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ENHANCED OIL RECOVERY BY POLYMER FLOODING

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ABSTRACT

Chemical flooding is relies on the addition of one or more chemical compounds to an injected fluid either to reduce interfacial tension between the reservoir oil and injected fluid or to improve the sweep efficiency of the mobility ratio. Both mechanism are designed to increase the capillary number. In this article investigated the effect of polymer concentration in injection stream on some parameters such as: Polymer adsorption concentration, Polymer in solution, Water-Oil capillary pressure, Oil production total.

KEY WORDS
Chemical Flooding, Interfacial Tension, Sweep Efficiency

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INTRODUCTION

The addition of large-molecular-weight molecules called polymers to an injected water can often increase the effectiveness of a conventional water flood. Polymers are usually added to the water in concentrations ranging from 250 to 2000 parts per million (ppm) (1). A polymer solution is more viscous than a brine without polymer. In a flooding application, the increased viscosity will alter the mobility ratio between the injected fluid and the reservoir oil. The improved mobility ratio will lead to better vertical and areal sweep efficiencies and thus higher oil recoveries (2). Polymers have also been used to alter gross permeability variations in some reservoirs. In this application, polymers form a gel-like material by cross-linking with other chemical species. The polymer gel sets up in large permeability streaks and diverts the flow of any injected fluid to a different location (3).

Polymer flooding has not been successful in high temperature reservoirs. Neither polymer type has exhibited sufficiently long-term stability above 160 °F in moderate-salinity or heavy-salinity brines (4).

Polymer flooding has the best application in moderately heterogeneous reservoirs and reservoirs oils with viscosities less than 100 centipoise (cp). In the United States, there has been a significant increase in the number of active polymer projects since 1978. The projects involve reservoirs having widely differing properties, that is, permeabilities ranging from 20 to 2000 millidarcies (md), in situ oil viscosities of up to 100 cp, and reservoir temperatures of up to 200◦F (5).

Since the use of polymers does not affect the microscopic displacement efficiency, the improvement in oil recovery will be due to an improved sweep efficiency over what is obtained during a conventional water flood. Typical oil recoveries from polymer flooding applications are in the range of 1–5% of the initial oil in place. It has been found that operators are more likely to have a successful polymer flood if they start the process early in the producing life of the reservoir (6).

The main objective of polymer injection during water flooding of oil reservoirs is to decrease the mobility of the injected water. This decrease results in a more favorable fractional flow curve for the injected water, leading to a more efficient sweep pattern and reduced viscous fingering. Certain plugging effects within highly permeable layers may also occur and result in the diversion of the injected water into less permeable zones of the reservoir. [Fig. 1] and [Fig. 2] show the effect of rate velocity of water (7).

The mobility decrease of the injected water resulting from the addition of polymer is due to two effects. Firstly, the viscosity of the polymer solution is higher than that of pure water (the viscosity of the polymer solution increases as the concentration of the polymer in the water increases). Secondly, the rock permeability to water is reduced after the passage of a polymer solution through the rock material (the permeability to oil is, however, largely unaffected). Both effects combine to reduce the value of the water mobility while that for the oil is unaltered.

To achieve maximum efficiency, the polymer solution is often applied in the form of a tapered slug. At the front edge of the slug, the displacement is stable but the interface between the water and the polymer solution smears due to physical dispersion of the polymer. At the rear edge, the mobility ratio is unfavorable and is dominated by viscous fingering. Both effects cause deterioration of the slug .

Certain polymer solutions, such as those of the PA type, exhibit a strong sensitivity to the presence of certain salts. In particular, sodium chloride can influence the viscosity characteristics of PA solutions to such an extent that in highly saline reservoirs it is often necessary to preflush with fresh water to reduce the exposure of the polymer solution to the reservoir brine.

When a polymer solution is injected into the reservoir some of the long chain molecules constituting the polymer are adsorbed onto the rock surfaces. Mechanical entrapment of some of the large molecules at the entrance to small pore throats may also occur and account for an apparent loss of polymer from the invading solution. Experimentally, the reservoir rock material is believed to retain a specific capacity of polymer. The main effects of polymer loss occur at the leading edges of the polymer slug where a stripped water bank is created and the

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slug width is gradually reduced in time. Some desorption effects can occur as the trailing edge of the slug passes but these effects are usually small compared with the adsorption losses.

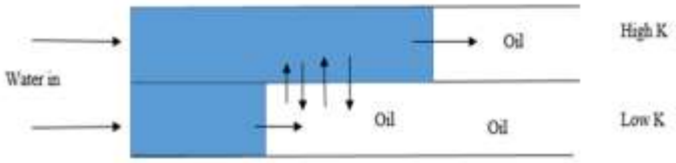

Fig . 1: High rate case – oil is expelled into nearly residual oil saturation part of reservoir and is therefore hardly mobile

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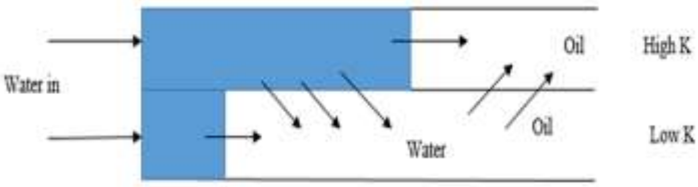

Fig. 2: Low rate case – oil is expelled into high oil saturation part of reservoir with good mobility

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A further effect caused by the adsorption and entrapment processes is a reduction in the relative permeability of the polymer solution. The reduction results from an interaction between the aqueous solution and the polymer retained by the rock material. For modeling purposes it will be assumed that the reduction in permeability to the polymer solution is proportional to the quantity of polymer lost to the rock material. The permeability of the rock to water is thus permanently reduced after the passage of a polymer slug compared to its value before the passage.

In core flooding experiments, it is often observed that injected polymer slugs break through to producers earlier than tracer slugs (for example, Nacl). The polymer fluid velocity is higher than that of the tracer fluid within the porous medium and is due to the fact that only a fraction of the total pore space is available to the polymer fluid. As the inaccessible pore space to the polymer fluid increases, the effective polymer velocity through the rock increases and leads to a faster breakthrough of polymer.

The rheology of polymer solutions is not simple. At low flow rates the viscosity of the solution is approximately constant and depends only on the concentration of polymer in the solution. At higher flow rates the solution viscosity reduces in a reversible (elastic) manner. At even higher velocities the large polymer molecules begin to break up, and the viscosity reduction becomes irreversible (plastic). The effects tend to be greatest in the vicinity of injection wells where the fluid velocity is greatest, and so is the shear rate.

Method

The polymer flood simulation model

The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black- oil equations are therefore used to describe the hydrocarbon phases in the model .

Modification is required to the standard water equation and additional equations are needed to describe the flow of polymer and brine within the finite difference grid. The water, polymer and brine equations used in the model are as follows:

$$\frac{d}{dt}\left(\frac{VS_w}{B_r B_w}\right) = \sum\left[\frac{TK_{rw}}{B_w \mu_{w\,eff} R_K}(\delta P_w - \rho_w g D_z)\right] + Q_w \quad (1)$$

$$\frac{d}{dt}\left(\frac{VS_w^* C_p}{B_r B_w}\right) + \frac{d}{dt}\left(V\rho_r C_a \frac{1-\phi}{\phi}\right) = \sum\left[\frac{TK_{rw} C_p}{B_w \mu_{p\,eff} R_K}(\delta P_w - \rho_w g D_z)\right] + Q_w C_p \quad (2)$$

$$\frac{d}{dt}\left(\frac{VS_w C_n}{B_r B_w}\right) = \sum\left[\frac{TK_{rw} C_n}{B_w \mu_{s\,eff} R_K}(\delta P_w - \rho_w g D_z)\right] + Q_w C_n \quad (3)$$

$$S_w^* = S_w - S_{dPV} \quad (4)$$

Where

S_{dPV} : Denotes the dead pore space within each grid cell .

C_a : Denotes the adsorption isotherm which is a function of the local polymer solution concentration .

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ρ_r : Denotes the mass density of the rock formation .

$\emptyset$: Denotes the porosity .

ρ_w : Denotes the water density .

R_K : Denotes the relative permeability reduction factor for the aqueous phase due to polymer retention .

C_n , C_p : Denote the local concentration of polymer and sodium chloride in the aqueous phase .

μ_{eff} : Denotes the effective viscosity of the water, polymer and salt components .

D_z : Is the cell center depth .

The model makes the assumption that the density and formation volume factor of the aqueous phase are independent of the local polymer and sodium chloride concentrations.

The principal effects of polymer and brine on the flow of the aqueous phase are represented by equations (1) to (4).

The fluid viscosities($\mu_{w\,eff}$, $\mu_{p\,eff}$, $\mu_{s\,eff}$) are dependent on the local concentrations of salt and polymer in the solution. Polymer adsorption is represented by the additional mass accumulation term on the left hand side of equation (2) .

Treatment of fluid viscosities

The viscosity terms used in the fluid flow equations contain the effects of a change in the viscosity of the aqueous phase due to the presence of polymer and salt in the solution. However, to incorporate the effects of physical dispersion at the leading edge of the slug and also the fingering effects at the rear edge of the slug the fluid
components are allocated effective viscosity values that are calculated using the Todd Longstaff technique. The effective polymer viscosity is taken to be :

$$\mu_{p,\ eff} = \mu_m (C_p)^{\omega} . \mu_p^{1-\omega} \tag{5}$$

ω : is the Todd-Longstaff mixing parameter.

The mixing parameter is useful in modeling the degree of segregation between the water and the injected polymer solution. If $\omega = 1$ then the polymer solution and water are fully mixed in each block. If $\omega = 0$ the polymer solution is completely segregated from the water.

The partially mixed water viscosity is calculated in an analogous manner using the fully mixed polymer viscosity and the pure water viscosity (μ_w) ,

$$\mu_{w,\ eff} = \mu_m (C_p)^{\omega} . \mu_w^{1-\omega} \tag{6}$$

Treatment of polymer adsorption

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes. The adsorption model can handle both stripping and desorption effects.

Treatment of permeabilities reductions and dead pore volume

The adsorption process causes a reduction in the permeability of the rock to the passage of the aqueous phase and is directly correlated with the adsorbed polymer concentration. In order to compute the reduction in rock permeability, the user is required to specify the residual resistance factor (RRF) for each rock type. The actual resistance factor can then be calculated:

$$R_K = 1 + (RRF - 1) \frac{C_a}{C_{a\,max}} \tag{7}$$

The value of the maximum adsorbed concentration , $C_{a\,max}$, depends on the rock type and needs to be specified by the user .

Treatment of shear thinning effect

The shear thinning of polymer has the effect of reducing the polymer viscosity at higher flow rates . The flow velocity is calculated as :

$$V = B_w . \frac{F_w}{\emptyset A} \tag{8}$$

Where

F_w : is the water flow rate in surface units .

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B_w : is the water formation volume factor .

$\emptyset$: is the average porosity of the two cells .

A : is the flow area between two cells .

The reduction in the polymer viscosity is assumed to be reversible, and is given by :

$$\mu = \mu_w[(P - 1)M + 1] \quad (9)$$

μ_w : is the viscosity of water with no polymer present .

P : is the viscosity multiplier assuming no shear effect (entered using the PLYVISC or PLYVISCS keywords in Eclipse)

M : is the shear thinning multiplier supplied in the PLYSHEAR keyword in Eclipse .

Simulation

Introducing the reservoir (fig3) :

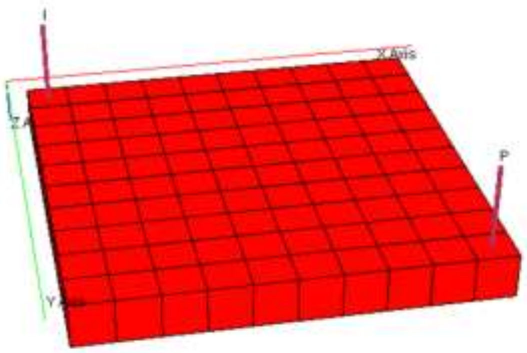

Fig. 3: 3D view of the reservoir

In this simulation investigated some parameters such as :

- The concentration of polymer in the injection stream for the well .
- Polymer adsorption concentration .
- Polymer in solution .
- Water-Oil capillary pressure .
- Oil production total .

RESULTS

Fig 4 to fig 7 show the Sensitivity analysis on “concentration of polymer in the injection stream for injection well” , 50 lb/STB and 60 lb/STB .

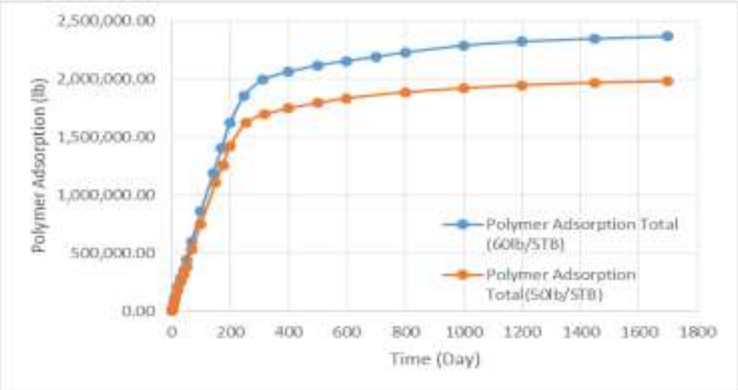

Fig. 4: Effect of concentration of polymer in the injection stream on polymer adsorption

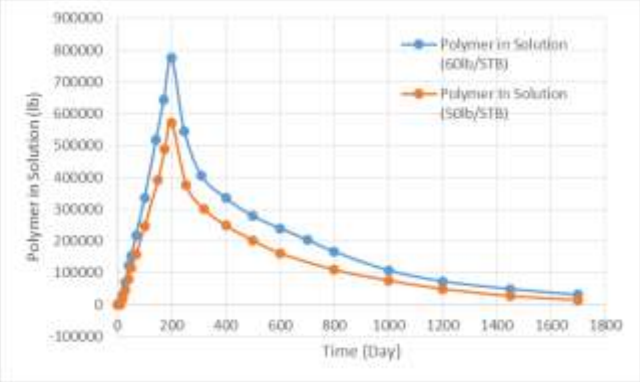

Fig. 5: Effect of concentration of polymer in the injection stream on polymer in solution

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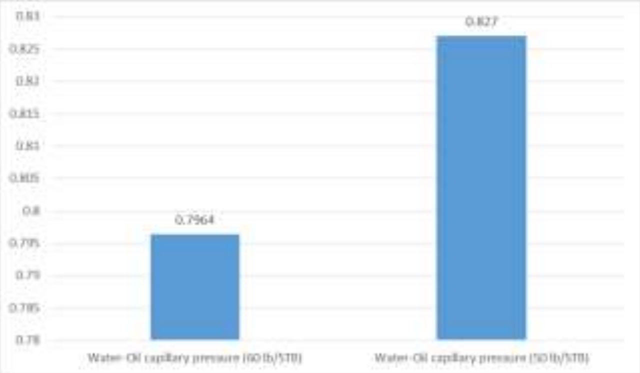

Fig . 6: Effect of concentration of polymer in the injection stream on water-oil Capillary pressure after 1700 days

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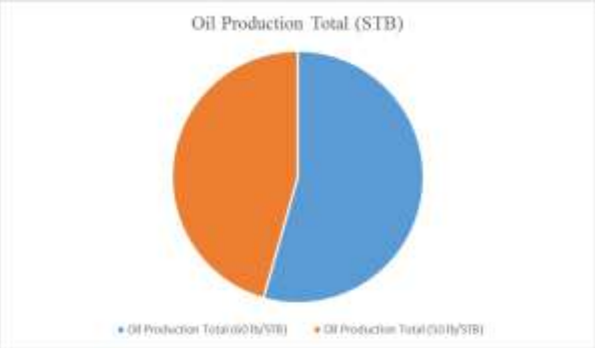

Fig . 7: Effect of concentration of polymer in the injection stream on oil production total (STB)

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CONCLUSION

Use of polymer is basically improve the relative mobility ratio of oil-water front or augment water flooding . Polymer gels are used to alter water flow to the portion of oil zone that have not been swept properly . According to the simulation results, increasing the concentration of polymer in the injection stream (50 to 60 lb/STB) lead to improve oil recovery due to :

- Increasing adsorption of polymer that lead to block water channels and alter the water flow to the unsweep oil zone .

Increasing the polymer in solution that helps to decrease IFT between oil and water , therefore enhances capillary number .

CONFLICT OF INTEREST
None

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