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Modeling the Application of Polymer Flooding for Enhanced Oil Recovery

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Abstract— Polymer flooding is chemical method employed by engineers to enhance the recovery of oil from oil reservoirs. The technique works mainly by increasing the viscosity of injected water to improve overall sweep efficiency. For this work, recovery by polymer injection was simulated using Schlumberger Eclipse. Natural depletion of the reservoir was run to 100bars. 5 vertical wells were used and a recovery of 30% was achieved with a production plateau of about 8years. This is preferred to the use of 4 or 6 producing wells which yielded a field efficiency of 25% and 30% respectively. The 5 and 6 producing wells cases were very similar as they both had 30% recovery, similar production plateau and water cut. The 5 wells case is the preferred choice as it is more cost effective to drain the reservoir with fewer wells. Polymer injection was simulated by commencing water injection as a secondary recovery mechanism after reservoir depletion to a bottom-hole flowing pressure of above 260 bar followed by a polymer flood. This gave a significant increase in oil recovery from 30% to about 53% with the production plateau sustained for 4.8 years. A total of 11 wells were used, 7 producers and 4 injector wells.

Index Terms— Waterflooding, Polymer Flooding, Enhanced Oil Recovery, Field Oil Recovery Efficiency.

1 Introduction

Chemical flooding methods are considered as a special branch of EOR processes to produce residual oil after water flooding. These methods are utilized in order to reduce the interfacial tension, to increase brine viscosity for mobility control, and to increase sweep efficiency during tertiary oil recovery. Polymers tend to work better in different conditions, thus several factors would be taken into consideration. It is necessary to consider the reservoir permeability and oil viscosity and several other reservoir properties of optimum application [1]. A thorough Cloud point analysis for thermal stability in high brine concentrations and high temperature reservoir must be conducted to prevent precipitation during polymer injection or flow through the reservoir. [2] it is also important to consider the reservoir rock composition and polymer adsorption level to determine the best anionicity (degree of hydrolysis.).

Surfactants are considered as good enhanced oil recovery agents since 1970s because it has the ability to significantly lower the interfacial tension and alter wetting properties [3], [4]. Displacement by surfactant solutions is one of the important tertiary recovery processes by chemical solutions. The addition of surfactant decreases the interfacial tension between crude oil and formation water, lowers the capillary forces, facilitates oil mobilization, and enhances oil recovery. The surfactant is dissolved in either water or oil to form microemulsion which in turn forms an oil bank [5]. The formation of oil bank and subsequent maintenance of sweep efficiency and pressure gradient by injection of polymer and chase water increase the oil recovery significantly [5], [6]. The idea of injecting surfactant solution to improve imbibition recovery was proposed for fractured reservoirs [7] and carbonaceous oil fields in the United States [8]. The effects of capillary imbibition and lowering of IFT using surfactant slug have been reported by many researchers [9].

It is well known that use of polymer increases the viscosity of the injected water and reduces permeability of the porous media, allowing for an increase in the vertical and areal sweep efficiencies, and consequently, higher oil recovery [10]. The main objective of polymer injection is for mobility control, by reducing the mobility ratio between water and oil. The reduction in the mobility ratio is achieved by increasing the viscosity of the aqueous phase. Another main accepted mechanism of mobile residual oil after water flooding is that there must be a rather large viscous force perpendicular to the oil–water interface to push the residual oil. This force must overcome the capillary forces retaining the residual oil, move it, mobilize it, and recover it [11]. The injection of polymer helps to propagate the oil bank formed by surfactant injection by increasing the sweep efficiency. Austad in 1994 reported that significant improvements can be obtained by co-injecting surfactant and polymer at a rather low chemical concentration [12]. However, for this work, only polymer flooding is modelled using Schlumberger Eclipse ®

2 Research Methodology

2.1 Building the Polymer Injection Model

Prior to the building the reservoir model in Eclipse, the following manual computations were made:
To calculate an estimate of the recovery, and the optimum number of producers and injectors for the flood, the following parameters were obtained in this sequence:

1. Displacement efficiency, Ed

$$E_d = \frac{S_{wm} - S_{wc}}{1 - S_{wc}} \tag{1}$$

International Journal of Scientific & Engineering Research Volume 8, Issue 9, September-2017
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Where S_{wm} is the water saturation behind the front.

2. Recovery Efficiency, R

$$R = E_d \times E_a \times E_v \quad (2)$$

Where E_a =f(inverse mobility ratio, f_w) and E_v = f(rock properties)

3. Cumulative production by polymer injection, N_{po}

$$N_{pol} = (OOIP - N_p)*R \quad (3)$$

Where N_P is recovery during primary stage.

4. Estimated Ultimate Recovery

$$EUR = \frac{N_p + N_{pol}}{OOIP} * 100 \quad (4)$$

5. Number of producers, n_p & Number of Injectors, n

$$n_p = \frac{Q_p}{q_p} \qquad n_i = \frac{Q_i}{q_i} \quad (5)$$

Furthermore, 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. The water, polymer and brine equations used in the model are as follows:

$$\frac{d}{dt}\left(\frac{VS_w}{B_r B_w}\right) = \Sigma\left[\frac{T k_{rw}}{B_w \mu_{w.eff} R_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w \quad (6)$$

$$\frac{d}{dt}\left(\frac{V^* S_w C_n}{B_r B_w}\right) + \frac{d}{dt}\left(V \rho^r C_p^a \frac{1-\varphi}{\varphi}\right) = \Sigma\left[\frac{T k_{rw}}{B_w \mu_{w.eff} R_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w C_p \quad (7)$$

$$\frac{d}{dt}\left(\frac{VS_w C_n}{B_r B_w}\right) = \Sigma\left[\frac{T k_{rw} C_n}{B_w \mu_{s.eff} R_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w C_n \quad (8)$$

Where;

$$V^* = V\left(1 - S_{dpv}\right)$$

S_{dpv}= dead pore space within each grid cell
C_p^a= polymer adsorption concentration
ρ_r= Mass density of the rock formation
φ= Porosity
ρ_r= Water Density
R_k= Relative permeability reduction factor for the aqueous phase due to polymer retention
C_p, C_n= Polymer and salt concentrations respectively in the aqueous phase
$\mu_{a.eff}$= Effective viscosity of the water (a = w), polymer (a = p) and salt (a = s)
D_z= Cell center depth
B_r, B_w= Rock and water formation volumes
T= Transmissibility
k_{rw}= Water relative permeability
S_w= Water Saturation
V= Block pore volume
Q_w= Water production rate
P_w= Water Pressure
g= Acceleration due to gravity

2.2 Model Considerations

The model makes the assumption that the density and formation volume factor of the aqueous phase are independent of the polymer and salt concentrations. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components in the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations. The equation solved by the Eclipse polymer model are a discretised form of differential equations. A fully implicit time discretization is used in order to avoid numerical instability problem. It can be inferred that the reservoir is slightly heterogeneous.

TABLE 1
FIELD CALCULATION SUMMARY

PARAMATERS	FIELD RESULTS
F_{wf} (%)	90
S_{wc} (%)	15
S_{wm} (%)	72
S_{wgr}(%)	65
End point Mobility ratio (MR)	0.334954
Inverse Mobility Ratio (1/MR)	2.98549
E_d @ f_{wf} (%)	67
E_a @ f_{wf} (%)	98
E_v (%)	70
(%) Recovery,R	46.5
OOIP	31104045
N_p	1517877.4
N_w	13757567.9

With these parameters, the estimated ultimate recovery was obtained to be 47.8%.

3 Result and Discussion

A total of 7 producers and 4 polymer injectors were used as the best case. With this optimum amount of producers and injectors chosen, different periods of injection scenarios were evaluated to determine the optimum FOE water injection can yield.
The primary recovery case showed a decline in reservoir pressure to 260bars in 4 years hence polymer injection was to be initiated after 4 years of natural depletion. This case scenario was run and it showed a very poor performance. This observation prompted the reduction in injection time with decrements of 1 year till an optimum case was gotten. This is shown in the following outlined plots.

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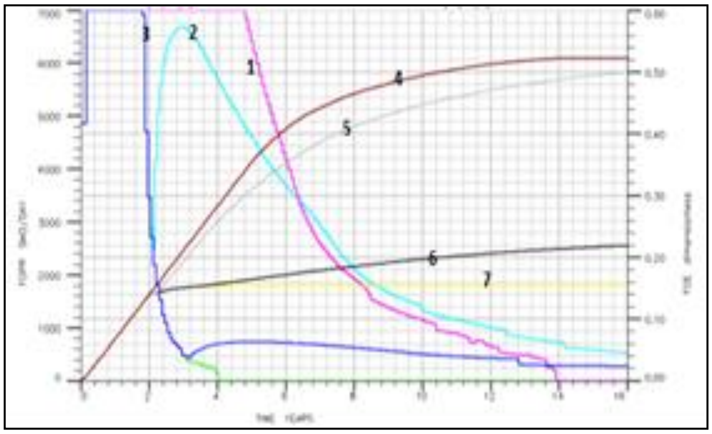

Fig 1: Field Oil Production Rate (FOPR) and Field Oil Recovery Efficiency (FOE) vs. Time

1 – FOPR after 1 year of injection
2 – FOPR after 2 years of injection
3 – FOPR after 3 years of injection
4 – FOE after 1 year of injection
5 – FOE after 2 years of injection
6 – FOE after 3 years of injection
7 – FOE after 4 years of injection

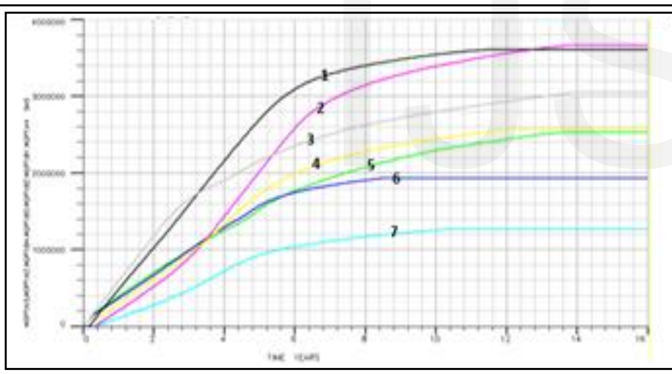

Fig 2: Variation in Well Oil Production Total (WOPT) for Each Production Well with Time

1 – WOPT from well B1
2 – WOPT from well B3
3 – WOPT from well A4
4 – WOPT from well B2
5 – WOPT from well N3
6 – WOPT from well N2
7 – WOPT from well B4

It was observed from the simulation run that the best case was at commencement of polymer injection after 1 year of natural reservoir depletion. This case gave the best oil recovery of about 52.5% and a longer production plateau of about 5 years. Further field analysis was carried out with this case to ensure that overall field performance meets both oil production and polymer injection constraints.

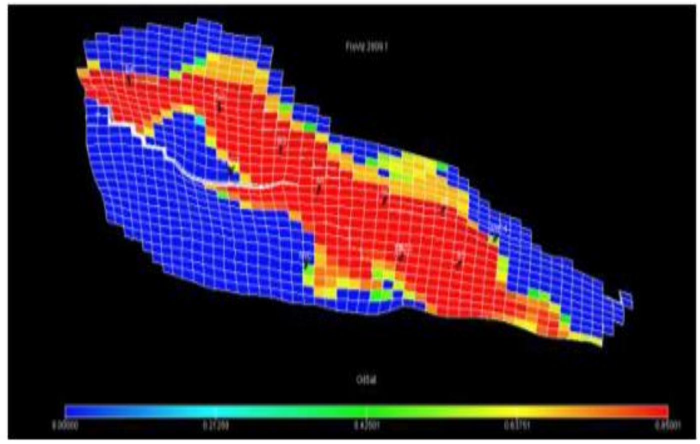

Fig 3: 3D View of Simulation Model Showing Injectors and Producers before Flooding

An early injection led to reservoir pressure maintenance at approximately 320 bar which is well above the bubble point pressure of 260 bar. This was adopted and individual production and injection well performances were evaluated from plots of Well Water Injection Rate (WWIR)

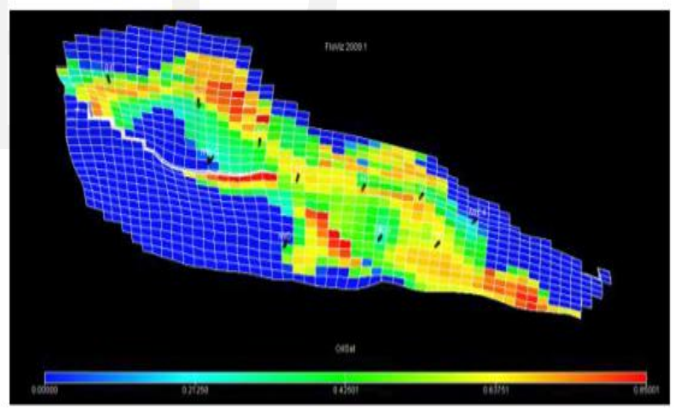

Fig 4: Oil Sweep by Polymer – Assisted Water Injection after 15 years

At the end of the 15 year production life of the reservoir, it is observed that the polymer injection case showed a favourable overall performance. A remarkably high oil recovery from this reservoir was recorded as shown in figure 4 above. Characteristic trends observed are summarized below:

- Ultimate Oil Recovery: The optimized oil recovery obtained by depleting the reservoir with 7 wells and commencing polymer injection after 1 year is 52.5%.
- Reservoir pressure: The reservoir pressure declined steadily till it was maintained at an average pressure of 320 bar.

International Journal of Scientific & Engineering Research Volume 8, Issue 9, September-2017
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- Water Cut: There was considerable water production accompanying the oil during the entire producing life of the reservoir. This is due to the injection of water to push the polymer flood in addition to the presence of an active water drive.

Gas-oil ratio: There was no change in the producing gas-oil ratio during the life of the reservoir due to the good pressure maintenance by the injected water preventing/limiting release of gas from solution

4 Conclusion

From this investigation, polymer injection showed an overall increase in Field Oil Recovery Efficiency (FOE), Field Oil Producing Rate (FOPR), reduction in Field Gas Oil-Ratio (FGOR) and better pressure maintenance when compared to a natural reservoir depletion case,. However, results also sowed that there was an increased water production due to the water drive required to flush the polymer and maintain the desired volumetric sweep of the flood. This increased water production is typically not desirable. This study has also deduced that a 23% increase in oil recovery can be achieved by polymer flooding processes with a production plateau sustained within 4 to 8 years for 7 producing wells and 4 injector wells.

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