

Using Polymer Alternating Gas to Enhance Oil Recovery in Heavy Oil

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Abstract. CO₂ has been used to recover oil for more than 40 years. Currently, about 43% of EOR production in U.S. is from CO₂ flooding. CO₂ flooding is a well-established EOR technique, but its density and viscosity nature are challenges for CO₂ projects. Low density (0.5 to 0.8 g/cm³) causes gas to rise upward in reservoirs and bypass many lower portions of the reservoir. Low viscosity (0.02 to 0.08 cp) leads to poor volumetric sweep efficiency. So water-alternating-gas (WAG) method was used to control the mobility of CO₂ and improve sweep efficiency. However, WAG process has some other problems in heavy oil reservoir, such as poor mobility ratio and gravity overriding. To examine the applicability of carbon dioxide to recover viscous oil from highly heterogeneous reservoirs, this study suggests a new EOR method--polymer-alternating gas (PAG) process. The process involves a combination of polymer flooding and CO₂ injection. To confirm the effectiveness of PAG process in heavy oils, a reservoir model from Liaohe Oilfield is used to compare the technical and economic performance among PAG, WAG and polymer flooding. Simulation results show that PAG method would increase oil recovery over 10% compared with other EOR methods and PAG would be economically success based on assumption in this study. This study is the first to apply PAG to enhance oil recovery in heavy oil reservoir with highly heterogeneous. Besides, this paper provides detailed discussions and comparison about PAG with other EOR methods in this heavy oil reservoir.

1. Introduction

Although CO₂ flooding is a well-established EOR technique, its density and viscosity nature is a challenge for CO₂ projects. As low density (0.5 to 0.8 g/cm³) causes gas to rise upward in reservoirs and bypass many lower portions of the reservoir, and low viscosity (0.02 to 0.08 cp) leads to poor volumetric sweep efficiency. In heterogeneous reservoirs with high-permeability zones and natural fractures, the condition is even worse.

Almost all commercial miscible gas injection projects used WAG to control mobility of gas and alleviate fingering problems. Recovery of WAG is better than gas injection, and 80% of commercial WAG projects in the US are economic. However, recent studies show that most of the fields could not reach the expected recovery factor from the WAG process, especially, for reservoirs with high-permeability zones or with natural fractures (Christensen et al. 2001).

To overcome the issues of gas breakthrough and gravity segregation, we proposed a new combination method, termed as PAG, which combines the features of CO₂ flooding and polymer flooding. Coupling of polymer with CO₂ is expected to improve the efficiency of WAG. The main feature of PAG is that



polymer is injected with water in the WAG process. Zhang et al (2010) carried out experiment which polymer injection chased with gas alternative water (PGAW) based on Saskatchewan crude. They stated that coupled CO₂ and polymer injection could get better efficiency and higher recovery than WAG and polymer flooding. Majidaie et al. (2012) carried out the first coupled CO₂ and polymer injection simulation study for light oil based on a synthetic and homogeneous model. Their study showed PAG and WAG have the same recovery. And their also mentioned that chemical slug of polymer-surfactant-alkali would significantly increase oil recovery. Li and Schechter (2014) conducted PAG numerical simulation study for a high heterogeneous field of North Burbank Unit in North Oklahoma. Their study indicated optimized PAG process could increase oil recovery by about 14.3% compared to 7.3% with WAG in high heterogeneous reservoir. Moon Sik Jeong (2014) carried out a case study of PAG numerical simulation for heavy oil in a synthetic reservoir model. Results showed PAG process could reach the highest oil recovery, which was 89% higher than results of water flooding or CO₂ flooding, and 45% higher than WAG process. Kong et al. (2015) studied PAG performance in Cranfield reservoir with CMG-Stars, and their results indicated that PAG reached the highest recovery with lowest CO₂ injection volume, which led to a better project economic result compared with water flooding and WAG. Md Sarim Jamal et al. (2016) studied the optimization parameter and NPV based on a homogeneous model in light oil. Their results showed that PAG was a better alternative to other EOR methods.

In this paper, a heterogeneous reservoir model was built with using a field case geological model from Liaohe Oilfield in China. Field scale simulations are performed taking into account of reservoir heterogeneity and heavy oil fluid properties. In the following section, the reservoir and fluid model were described. Then performance between PAG and other EOR methods, including continuous CO₂, water alternating gas and polymer flooding, were compared. Finally, economic feasibility of PAG was studied.

2. Reservoir Model

A reservoir model was built based on a geological model from Liaohe Oilfield. The reservoir sector model size is 3000 ft × 2278 ft × 40 ft in X-Y-Z direction. The reservoir is thick enough to see the effect of gravity segregation. The reservoir is located 3,000 ft beneath the surface and has no dip. The reservoir is heterogeneous and consists of a sandstone formation. **Figure 1** shows the reservoir model. The location of injection and production wells are shown in Figure 1 in the model. In all simulations the injection rate is fixed at 0.1 PV/yaer for gas injection well and 0.1 PV/year for water injection well, and the bottom-hole pressure (BHP) at the producers is fixed at 200 psi and at the injectors is fixed at 3,100 psi in the EOR process. **Table 1** presents the input of reservoir rock and fluid properties that were used in the simulation study.

Table 1. Reservoir rock and fluid properties

Parameters	Value
Reservoir size,ft	3300×2278×60
Number of grid	31×23×10
Porosity	0.3
kv/kh	0.1
Average Perm. , md	500
Water density, lb/ft ³	63.0
Water viscosity,cp	0.5
Initial oil saturation	0.55
Initial water saturation	0.45

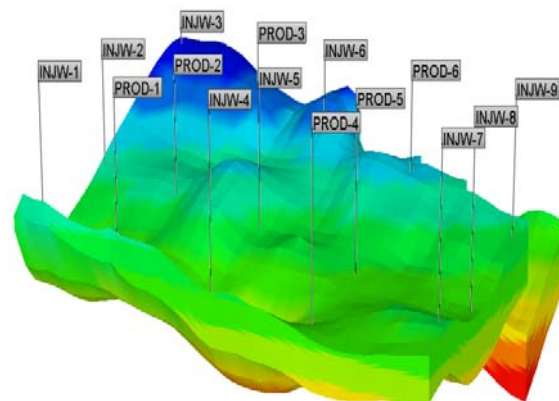


Figure 1. 3D view of the reservoir model

Fluid Characterization

The Peng-Robinson equation of state (EOS) was used in this study for fluid modeling from Liaohe Oilfield. After lumping, splitting and regression, the component and their parameters used in studied are shown in **Table 2**.

Table 2. Oil component and parameters

Component name	Mole %	Pc atm	Tc K	Acentric factor	Mole weight	Omega A	Omega B
CO ₂	0.020	72.800	304.200	0.2250	44.0	0.4572	0.0778
N ₂ toCH ₄	20.539	45.045	188.488	0.0090	16.4	0.4572	0.0778
C ₂ toC ₅	3.600	39.357	401.770	0.1757	52.6	0.4572	0.0778
C ₆ toC ₁₂	22.654	19.917	613.414	0.4235	130.0	0.4572	0.0778
C ₁₃ toC ₃₅	42.140	13.709	797.799	0.8515	299.7	0.4572	0.0778
C ₃₆ +	11.047	5.227	1262.265	1.6124	1415.0	0.4572	0.0778

Parameters for Polymer Flooding

Rock adsorption and polymer viscosity are two important parameters for polymer flooding. The correlation between polymer viscosity and polymer concentration is shown in **Figure 2**. **Figure 3** shows a correlation between polymer concentration and polymer adsorption. The maximum adsorption is 130 ug/ (g rock). Residual resistance factor (RRF) value of 2.0 at 1,000 ppm was assumed in this study.

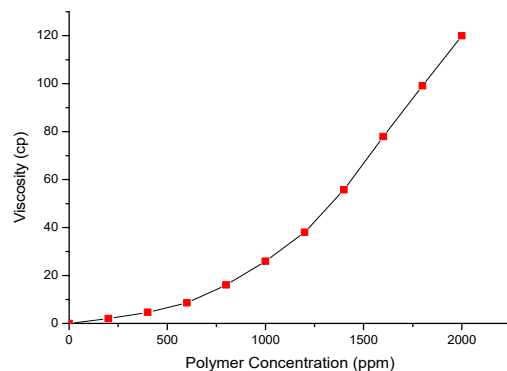


Figure 2. Correlation between polymer concentration and polymer viscosity

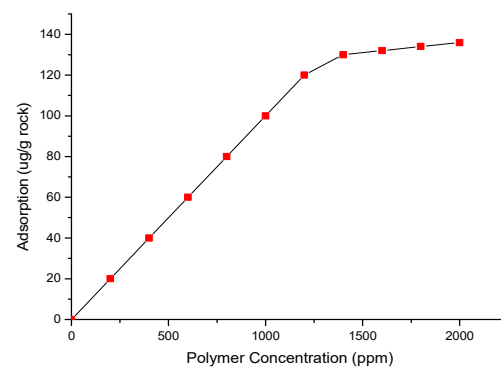


Figure 3. Correlation between polymer adsorption and concentration

3. Simulation Results and Discussion

Five different development methods including water flood, polymer flood, continue gas injection (CGI), WAG, and PAG, were studied. The results were compared, including recovery factor, oil rate, GOR, saturation profile, etc. The amount of water and gas injection, oil and gas production, and oil recovery are listed in **Table 3**.

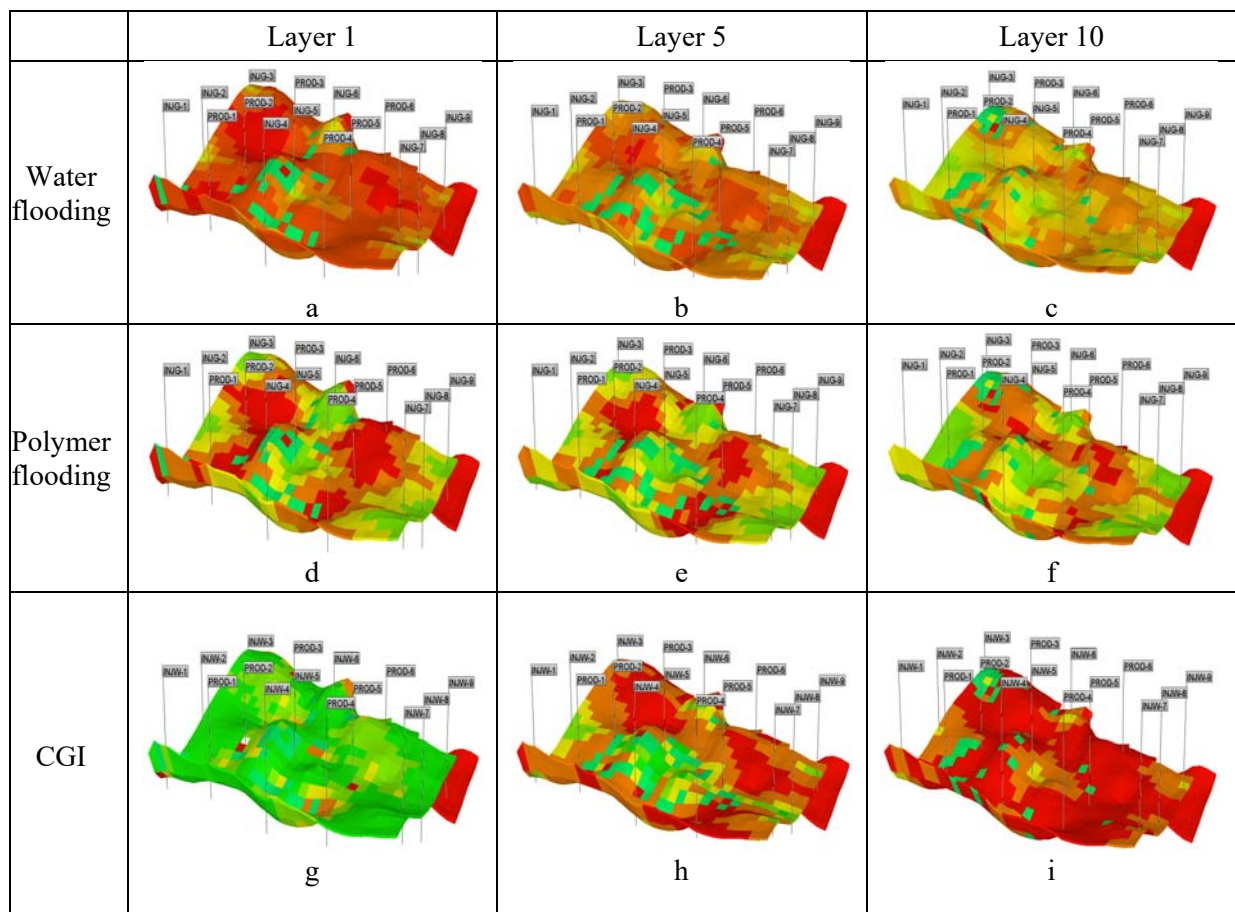
Waterflooding (WF)

Nine injectors in the reservoir simulation model inject fluid (water/gas) with a maximum injection pressure of 3,100 psi, starting in 2014. Prior to the water flooding, the reservoir oil saturation is about 0.55. After 18-year's water flooding, the oil saturation is reduced to 0.46. **Figures 4.a-4.c** indicates that remaining oil saturation in Layer 1 is much higher than that in Layers 5 and 10. The main mechanism

behind it is gravity effect—water has higher density than oil, so that water would go to lower layers and bypass upper layers, which leads to poor sweep efficiency.

Table 3. Simulation results

Case	Water injection (bbls)	Gas injection (mmscf)	Gas production (mmscf)	Oil production (bbls)	Oil recovery Factor
Waterflooding	5.00×10^6			0.48×10^6	14.20
Polymer flood	3.79×10^6			0.78×10^6	23.16
CGI	1.84×10^6	6.38×10^3	6.10×10^3	0.68×10^6	19.91
WAG	3.44×10^6	3.16×10^3	2.85×10^3	0.72×10^6	21.10
PAG	3.24×10^6	3.16×10^3	2.54×10^3	1.15×10^6	33.60



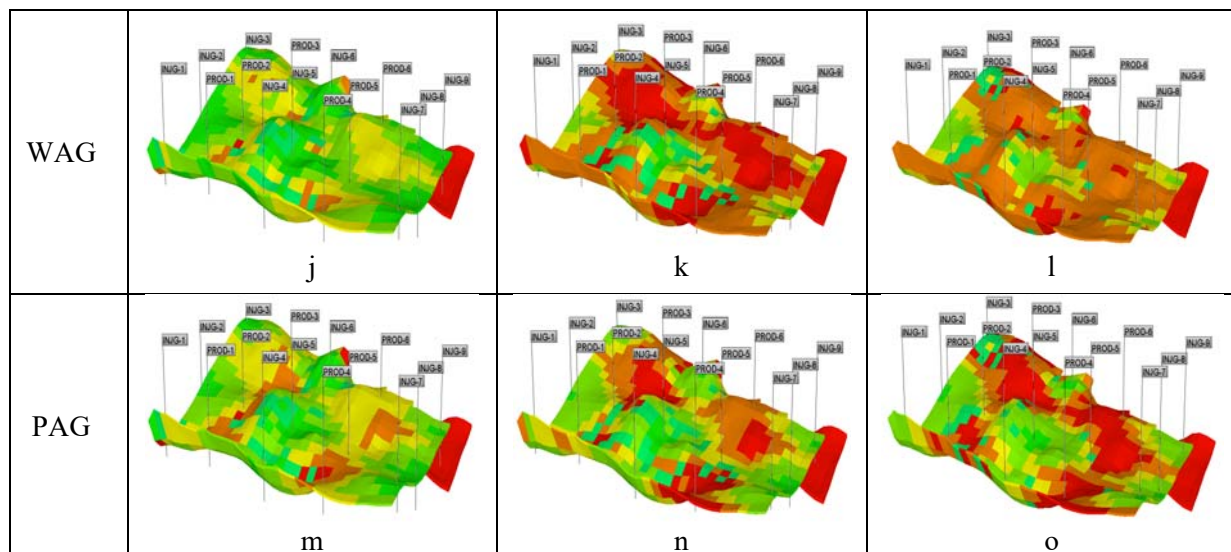


Figure 4. Oil saturation after injection

The total oil rate from 6 producers in the pilot region is shown in **Figure 5**. It indicates steep oil production decline is due to quick breakthrough of the injection water. The oil recovery factor is about 14.2% with high water cut of 98%, as shown in **Figure 6** and **Figure 7**.

Polymer Flooding (PF)

In the polymer flooding process, polymer was added to the water injection wells with a concentration of 1,000 ppm in the simulation model. After polymer flooding, the remaining oil saturation is reduced to 0.39 (Figure 8). Comparing **Figures 4.d-4.f** with **Figures 4.a-4.c**, the results clearly show that oil saturation in Layer 1 after polymer flooding is much lower than that after water flooding. In other words, upper layers have more remaining oil saturation than lower layers. Figure 5 shows that highest oil rate after polymer flooding is 145 bbl/day, which is 2 times higher than oil rate before polymer flooding. Figure 6 shows that water cut decreases from 95% to 65%. The oil recovery factors after polymer flooding is also shown in Figure 7. It shows polymer flooding can reach oil recovery factor to 23.16%, while water flooding only gets 14.20%.

Continuous Gas Injection (CGI) with CO₂

In continuous gas injection process, injecting CO₂ continuously with well constraint of maximum rate of 1.5 mmcsfd through 9 injectors, and a maximum injection well pressure of 3,100 psi. **Figures 4.g-4.i** show that gas only swept the upper part of reservoir and left large un-swept area in the lower layers, which is due to the gravity override of lower CO₂ density. As shown in **Figures 5** and **6**, CGI could reach a peak oil rate of 246 bbl/day and reduce water cut to 20%. The oil recovery factor after CGI is 20%, which is higher than after water flooding (Figure 7). CGI would result in early gas breakthrough, as indicated by Figure 9 which shows gas-oil-ratio increases sharply after 6-month's CO₂ injection.

Water Alternating Gas (WAG)

To alleviate the early gas breakthrough and low swept efficiency of CO₂ flooding, WAG process is implemented and investigated. In the WAG process, water and CO₂ is injected alternately at 1:1 ratio and 6 months per cycle, which means 3 month of water and 3 month of CO₂ injection. As shown in **Figures 5** and **6** WAG could reach a peak oil rate 225 bbl/day and reduce water cut to 60%.

According to Figure 7, WAG process obtains oil recovery of 21.1%, which is higher than water flooding because of CO₂ miscibility with water conformance control. WAG significantly reduces gas production rate and alleviates gas early breakthrough, which can be demonstrated in **Figure 8** as there is much lower gas-oil-ratio after WAG than after CGI. **Figures 4.j-4.l** and **Figures 5.g-5.i** shows

that Layer 1 has lower oil saturation in CGI process than in WAG process, but Layers 5 and 10 have higher oil saturation in CGI process than in WAG process. It indicates WAG improves CGI performance. However, it also shows that gas swept the upper part of reservoir and still left large unswept area in the lower layers because of gravity override caused by low CO₂ density.

Polymer Alternating Gas (PAG)

To overcome these problems, the combination of polymer flooding and CO₂ flooding is used. It has advantages of CO₂ flooding and polymer flooding, solubility of CO₂ injection, and mobility control of polymer injection. In a PAG process, polymeric solution is injected into reservoir instead of water in WAG process. The polymer concentration 1000 ppm is used based on reservoir permeability and heterogeneous during PAG process. The simulation result shows that peak oil rate after PAG is 370 bbl/day, which is 50% higher than WAG and 190% higher than after polymer flooding. Water cut also can be decreased from 95% to 28%. Figure 8 shows that GOR in PAG is only one eighth of CGI process and one fourth of WAG process. As shown in Figure 7, PAG achieves the highest oil recovery of 33.65%. The oil recovery enhanced by PAG is 43% more than polymer flooding and 57% more than WAG process. The additional recovery by PAG resulted from mobility ratio control. **Figures 4.m-4.o** depicts the oil saturation distribution of PAG process in the end of production. Layer 1 has higher remaining oil saturation in PAG process than that in WAG process, which means more gas is injected to lower layers in PAG so that poor sweep efficiency is improved. Layers 5 and 10 have lower remaining oil saturation in PAG process than that in WAG process.

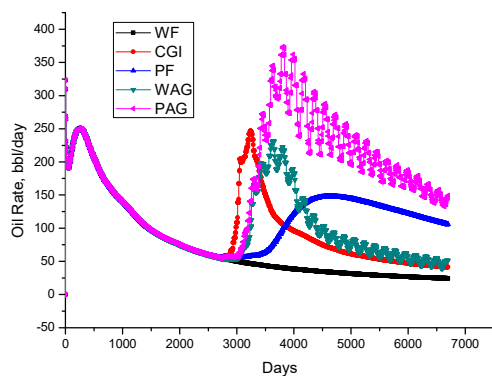


Figure 5. Oil rate for different methods

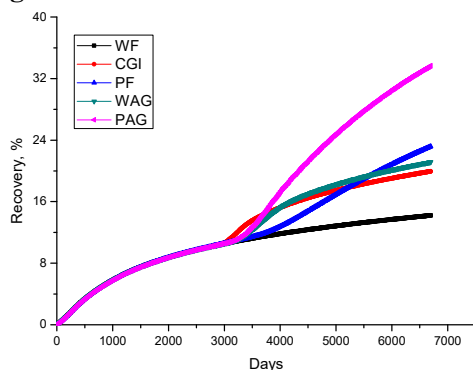


Figure 7. Oil recovery for different methods

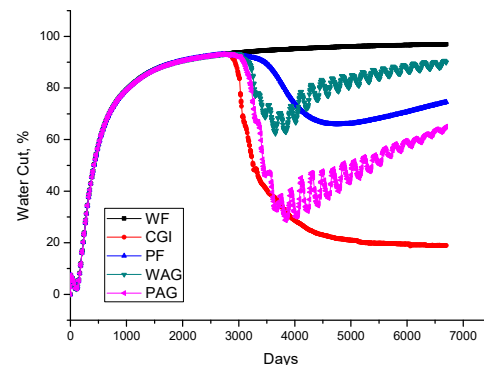


Figure 6. Water cut for different methods

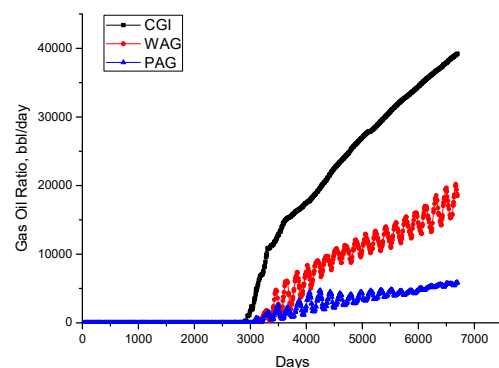


Figure 8. Gas oil ratio for different methods

4. Summary

A new hybrid EOR method, named polymer alternating gas (PAG) which adds polymer to water alternating gas (WAG) process, was studied using a field model from heavy oil reservoir. The main reasons of low oil recovery in this field are high oil viscosity and high reservoir heterogeneity. Reservoir simulation results showed PAG significantly enhanced oil recovery, compared with other EOR methods.

(1) With controlling mobility ratio, PAG process has better sweep efficiency than other EOR methods. The PAG process would reach oil recovery factor of 33%. It was 45% higher than that of polymer flooding and 57% higher than that of WAG.

(2) In heterogeneous heavy oil reservoir, water and CO₂ breakthroughs are main reasons that reduce oil recovery in WAG process. Comparison to WAG, PAG can decrease water cut from 95% to 28%, which is lower than WAG and polymer flooding. Moreover, GOR in PAG process was also lower than that in WAG method.

Acknowledgments

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