluid and the possibility of choosing the saturation at placement, one can tailor the permeability reduction by varying only the saturation at placement. The constraints may be a maximum reduction in oil permeability or a minimum reduction in the water permeability. As shown in given Fig., it is possible to obtain good oil productivity after placement using strong gel systems, by only optimizing the saturation. It is believed that such a DPR treatment will be more robust than single polymer retention.

2.5 Candidate Well Selection

Several factors have to be taken into account for DPR candidate well selection, some are:

1) Heterogeneity

For both permeability and saturation issues, strong vertical heterogeneity is a positive factor for the choice of a candidate well. The presence of both highly oil saturated and highly water-saturated layers producing together is preferable than having all the layers producing at the same water cut. Also, a strong permeability contrast between the layers is advantageous because the placement of the gel will be favored. In bullhead treatments, the gelant will invade more deeply the high-permeability watered out layers (to be plugged) and less far the low-permeability oil-saturated layers (to be protected). From a more general point of view, since vertical heterogeneity is a factor enhancing water breakthrough, it makes at the same time the well a good candidate for a water shutoff treatment.

2) Crossflow

When there is crossflow between the layers, water can rapidly bypass the gel in place and therefore will return to the same rate as before treatment. Crossflow is thus a negative factor for candidate choice. As a consequence, wells with a water coning are, in principle, bad candidates for RPM treatments. On the other hand, multilayered wells with no communication between the layers are good candidates.

3) Production mode

Since a gel treatment reduces the well productivity index, maintaining well production requires a higher drawdown on the well either through more activation (pumping, gas lift) or through reduction of the water cut (for eruptive wells) by lightening of the fluid column. Also, good pressure maintenance in the reservoir (active aquifer, gas cap) is an advantage for maintaining well productivity.

4) Technical constraints

The gel should withstand reservoir conditions for long periods of time. Thermal stability is often a major factor for treatment selection. Also local environmental regulations, well accessibility etc. may play an important role in candidate selection.

5) Economical constraints

Water shutoff treatments are usually considered as workover operations. Treatment decision is based on comparison of costs vs. expected returns. It is very important to evaluate both at an early stage. A candidate well should have a potential of incremental oil production sufficient to cover treatment cost and make significant profit. An expensive treatment can be perfectly suitable for a big offshore well, but completely inadequate for a small onshore well. Although in most cases producing more oil is the target, sometimes the operator can tolerate some loss in oil production provided water production is strongly reduced. This is frequently the case under offshore conditions when water handling capacities are limited. As a rule of thumb, treatment costs should be paid out by three months of post-treatment production.

6) Origin of water production

Some methods have been proposed to identify the origin of water production in a given well. Although none of them has reached commercial practice, these methods may help in the selection of candidate wells. For example, the profiles of WOR plots are markedly different for coning than for multilayer production. Recently, a method based on water cut analysis at the level of a field pattern has been proposed to identify the contribution of surrounding wells (injectors and producers) to the productivity of the candidate well.

7) Logs

Log analysis is a good indicator of the configuration of the part of the reservoir surrounding the wellbore. Resistivity logs give the saturation of the different layers. Gamma-ray logs point to the presence of shale barriers and help to evaluate clay vertical distribution. Whenever possible production logs are run before and after the gel treatment in order to identify the contribution of each individual layer in terms of total fluid flow and water production.

2.6 Methodology

The preparation of a RPM water shutoff treatment requires laboratory experiments, numerical simulations and on-field adjustments. The laboratory study aims at (1) verifying polymer/additives injectivity and compatibility, (2) optimizing chemical formulations, (3) running two-phase flow corefloods under reservoir conditions to measure end point relative permeabilities before and after polymer treatment. Numerical simulations are run in three phases, i.e. (1) establishment of a history match of fluid production from the candidate well with a simplified near-wellbore reservoir description, (2) simulation of polymer injection, (3) post treatment production forecasts. Numerical simulations aim at sizing treatment slug volume and evaluating expected performances.

Onfield adjustments are made with a light lab equipment enabling treatment survey during field operations. This equipment includes *BrookfieldTM* type viscometer, pH meter and in-flow wellhead pressure recorder. Quick compatibility checks with actual fluids are usually done before starting operations. During polymer injection, solution viscosity has to be adapted to the actual wellhead pressure, which of course has to remain below the fracturation pressure (a 20% safety factor is usual).

2.7 CASE STUDY

Evaluation of Commercial Crosslinked Polyacrylamide Gel Systems for Injection Profile Modification

This is identify the best polymer gel systems for a particular field application. Beaker tests are used to rapidly screen gel systems. Results are presented from a full-scale laboratory evaluation of 15 commercially available polyacrylamide polymers with a Cr(III)-redox crosslinker for profile modification in a thick, multizone reservoir. Beaker tests showed that low levels of polymer hydrolysis were required to produce consistent gels at reservoir conditions. In addition, the pH of the gel solution in the buffered field brine had a large effect on the gel properties. The selection process is complicated by the number of different polymers and crosslinkers that can be used to form gels. For example, the polymer can be synthetic or a biopolymer; can be purchased in several forms (broth, solid, emulsion, dispersion, solution); and can vary in terms of percent hydrolysis, type of ionic character, and molecular weight. Ionically crosslinked gels can be formed in situ, with either the aluminum citrate process or the redox process involving the reduction of chromium (VI) to chromium (111) or formed on the surface with chromium (111). Crosslinked gels can also be formed in situ.

2.7.1 TARGET RESERVOIR

The target reservoir for this work was comprised of a massive sand/shale sequence with an average net pay of 1167 feet [355.7 m]. The average reservoir temperature ranged from 160° to 180° F [71.1 to 82.2°C], while some of the injection wells had near wellbore temperatures of 120 F [48.8°C]. A review of the available core data showed that that geometric mean air permeability was 23 md .

The waterflood in the target raaervoir has not performed well, One of the factors accounting for the lower than expected recovery is the wide permeability variation between reservoir layer). The thief zones that are created by this condition are bounded by shale barriers that extend throughout the reservoir. With time, these zones have become watered out, and injected water has been recycled through the reservoir. Consequently, there is considerable incentive for improving the waterflood performance with gel polymer treatments.

2.7.2 METHODOLOGY

The methodology that was used here for evaluation was comprised of five steps. First, gel system candidates were solicited from service companies and vendors. Second, the polymers were characterized according to percent solids, percent hydrolysis, and molecular weight, Third, statistically designed beaker screening experiments were used to group gel system and identify important variables affecting gelation. Fourth, beaker tests were again employed in statistically designed

Response surface experiments to define formulations for coreflood tests, Finally, corefloods were conducted to evaluate the most promising gel systems.

2.7.3 EXPERIMENTAL PROCEDURES

The candidate polymers were characterized by percent solids, percent hydrolysis, and molecular weight. Percent solids were determined by precipitating the polymer with methanol (emulsions) or acetone (dispersions) and then drying the precipitate to constant weight. C-13 NMR was used to determine the fraction of hydrolyzed carboxylic acid groups relative the amide groups on the polymer backbone. Brookfield viscosity measurements over a wide range of shear rates were used to rank the candidate polymers according to molecular weight. When the polymers had equivalent hydrolysis levels intrinsic viscosity (IV) measurements were used to further classify the polymers, some of the gel times were measured with a Brookfield viscometer by continuously monitoring the solution viscosity at a low shear rate. Rolling ball viscometers were also used to measure gel times in the response surface experiments and when preparing oxygen-excluded samples in a glove box. In both instances, gel times were measured at temperature. The gel point was defined as the intercept of the extrapolation of the two straight line sections of the viscosity-versus-time curves. Gel strengths were measured 24 hours and one week after the gel point with a "capillary" viscometer. The flow time of the gel solutions into a capillary tube under a constant vacuum was recorded. The log of the *flow* time at 5 inches vacuum was used to rank the gels according to strength. Thus a gel with a flow time of 10 seconds had gel strength ranking (GSR) of 1, a gel with a flow time of 100 seconds had a GSR of 2.

A typical coreflood was conducted by saturating a heated Berea core plug with produced field brine, oilflooding it to initial water saturation with a mineral oil, and then waterflooding it to residual oil saturation with produced field brine. No other steps were taken to precondition the core before use. Next, multiple pore volumes of gel solution, also mixed in produced field brine, were injected at constant rate through the core plug. Effluent samples were collected for pH, gel time, and gel strength measurements. The core was then shut in until gels had formed in the effluent sample. Finally, the core permeability und the effluent gel strengths were measured. Two types of stability tests were run. In the static aging tests, permeability was periodically measured while the core plugs were aged at temperature under no-flow conditions. In the dynamic stability test, fluid was continuously injected.

2.7.4 RESULTS AND DISCUSSION

Gel System Solicitation

A total of 30 different gel systems, 15 polymers and either a chelated or a chromium (111) crosslinker, were recommended for the field application. The reservoir description allowed a priori selection of the crosslinker, thereby reducing the number of systems from 30 to 15. The gel system had to provide high levels of permeability reduction to completely isolate the thief zones from the productive interval. In addition, near wellbore treatment would be effective because of the shale barriers isolating the thief intervals. Therefore, bulk gels with relatively short gel times formed by the redox process were examined instead of layered gels formed by the aluminum citrate process. Surface formed gels were not considered because of the low permeability of the formation.

2.7.5 Polymer Characterization

Fifteen polyacrylamide polymers with a wide variation in molecular weight and levels of hydrolysis were submitted by vendors and were included in the testing program.

2.7.6 Screening design

The screening experiment is evaluated by Pusher 1000 and Hivis 350. The results of the screening experiment showed that molecular weight and salinity were key variables affecting both gel time and gel strength. The salt screening effects allow hydrolyzed polymers to interact more freely, accelerating the rate of crosslinking. However, the polymers also assume a coiled configuration, leading to intra-molecular crosslinking and decreased gel strength. Two more screening tests were conducted to further examine the effects of molecular weight and polymer hydrolysis on gel properties. The results from the experiment with Cyanaperm 220 and Pusher 500 could not be analyzed because the formulations failed to from gels at many of the test conditions. Instead, the polymers formed flocks or precipitate. The screening effect from the ions in the mix water produced conditions that favored intra-molecular crosslinking and not the formation of a gel matrix. The tests could have been repeated at higher polymer concentration in an attempt to exceed the critical polymer concentration. In addition, *the results from the experiment using low hydrolysis polymers looked promising.* Thus, polymers with high levels of hydrolysis were not considered further for this application. Unlike the high hydrolysis polymers, the Cyanagel 150 and Alcoflood 935L formulations produced consistent gelation at all conditions tested. Two conclusions were drawn from the screening experiments:

(1)First, polymers with 0 to 4 percent hydrolysis were good candidates for redox triggered gelation for the specific reservoir conditions being evaluated.

(2)Second, because of the extreme sensitivity of the gel reaction to polyelectrolyte changes at these low hydrolysis levels, each polymer candidate had to be evaluated separately at condition that closely matched those of the field.

The screening experiments reduced the number of polymer candidates from fifteen to two.

2.7.7 Coreflood Evaluation

The beaker tests provided a good understanding of the factors affecting gel time and gel strength for the Cyanagel 150 and Alcoflood 935L systems. The next step was to evaluate the performance of both systems in coreflood. Berea was chosen over samples of reservoir rock because of the limited supply of field cores. The main objectives of the coreflood tests were to :

1) Compare the performance of similar Cyanagel 150 and Alcoflood 935L formulations.
2) Demonstrate in-depth gelation, and
3) Measure the stability of a gel under continuous injection.

A polymer concentration of 5000 ppm was chosen because at lower polymer concentrations the Alcoflood gel was much weaker than it was at 5000 ppm. A mole ratio of 4 was chosen because of the rapid gelation of Cyanagel 150 at higher mole ratios. Finally, a dichromate concentration of 600 ppm was chosen to insure adequate strength of both types of gels. Tests are conducted and is was observed that Cyanagel 150 was flat, while that for Alcoflood 935L continued to rise with time. These observations are consistent with the polymer characterization results reported earlier that indicated that Alcoflood 935L had a higher molecular weight than Cyanagel 150. At the beginning of the test the cores were first tested following treatment, and the results at the end of the test 50+ days later. The aging time, core permeability residual resistance factor (RRF, mobility of brine before gel treatment divided by mobility of brine after gel treatment), and GSR values of the injected gel and last effluent pore volume are reported.

The coreflood results show that even in a relatively clean system such as Berea, significant pH changes can occur that will impact the performance of a gel system. This effect is expected to be worse in actual reservoir rock where more rock/fluid interaction will take place. The implication of this result is that in the field application of gelled polymer technology, the pH of these systems in the reservoir must be maintained within a narrow pH range. Otherwise, field performance will not match laboratory observations. The Alcoflood formulation was selected for further evaluation over the Cyanagel formulation for two reasons. First, beaker tests had shown that the Alcoflood gel times were longer than the Cyanagel gel times, providing more flexibility in the field. Second, although the coreflood had shown that Cyanagel had the better injectivity, in the event that gels did not form in the formation, the Alcoflood polymer would provide more permeability reduction than the Cyanagel polymer.

2.7.8 CONCLUSIONS

1. The methodology and techniques described have proven to be very useful in identifying the best potential polymer gel system for a given field application.

2. Polymers with 0 to 4 percent hydrolysis were found to be the best gelled polymer candidates for redox triggered gelation at the target field. Polymers with higher degrees of hydrolysis produced precipitates.

3. Generally, gels produced in beakers with Cyanagel 150 had shorter gel times and greater gel strengths than those produced with Alcoflood 935L.

4. Coreflood showed that both gel systems were capable of producing significant levels of permeability reduction for 50 days at reservoir temperature. In contrast to the results from the beaker tests, the Alcoflood system outperformed the Cyanagel system in the coreflood.

5. The reason for the superior coreflood performance of the Alcoflood formulation over the Cyanagel formulation was attributed to the pH changes that occurred in the formulations during core treatment.

6. The coreflood data suggest that an important limitation in the field application of gelled polymers will be the ability to control the pH of these systems in the reservoir within a narrow pH range.

7. A continuous injection coreflood showed that the Alcoflood gel began to degrade once a certain pressure gradient was reached. At that point the gel began to break down and move through the core.

3.0 BASIC CONCEPTS RELATED TO DPR

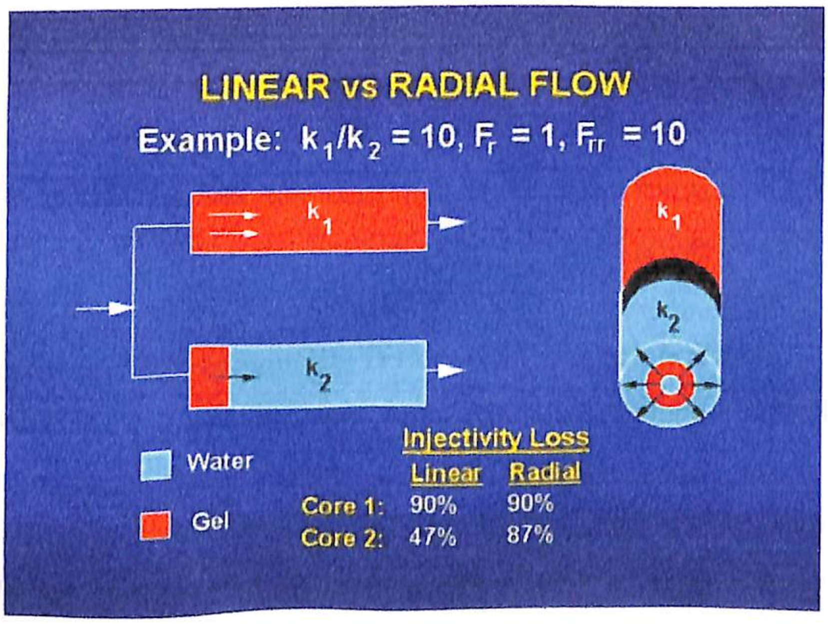
1 Linear Versus Radial Flow

Basic calculations using the Darcy equation reveal three important facts:

1) First, gelants and similar fluid blocking agents can penetrate a significant distance into all open zones.
2) Second, an acceptable gelant placement is much easier to achieve in linear flow than in radial flow.
3) Third, if flow is radial, then hydrocarbon-productive zones must be protected during gelant placement.

Justification:

The above statements can be understood by comparing calculations for linear versus radial parallel corefloods (see Fig. 1). In each set of corefloods, assume that Core 1 is 10 times more permeable than Core 2 (i.e., k1/k2=10) and both cores have the same porosity. Initially, all cores are filled with water.



LINEAR vs RADIAL FLOW

Example: $k_1/k_2 = 10$, $F_r = 1$, $F_{rr} = 10$

🟦 Water

🟥 Gel

Injectivity Loss

	Linear	Radial
Core 1:	90%	90%
Core 2:	47%	87%

Linear versus radial parallel corefloods

A gelant-with a water-like viscosity, i.e., the resistance factor, Fr, is equal to 1-is injected simultaneously into Cores 1 and 2 until Core 1 is filled. For the parallel linear corefloods, the gelant fills the first 10% of the pore space in Core 2. For the radial floods, the volume of gelant entering Core 2 is also 10% of the volume that enters Core 1; however, because *the radius of the gelant front varies with the square root of the volume injected*, so the final gelant radius in Core 2 is approximately 1/3 (i.e.,~ v0.1) that in Core 1.

After the gelant is placed, flow is stopped to promote gelation. Wherever the gel forms, the permeability to water is reduced by a factor of 10 (i.e., the residual resistance factor, Frr, is equal to 10). Next, water injection is resumed, and the final water injectivity is determined for each core. In both the linear and radial corefloods, *Core 1 is completely filled with gel, so it experiences a 90% injectivity loss*. For the linear case, a 47% injectivity loss is calculated for Core 2 (using the Darcy equation for flow in series).

Since a much larger injectivity loss occurs in the high-permeability core, the gel treatment significantly improves the injection profile. However, the damage to Core 2 is significant.

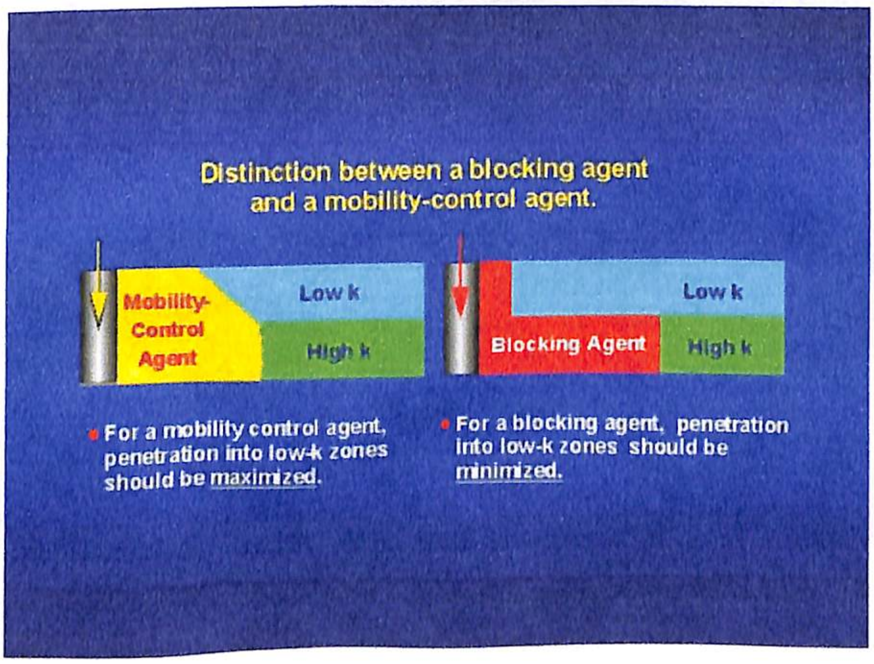
In the radial system, calculations (again, using the Darcy equation for flow in series) reveal that Core 2 experiences an 87% injectivity loss. Therefore, in radial flow, the gel treatment causes approximately a 90% injectivity loss in both cores without significantly improving the injection profile. These simple calculations illustrate two of the three important facts that are revealed by the Darcy equation:

An acceptable gelant placement is much easier to achieve in linear flow (e.g., vertically fractured wells) than in radial flow (e.g., wells without fractures), and if flow is radial, then hydrocarbon-productive zones must be protected during gelant placement

2 Gel Treatments are Fundamentally Different from Polymer Floods

The distinction between a blocking agent (e.g., a gel) and a mobility-control agent (e.g., a polymer solution) is an important concept to understand (see Fig.). A mobility-control agent should penetrate as much as possible into the less-permeable zones so that oil can be displaced from poorly swept zones. In contrast, we wish to minimize penetration of blocking agents into the less-permeable, oil-productive zones. Any blocking agent that enters the less-permeable zones can hinder subsequent injected fluids (e.g., water, CO2, steam) from entering and displacing oil from those zones.

Important distinctions also exist between polymer solutions that are used in mobility-control applications and gelants and gels that are used in blocking applications. Laboratory results consistently show three characteristics of gelants and gels in porous rock. First, early in the gelation process, gelants flow freely through porous media, like uncrosslinked polymer solutions. Second, after gel aggregates grow to approach the size of pore throats, they become trapped and no longer flow at any significant rate. Third, the transition between these two conditions occurs over a relatively short time period. These facts further emphasize that gel treatments are not polymer floods. Gels, crosslinked polymers, gel aggregates, and the so-called "colloidal dispersion gels" (1) are not simply viscous polymer solutions, (2) do not propagate through porous rock like polymer solutions, and (3) do not enter and plug the most-permeable zones first and plug progressively less-permeable zones later. Thus, one cannot simply add a small amount of crosslinker to a polymer solution and expect it to act like a super polymer flood. One should be concerned if a vendor uses traditional polymer-flooding arguments or simulations to argue the benefits of a gel treatment.


Distinction between a blocking agent and a mobility-control agent.

- For a mobility control agent, penetration into low-k zones should be maximized.
- For a blocking agent, penetration into low-k zones should be minimized.

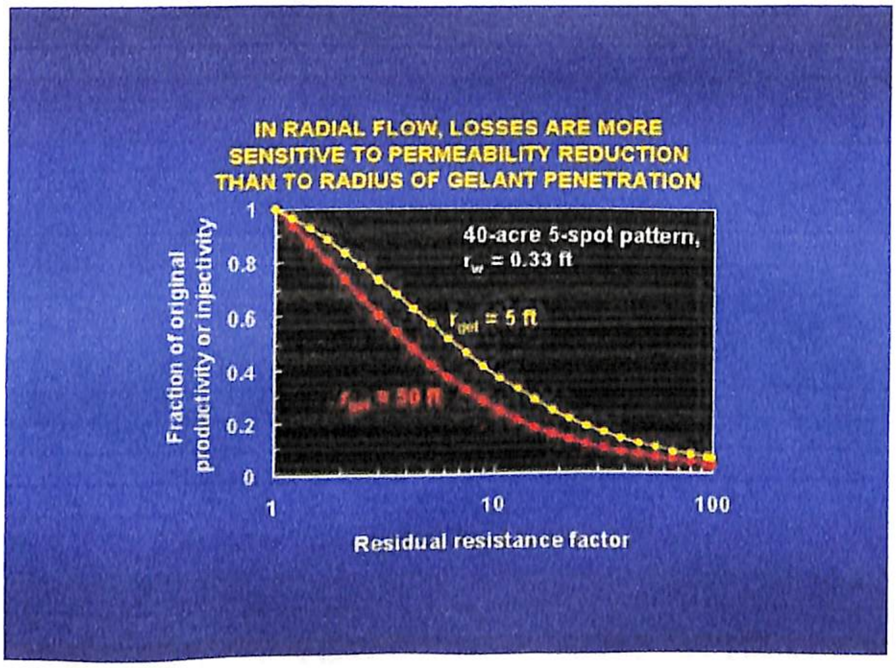
Distinction between a mobility-control agent and a blocking agent.

3 In radial flow, How much reduction in ko can be tolerated

The fraction of original injectivity or productivity retained (I/Io) after a polymer or gel treatment as a function of the residual resistance factor (i.e., the permeability reduction provided by the polymer or gel). Fig. (1) applies to a waterflooded reservoir with a 40-acre, 5-spot pattern with a unit-mobility displacement. The wellbore radius was 0.33 ft.

Two cases of radii of gelant penetration, rp, are presented-5 ft and 50 ft. A comparison of these two curves reveals that for a given residual resistance factor, the injectivity or productivity losses are not strongly dependent on the radius of gelant penetration.

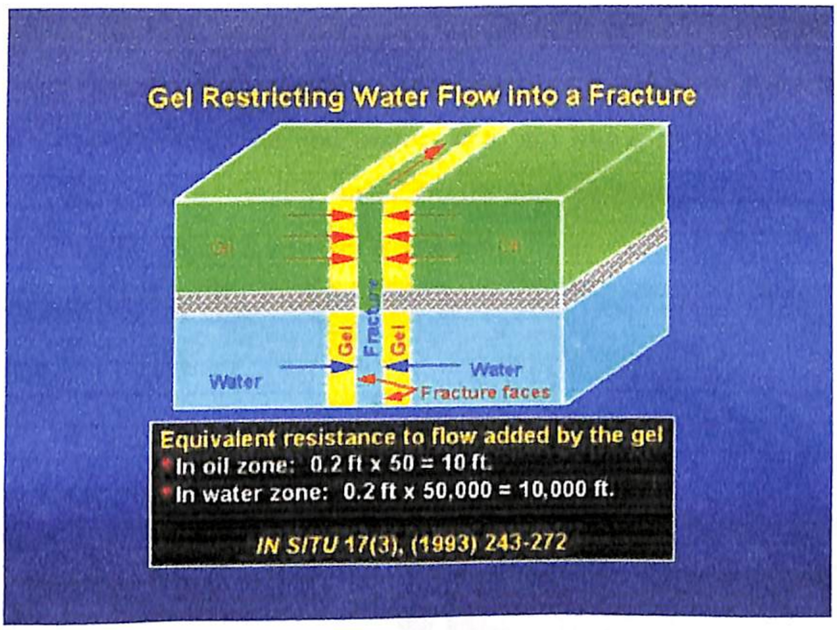
For radial flow, Fig. (1) reveals that relatively small residual resistance factors can cause significant injectivity or productivity losses. For example, for a gel radius of 50 ft, a Frr value of 2 causes a 27% loss in I/Io, while a Frr value of 10 causes a 75% loss. Both of these losses might be considered unacceptable if these are oil zones. Thus, in unfractured wells, hydrocarbon residual resistance factors (Frro) must be small. (Depending on the rock and the gelant system, these low Frro values may be difficult to obtain in a predictable and controllable manner.)



IN RADIAL FLOW, LOSSES ARE MORE SENSITIVE TO PERMEABILITY REDUCTION THAN TO RADIUS OF GELANT PENETRATION

Fig.(1). Fraction of original injectivity or productivity retained (I/Io) versus residual resistance factor. Radial flow (unfractured well)

The disproportionate permeability reduction may be of greater value in treating production wells where vertical fractures cut through both water and hydrocarbon zones (see Fig. (2)). When a gelant is injected into a fractured production well, hopefully, it will propagate a large distance down the length of the fracture while leaking off a very short distance into the porous rock. Assume that the gelant leaks off 0.2 ft into both the oil and water zones. Also, assume that the gel reduces ko by a factor of 50 while reducing kw by a factor of 50,000. (We. are aware of a gel with these properties.25) Upon first consideration, a Frro value of 50 might appear to be prohibitively high. However, because of the short distance of leakoff in this example (0.2 ft), the gel only adds the equivalent of 10 feet of additional rock that the oil must flow through to enter the fracture (i.e., 0.2 ft x 50). In contrast, for the water zone, the water must flow through the equivalent of 10,000 ft of additional rock to enter the fracture (i.e., 0.2 ft x 50,000). Thus, the gel can substantially reduce water production without significantly affecting oil productivity



Gel Restricting Water Flow Into a Fracture

Equivalent resistance to flow added by the gel
- In oil zone: 0.2 ft x 50 = 10 ft.
- In water zone: 0.2 ft x 50,000 = 10,000 ft.

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Gel restricting water entry into a fracture.

4 Gel Treatments are Fundamentally Different from Polymer Floods

The distinction between a blocking agent (e.g., a gel) and a mobility-control agent (e.g., a polymer solution) is an important concept to understand (see Fig.). A mobility-control agent should penetrate as much as possible into the less-permeable zones so that oil can be displaced from poorly swept zones. In contrast, we wish to minimize penetration of blocking agents into the less-permeable, oil-productive zones. Any blocking agent that enters the less-permeable zones can hinder subsequent injected fluids (e.g., water, CO2, steam) from entering and displacing oil from those zones.

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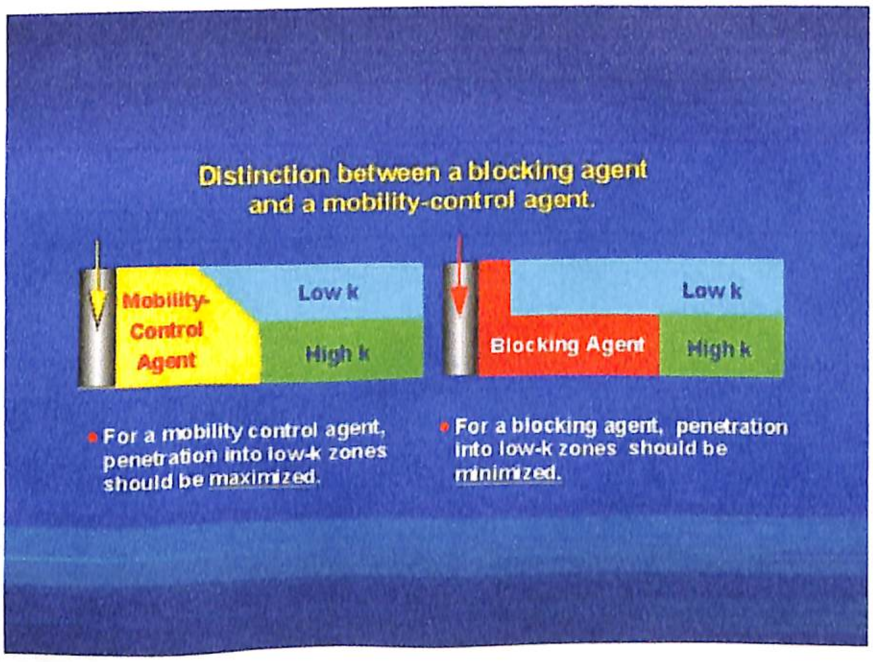


Distinction between a blocking agent and a mobility-control agent.

- For a mobility control agent, penetration into low-k zones should be maximized.
- For a blocking agent, penetration into low-k zones should be minimized.

Distinction between a mobility-control agent and a blocking agent

4.0 Problems and limitations associated with existing polymer gel Technology:

The polymer gel flooding process has been field tested extensively and can be classified as proven Technology. However the following Problems are associated with existing polymer gel Technology:

1) Low Mechanical properties

2) Bacterial degradation

3) Polymer slug break down due to high crosslinking density and the polymer debris will be coming out of the producing well.

4) Degradation of polymer gel due to the following parameters:

- Temperature above 80°c
- Presence of free radicals
- PH
- Shear forces
- Salinity-presence of ions in reservoirs.

5) High Shrinkage

5.0 PROGRAM FOR CALCULATION OF POLYMER VISCOSITY

```
#include<iostream.h>
#include<conio.h>
#include<stdio.h>
#include<math.h>
void main()
{
long float swi,sw,swd,krw,kro,viscopol,viscooil,mobilityr,frw,s,t,frws,frwt,derivative;
long float pd,dist1,dist2,k,rw,up=0,i=0,j=0,vsw,ub,h[50],l[50],frr,end;
long float qi,a[50],b[50],c[50],d[50],e[50],f[50],g[50],p,q,r,spa,ht,por,area;
long float sor,swmax,swdmax,krwendpt,kroendpt,viscowat;
long float resistfac;
clrscr();
cout<<"\n\n ENTER THE VALUE OF INTERSTITIAL(IMMOBILE) WATER
SATURATION(fraction)";
cin>>swi;
cout<<"\n ENTER THE INITIAL VISCOSITY OF POLYMER SOLUTION (in
centipoise)\t";
cin>>viscopol;
cout<<"\n ENTER THE VISCOSITY OF OIL (in centipoise)\t";
cin>>viscooil;
cout<<"\n ENTER THE VISCOSITY OF WATER (in centipoise)\t";
cin>>viscowat;
cout<<"\n\n ENTER THE VISCOSITY OF BRINE(centipoise)\t";
cin>>ub;
cout<<"\n\n ENTER THE VALUE OF PRESSURE DIFFERENCE(PSI)\t";
cin>>pd;
cout<<"\n\n ENTER THE DISTANCE BETWEEN TWO PRODUCTION
WELLS(FEET)\t";
cin>>dist1;
cout<<"\n\n ENTER THE DISTANCE BETWEEN PRODUCTION AND INJECTION
WELL(FEET)\t";
cin>>dist2;
cout<<"\n\n ENTER THE ABSOLUTE PERMEABILITY OF THE
FORMATION(millidarcy)\t";
cin>>k;
cout<<"\n\n ENTER THE POROSITY OF THE FORMATION(in fraction)\t";
cin>>por;
cout<<"\n\n ENTER THE WELL BORE RADIUS(feet)\t";
cin>>rw;
cout<<"\n\n ENTER THE AREA SPACING OF THE WELL(in acres)\t";
cin>>spa;
cout<<"\n\n ENTER THE THICKNESS OF THE FORMATION(in feet)\t";
cin>>ht;
cout<<"\n\n ENTER THE VALUE OF RESIDUAL OIL SATURATION";
```

```
cin>>sor;
swmax=(1-sor);
swdmax=((swmax-swi)/(1-swi));
krwendpt = pow(swdmax,3);
kroendpt = pow((1-swmax)/(1-swi),3);
clrscr();
mobilityr=(krwendpt*viscooil)/(kroendpt*viscowat);
if(mobilityr>1)
{
cout<<"\n\n\nGO FOR POLYMER FLOODING\n\n";
cout<<"\n\nEND POINT MOBILITY RATIO is\t"<<mobilityr;
}
else
{
cout<<"WATER FLOODING IS FEASIBLE";
goto end;
}
getch();
clrscr();
area=sqrt(spa*43560)*ht;
for(sw=.1;sw<=1;sw=sw+.05)
{
swd=((sw-swi)/(1-swi));
krw = pow(swd,3);
kro = pow((1-sw)/(1-swi),3);
mobilityr=(krw*viscooil)/(kro*viscopol);
frw= (mobilityr/(1+mobilityr));
qi=(3.541*k*krw*pd)/(viscopol*(log(dist1/rw)+1.571*(dist2/dist1)-1.838));
j++;
d[j]=qi;
b[j]=krw;
c[j]=kro;
e[j]=frw;
a[j]=sw;
}
getch();
for(sw=.1;sw<=1;sw=sw+.05)
{
s=sw+.01;
t=sw-.01;
swd=((s-swi)/(1-swi));
krw = pow(swd,3);
kro = pow((1-s)/(1-swi),3);
mobilityr=(krw*viscooil)/(kro*viscopol);
frws= mobilityr/(1+mobilityr);
swd=((t-swi)/(1-swi));
```

```
krw = pow(swd,3);
kro = pow((1-t)/(1-swi),3);
mobilityr=(krw*viscooil)/(kro*viscopol);
frwt= mobilityr/(1+mobilityr);
derivative = ((frws-frwt)/.02);
i++;
f[i]=derivative;
}
clrscr();
cout<<"\n\n\nsw\t"<<"\tkro\t"<<"\tkrw\t"<<"\tfrw";
for(i=1;i<=j;i++)
{
vsw=(d[i]/(area*por))*f[i];
if(vsw>0)
up=b[i]*((k*pd)/(vsw*dist2*1.127));
frr=up/ub;
g[i]=vsw;
h[i]=frr;
l[i]=up;
printf("\n%0.3f\t\t%0.3f\t\t%0.3f\t\t%0.3f",a[i],c[i],b[i],e[i]);
}
getch();
clrscr();
cout<<"\n\n\ndfw/dsw"<<"\t\tqi\t\t"<<"vsw";
for(i=1;i<=j;i++)
printf("\n%.3f\t\t%.3f\t\t%.3f",f[i],d[i],g[i]);
getch();
clrscr();
cout<<"\n\n\nvsw"<<"\t\tup\t\t"<<"frr";
for(i=1;i<=j;i++)
printf("\n%.2f\t\t%.2f\t\t%.2f",g[i],l[i],h[i]);
getch();
end:
cout<<"\n\n\n\n\tTRY FOR NEXT FIELD";
getch();
}
```

5.1 INPUT DATA SCREEN

ENTER THE VALUE OF INTERSTITIAL(IMMOBILE) WATER SATURATION(fraction).1

ENTER THE INITIAL VISCOSITY OF POLYMER SOLUTION (in centipoise) 10

ENTER THE VISCOSITY OF OIL (in centipoise) 5

ENTER THE VISCOSITY OF WATER (in centipoise) 1

ENTER THE VISCOSITY OF BRINE(centipoise) 1.2

ENTER THE VALUE OF PRESSURE DIFFERENCE(PSI) 400

ENTER THE DISTANCE BETWEEN TWO PRODUCTION WELLS(FEET) 1000

ENTER THE DISTANCE BETWEEN PRODUCTION AND INJECTION WELL(FEET) 500

ENTER THE ABSOLUTE PERMEABILITY OF THE FORMATION(millidarcy) 50

ENTER THE POROSITY OF THE FORMATION(in fraction) .18

ENTER THE WELL BORE RADIUS(feet) .5

ENTER THE AREA SPACING OF THE WELL(in acres) 5

ENTER THE THICKNESS OF THE FORMATION(in feet) 10

ENTER THE VALUE OF RESIDUAL OIL SATURATION.3

5.2 OUTPUT SCREEN

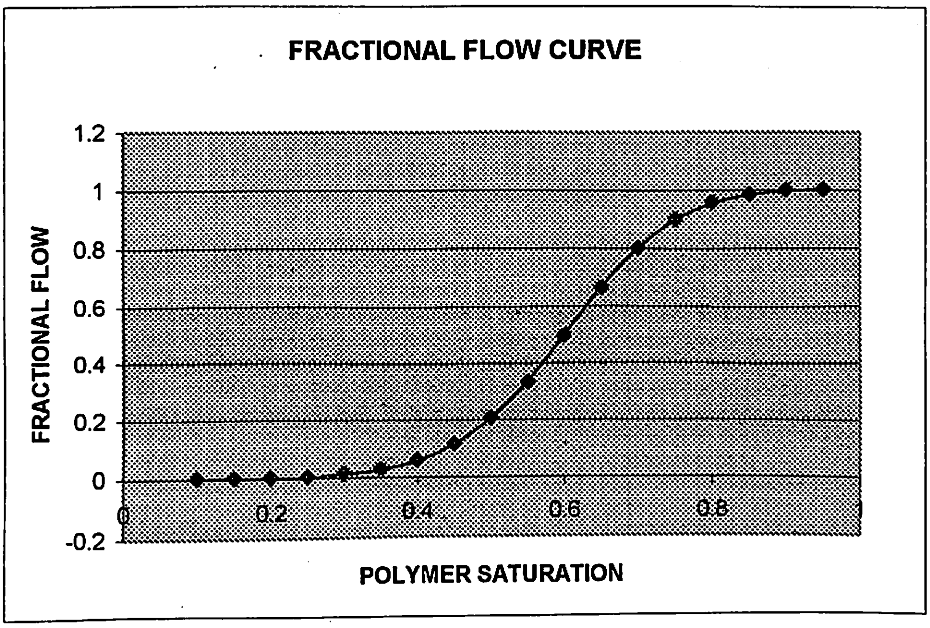
```
GO FOR POLYMER FLOODING


END POINT MOBILITY RATIO is     12.812363
```

sw	kro	krw	frw
0.100	1.000	0.000	0.000
0.150	0.842	0.000	0.000
0.200	0.702	0.001	0.001
0.250	0.579	0.005	0.004
0.300	0.471	0.011	0.012
0.350	0.377	0.021	0.028
0.400	0.296	0.037	0.059
0.450	0.228	0.059	0.114
0.500	0.171	0.088	0.204
0.550	0.125	0.125	0.333
0.600	0.088	0.171	0.494
0.650	0.059	0.228	0.660
0.700	0.037	0.296	0.800
0.750	0.021	0.377	0.898
0.800	0.011	0.471	0.955
0.850	0.005	0.579	0.984
0.900	0.001	0.702	0.996
0.950	0.000	0.842	1.000

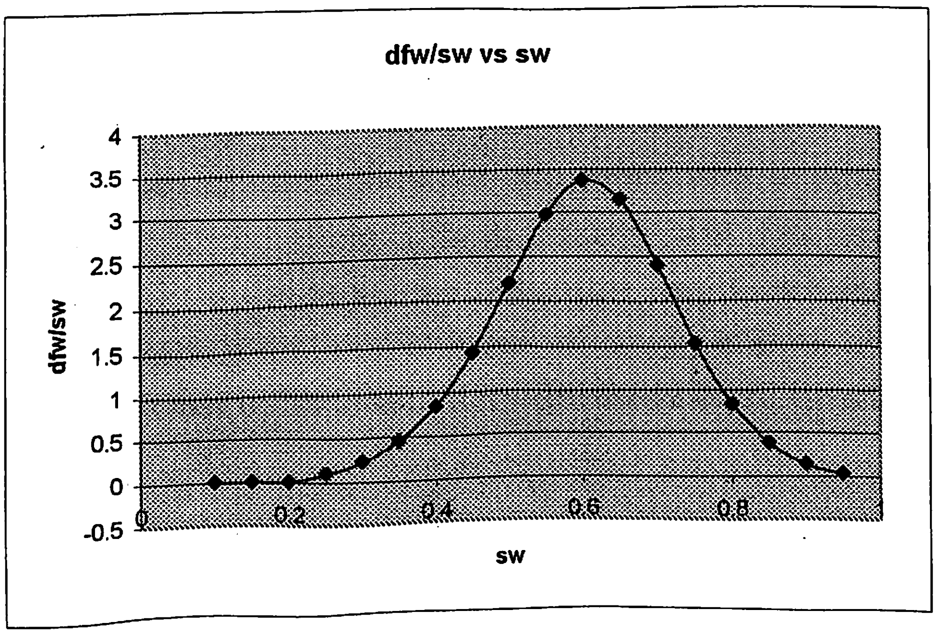
dfw/dsw	qi	vsw
0.000	0.000	0.000
0.007	0.185	0.000
0.033	1.484	0.000
0.096	5.007	0.001
0.220	11.868	0.003
0.448	23.180	0.012
0.832	40.055	0.040
1.420	63.606	0.107
2.191	94.945	0.248
2.961	135.186	0.476
3.370	185.440	0.744
3.144	246.820	0.924
2.399	320.440	0.915
1.525	407.411	0.740
0.823	508.847	0.499
0.373	625.859	0.278
0.132	759.562	0.119
0.026	911.066	0.029

vsw	up	frr
0.00	0.00	0.00
0.00	4181.04	3484.20
0.00	832.17	693.48
0.00	288.25	240.20
0.00	125.07	104.22
0.01	61.55	51.29
0.04	33.14	27.62
0.11	19.42	16.18
0.25	12.58	10.49
0.48	9.31	7.76
0.74	8.18	6.82
0.92	8.77	7.31
0.92	11.49	9.58
0.74	18.07	15.06
0.50	33.50	27.92
0.28	73.83	61.53
0.12	209.31	174.43
0.03	1045.99	871.66

sw	fw
0.1	0
0.15	0
0.2	0.001
0.25	0.004
0.3	0.012
0.35	0.028
0.4	0.059
0.45	0.114
0.5	0.204
0.55	0.333
0.6	0.494
0.65	0.66
0.7	0.8
0.75	0.898
0.8	0.955
0.85	0.984
0.9	0.996
0.95	1



sw	dfw/dsw
0.1	0
0.15	0.007
0.2	0.003
0.25	0.096
0.3	0.22
0.35	0.448
0.4	0.832
0.45	1.42
0.5	2.191
0.55	2.961
0.6	3.37
0.65	3.144
0.7	2.399
0.75	1.525
0.8	0.823
0.85	0.373
0.9	0.132
0.95	0.026



6.0 Conclusion

Polymer flood is an efficient EOR process. By the application of the appropriate process the recovery of oil can be improved significantly. Polymer increases the viscosity of water thus increases the sweep efficiency as it decreases the bypassing of oil, delays early breakthrough in highly heterogeneous reservoir.

DPR (Disproportionate Permeability Reduction) is most effective when used against the water production caused by coning or in situations where the watered out layers are separated from the oil producing layer.Also from the discussion three important facts can be concluded:

1) Gelants and similar fluid blocking agents can penetrate a significant distance into all open zones.
2) An acceptable gelant placement is much easier to achieve in linear flow than in radial flow.
3) If flow is radial, then hydrocarbon-productive zones must be protected during gelant placement.

These facts mean that excess channeling and water production problems can be treated much more readily if they are caused by linear-flow phenomena, such as vertical fractures, fractured systems, or flow behind pipe. Even so, placement of blocking agents is very important in linear flow as well as in radial flow. When flow is radial (e.g., unfractured wells), field engineers would be well-advised not to apply blocking-agent treatments in wells with radial flow unless hydrocarbon productive zones are protected during placement of the blocking agent.

A strong need exists for the development of new ideas to optimize placement of gels and other blocking agents, both in linear and radial systems.

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