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Sensitivity Analysis and Optimization of the Effective parameters on ASP Flooding Compared to Polymer Flooding Using CMG-STARS

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Abstract

Polymer and ASP flooding are two popular chemical enhanced oil recoveries (EOR) method for increasing oil recovery in the tertiary stage of oil production. Many parameters, effect on the performance of these methods. In this paper, fractional factorial design for eight variables is considered to determine the number of simulations. CMG-STARS is used to create a 1/6 inverted 7 spots with two wells. 64 runs for polymer and ASP are considered and the effect of parameter as single and two parameter interactions is discussed. The results show ASP flooding has better performance to increase oil recovery factor compared to polymer flooding in oil wet carbonate reservoir. Over there, connate water saturation has a main effect on recovery factor. On the other hand, two parameters interaction effect, are different for ASP and polymer flooding. Finally, a regression model based on variables is generated for estimating the recovery factor in polymer and ASP flooding.

Keywords: Optimization; ASP; Polymer flooding; Simulation; Sensitivity analysis

Abbreviations: ANOVA: Analysis of Variance; ASP: Alkaline Surfactant Polymer; BHP: Bottom Hole Pressure; cEOR: Chemical Enhanced Oil Recovery; CMG: Computer Modelling Group; EOR: Enhanced Oil Recovery; H: Thickness; HPAM: Hydrolyzed-polyacrylamide; IFT: Interfacial Tension; K: Horizontal Permeability; Kro: Oil Relative Permeability; M: Mobility Ratio; PF: Polymer flooding; RF: Recovery Factor; S: Salinity; SDS: Sodium Dodecyl Sulfate; Siw: Connate Water Saturation; STW: Surface water Rate; T:; Temperature; WC: Water Cut; Yo: Oil Viscosity

Introduction

Energy consumes in the world is increasing. Fossil fuel is the main source of energy supply today compared to other conventional energy such as wind, sun. Production of oil and gas from hydrocarbon reservoirs occurs firstly because of reservoir pressure by helping of gas cap drive or water drive system. Production of the reservoir causes of pressure depletion. Therefore, production of well after towards to decrease. This period of production is named as primary recovery [1]. After this stage more than 80% of oil remains in the reservoir as residual oil. Production of the reservoir is not limited to, primary stage, after this stage, secondary recovery stage is applied. In secondary oil recovery stage, external fluid such as water and gas is injected to the aquifer or gas cap of reservoir to increase pressure. This external force helps to increase oil production. In last of old on this stage 60-70% of oil is remained as not produced oil. Extra, production of oil may increase by applying EOR process [2]. EOR includes Thermal, Chemical, Microbial, and Gas injection [3]. Each of EOR process has limitation for applying in the reservoir due to reservoir condition [4]. Chemical EOR (cEOR) process is the most applicable process in field scale in the world. The cEOR includes polymer, surfactant, alkaline, and a mixture of them [5]. Adding water soluble polymer such as Xanthan and HPAM increases the viscosity of displacing fluid. By increasing of viscosity, areal and vertical sweep efficiency are improved due to decreasing of the mobility ratio toward less than one (M<1). Extra, polymer flooding avoids the fingering phenomena and allows the displacing fluid to sweep total porous media when reaches production well [6]. More than, the benefits of polymer flooding include: Increase vertical and areal sweep efficiency, control the water/oil mobility, improved oil recovery, significantly less water required compared with typical water flooding and steam injection, and need low cost compared to the other expensive EOR method [7]. In oil wet reservoir rock, large amount of oil remained in porous media after primary and secondary oil recovery stages [8]. Surfactant flooding can improve the oil recovery factor in this type of reservoir by decreasing interfacial tension (IFT) between oil and water in pores [9]. The amount of residual oil in porous media is related to capillary number [10] where by increasing the capillary number, the residual oil saturation decreases [11]. This parameter is defined as:

$$N_c = u^*\mu / \sigma \tag{1}$$

Where u is the fluid velocity, σ is IFT, and μ is the fluid viscosity [9]. According to capillary number equation, a method that reduces the IFT, can help to increase oil recovery such as surfactant flooding. Squires in 1917 stated water as displacing fluid might have effective behavior by adding alkaline in water. The alkali reacts with natural acids in the oil, leading to the generation of *in situ* soaps at the oil-water interface [12]. The reaction is shown in below:

$$HA + OH^- \rightarrow A^- + H_2O \tag{2}$$

Where HA is acid and A^-is soap. These soaps help to decrease IFT and reduce the adsorption of surfactant rock surface. This reaction strongly depends on acid number of oil [10]. Surfactant in porous media has rule as a dishwashing-liquid when help to clean the layers of fat on the dish surface does not clean with water. Surfactant reduces the IFT between oil and water or decreases the capillary number. These phenomena increase the production of oil in oil wet reservoir rock such as limestone [10]. In this process mixture of alkaline, surfactant, and

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polymer are injected to the reservoir. Alkaline firstly reacts with an acid component of oil and creates soaps as a surfactant. A synthetic injected surfactant, reduces the IFT and the polymer increases the viscosity of a slug [13]. Many parameters, effects on performance of the polymer flooding and ASP [14]. In this paper, these parameters are discussed in a simulation study by using of the CMG-STARS [15]. To find which parameter has a main effect on recovery factor, statistical methods are applied to determine the number of simulations and reduce the number of simulation runs. A fractional factor design is used to determine the number of runs by using of Minitab software [16]. Finally, a correlation is obtained based on parameters to estimate the oil recovery factor for polymer and ASP flooding.

Simulation Study

A 1/6 inverted 7spot model with two wells is considered in STARS. The model properties are summarized in Table 1. Sodium hydroxide, SDS, and HPAM are considered as alkaline, surfactant, and polymer (Figure 1). In ASP flooding, Sodium hydroxide and SDS are injected in 3% weight and HPAM is injected in 5% weight. Over there, in polymer flooding HPAM is injected in 10% weight. For statistical study of parameter and number of runs, fractional factorial design is considered for eight variables as 2^{8-2} (64 Runs) with ¼ fraction with resolution of five (V) in Minitab. The variables and their maximum and minimum value are summarized in Table 2.

Reservoir and well properties	
Grid system	1/6 Invert 7spot, Nx:15, Ny:8, Nk:1
Rock type	limestone-oil wet, porosity:20%
Producer	BHP=1000 psi, WC=60%, location :8,8,1
Injector	STW:100 bbl./Day, location: 8,1,1

Table 1: Reservoir and well properties.

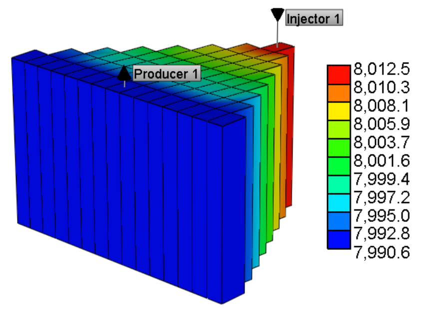

Figure 1: Reservoir mode, the color shows grid top.

Variables	Min.	Max.
Salinity (S)	10000 ppm	50000 ppm
Oil viscosity (yo)	1 cp	5 cp
Thickness (H)	200 ft.	1000 ft.
Horizontal permeability (K)	100 mD	1000 mD
Connate water saturation (Siw)	0.15%	0.45%
Oil relative permeability (Kro)	0.5	0.8
Reservoir Dip (Angle, degrease)	5°C	50°C
Temperature (T)	30°C	80°C

Table 2: Variables properties.

Variables	Polymer Flooding		Alkaline Surfactant Polymer	
	Effect	P-value	Effect	P-value
Salinity (S)	0.166	0.572	-0.0144	0.592
Oil viscosity (yo)	-3.801	0	-2.7	0
Thickness (H)	1.05	0.001	-3.784	0
Horizontal permeability (K)	1.984	0	3.969	0
Connate water saturation (Siw)	-11.128	0	-11.506	0
Oil relative permeability (Kro)	0.284	0.339	-0.562	0.043
Reservoir Dip (Angle)	1.566	0	3.531	0
Temperature (T)	0.519	0.084	0.344	0.205

Table 3: Main effect.

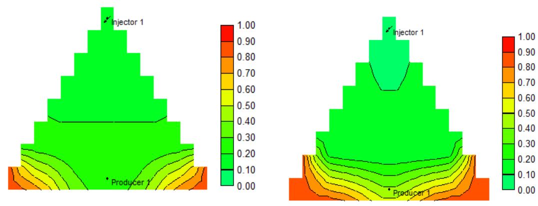

Figure 2: Comparison of residual oil saturation after polymer flooding (Left) and ASP flooding (Right).

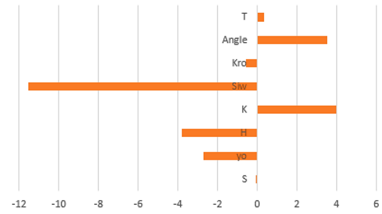

Figure 3: Tornado plot for ASP flooding.

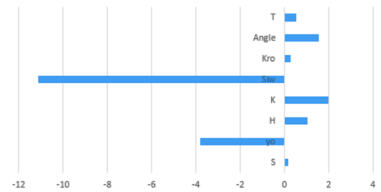

Figure 4: Tornado plot for polymer flooding.

Results and Discussion

The simulator runs for 64 cases that are generated based on a fractional factorial design of Minitab, according to fluid and rock properties. The recovery factor is considered as a response of this design. In this study, two factor interactions are discussed. Table 3 shows the matrix of runs. The results show ASP flooding has better performance compared to polymer flooding. Figure 2 in bellow shows the residual oil saturation after polymer and ASP flooding.

The main effect of each variable on recovery factor is calculated by using statistical approaches. Table 3 presents the effect of each parameter. The main effect is calculated as:

Main effect= (RF when variable has maximum value) - (RF when variable has minimum value)

According to Table 3, connate water saturation has most effect on recovery factor in polymer flooding and ASP flooding. It shows when connate water saturation has minimum value the recovery factor has maximum value. Tornado plot shows the effect of each parameter on polymer flooding and ASP flooding efficiency clearly in Figures 3 and 4.

The interaction of two variables effect on recovery factor is presented in Tables 4 and 5. Interaction of S*H, S*Yo, K*H, H*Angle,

Runs	S	Yo	H	K	Siw	Kro	Angle	T	RF (PF)	RF (ASP)
1	10000	1	1000	1000	0.15	0.8	50	30	73	82.3
2	10000	1	200	1000	0.15	0.8	5	30	70	78.5
3	50000	1	200	1000	0.45	0.5	50	80	59.1	70.6
4	50000	1	200	1000	0.15	0.5	50	30	71	81.3
5	10000	1	200	100	0.15	0.5	50	80	70	79.3
6	50000	5	200	100	0.15	0.8	50	30	64.7	73.5
7	50000	5	200	100	0.45	0.5	50	30	53.4	64.5
8	10000	5	200	1000	0.45	0.5	50	80	56.2	68.7
9	10000	5	1000	1000	0.45	0.5	5	80	56.15	61
10	50000	1	1000	1000	0.15	0.5	5	30	71.6	75.6
11	50000	5	1000	100	0.45	0.5	5	30	54.5	57.8
12	10000	1	200	100	0.45	0.8	50	80	58	66.8
13	10000	1	200	100	0.45	0.5	50	30	58.4	68.1
14	50000	5	200	1000	0.45	0.5	5	30	55.2	65.5
15	10000	5	1000	1000	0.15	0.8	5	80	67.7	71.9
16	10000	5	1000	100	0.45	0.5	50	80	55.5	60.3
17	10000	1	200	1000	0.45	0.8	5	80	59.4	68.1
18	50000	5	1000	100	0.15	0.8	5	30	65.3	68.4
19	10000	1	1000	1000	0.45	0.8	50	80	60.8	69.2
20	10000	5	200	100	0.45	0.8	5	30	54.6	63.3
21	50000	5	200	100	0.45	0.8	50	80	54.3	63.1
22	50000	1	1000	1000	0.15	0.8	5	80	71.4	74.8
23	50000	1	1000	100	0.15	0.8	50	80	71.2	74.5
24	10000	1	1000	1000	0.45	0.5	50	30	60.6	69.1
25	50000	1	1000	1000	0.45	0.5	5	80	60.4	63.1
26	50000	5	200	1000	0.45	0.8	5	80	54.6	63.4
27	50000	1	200	100	0.45	0.5	5	80	57.6	67.1
28	50000	5	200	100	0.15	0.5	50	80	64.6	74.7
29	10000	5	200	100	0.15	0.8	5	80	65.2	74.1
30	50000	5	200	1000	0.15	0.8	5	30	65	74
31	50000	5	1000	100	0.15	0.5	5	80	64.8	69
32	10000	5	200	100	0.45	0.5	5	80	59.4	64.6
33	50000	1	200	100	0.45	0.8	5	30	54.8	63.2
34	10000	1	1000	100	0.45	0.5	5	30	54.6	58.3
35	10000	5	1000	1000	0.15	0.5	5	30	67.4	72.8
36	50000	1	200	1000	0.15	0.8	50	80	71.3	81.3
37	50000	5	1000	1000	0.45	0.5	50	30	58.5	66.8
38	50000	1	1000	100	0.15	0.5	50	30	71.4	75.3
39	50000	5	1000	1000	0.45	0.8	50	80	59.2	66.8
40	10000	5	200	100	0.15	0.5	5	30	64.8	75.2
41	50000	1	200	100	0.15	0.5	5	30	69.5	78.3
42	10000	5	1000	100	0.15	0.8	50	80	67.3	71.4
43	50000	1	1000	1000	0.45	0.8	5	30	60.7	63.4
44	10000	5	1000	100	0.45	0.8	50	30	56	58.9
45	50000	5	1000	1000	0.15	0.8	50	30	71	79
46	50000	5	200	1000	0.15	0.5	5	80	65.5	75.5
47	10000	5	1000	1000	0.45	0.8	5	30	56.3	58.8
48	10000	1	1000	100	0.15	0.8	5	30	65.4	68.3
49	10000	5	1000	100	0.15	0.5	50	30	66.7	72
50	10000	1	200	100	0.15	0.8	50	30	69.9	78.4
51	10000	1	1000	100	0.15	0.5	5	80	64.9	68.9
52	10000	1	200	1000	0.45	0.5	5	30	55.25	65.4
53	50000	5	1000	1000	0.15	0.5	50	80	70.2	79.3
54	10000	5	200	1000	0.15	0.8	50	80	68.5	79.4
55	10000	1	200	1000	0.15	0.5	5	80	70.2	80
56	50000	1	1000	100	0.45	0.8	50	30	59.3	62
57	50000	1	200	1000	0.45	0.8	50	30	59.7	70.5
58	10000	5	200	1000	0.45	0.8	50	30	57.2	68.5
59	10000	1	1000	1000	0.15	0.5	50	80	72.7	81.4
60	10000	1	1000	100	0.45	0.8	5	80	59.3	61.8
61	10000	5	200	1000	0.15	0.5	50	30	67.4	79.4
62	50000	5	1000	100	0.45	0.8	5	80	55	57.1
63	50000	1	1000	100	0.45	0.5	50	80	59.4	62
64	50000	1	200	100	0.15	0.8	5	80	69.9	78.2

Table 4: Matrix of runs.

and Angle*T have main effect on polymer flooding efficiency, but interaction of H*K, K*Angle, H*Angle, and S*H have main effect on ASP flooding. The P-value of these interactions are zero for ASP but in polymer flooding have value more than zero. The Pareto plot shows the effect of variables in Figures 5 and 6. Analysis of Variance (ANOVA) for RF shows the correlation coefficient (R^2) and adjusted coefficient (R2_adjusted) has a value of 99.02% and 97.72% for ASP flooding. But for polymer flooding, shows value of 98.48% and 96.46%. These results show there is a good fit between data and model. Figures 7 and 8 show the relation between the predicted and actual value of recovery factor for ASP flooding and polymer flooding. Finally, by using of coefficients are generated in Minitab, a regression model for polymer and ASP flooding is obtained based on a variable. With these regression models the value of recovery factor might be estimated if the value of each parameter be known.

Factors	Polymer Flooding Interaction Effect (IE)	P-value	Alkaline Surfactant Polymer Interaction Effect (IE)	P-value
S*Yo	-0.825	0.008	0.025	0.925
S*H	1.056	0.001	0.675	0.017
S*K	0.184	0.529	-0.081	0.761
S*Siw	-0.291	0.324	-0.106	0.691
S*Kro	-0.241	0.413	-0.262	0.33
S*Angle	-0.159	0.586	-0.356	0.19
S*T	-0.337	0.254	-0.256	0.342
Yo*H	0.259	0.378	0.281	0.298
Yo*K	-0.112	0.7	-0.038	0.888
Yo*Siw	0.5	0.095	0.225	0.403
Yo*Kro	-0.181	0.536	-0.406	0.137
Yo*Angle	-0.363	0.221	-0.162	0.545
Yo*T	-0.134	0.646	-0.225	0.403
H*K	0.956	0.003	1.612	0
H*Siw	0.144	0.623	-0.275	0.308
H*Kro	0.313	0.29	0.306	0.258
H*Angle	0.769	0.013	1.425	0
H*T	-0.291	0.324	-0.112	0.674
K*Siw	-0.409	0.168	-0.219	0.416
K*Kro	0.241	0.413	0.212	0.429
K*Angle	0.284	0.334	1.581	0
K*T	-0.3	0.309	-0.119	0.657
Siw*Kro	0.028	0.923	0.062	0.815
Siw*Angle	-0.453	0.129	-0.156	0.56
Siw*T	0.438	0.142	0.256	0.342
Kro*Angle	0.109	0.708	0.113	0.674
Kro*T	0.119	0.685	0.337	0.213
Angle*T	-0.513	0.088	-0.394	0.149

Table 5: Main effect of two variable interactions.

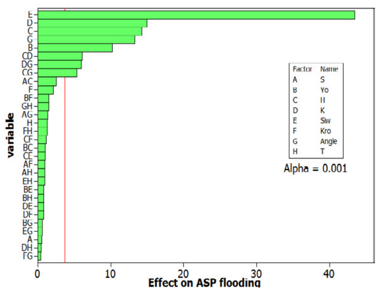

Figure 5: Pareto plot for ASP flooding.

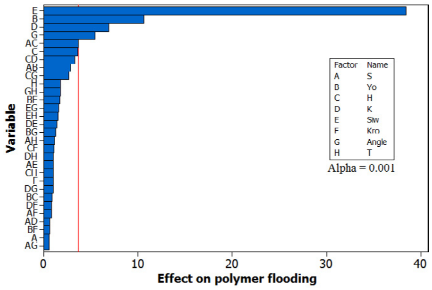

Figure 6: Pareto plot for polymer flooding.

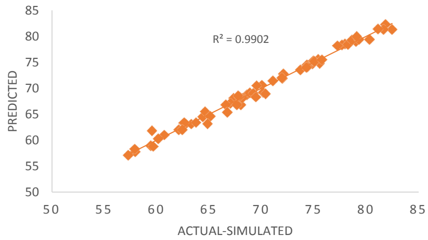

Figure 7: Relation between actual and predicted value of recovery factor of ASP.

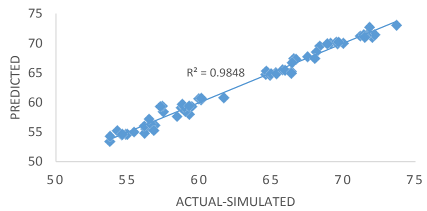

Figure 8: Relation between actual and predicted value of recovery factor of polymer flooding.

Regression model for ASP

RF=70.059-0.072*S-1.35*Yo-1.894*H+1.984*K-5.753*Siw+0.281*Kro+1.766*Angle+0.172*T+0.012*S*Yo+0.337*S*H-0.041*S*K-0.053*S*Siw-0.131*S*Kro-0.178*S*Angle-0.128*S*T+0.141*Yo*H-0.019*Yo*K+0.112*Yo*Siw-0.203*Yo*Kro-0.081*Yo*Angle-0.112*Yo*T+0.806*H*K-0.137*H*Siw+0.153*H*Kro+0.712*H*Angle-0.056*H*T-0.109*K*Siw+0.106*K*Kro+0.791*K*Angle-0.059*K*T+0.031*Siw*Kro-0.078*Siw*Angle+0.128*Siw*T+0.056*Kro*Angle+0.169*Kro*T-0.197*Angle*T

Regression model for Polymer flooding

RF=62.85+0.082*S-1.554*Yo+0.525*H+0.992*K-5.56*Siw+0.142*Kro+0.782*Angle+0.259*T-0.412*S*Yo+0.528*S*H+0.092*S*K-0.145*S*Siw-0.12031*S*Kro-0.079*S*Angle-0.168*S*T+0.129*Yo*H-0.056*Yo*K+0.25*Yo*Siw-0.09*Yo*Kro-0.181*Yo*Angle-0.067*YoT+0.478*H*K+0.071*H*Siw+0.156*H*Kro+0.384*H*Angle-0.145*H*T-0.204*K*Siw+0.12*K*Kro+0.142*K*Angle-0.15*K*T+0.014*Siw*Angle+0.218*Siw*Angle+0.218*Siw*T+0.054*Kro*Angle+0.059*Kro*T-0.256*Angle*T

Conclusions

According to the results of simulation and statistical study, main results of this work include:

- ASP flooding in oil wet limestone has a great performance with high oil recovery compared to polymer flooding.

• Main effect analysis shows reservoir salinity (S), oil viscosity (Yo), thickness (H), permeability (K), connate water saturation (Siw), oil relative permeability (Kro), reservoir dip (Angle), and temperature (T) have an effect on oil recovery.

• Main effect analysis shows connate water saturation has most influence on oil recovery compared to other parameters. When connate water saturation has minimum value, oil recovery has maximum value.

• The interaction effect of S*H, S*Yo, K*H, H*Angle, and Angle*T have most influence on oil recover factor in polymer flooding, but the interaction effect of H*K, K*Angle, H*Angle, and S*H have most influence on oil recovery in ASP flooding.

• According to Tornado Plot, reservoir thickness (H) and oil relative permeability (Kro) help to increase oil recovery when have a minimum value in ASP but in polymer flooding have a main effect to increase oil recovery when have maximum value.

• According to Tornado Plot, reservoir permeability (K) has great effect on oil recovery after connate water saturation (Siw) in ASP, but in polymer flooding oil viscosity is the second main effect.

• A regression model is obtained based on parameter to estimate the recovery factor when the value of parameters is known for polymer and ASP flooding.

Future Developments

• This approach can be applied in fractured carbonate reservoir for screening the parameters includes fracture spacing, porosity and permeability of fracture.

• This method can be applied on the other EOR method such as foam injection.

• Today's high temperature and high salinity condition is a new challenge for chemical flooding such as polymer and ASP flooding. This approach can be applied in this condition by using of thermoviscosifying polymer and new stable surfactant.

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