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A Field Scale Simulation Study of Surfactant and Polymer Flooding in Sandstone Heterogeneous Reservoir

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Abstract

In the current work, three scenarios were considered including water, polymer, and surfactant/polymer flooding for a heterogeneous sandstone reservoir in the Asmari Field located at the South West of Iran in a simulation work. No injection of chemical flooding has been done on this typical reservoir. Most of Enhanced Oil Recovery methods were considered to be water and gas injection in this reservoir so far. UTCHEM was used as a 3D, and compositional simulator to model of chemical flooding process. Sensitivity analyses of vital parameters have been carried out and the results of simulation work were presented.

Keywords: Surfactant and polymer flooding; Heterogeneous sandstone reservoir; Recovery factor; Sensitivity analysis; Viscose force

Introduction

One of the most important methods of Enhanced Oil Recovery is chemical flooding. To recover oil from conventional oil reservoir (25 API, or higher), micellar flooding (microemulsion) and Alkaline injection play a significant role after water-flooding in which recovery factor might reach 60% Original Oil in Place. Surfactant and Polymer flooding has been tested in both sandstone and carbonate reservoir showing higher recovery factor for homogenous reservoir due to effect on IFT between displacing and displaced fluids which is dominant in sandstone reservoir. IFT can be decreased 1000 fold increasing capillary number. This scenario results in lowering residual oil saturation. There is one limitation of applying chemical, that is, adsorption of surfactant onto the rock surface must be considered to increase the efficiency of method [1]. The main mechanism for sulfonate solution is dispersion or emulsification of residual oil into the injection water in the presence of active materials. Under micellar flooding, a successful *in situ* oil emulsification process must be capable of mixing oil and keeping dispersion until it reaches to the production wells. Another important function of micellar flooding is mobility control categorized into (a) immiscible displacement or secondary recovery above residual oil saturation and (b) miscible displacement of immobile phase. Micellar flooding is classified as a miscible displacement where one part is homogeneous (single phase) and one parts two phases [2]. Since the slug of size of chemical flooding is big especially in field application, the properties of flooding fluids influence the reservoir entirely, not partially. So if regional gradient pressure increases, it affects the pressure gradient between injection and production wells. The increase in pressure drop near well-bore will cause regional displacement efficiency. This goal can be done by increase in permitted injection pressure [3]. A scale-up methodology for chemical flooding has been successfully developed in which oil recovery is dependent upon the grid block size. Low oil recovery can be obtained by coarser grid size because the larger grid blocks cause larger surfactant dilution. However, if system is simulated in the optimum salinity, consequently, good recovery can be observed. On the other hand, finer grid blocks have larger simulation time which is not feasible especially in the field scale optimization [4]. Yuan et al. [5] truly stated that water flooding is more sensitive than polymer flooding to the coarse grid blocks. If polymer continuously injected for a long period, polymer behavior and injection well operating condition have more influence on oil production than grid size. However, if polymer is followed by water postflush, fingering would be another challenging must be controlled by a finer grid blocks. The strong relations of phase behavior and interfacial tension with salinity in anionic surfactant have been first developed by Healy and Reed [6] and Healy et al. [7]. Nelson and Pope [8] and Hirasaki et al. [9] concluded that optimum design of chemical flooding is affected by salinity gradient. The concepts of dispersion and adsorption are of interest to the petroleum industry. While dispersion causes the mixing of chemical slug, adsorption causes the loss of chemical slug. To have the higher recovery factor, chemical loss must be controlled. The adsorption of surfactant and polymer is dependent upon the petro-physical nature of rock and fluid affected by rock matrix [10].

Another important mechanism of surfactant flooding is the cation exchange capacity. The charge of surface in the clay mineral is pH and salinity dependent. For example, the surface charge of silica and calcite in water is positive at low pH, but negative at high pH. For silica, the surface becomes negatively charged when the pH is increased above about 2–3.7, whereas calcite does not become negatively charged until the pH is greater than about 8–9.5. When the effects of brine chemistry are removed, silica tends to adsorb simple organic bases (cationic surfactant), while the carbonates tend to adsorb simple organic acids (anionic surfactant). This occurs because silica normally has a negatively charged weak acidic surface in water near neutral pH, while the carbonates have positively charged weak basic surfaces [11]. It would be favorable to produce the condition so-called micro-emulsion in which solubilization is so high that water and oil can be mixed over the wide range of composition. As much as about 20% to 25% would be necessary to provide micro-emulsion condition. However, in order to reduce the amount of surfactant due to economic problems, optimum slug size of micro-emulsion needs to be designed [12]. A system including a micro-emulsion in equilibrium with oil, a micro-emulsion water system, and intermediate micro-emulsion system in equilibrium

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with excess oil and water is named as Winsor type I, II and III. System can exist in one phase in which solubilization ratio of water and oil is high. Figure 1 is depicted the ternary diagram of micro-emulsion systems [13]. When the plate point is at the left side of the diagram, system is in the equilibrium with oil meaning the amount of solution salinity is high. By decreasing salinity, plait pint is shifted to the right side in which system is in equilibrium with water and soluble with oil. Plait point at the middle of ternary diagram indicates intermediate system. Thus, phase behavior of surfactant is extremely dependent on the amount of salt in the system, temperature, oil composition and co-surfactant molecular weight (it can be added to the top of the ternary diagram along with surfactant). In the miscible region, most of the oil can be recovered as a result of high solubilization ratio. Most of the oil Fields in Iran are using miscible/immiscible gas injection or thermal methods to recover oil. However, the application of such techniques might be restricted, particularly for reservoir depths over 4500 ft and high viscous oil. Hence, the results of current numerical work aims to evaluate different schemes of chemical flooding on one of the Iranian Oil Field, taking into account the polymer (P) and the surfactant-polymer (SP) flooding. The simulation tuning was performed to select the best scenario as a base case. Sensitivity analyses on the base case to evaluate the vital parameters on oil production including dispersion, producer Bottomhole pressure were performed. The results of the present work are of practical importance for petroleum industry.

Research Methodology

Field characterization

The reservoir is 30 km long, around 1.5 to 3.5 km wide which has been extended from the North-West to South-East. The reservoir was discovered in 1963 by drilling the first well and starts producing oil in 1974. This reservoir is under saturated and oil column reached 66 meters in some places. Based on comprehensive investigation by National South Iranian Oil Company, the amount of original oil in place was estimated 2905 MMbbl. The total number of wells drilled in the reservoir is 29 in which 17 wells perforated in Asmari layer and the rest is completed to Bangestan and Khami layers. According to lithology changes, petrophysical characterization, reservoir has been divided into 8 main layer and 19 sub-layer in which only layers 1, 2, 3 and the top of layer 4 contained oil. Although other layers have suitable porosity, however, water saturation can reach up to 70% or 80% in some places. Layer 1 generally consists of carbonate, layer 2 is sandstone and layer 3 composed of carbonate and sandstone. Lower layers have also some shales.

Batch experiment of laboratory parameters

In order to calculate vital parameter such as effective salinity based on solubilization parameter, running simulation of batch experiment would be necessary to match experimental data and simulation result. In this work, effective salinity would be 0.6 meq/ml, which is the average between lower and upper salinity. This effective salinity will result in solubilization ratio of 2.6 by using surfactant Alfoterra® 18.

UTCHEM parameters for polymer properties

The polymer input data for UTCHEM was provided by Anderson [14] which has been done by University of Texas Laboratory. Hydrolyzed polyacrylamide was employed to obtain phase behavior of polymer. From these tests, polymer viscosity as a function of shear rate, permeability reduction factor, polymer concentration, and salinity can be graphically assessed. UTCHEM polymer parameters is then taken from curve fit and put into simulator.

Simulation model

After surfactant and polymer parameters were obtained, the second step is to develop a simulation model which is representative of reservoir. In the current work, a quarter 5-spot model with pressure-constrained for producer and constant rate for injector. Producer Bottomhole pressure is 1974 psi which is related to field operator data and fracture gradient limitation and reservoir pressure would be 3554 psi. The reservoir is 6462 feet deep, 179°F, and 40 feet thick. The reservoir permeability is given by field operator showing heterogeneous reservoir with higher permeability in the middle, lower permeability at top and moderate permeability as compared to two other layers at the bottom. Table 1 depicts some important parameters for simulation model. Table 2 shows fluid properties used in this study. Figure 2 shows permeability model used in this model which is one block heterogeneous model.

Base case model description

Base case model is based on surfactant/polymer flooding, all the sensitivity analysis then applied to the base case to understanding the effect of parameters. This is 250 by 250 by 40 blocks modeled by UTCHEM. There are 25 blocks in X direction, 25 blocks in Y direction and 4 blocks in Z direction as shown in Figure 2. Vertical injection was considered in all cases perpendicular to X direction except where the comparison of horizontal and vertical wells is going to be modeled. The top, bottom and side of block were sealed. In all cases where surfactant is applied, under optimum micellar system is formed with the salt amount close to effective salinity. Three scenarios were considered including water flooding (water only), polymer flooding and surfactant/polymer flooding (SP flood). The grid model is composed of 2500 blocks, total simulation time is 365 days (0.32 PV) and the well spacing of 353 ft. UTCHEM solved all the equation based on IMPES method. It could be interesting to note that injection and production wells are not the partial completion and perforated through 4 layers. The well data for base case is tabulated in Table 3.

Simulation Results and Discussion

The comparison of three methods in this reservoir is depicted in Figure 3. As it can been seen, SP flooding has higher recovery factor than polymer and water flooding. However, the time of breakthrough in three methods is the same which would be after 10 days. In the first 50 days, there would be a little difference between three scenarios in terms of recovery factor. This result can be interpreted by this fact that surfactant has contact with the whole rock grids, resulting

Reservoir dimension model	250 feet × 250 feet × 40 feet
Depth	6462 feet
Porosity	0.23
Permeability	Average=50 md
	Min=34 md
	Max=100 md
	Kv/Kh =0.1
Residual oil saturation	0.3
Relative permeability endpoint	Water=0.4
	Oil=0.25
Relative permeability exponent	Water=2.9
	Oil=3.3
Maximum simulation time	365 days
Average reservoir pressure	3554 psi

Table 1: Simulation model properties for field scale.

Viscosity		Water =1.13
		Oil=1.24
Initial brine composition		35064 ppm NaCl

Table 2: Fluid properties.

Number of Injectors	1
Number of producers	1
Well spacing	353 ft
Perforated layers of injector	All 4 layer were perforated in vertical well
Perforated layers of producer	All 4 layer were perforated in vertical well
Producer BHP	1974 psi
Constraint on producer or injector	Constant rate on injector and pressure-constrained producer
Injected surfactant concentration	2%
Injected polymer concentration	0.15
Alcohol concentration	No alcohol in base case

Table 3: The well data for base case.

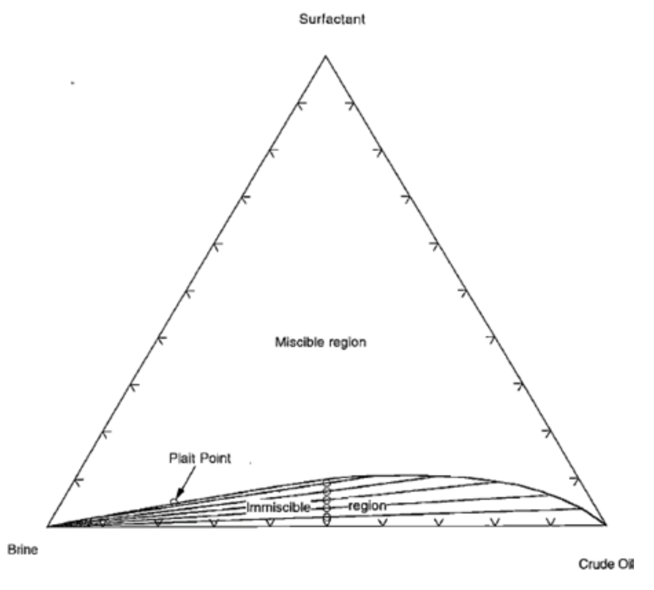

Figure 1: Ternary diagram of micro-emulsion system by Labrid.

in lower capillary forces. On the other hand, water imbibition was directly occurred in water flooding. After 50 days, water flooding gradually decrease capillary pressure while surfactant sharply lowered capillary forces. Thus, it results in high difference between water and surfactant flooding in terms of recovery factor. In another version, surfactant has reduced the residual oil saturation and mobilized oil by increasing relative permeability to water. Another mechanism that causes surfactant override water flooding is to decrease IFT through the formation of micro-emulsion. In addition, polymer is used to increase volumetric sweep efficiency through mobility control. In the current work, the effect of changing wettability is considered to be negligible. The most important forces improving recovery factor in base case is viscose forces. Gravity segregation is negligible because the height of grid block is not high as compare to X, Y direction. The second interesting result is the comparison of polymer flood and water flooding. As we see from the graph, water flooding overrides polymer flooding until 100 days injection. This can be inferred to permeability reduction factor, plugging of pore volumes and interaction of rock while water flooding constantly imbibe water and make oil pulled out of pore volumes. Secondly, at the beginning time of injection, due to high salinity gradient polymer cannot acts like surfactant. After 100 days injection, polymer shows higher recovery than water flooding and outweighed around 5% recovery factor. Recovery factor for reservoir have been obtained 53%, 32%, 28% for SP, Polymer and Water flooding respectively. A little difference between water and polymer flooding can be due to low oil viscosity. Therefore, polymer flooding is not recommended for this reservoir because it is not economic. After 250 days injection, unusual result was seen from SP flooding in which trend shifted to up. This phenomenon can be the consequences of two main reasons. First, the existence of high gradient pressure between injector and producer caused turbulent flow of fluids and high recovery. Second, the influence of longitudinal and transverse Dispersivity causes the production of more oil because the ratio of vertical to horizontal solubilization started showing its effect. Figure 4 shows residual oil saturation and oil relative permeability after 1 year injection. Oil relative permeability reached 0.50 as result of SP flooding giving residual oil saturation of 5% at the end.

Sensitivity analysis on longitudinal and transverse dispersivity

Two cases were simulated to indicate the impact of longitudinal and transverse dispersivity. The comparison of results is demonstrated in Figure 5. Transverse dispersion is defined as a mixing in the flow direction perpendicular to the macroscopic flow while Longitudinal

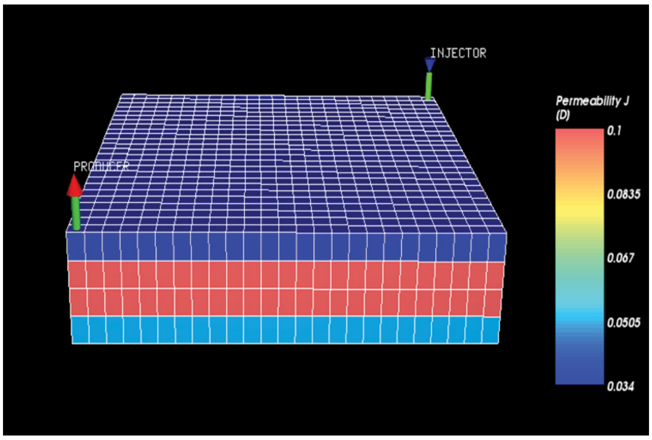

Figure 2: Simulation model permeability (D).

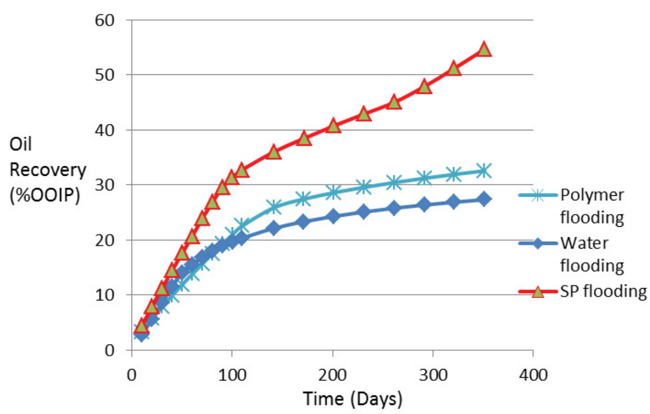

Figure 3: Base case simulation and comparison of three methods.

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is the mixing of fluid in the flow direction. These two factors are extremely dependent upon phase fluid saturation, the path of flow. The path of flow (streamline) is different from one porous medium to another one. The particles of fluid flow molecularly diffuse to each other across streamline [15]. Thus, fluid molecules not only diffused in the direction of flow but also in the way perpendicular to it. Surfactant as a third component can be diffused in the water and oil molecules causing the mixing of oil, water components. In one case, transverse and longitudinal coefficient is not included in the calculation resulting in 47% recovery factor. When these coefficients are considered, oil recovery factor reached 55%. If transverse and longitudinal coefficient is not applied, no dispersion of flow occurred resulting in dropping surfactant concentration and delay in oil production.

The comparison of vertical and horizontal injector wells

Figure 6 depicts the comparison of vertical and horizontal wells in terms of oil recovery. There have made some changes in the base case of vertical well including partial well completion. Vertical injector is perforated across the first layer and its producer is completed all layers. In horizontal injector and vertical producer, the horizontal injector has been completed up to the fifth grid blocks in the X direction. According to the Figure 6, a little difference is observed between horizontal and vertical injector. Since the porous media in our case is heterogeneous and the lower parts of the block have lower Z permeability, less oil can be mobilized to the horizontal perforated zone. The combination of lower Z permeability and the weakness of gravity forces caused the little difference between horizontal and vertical injector wells in the case of heterogeneous reservoir while it is expected that horizontal injector well has higher recovery factor.

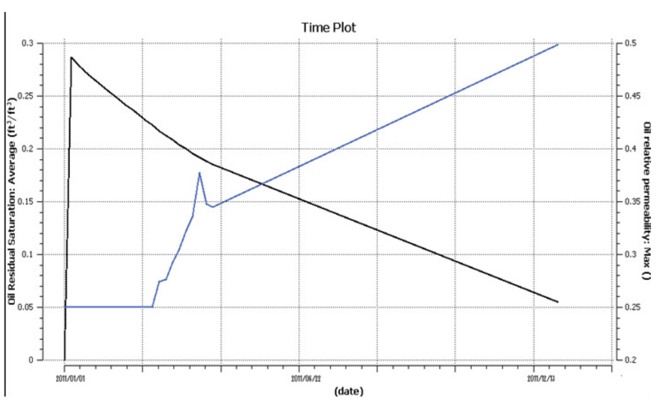

Figure 4: Time plot of residual oil saturation and oil relative permeability.

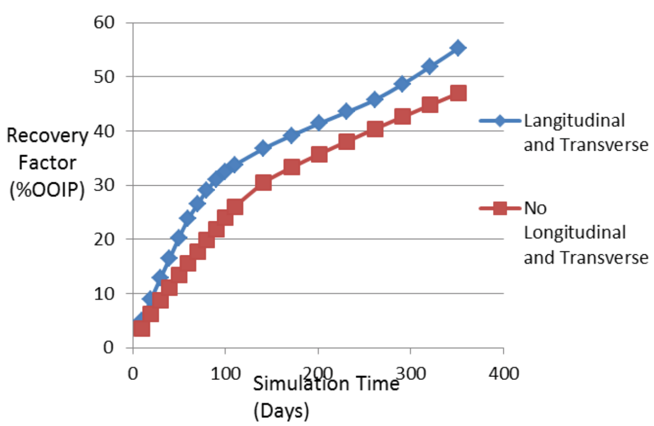

Figure 5: Sensitivity analysis on transverse and longitudinal dispersivity.

Figures 7a-7c indicate how polymer, surfactant could were pushed the oil from injector toward producer. As it can be seen, volumetric sweep efficiency increased and residual oil saturation significantly decreased. Salinity gradient is reduced to 0.2 meq/ml of water in the drive water behind the surfactant slug.

Effect of producer bottom-hole pressure

Figure 8 shows the effect of pressure differential on oil recovery factor. In the current work, base case which is our best case has the pressure of 1974 psi based on drawdown 1.8. Since the effect of gravity and capillary forces is found to be negligible, thus gradient pressure has an effective influence on effluent flow. By decreasing pressure differential, that is, increase in Pwf, the oil recovery factor is reduced. The correlation of differential pressure and capillary number index can be calculated from Taber's Equation [16] as follows:

$Nc = \Delta P / \sigma L$

Where,

$\Delta P/L$: Imposed Gradient Pressure between two points (atm/cm)

σ: Interfacial Tension (dyne/cm)

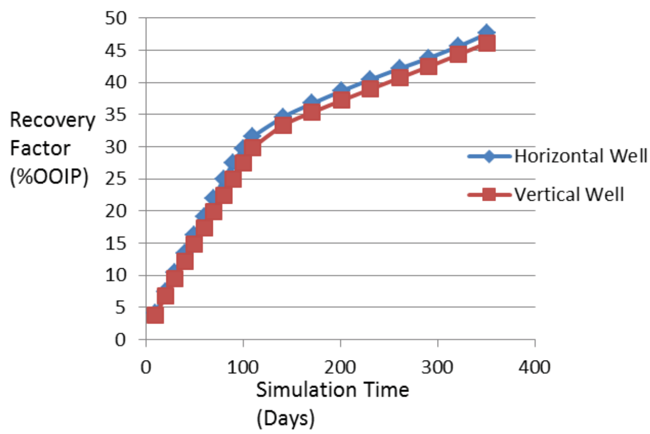

Figure 6: The comparison of vertical and horizontal wells on effluent oil.

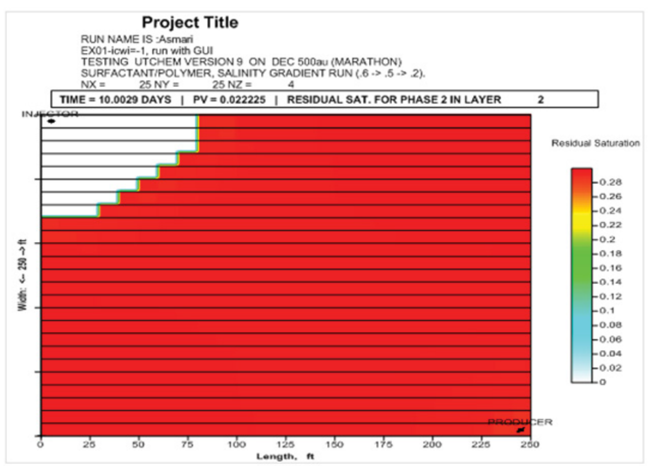

Figure 7a: The residual oil saturation after 10 days injection.

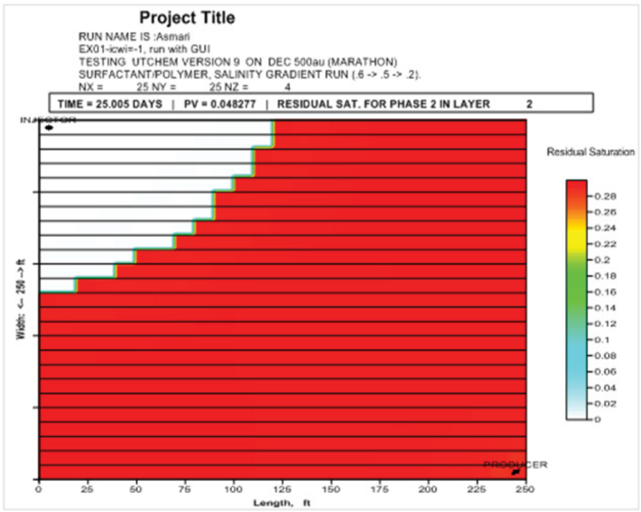

Figure 7b: The residual oil saturation after 25 days injection.

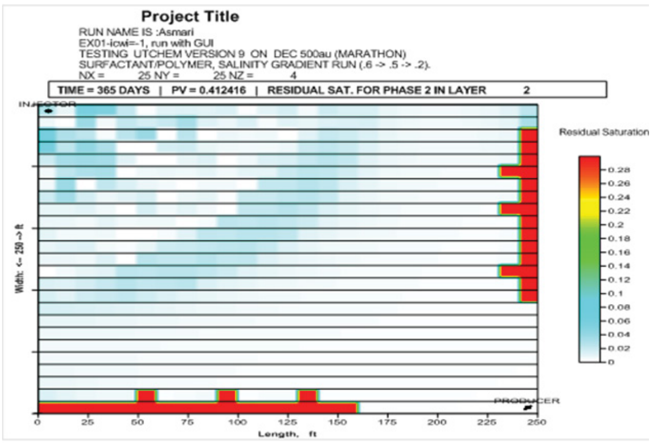

Figure 7c: The residual oil saturation after 365 days injection.

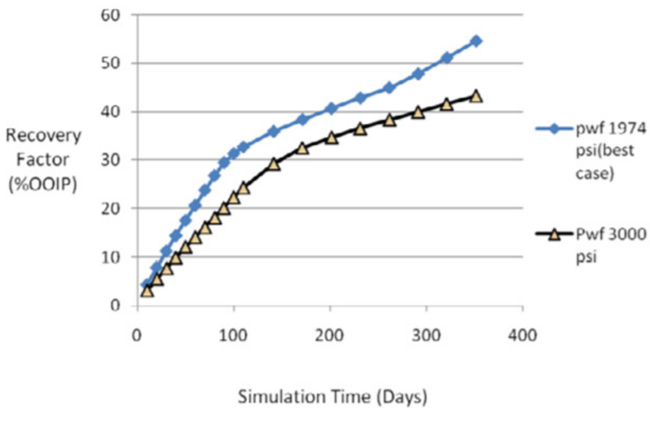

Figure 8: Sensitivity analysis on bottom hole flowing pressure.

The higher gradient pressure will result in higher capillary number and consequently lowered residual oil saturation. On the other hand, by applying higher gradient pressure, the fluid phase behavior is changed from Laminar to Turbulence flow causing higher oil production.

Conclusions

At the first step, base case model composed of SP flooding was developed and the result was compared to water and polymer flooding. Sensitivity analysis has been done on the base case to show the impact of several important parameters in chemical flooding. The brief description of sensitivity analysis results is as follows:

1. The comparison of SP flooding, polymer and water injection in this field proved that SP flooding could recover more oil out of pore volumes and improve recovery factor. Due to low viscosity of oil field, the value of recovery factor for polymer stayed close to recovery factor obtained from water flooding.

2. Another factor which has positive effect is Longitudinal and Transverse Dispersivity coefficient. If these factors are included in the input parameters of simulator, recovery factor reaches 55% as compared to 47% OOIP when they are negligible. This can be referred to diffusion of surfactant into the water and oil molecules.

3. If horizontal injector well is perforated into the block grid, it can produce oil better than vertical injector well. However, the difference of 1 percent recovery factor proved that due to high cost of drilling well horizontally, this is not economically feasible. Another work must be studied to analyze the economic feasibility of both horizontal and vertical wells to show weather horizontal well would be suitable or not.

4. Bottomhole flowing pressure has a direct relation with capillary number index, that is, residual oil saturation is reduced if pressure gradient increased. The base case has the Bottomhole pressure of 1974 psi.

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