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POLYMER FLOODING: STUDY OF FACTORS INFLUENCING THE OIL RECOVERY

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Abstract. *Nowadays, the interest on enhanced oil recovery methods is motivated by the high oil prices and the large dependence of society for petroleum derivatives. Thus, oil companies seek to maximize the exploration during the period of concession. The methods for enhanced oil recovery are classified as miscible, thermal and chemical methods. The polymer injection is a chemical process where polymer is added to the injection water aiming increase its viscosity, consequently reducing the water-oil mobility ratio and increasing the sweep efficiency. Nevertheless, it is worth highlight that, previous to EOR method selection, any case must be submitted to screening criteria. In the case of polymer flooding, the selected criteria include evaluation of hazardous conditions for the polymer that can lead its degradation. So, this paper presents an analysis on a laboratory scale of oil recovery with water injection alternated with a polymer slug (WAP) compared to the continuous water flooding (WF) case. The simulated cases including different conditions were built and evaluated using a commercial simulator. Variations in the slug size of the injected polymer solution, injection starting time of the polymer slug, relative permeability curves, polymer viscosity, residual oil and initial water saturation were carried out to determine the effects on oil recovery. As a result of the analyses, it was possible establish the following observations: (1) larger slugs of polymer solution lead to larger volumes of produced oil, however with decreasing amounts of produced oil per mass of polymer; (2) anticipation on the injection of the polymer solution leads to an anticipation in oil production; (3) lower values of relative permeability to water at residual oil saturation lead to high difference on relative gain of oil production once the final mobility ratio is lower; (4) higher viscous polymer solutions lead to lower value of the mobility ratio and higher oil production, however requires higher injection pressures; (5) lower residual oil and initial water saturation leads to a high oil recovery, mainly as consequence of the higher amount of mobile oil.*

Keywords: *polymer flooding, oil recovery, simulation, mobility ratio.*

1. INTRODUCTION

Nowadays, hydrocarbons are the most important source of energy and essential to the necessity and development of the society. The exploration and production of petroleum require considerable investment, and the development of new technologies in order to work in increasingly complex conditions and areas with very difficult access (Thomas, 2001). The study and the development of new techniques enables maximize the recovery during the period of exploration's concession.

The water flooding is widely used because it is relatively simple and inexpensive, but has some disadvantage because as water generally is less viscous than oil. In such case, water tends to prematurely arrive at the producer and the water-oil ratio tends to grow fast, resulting in small oil production due to low sweep efficiency.

The facility of a fluid flow through a porous medium is defined as the mobility (λ), which is the ratio between its effective permeability (k) and its viscosity (μ). Thus, the mobility ratio (M) is defined as the ratio between the displacing phase mobility and the displaced phase one.

Therefore, the need for usage of advanced recovery methods, among which stands out the polymer flooding, has emerged. This method was first applied in the early 60's, as a means of reducing the mobility ratio by increasing the water viscosity (Sorbie, 1991). The method is more efficient in heterogeneous models, due to better distribution of the injected fluid along the reservoir. Thus, much of the oil not contacted by water flooding can be displaced and produced due to the increase on the sweep efficiency (Assunção, 2011 and Sedaghat, 2013).

Water injection alternated with a polymer slug (WAP) is performed by injecting brine followed by a slug of polymer solution, the changing for brine injection again. Continuous polymer flooding can be economically unviable or technically limited due to low injectivity. According to Du (2004), projects of polymer solution flooding have been successful with polymer slug ranging between 7% and 33% of the pore volume.

Compared to the continuous water flooding, the polymer flooding may cause an increase in oil recovery by increasing the sweep efficiency and reducing production water-oil ratio. Therefore, more oil is produced while handling less water, which may be significant in reducing costs. In addition, the polymer flooding provides an anticipation of oil production, which can be profitable, due to the anticipation of revenue.

According to Needham, 1987, polymer flooding can increase oil recovery compared to water flooding. This happens through the effects of the polymer on the fractional flow by diverting the injected water for nom swept zones.

Two polymers are most commonly used: HPAM (partially hydrolyzed polyacrylamide) and xanthan gum. The HPAM is a copolymer of acrylamide and acrylic acid formed by partial hydrolysis of amide groups to carboxyl groups. The higher is the degree of hydrolysis, the higher is the HPAM viscosity. The performance of polyacrylamide in oil recovery injection will depend on its molecular weight ($1x10^6$ to $20x10^6$ Daltons) and its degree of hydrolysis (Sheng, 2011). Polyacrylamides have an additional feature besides the adjustment of the viscosity, which is to change the permeability of the reservoir rock, which also decreases the mobility of injected water. With this condition, a low concentration of polymer can be used to gain control of mobility (Rosa, 2006).

Xanthan gum is a polysaccharide polymer produced by the microorganism Xanthomonas campestris. The polymer is formed by the remains of a protective cover or shell developed by the body. Its average molecular weight ranges from $1x10^6$ to $15x10^6$ Daltons (Sheng, 2011).

The polysaccharides can tolerate shear effects, which makes them easier to handle and pump. Moreover, the polysaccharides can be mixed in water salinity since they are more resistant to viscosity degradation than the polyacrylamides. However, they are susceptible to attack by bacteria after they are introduced into the reservoir and do not have the same effect of reducing water permeability as in the case of HPAM (Rosa, 2006). HPAM has a lower cost per quantity in relation to polysaccharides, and to date, more than 90% of field applications have used HPAM (Sheng, 2011).

When the polymers are used in recovery operations, it is crucial that their properties are not rapidly degraded. The solutions must remain stable over a long period in reservoir conditions, since the viscosity of the polymer solution is the main property of interest in this regard. The degradation of the polymer refers to any procedure that breaks the molecular structure of the macromolecule (Sorbie, 1991).

Before starting an EOR development project, the parameters of the reservoir must be evaluate against selection criteria. This check may indicate whether the polymer flooding is possible or not, what type of polymer is more likely to be successful, and if the project may prove effective in terms of technical performance and profit capacity (LITTMANN, 1988).

Thus, this paper presents an analysis on a laboratory scale, using a commercial simulator. The oil recovery with water injection alternated with a polymer slug is compared to the continuous water flooding. Effects on oil recovery caused by variations on the slug size of the injected polymer solution, injection starting time of the polymer slug, relative permeability curves, polymer viscosity, residual oil and initial water saturation are evaluated.

2. POLYMER FLOODING

Laboratory tests have shown that the injection of the polymer can increase the recovery of heavy oil more than 20%. And, can be use water with low salt to prepare the polymer solutions, moreover, the injection facility must be carefully designed to minimize degradation (Gao, 2011).

Some studies claim that polymer flooding can reduce the residual oil saturation, while others observed no significant variations. Wu, 2007, noted that the injection of HPAM polymer reduced the residual oil saturation to 0275, compared with the water flooding (0.314). And Huh, 2008, noted that polymer flooding after water flooding cannot mobilize the residual oil, however, as secondary methods, the polymer can reduce the residual oil saturation of 2 to 22 percentage points.

Studies by Kamaraj, 2011, with data from the north slope of Alaska reservoir, showed that reductions in residual oil saturation can provide additional amounts of oil recovery with polymer flooding, and that the impact of the reduction in saturation decreases with heterogeneity. It examined cases with 20%, 60% and 100% reduction in the amount of S_{or}, and found that polymer flooding is effective even for reservoirs that have been widely recovered with water.

Rangel, 2012, found that a higher concentration of the polymer solution increases the efficiency of oil recovery process. According to tests conducted by Zhang, 2014, when a porous medium is first contacted with a dilute solution of HPAM, adsorption and trapping process of the polymer molecules occurs. After that, no additional mechanical trapping takes place when this area is exposed to higher concentrations. Thus, in field applications, he suggests to inject a first slug with low concentration, to satisfy small retentions of polymer.

Test on reservoir with low mobility ratios than 42, and oils with viscosities of at most 126 cp, have achieved good results with polymer flooding (Du, 2004). And studies with values of initial water saturation to 0.47 have shown success for polymer flooding (Du, 2004). And second Sedaghat, 2013 a higher connate water saturation results in lower oil recovery, regardless of the conditions of wettability.

By comparing the conditions of the interest reservoir with the screening criteria, you can check if the application of the method of recovery is favorable and the correct choice of solution to be injected and their characteristics. Table 1 brings together a screening criteria analyzed by several authors.

Table 1. Screening criteria for polymer flooding.

Properties	Criteria	Unit
Reservoir Temperature	< 200	ºF
Depth	< 2700	m
Porosity	> 0.18	
Reservoir Permeability	20 a 2300	md
Mobility Ratio	< 42	
Gravity	15 a 40	ºAPI
Water Relative Permeability	0.28 a 0.8	
Initial Water Saturation	< 0.47	
Oil Saturation	> 50	% PV
Oil Viscosity	< 126	cp
Injected solution volume	7 a 33	% PV
Injected solution concentration	150 a 4000	ppm

Adapted from Abou-Kassem, 1999; Al-Bahar, 2004; Du, 2004; Green 2008

3. METHODOLOGY AND APPLICATION

In this work, analysis of polymer flooding for oil recovery compared to continuous water flooding is performed using the commercial simulator STARS (Advanced Processes & Thermal Reservoir Simulator) developed by CMG (Computer Modeling Group Ltd.). The laboratory model has dimensions 20x20x10 cm³ and the grid corresponds to 20 blocks in the direction I and J, and 10 blocks in the direction K.

The reservoir model is considered homogeneous with 1000 mD permeability, porosity of 0.20, temperature of 24ºC, initial water saturation of 0.2 and residual oil saturation of 0.3.

The oil in the reservoir was characterized as heavy oil with 20ºAPI and viscosity of 23.86 cp. The polymer solution used was based on the HPAM polymer, with a density of 1.11 g/cm³, viscosity of 15 cp for a shear rate of 10 s^{-1} and concentration of 2,500 ppm and water with salinity of 100.000 ppm (Assunção, 2011, and Valdivia, 2005). However the simulator does not identify polymer type, only its properties.

The production scheme consists of two vertical wells, one injector and one producer, arranged to represent a quarter of five-spot, the most broadcast scheme in analysis of recovery methods (Rosa, 2006). The maximum injection pressure is 5000 kPa and the maximum injection flow rate is 0,425cm³/min. The pressure at the producer is limited to 101 kPa (Valdivia, 2005). The operating conditions of the wells were kept equal for recovery scenarios for water flooding and polymer flooding.

Initially, a comparison between the continuous water flooding and water injection alternated with a polymer slug was performed to verify the efficiency of these base cases with relation to oil recovery. The simulated period considered was 94 hours of production, which corresponds to the injection of three pore volumes (PV) and the strategy adopted was to inject the polymer slug 900 minutes (0.48 PV) after the start of the simulation. The slug size corresponds to 0.32 PV.

The other simulated cases had modified values with respect to the polymer slug size, the start time of the injection of that slug, the relative permeability of water at residual oil saturation, the polymer viscosity, the residual oil saturation and the initial water saturation.

4. ANALYSIS AND DISCUSSION OF RESULTS

In this section the results obtained for the two base cases were compared with respect to oil recovery, together with an analysis of the modified parameters. The results are described below and compiled in Table 4.

4.1 Comparison between continuous water flooding and water injection alternated with a polymer slug

In the case of water injection alternated with a polymer slug, the slug size corresponds to 32% of the pore volume (injected during 600min), and the injection of the polymer slug was initiated after the injection of water corresponding to 48% of the pore volume (900 minutes), and once the slug is completely injected, water is injected again until the end of the simulation.

From the results, the water injection alternated with a polymer slug (WAP) favors the oil recovery when compared with continuous water flooding (Figure 1). In the WAP case, oil recovery factor was increased by 5%. Another way to verify the efficiency of polymer flooding is through the reduction of the water-oil ratio, also shown in Figure 1, where you can still check the injection starting time of the polymer slug.

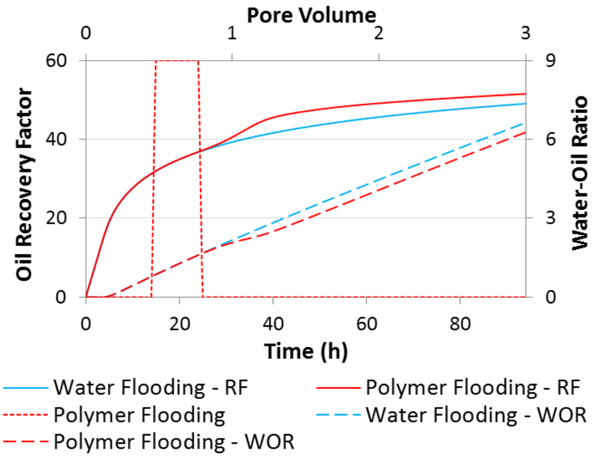


Figure 1. Oil recovery factor and the water-oil ratio for WAP and WF.

The mobility ratio can provide data relating to injected fluids in the reservoir, since values close to one are said to be favorable. During water flooding, the terminal mobility ratio is 11.18, and with the polymer slug the value is reduced to 1.49, due to the increased viscosity of the injected fluid.

Table 2 summarizes results data to facilitate a quantitative comparison. The results included are: recovery factor, volumes of oil and water produced, volumes of water injected and relationships between these values for the two studied base cases.

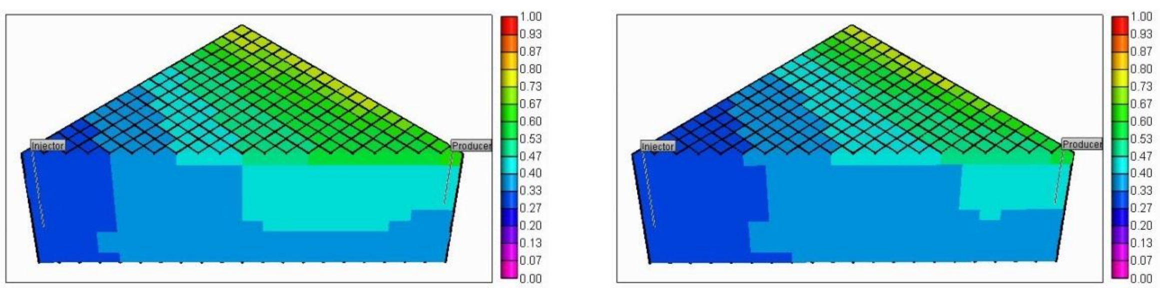
Table 2. Comparison between water and polymer flooding

		Water Flooding	Polymer Flooding	Δ
M		11.18	1.49	
RF	(%)	49.06	51.53	5.03%
Np	(cm^3)	314.00	329.80	5.03%
Wi	(cm^3)	2397.00	2397.00	0%
Wp	(cm^3)	2082.60	2066.62	-0.77%
Wi/Wp		1.15	1.16	0.77%
Wi/Np		7.63	7.27	-4.79%
Wp/Np		6.63	6.27	-5.52%

M = Terminal Mobility Ratio; RF = Recovery Factor; Np = Oil Production; Wi = Water Injected; Wp = Water Production.

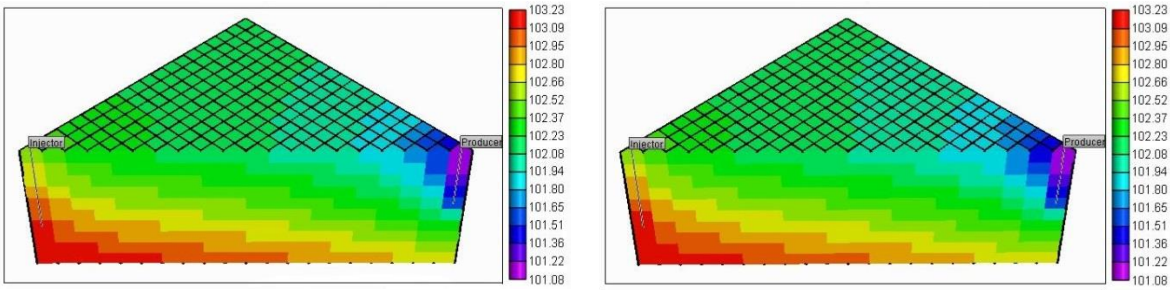
The injection of polymer slug increases the oil production and reduces the water production compared to the continuous water flooding, thus reduce the ratio of water injected to oil produced, and increasing the ratio of water injected to water produced.

Observing the oil saturation maps at the end of the simulation (Figure 2), there is a piston effect and an improvement in the areal and vertical sweep efficiencies in the case of polymer slug flooding relative to the continuous water flooding. Furthermore, it is possible to see the reduction of oil saturation due to the water injection alternated with a polymer slug (WAP) compared to the area flooded by water (WF). Gravitational effects can also be observed for the two analysed cases, one can see smaller values of oil saturation in the low layers. The Figure 3, shows higher pressure values for WAP in comparison with WF.



Water Flooding Water injection alternated with a polymer

Figure 2. Maps of oil saturation at the end of the simulation period.



Water Flooding Water injection alternated with a polymer

Figure 3. Maps of pressure at the end of the simulation period.

4.2 Change in polymer slug size

The amount of oil being produced changes according the polymer slug size and this is directly linked to the costs of the process. The continuous polymer flooding eliminate the risk of viscous fingering and thus provides better results compared to the continuous water flooding or water injection alternated with a polymer slug, though it can be impractical.

In order to investigate the effect of the slug size in the oil recovery, the base case of polymer injection was used as a template and simulations for different injected polymer slugs were performed. The slug injection initiates 900 minutes after the water flooding starting and the injected volume of polymer solution corresponds to 10%, 20%, 40% and 50% of the pore volume. Figure 4 presents the oil recovery factor resultant of each studied case, where the slug size zero corresponds to continuous water flooding.

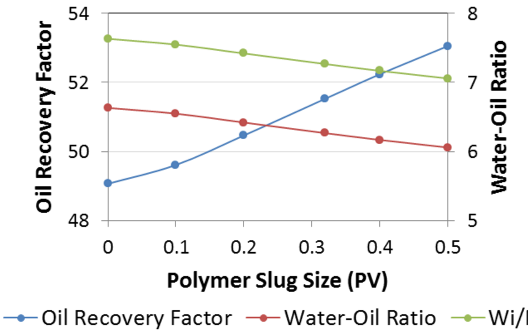


Figure 4. Variation of the oil recovery factor as a function of polymer slug size.

For slugs with values less than 10% of the pore volume is observed that the gain in the oil recovery factor is lower when compared with the gain obtained by larger slugs. As the slug size is increased, the process tends to a continuous polymer flooding.

It is necessary to find the slug size of polymer which has favorable values of recovery and costs. Thus, in Figure 5, you can check the volume of oil produced per mass of polymer needed for each injection condition.

By Figure 5, it appears that the relationship with the slug size of polymer is not linear; so for values greater than 32% of the pore volume, the ratio of oil produced per mass of polymer varies little when compared to smaller values of slug size of polymer.

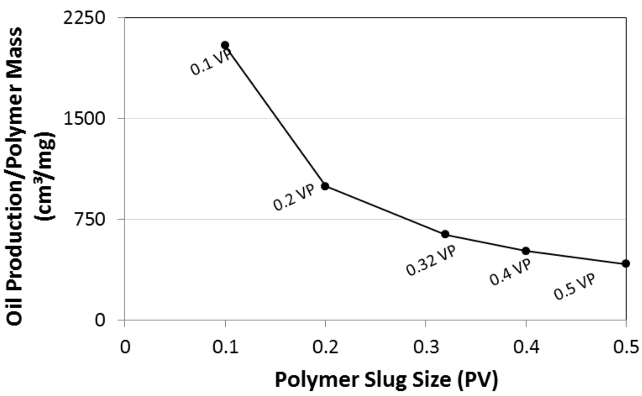


Figure 5. Variation the volume of oil produced per mass of polymer to polymer slug size.

4.3 Change the injection starting time of the polymer slug

To evaluate the effect that the choice of the injection starting time of the polymer slug causes to the recovery factor, simulations were performed modifying only this condition in the WAP base case template. The cases analyzed included the injection starting time of the polymer slug at the beginning of the simulation, at the breakthrough time (92 minutes, 5% Vp) and at water cut corresponding to the injection of 1.5 Vp. The amount of injected solution was kept the same (0.32 Vp), changing only the instant of the injection starting time of the polymer slug and consequently also the end moment. Figure 6 shows the variation of oil recovery factor as a function of the starting time of polymer injection.

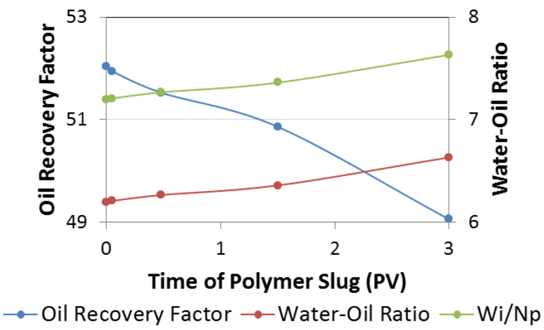


Figure 6. - Variation of the recovery factor as a function of starting time of injection of the polymer slug.

By observing the curves in the Figure 6, it appears that as soon the injection of the polymer slug begins, higher is the oil recovery and lower are the ratio of water produced or injected by oil produced. Another fact is that the polymer slug instart too late, because then its effect will be reduced, and the results obtained from water injection alternated with a polymer slug are close to those of a continuous water flooding.

The polymer flooding increases oil recovery, thus the anticipation of the starting time of the slug injection leads to an anticipation of oil production.

4.4 Change in the water relative permeability in the residual oil saturation

The water flooding base case and the water alternating with polymer slug cases were used to verify the change in the recovery factor for changes in terminal values of relative permeability to water. Permeability curves obeyed the Corey model And the terminal permeability values are analyzed within the range described in the selection criteria summarized in the Table 1.

Figure 7 shows the variation of the oil recovery factor, the ratios between injected or produced water and produced oil, all against values of relative permeability to water. The dotted lines refer to continuous water injection and the continuous ones represent the injection of water alternate with polymer slug.

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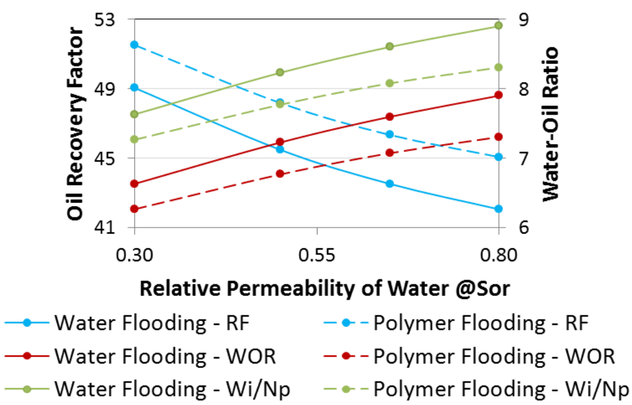

Figure 7. Variation of the recovery factor as a function of the relative permeability of water @S_{or}.

Higher water relative permeability values result in lower oil recovery factor. However, as the values of water relative permeability increases, the reduction in the value of the recovery factor is smaller. The polymer slug flooding remains more favorable in relation to continues water flooding, which is shown in Figure 7.

The increase in water relative permeability leads to an increase in the mobility ratio, as can be seen Table 3.

Table 3. Terminal mobility ratio for different relative permeability of water.

K_{rw} @S_{or}	Terminal Mobility Ratio	
	Water Flooding	Polymer Flooding
0.3	11.18	1.49
0.5	18.64	2.49
0.65	24.23	3.23
0.8	29.83	3.98

4.5 Change in viscosity of the polymer

Another factor that increments the mobility ratio is the increase in the viscosity of the injected solution. Thus, simulations were performed considering the polymer viscosity of 7cp, 20cp and 30cp at shear rate of 10 s^{-1}, and unchanging the other parameters of the base polymer flooding model.

Figure 8 demonstrates the variation of the oil recovery factor, the ratio between water injected and oil produced, and the ratio between produced water and produced oil, all against the polymer viscosity.

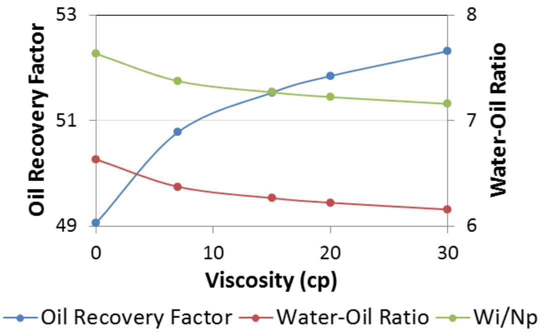

Figure 8. Variation of the recovery factor as a function of viscosity.

An increase in the viscosity of the polymer favors the recovery of oil. However, a disadvantage already observed in previous studies (Abou-Kassem, 1999, Green, 2008), is that polymers having very high viscosity values require higher injection pressures, which may not always be achieved due to the possibility of fracturing occurrence.

Figure 9 shows the history of pressure in the injection well, where the pressure increase occurs according to the increase of viscosity of the polymer.

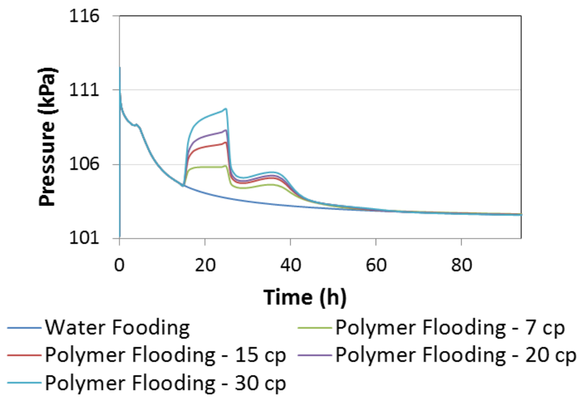

Figure 9. Pressure profiles in injected well.

The increased of the polymer viscosity causes a decrease in mobility ratio. For viscosity corresponding to 7cp, 20cp and 30cp, the values of mobility ratio are 2.49, 1.23 and 0.92, respectively.

4.6 Change in residual oil saturation

Values of residual oil saturation were changed to see the effects on recovery. Figure 10 shows the variation of the oil recovery factor, the ratio of water injected to oil produced, and water-oil ratio, all in relation to residual oil saturation. The continuous lines refer to water flooding and the dotted line refers to the water injection alternated with a polymer slug.

As expected, a lower value of residual oil saturation results in a higher recovery factor, because a larger volume of mobile oil is available. Moreover, it appears that the larger the value of the residual oil saturation, the curves of recovery factor for the two cases of injection become closer.

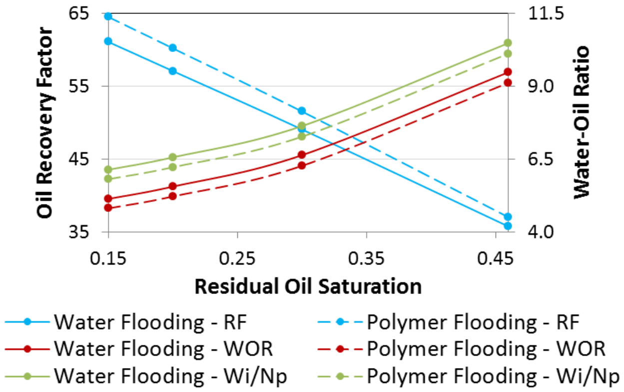

Figure 10. Variation of the recovery factor as a function of residual oil saturation.

4.7 Change in initial water saturation

The variation in initial water saturation changes the amount of mobile oil that can be accessed, so cases with different values of initial water saturation were simulated, ranging between 0.15 and 0.47. Figure 11 shows the variation of the oil recovery factor, the ratio of water injected to oil produced, and water-oil ratio, all in relation to the initial water saturation. The continuous lines refer to water flooding and the dotted line refers to the water injection alternated with a polymer slug.

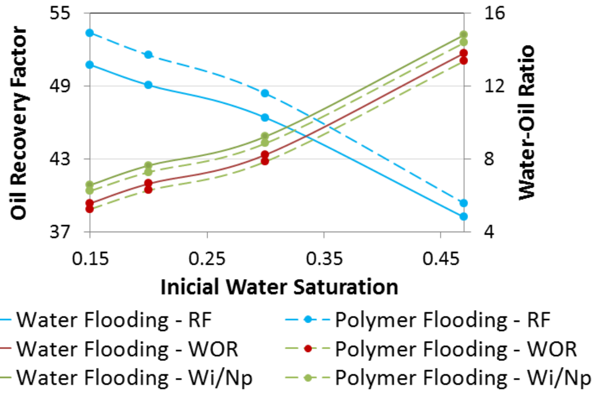

Figure 11. Variation of the recovery factor as a function of the initial water saturation.

The higher the value of the initial water saturation, the lower is the recovery factor. It is also observed that the decrease in the amount of recovery is enhanced for higher values of initial water saturation. Besides that, the gain in oil production for polymer flooding in relation to water flooding becomes ever larger as lower is the initial water saturation, i.e., the amount of mobile oil is larger.

The results obtained in water flooding and water injection alternated with a polymer slug as a method of enhanced oil recovery, along with cases where modifications were made based on the parameters of the model are summarized in Table 4. Thus, it is possible to have a quantitative analysis of all the cases studied. The last three columns brings the difference between the analyzed case and the base polymer case.

Table 4. Water flooding and water injection alternated with a polymer slug.

		M	RF (%)	Np (cm^3)	Wi (cm^3)	Wp (cm^3)	Wi/Wp	Wi/Np	Wp/Np	$\Delta FR_{Base\ Case}$ (%)	$\Delta Np_{Base\ Case}$ (%)	$\Delta Wp_{Base\ Case}$ (%)
Base case	Water	11.18	49.06	314.00	2397.00	2082.60	1.15	7.63	6.63			
Base Case	Polymer	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27			
Polymer Slug Size (Figure 4)	Polymer - 10% Vp	1.49	49.61	317.49	2397.00	2079.21	1.15	7.55	6.55	-3.73%	-3.73%	0.61%
	Polymer - 20% Vp	1.49	50.46	322.97	2397.00	2073.61	1.16	7.42	6.42	-2.07%	-2.07%	0.34%
	Polymer - 32% Vp	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - 40% Vp	1.49	52.24	334.32	2397.00	2062.29	1.16	7.17	6.17	1.37%	1.37%	-0.21%
	Polymer - 50%Vp	1.49	53.06	339.56	2397.00	2057.08	1.17	7.06	6.06	2.96%	2.96%	-0.46%
Starting Time of the polymer slug (Figure 6)	Polymer - 0 Vp	1.49	52.04	333.03	2397.00	2063.69	1.16	7.20	6.20	0.98%	0.98%	-0.14%
	Polymer - 0.05 Vp	1.49	51.95	332.48	2397.00	2064.24	1.16	7.21	6.21	0.81%	0.81%	-0.12%
	Polymer - 0.48 Vp	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - 1.5 Vp	1.49	50.86	325.51	2397.00	2070.56	1.16	7.36	6.36	-1.30%	-1.30%	0.19%
Relative Permeability in the Residual Oil Saturation (Figure 7)	Water - k_{rw} = 0,3	11.18	49.06	314.00	2397.00	2082.60	1.15	7.63	6.63	0.00%	0.00%	0.00%
	Water - k_{rw} = 0,5	18.64	45.49	291.15	2397.00	2104.56	1.14	8.23	7.23	-7.28%	-7.28%	1.05%
	Water - k_{rw} = 0,65	24.23	43.53	278.59	2397.00	2116.56	1.13	8.60	7.60	-11.28%	-11.28%	1.63%
	Water - k_{rw} = 0,8	29.83	42.06	269.19	2397.00	2127.31	1.13	8.90	7.90	-14.27%	-14.27%	2.15%
	Polymer - k_{rw} = 0,3	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - k_{rw} = 0,5	2.49	48.19	308.41	2397.00	2087.33	1.15	7.77	6.77	-6.48%	-6.48%	1.00%
	Polymer - k_{rw} = 0,65	3.23	46.35	296.66	2397.00	2098.45	1.14	8.08	7.07	-10.05%	-10.05%	1.54%
	Polymer - k_{rw} = 0,8	3.98	45.07	288.48	2397.00	2108.07	1.14	8.31	7.31	-12.53%	-12.53%	2.01%
Polymer Viscosity (Figure 8)	Polymer - 7 cp	2.49	50.79	325.03	2397.00	2071.49	1.16	7.37	6.37	-1.45%	-1.45%	0.24%
	Polymer - 15 cp	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - 20 cp	1.23	51.85	331.81	2397.00	2064.71	1.16	7.22	6.22	0.61%	0.61%	-0.09%
	Polymer - 30 cp	0.92	52.32	334.83	2397.00	2061.80	1.16	7.16	6.16	1.53%	1.53%	-0.23%
Residual Oil Saturation (Figure 10)	Water - S_{or} = 0,15	11.18	61.10	391.04	2397.00	2004.94	1.20	6.13	5.13	24.53%	24.53%	-3.73%
	Water - S_{or} = 0,2	11.18	57.09	365.38	2397.00	2029.35	1.18	6.56	5.55	16.36%	16.36%	-2.56%
	Water - S_{or} = 0,3	11.18	49.06	314.00	2397.00	2082.60	1.15	7.63	6.63	0.00%	0.00%	0.00%
	Water - S_{or} = 0,46	11.18	35.72	228.62	2397.00	2167.79	1.11	10.48	9.48	-27.19%	-27.19%	4.09%
	Polymer - S_{or} = 0,15	1.49	64.53	412.98	2397.00	1982.99	1.21	5.80	4.80	25.22%	25.22%	-4.05%
	Polymer - S_{or} = 0,2	1.49	60.21	385.37	2397.00	2009.29	1.19	6.22	5.21	16.85%	16.85%	-2.77%
	Polymer - S_{or} = 0,3	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - S_{or} = 0,46	1.49	37.00	236.78	2397.00	2159.45	1.11	10.12	9.12	-28.20%	-28.20%	4.49%
Inicial Water Saturation (Figure 11)	Water - S_{wi} = 0,1	11.18	50.74	365.30	2397.00	2031.52	1.18	6.56	5.56	3.41%	16.34%	-2.45%
	Water - S_{wi} = 0,2	11.18	49.06	314.00	2397.00	2082.60	1.15	7.63	6.63	0.00%	0.00%	0.00%
	Water - S_{wi} = 0,3	11.18	46.38	259.73	2397.00	2136.80	1.12	9.23	8.23	-5.47%	-17.28%	2.60%
	Water - S_{wi} = 0,47	11.18	38.18	161.88	2397.00	2234.57	1.07	14.81	13.80	-22.18%	-48.45%	7.30%
	Polymer - S_{wi} = 0,1	1.49	53.37	384.26	2397.00	2012.00	1.19	6.24	5.24	3.57%	16.51%	-2.64%
	Polymer - S_{wi} = 0,2	1.49	51.53	329.80	2397.00	2066.62	1.16	7.27	6.27	0.00%	0.00%	0.00%
	Polymer - S_{wi} = 0,3	1.49	48.36	270.82	2397.00	2125.52	1.13	8.85	7.85	-6.15%	-17.88%	2.85%
	Polymer - S_{wi} = 0,47	1.49	39.33	166.77	2397.00	2229.41	1.08	14.37	13.37	-23.67%	-49.43%	7.88%

RF = Recovery Factor; Np = Oil Production; Wi = Water Injected; Wp = Water Production; $\Delta RF_{BaseCase}$ = Variation of Recovery Factor in relation to base case; $\Delta Np_{BaseCase}$ = Variation of Oil Production in relation to base case; $\Delta Wp_{BaseCase}$ = Variation of Water Production in relation to base case

5. CONCLUSION

The water injection alternated with a polymer slug reduces the mobility ratio and increases areal and vertical sweep, when compared with continuous water flooding. At the conditions studied in this work, the polymer slug (base case, 32% PV) provided 5% increase in the oil recovery factor in relation to the only water flooding. In addition, there were reductions in the injected water per produced oil (4.79%) and in the produced water-oil ratio (5.52%).

Variation in some parameters of the base model of water flooding and water injection alternated with a polymer slug caused changes in oil recovery. These changes included variations in the slug size of the injected polymer solution, injection starting time of the polymer slug, relative permeability curves, polymer viscosity, residual oil and initial water saturation.

The injection of larger polymer solution slug, for the same time of injection, generates greater volumes of oil produced, but reduces the ratio of oil produced per mass of polymer. The anticipation of the injection of the polymer solution, for the same volume injected, promotes anticipation in production.

The smaller the value of the water relative permeability at residual oil saturation, the higher the gain difference relative to the oil production, due to the mobility ratio is lower. More viscous polymer solutions (7cp, 20cp and 30cp) also lead to alter the values of mobility ratios to 2.49, 1.23 and 0.92, respectively. Thus, oil production was also higher. However, too high viscosity values require higher injection pressure, which cannot always be achieved.

The oil recovery is higher as higher the amount of mobile oil. Moreover, the gain with the polymer slug flooding relative to continuous water flooding increases as the mobile oil is larger.

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