Hindawi Publishing Corporation
Advances in Mechanical Engineering
Volume 2014, Article ID 978465, 9 pages
http://dx.doi.org/10.1155/2014/978465

Research Article

Compositional Simulation on the Flow of Polymeric Solution Alternating CO_2 through Heavy Oil Reservoir

Moon Sik Jeong, Jinhyung Cho, Jinsuk Choi, Ji Ho Lee, and Kun Sang Lee

Department of Natural Resources and Environmental Engineering, Hanyang University, 222 Wangsimni-ro, Seongdong-gu, Seoul 133-791, Republic of Korea

Correspondence should be addressed to Kun Sang Lee; kunslee@hanyang.ac.kr

Received 18 April 2014; Accepted 9 August 2014; Published 28 August 2014

Academic Editor: Shuyu Sun

Water-alternating-gas (WAG) method provides superior mobility control of CO_2 and improves sweep efficiency. However, WAG process has some problems in highly viscous oil reservoir such as gravity overriding and poor mobility ratio. To examine the applicability of carbon dioxide to recover viscous oil from highly heterogeneous reservoirs, this study suggests polymer-alternating-gas (PAG) process. The process involves a combination of polymer flooding and CO_2 injection. In this numerical model, high viscosity of oil and high heterogeneity of reservoir are the main challenges. To confirm the effectiveness of PAG process in the model, four processes (waterflooding, continuous CO_2 injection, WAG process, and PAG process) are implemented and recovery factor, WOR, and GOR are compared. Simulation results show that PAG method would increase oil recovery over 45% compared with WAG process. The WAG ratio of 2 is found to be the optimum value for maximum oil recovery. The additional oil recovery of 3% through the 2 WAG ratio is achieved over the base case of 1 : 1 PAG ratio and 180 days cycle period.

1. Introduction

Recently, interest in CO_2 flooding has grown as a method of enhanced heavy oil recovery. Injected CO_2 can extract the heavy oil components by oil swelling and viscosity reduction. However, the mobility ratio of CO_2 is unfavorable to recover heavy oils. It causes viscosity fingering and gravity override through heterogeneous reservoirs. These phenomena make an early breakthrough of injected CO_2 and reduce oil recovery. The problems led by poor viscosity ratio are more severe in heavy oils than light oils. Although the CO_2 flooding has been applied and its success has been reported in many heavy oil cases [1–7], there still remain the aforementioned problems that need to be solved in order to implement the CO_2 injection in the heavy oil reservoirs.

Mobility control in CO_2 flooding is very important to solve the low recovery efficiency problem. CO_2 injection method can achieve higher microscopic displacement efficiency than those of other processes. However, viscosity of CO_2 is usually about 1/10 that of oil in the reservoir conditions [8]. As a result, the sweep efficiency of CO_2 flooding is lower than efficiency of waterflooding. The water-alternating-gas (WAG) process is suggested by Caudle and Dyes [9] to improve sweep efficiency of CO_2 injection. Alternating or coinjection of CO_2 and water enhances the recovery of oil. The injected water increases sweep efficiency and stabilizes the gas front. When slugs of CO_2 and water are injected into reservoir consecutively, some part of CO_2 is dissolved in the oil and reduces the oil viscosity. Thus, the mobility ratio between displacing and displaced fluid is decreased. It becomes favorable condition to control the CO_2 breakthrough and improve recovery efficiency.

Another suggested technique which advances sweep efficiency for the heterogeneous reservoir including high permeable thief zones is integrated polymer and CO_2 flooding. Generally, polymer flooding is known as effective process when mobility ratio of waterflooding is high, the heterogeneity of reservoir is high, or both of them exist [10]. Polymer flooding is processed by adding polymer into the water to decrease mobility of displacing fluid. Dissolved polymer increases the viscosity of displacing fluid and decreases the effective permeability of aqueous phase through adsorption. High adsorption of polymer through mainly high permeable streaks reduces permeability so that it induces diverting

Table 1: Composition of viscous oil.

Component	Mole fraction
CO_2	0.00027
N_2 to C_1	0.30446
C_2 to C_4	0.01018
C_5 to C_7	0.02464
C_8 to C_{12}	0.09672
C_{13} to C_{19}	0.21201
C_{20} to C_{30}	0.35172
Total	1

displacing fluid into low permeable zones and increases the oil recovery. However, polymer flooding is not a great way to decrease residual oil saturation. The polymer degradation and shear effect have been problems in application of polymer flood. A substantial amount of polymer is required to reduce the unsuitably high viscosity ratio to a value of approximately one in the heavy oil reservoirs. The significant required number of polymers in such reservoirs leads to high cost [11].

To overcome these problems, such as viscous fingering, poor sweep efficiency, and polymer concentration, integrated EOR method as coupling polymer flooding and CO_2 flooding is of importance. It has both advantages of CO_2 flooding and polymer flooding, solubility of CO_2 injection and mobility control of polymer injection. According to Zhang et al. [11], polymer/gas-alternating-water (PGAW) is combination of these two methods. Majidaie et al. [12] simulated chemically enhanced water-alternating-gas (CWAG) injection in homogeneous reservoir. Li et al. [13] carried out a case study of polymer-alternating-gas (PAG) simulation. However, more research for coupling CO_2 flooding and polymer injection is still needed. The previous simulation studies [12, 13] have been carried out in light oil reservoir. Although Zhang et al. [11] assessed its performance considering heavy oil, it is limited with experimental scale. Applications of PAG process in heavy and heterogeneous reservoirs have not been conducted sufficiently. For this reason, specific purpose of this study focused on the simulation of PAG process in field scale heterogeneous reservoir containing heavy oil. To evaluate the effectiveness of PAG process in the model, four processes (waterflooding, continuous CO_2 injection, WAG process, and PAG process) are implemented and analyzed with oil recovery factor, WOR, and GOR. In addition, PAG ratio and PAG cycle have been parameterized to maximize the performance of PAG.

2. Numerical Simulation

2.1. Fluid Modeling. The oil properties of Schrader Bluff and West Sak are referenced for viscous oil modeling. Composition of the oil is reported in Table 1. The portions of intermediate components are small and heavy components are main part. Properties and viscosity data which are used for regression analysis are based on the literature study of Ning et al. (Tables 2 and 3) [14]. Peng and Robinson [15] method is applied to generate PVT data of referenced components.

Table 2: Properties of reservoir fluid.

Stock tank oil density	0.953 kg/m^3
STO API gravity	16.9
Gas oil ratio	32.2 m^3/m^3
Saturation pressure	101 atm

Table 3: Viscosity of the reservoir fluid at 24°C.

Pressure (atm)	Viscosity (kg/m·sec)
170	0.1411
136	0.1300
116	0.1250
109	0.1225

Due to solubility of CO_2 into heavy oil, K-values are calculated to represent an equilibrium state between components. The definition of K-value is the ratio of equilibrium gas component y_i to the equilibrium liquid composition x_i as follows:

$$K_i \equiv \frac{y_i}{x_i}. \qquad (1)$$

K_i is a function of pressure, temperature, and oil composition. K-values are calculated by satisfying the fugacity of equilibrium state based on EOS model. For the oil components given in Table 1, K-values are estimated on various pressures as depicted in Figure 1.

2.2. Hypothetical Reservoir Modeling. The hypothetical reservoir model is assumed as layered model which is discretized into $50 \times 1 \times 10$ grid blocks. Each grid block has dimension of 1.2 m× 3 m × 1.5 m (Figure 2). The depth of reservoir is 244 m and reference pressure and temperature at this point are 121 atm and 24°C. The porosity is 30%. Average permeability is 5.3×10^{-8} m^2 which has Dykstra-Parsons coefficient (V_{DP}) representing variation of permeability as 0.75 which is determined by permeability variation [16] as follows:

$$V_{\mathrm{DP}} = \frac{k_{50} - k_{84.1}}{k_{50}}, \qquad (2)$$

where k_{50} is permeability value at 50% probability and $k_{84.1}$ is permeability value at 84.1% of the cumulative sample. The range of coefficient varies from 0 to 1. If the heterogeneity of reservoir increases, the value of coefficient approaches to 1. Vertical/horizontal permeability ratio is assumed as 0.1. The initial water saturation is 0.2 and oil saturation is 0.8. Viscosity of water is 0.00045 kg/m · sec and oil and CO_2 viscosities are estimated to be about 0.094 kg/m · sec and 0.0001 kg/m · sec, respectively. The viscosity of polymeric solution is 0.022 kg/m · sec at the concentration of 1,000 ppm. Tables 4 and 5 present the input reservoir properties and permeability data used for this simulation. Water is injected during the first year and other processes (waterflooding, continuous CO_2 injection, WAG process, and PAG process) are implemented for next 10 years.

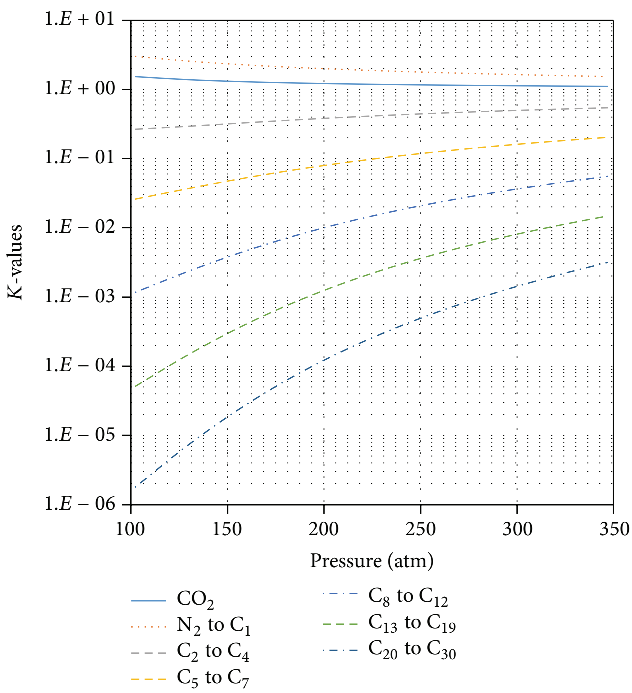

FIGURE 1: Estimations of K-values for reservoir oil components at 24°C.

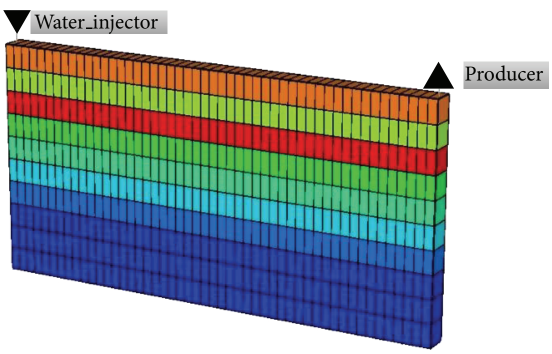

FIGURE 2: Hypothetical model consisting of different permeability layers.

2.3. Mobility Control. The objective of WAG process is originally to aim for the ideal oil recovery system: improvements of macroscopic and microscopic sweep efficiency at once. The injected water (or polymeric solution) is able to control the injected gas mobility as follows:

$$f_w = \frac{k_w/\mu_w}{k_w/\mu_w + k_o/\mu_o + k_g/\mu_g},$$
$$f_g = \frac{k_g/\mu_g}{k_w/\mu_w + k_o/\mu_o + k_g/\mu_g}, \quad (3)$$

where f is the fractional flow, k is the permeability, and μ is the viscosity [17].

The oil recovery factor (R_f) is determined by microscopic sweep efficiency and the macroscopic sweep efficiency. The macroscopic sweep efficiency can be described by the horizontal and vertical sweep efficiencies. The recovery factor is formulated by

$$R_f = E_v E_h, \quad (4)$$

where E_v is the vertical sweep efficiency and E_h is the horizontal sweep efficiency [10].

The mobility ratio (5) [18] affects horizontal sweep efficiency and the vertical sweep efficiency is related to the ratio of viscous to gravity forces (6) [19]. Consider

$$M = \frac{k_{r,\text{displacing fluid}}/\mu_{\text{displacing fluid}}}{k_{r,\text{displaced fluid}}/\mu_{\text{displaced fluid}}}, \quad (5)$$

$$R_{v/g} = \left(\frac{v\mu_o}{kg\Delta\rho}\right)\left(\frac{L}{h}\right), \quad (6)$$

where M is the mobility ratio, $R_{v/g}$ is the viscous/gravity forces ratio, v is Darcy velocity, μ_o is the oil viscosity, k is the permeability, g is the gravitational acceleration, $\Delta\rho$ is difference in oil and solvent densities, L is distance between wells, and h is height of reservoir.

TABLE 4: Input data for reservoir simulation.

Parameters	Values
Reservoir size (m^3)	$60 \times 3 \times 15$
Number of grids	$50 \times 1 \times 10$
Permeability	
Average (m^2)	5.3×10^{-8}
k_v/k_h	0.1
V_{DP}	0.75
Porosity	0.3
Pressure (atm)	121
Temperature (°C)	24
Initial saturation	
Water	0.2
Oil	0.8
Viscosity (kg/m·sec)	
Water	0.00045
Oil	0.094
CO_2	0.0001
Polymer 1,000 ppm	0.022

TABLE 5: Permeability data for layered reservoir.

Layer number	Permeability (10^{-7} m^2)
1	2.4
2	1.6
3	2.6
4	1.3
5	0.89
6	0.69
7	0.44
8	0.20
9	0.15
10	0.08

2.4. Polymer Behavior. The polymer adsorption at reservoir rock could be described by Langmuir-type isotherm [20] such as

$$ad = \frac{(a_1 + a_2 S_b) C_p}{1 + a_3 C_p}, \tag{7}$$

where a_1, a_2, and a_3 are coefficients of isothermal Langmuir equation, S_b is the salinity of the brine, and C_p is the mole fraction of polymer. Adsorption is assumed as irreversible process. By means of adsorption, not only more polymer concentration is required to reach target polymer concentration, but also induced reduction of permeability decreases flow capacity [21].

3. Results and Discussion

3.1. Comparison of Processes. This study aims to confirm the effectiveness of PAG process in the heavy oil reservoirs. To examine the performance of various injection processes such as waterflooding, continuous CO_2 injection, WAG process, and PAG process, oil recovery factors are compared as depicted in Figure 3. Oil recovery from waterflooding is slightly higher than recovery of CO_2 flooding. CO_2 flooding has better recovery efficiency than that of waterflooding until the recovery factor reaches 19%. The efficiencies of CO_2 flooding and waterflooding are reversed after that point. The reservoir considered in this simulation includes high permeable layer at the top. Gravity overriding effect and early breakthrough mainly occur through the high permeable streak. Figure 4 indicates the gravity overriding effect and CO_2 breakthrough after one year of CO_2 injection. The breakthrough can develop main CO_2 flow path and most of injected CO_2 passes through the path. Despite high potential for displacement efficiency, this effect reduces the sweep efficiency in application of CO_2 flooding. As this phenomenon makes no more increases in oil recovery after five years of CO_2 injection, oil recoveries between waterflooding and CO_2 flooding are reversed.

WAG process is implemented and investigated. WAG ratio is set as 1 : 1 and one cycle period is 180 days, respectively. According to Figure 3, WAG process obtains 26% oil recovery while recovery factors of waterflooding and CO_2 flooding are less than 20%. This improved oil recovery as much as 6% by application of WAG is reasoned from the increased sweep efficiency and displacement efficiency by applying water and CO_2 flooding. A great amount of oil is easily extracted to the producer.

In PAG process, polymeric solution is injected into reservoir instead of water in WAG process. The solution contains 1,000 ppm polymer and it could prove the effect of polymeric solution during PAG process. PAG process achieves the highest oil recovery in Figure 3. PAG process takes 37% recovery factor. The enhancement of oil recovery by PAG method is 89% over water or CO_2 flooding and 45% over WAG process. The additional recovery resulted from advance of mobility ratio. The comparison of viscosity between WAG and PAG is reported in Figure 5 which describes viscosity of aqueous phase near the injection well. The viscosity

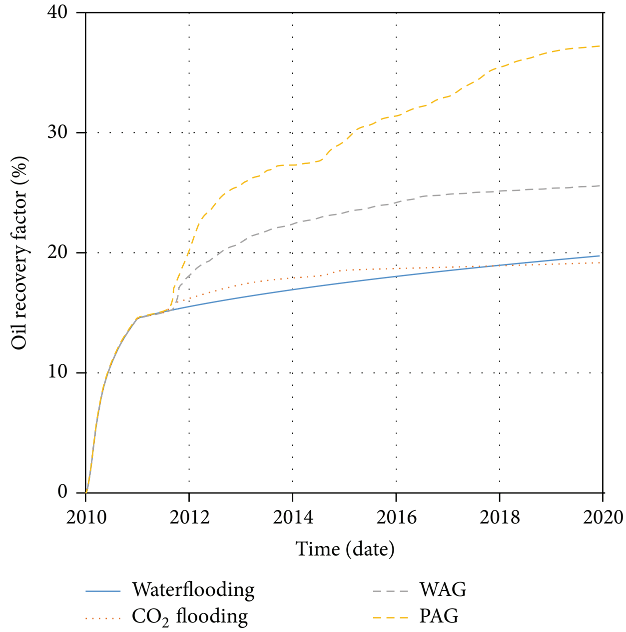

Figure 3: Oil recovery factors for different processes.

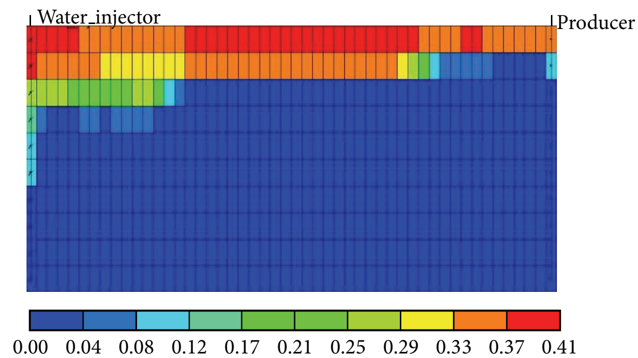

Figure 4: CO_2 mole fraction after one year of CO_2 injection in continuous CO_2 flooding.

obtained from PAG process continuously increases during the injection period of polymeric solution. The betterment of mobility ratio is due to high viscosity of injected polymeric solution and permeability reduction by adsorption. This improvement is indicated by resistance factor in Figure 6. The resistance factor is a ratio of water mobility to polymeric solution mobility. If the viscosity is increased by polymer injection, resistance factor is increased by reduction of polymer mobility [22]. These processes can alleviate viscosity fingering effect in heterogeneous reservoirs. A channeling due to the permeability heterogeneity of this layered system is a dominant factor to reduce sweep efficiency. Figures 7(a) and 7(b) show that improved mobility ratio in PAG process can mitigate viscosity fingering problem and form a stable front.

Figures 8 and 9 represent the water-oil ratio (WOR) and cumulative water production from different processes. According to Figure 8, the results signify that the WOR in the case of PAG process is much lower than those of

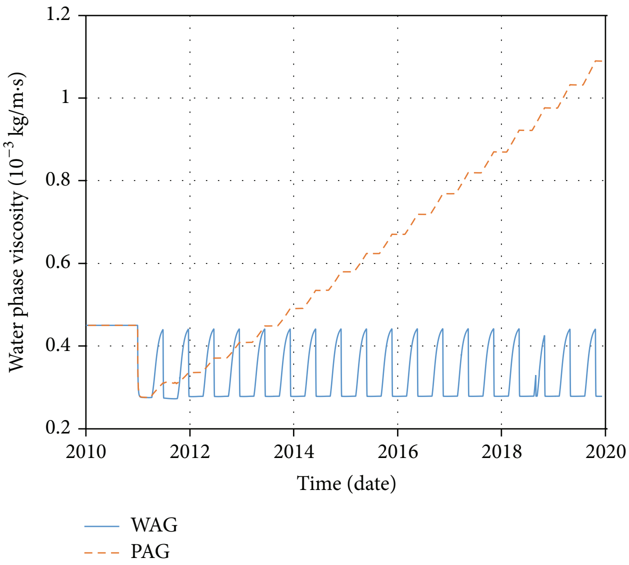

Figure 5: Viscosity of aqueous phase in high permeability zone.

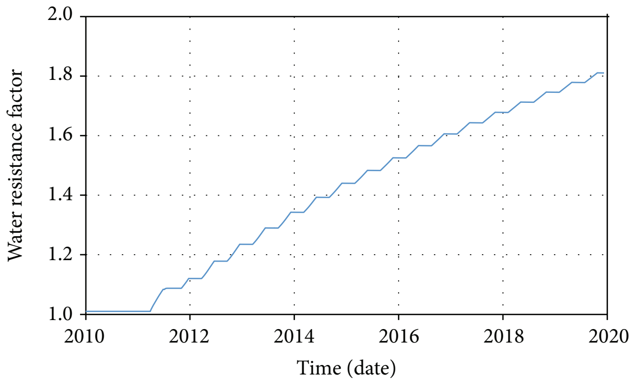

Figure 6: Resistance factor for aqueous phase in high permeability zone.

waterflooding and WAG process during production period, excepting 2014. At this time, WOR of PAG is sharply increased because produced oil rate reaches almost zero due to the temporary blockage with injected CO_2 and polymeric solution (Figure 10). In Figure 9, the PAG process indicates 42% and 12% reduction in cumulative water production compared to the waterflooding and WAG process, respectively. These improvements prove effectiveness for polymer injection which has great potential to reduce aqueous phase mobility.

Figures 11 and 12 describe the gas-oil ratio (GOR) and cumulative gas production. In Figure 11, similar problem with WOR existed at 2014. As aforementioned, the same problem at this point results from low oil rate. The amounts of gas productions are 3.4×10^5 m^3 in CO_2 flooding and $1.6 \times 10^5 m^3$ in WAG and PAG process. PAG process obtains 53% reduction in cumulative gas production compared to CO_2 flooding. GOR of PAG process is significantly lower than that

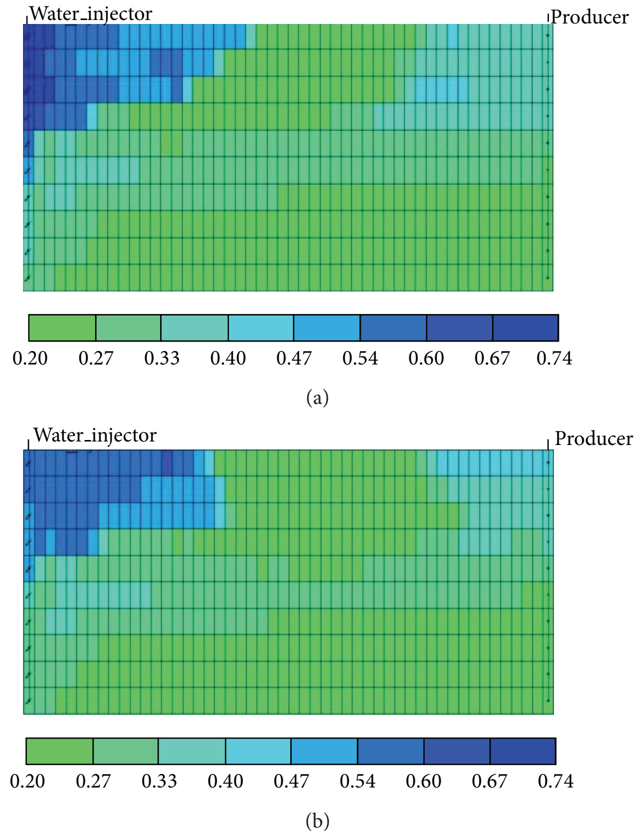

Figure 7: Water saturation after one cycle of WAG and PAG: (a) WAG process and (b) PAG process.

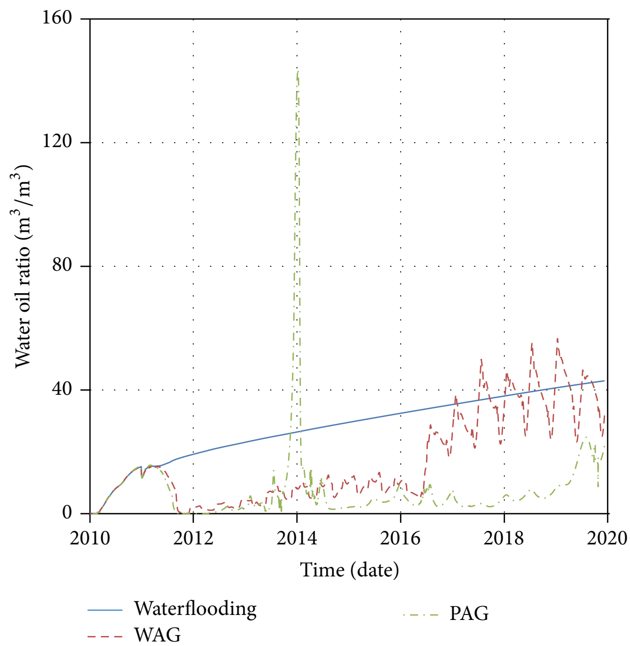

Figure 8: Water-oil ratios for different processes.

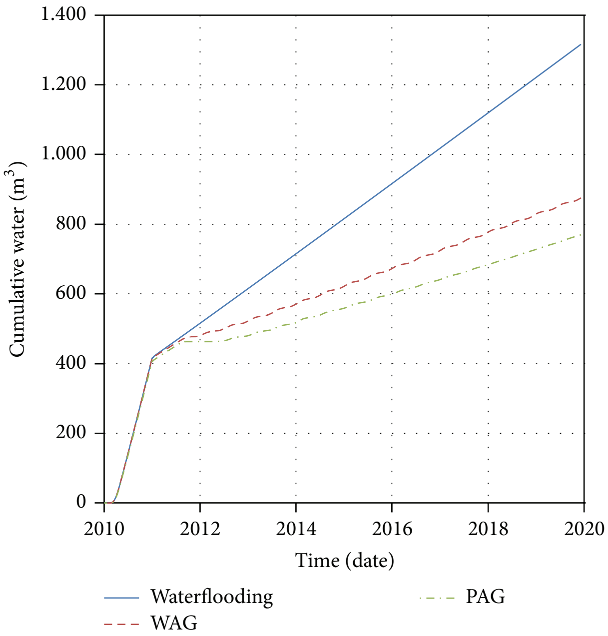

FIGURE 9: Cumulative water productions for different processes.

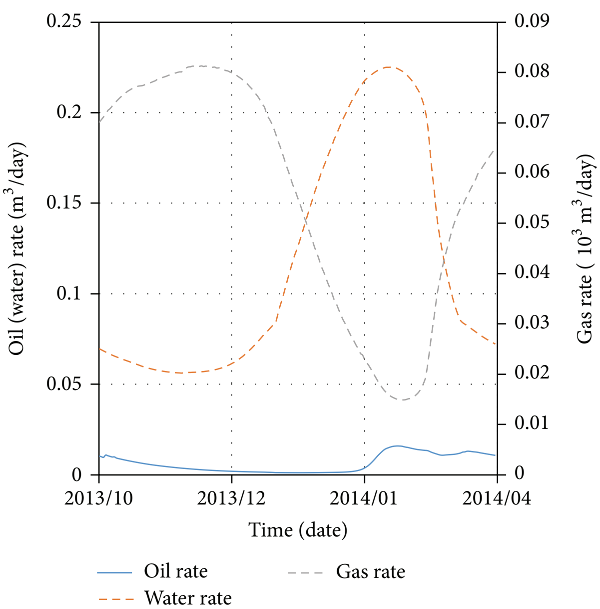

FIGURE 10: Produced oil, water, and CO_2 rate of PAG process in 2014.

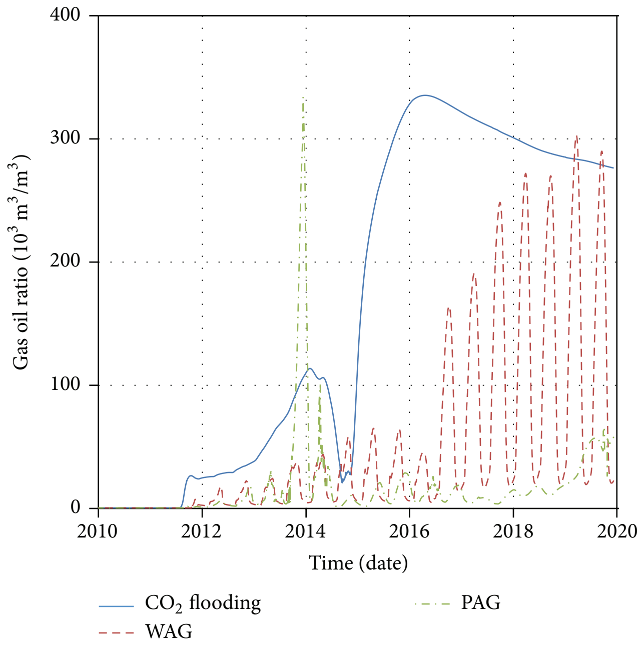

FIGURE 11: Gas-oil ratios for different processes.

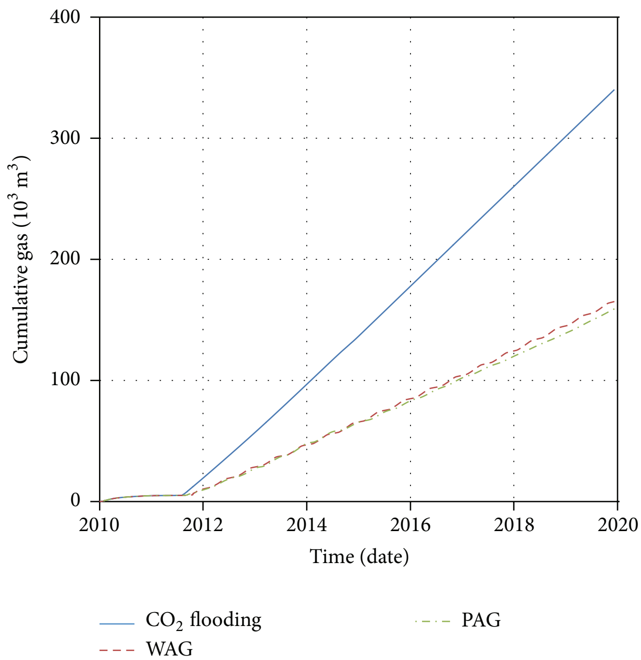

FIGURE 12: Cumulative gas productions for different processes.

of WAG process. PAG process in heterogeneous heavy oil reservoir attains better performance than WAG does.

Figure 13 depicts the oil saturation distribution for four processes at the end of production. Average oil saturation is 0.64 in waterflooding, 0.67 in CO_2 flooding, 0.63 in WAG process, and 0.56 in PAG process. In comparison with Figures 13(a), 13(b), and 13(c), Figure 13(d) shows that better recovery efficiency resulted from high sweep efficiency and high displacement efficiency. In PAG process, the reduced permeability contrast due to the preferential adsorption of polymer in relatively high-permeability layers enables water and CO_2 to penetrate into low-permeability layers and the recovery efficiency to be increased.

3.2. PAG Cycle and Ratio. PAG cycle and ratio are general parameters which determine the characteristics of PAG process. The base case is 1:1 PAG ratio and 180 days cycle period. Various PAG cycle periods are applied to compare

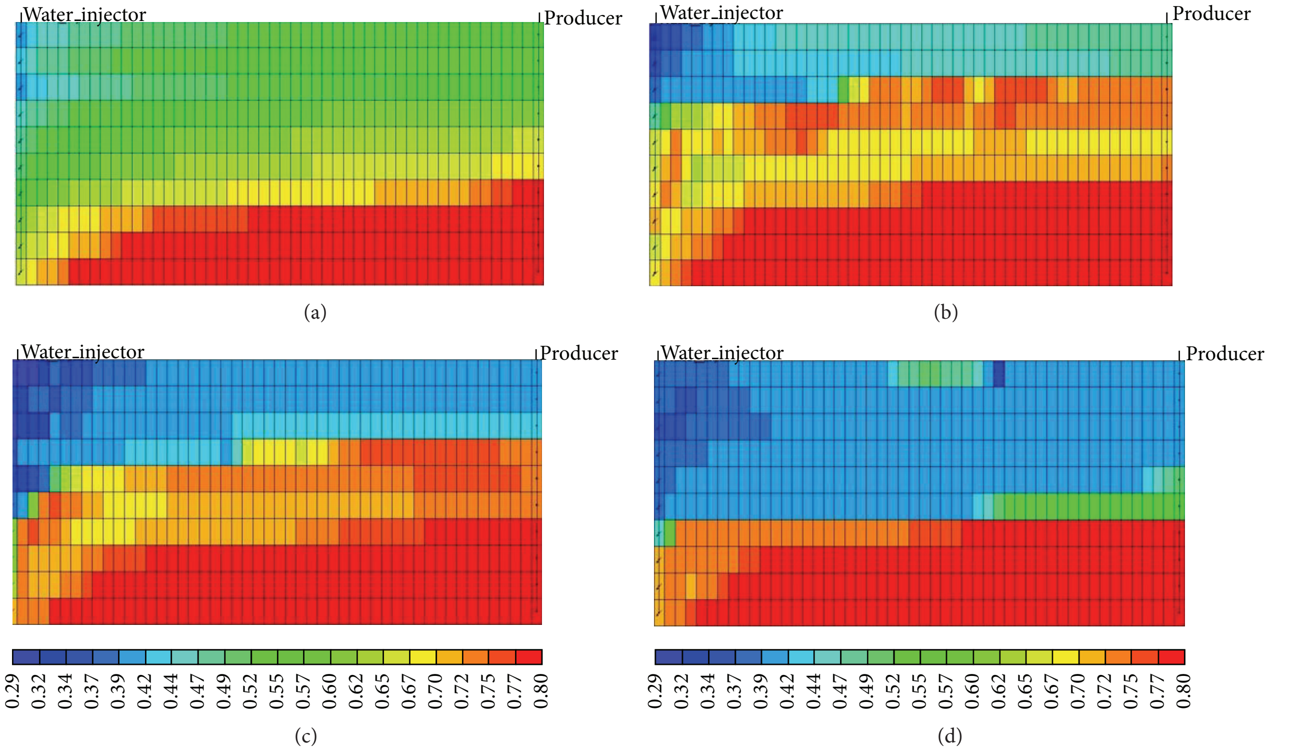

FIGURE 13: Oil saturations at the end of simulation: (a) waterflooding, (b) continuous CO_2 flooding, (c) WAG process, and (d) PAG process.

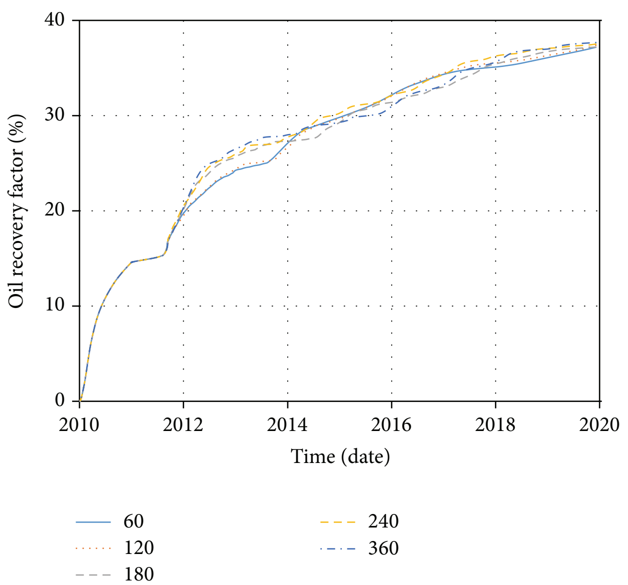

FIGURE 14: Oil recovery factors at different WAG cycle periods.

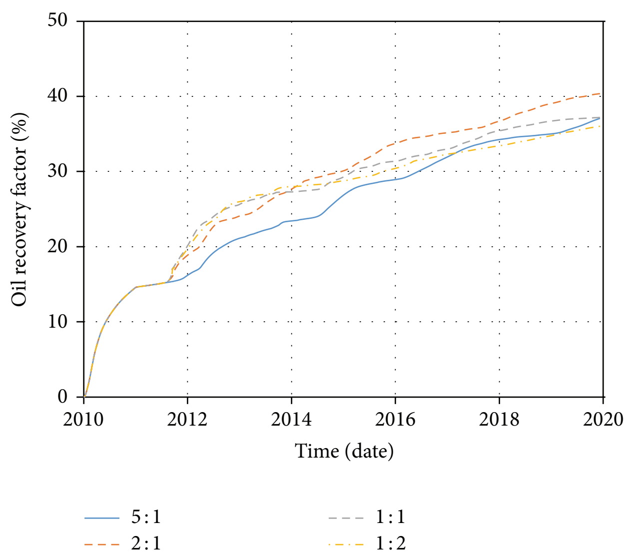

FIGURE 15: Oil recovery factors at different WAG ratio cases.

the oil recovery in the same PAG ratio (1 : 1). In this PAG process, CO_2 is injected first and polymeric solution follows. The results of these processes are shown in Figure 14. Ultimate recoveries are similar for all cases although increasing points of recovery factors are different. If the respective total amounts of injected CO_2 and polymeric solution are the same in five cases, they have similar efficiencies of sweep and displacement. These results are well matched with those from previous WAG simulation study [23].

Figure 15 is the result of oil recoveries for different PAG ratio processes. Oil recovery factor of 2 : 1 PAG ratio is 3% larger than that of 1 : 1 PAG ratio. As a result, injection of more polymeric solution has advantage for oil recovery by increased sweep efficiency. However, too much polymer injection could reduce the oil recovery because mobility of polymer is low and polymer does not reduce residual oil saturation (1 : 5 PAG ratio case).

4. Conclusions

The results of numerical simulation on the flow of polymeric solution with CO_2 in heavy oil reservoir were analyzed. The main challenges to reduce oil recovery are high viscosity of heavy oil and high heterogeneity of reservoir. The polymer-alternating-gas process showed significant advance of recovery efficiency compared with other processes.

(1) By the control of mobility ratio, the PAG process has better sweep efficiency than those of other processes. The PAG process represented the highest oil recovery factor by 37%. It was 89% higher than results of waterflooding or CO_2 flooding and 45% higher than consequence of WAG process.

(2) In heterogeneous heavy oil reservoir, water and CO_2 breakthroughs are key factors to reduce the oil recovery in WAG process. In comparison to WAG process, PAG process would decrease the WOR by 12%. Moreover, GOR in PAG process was maintained below GOR of WAG method.

(3) The cycle time of PAG process did not affect the recovery performance. However, 2 : 1 PAG ratio could improve the oil recovery factor by about 3% over the base case.

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

Acknowledgment

This work was supported by the Energy Efficiency & Resources Core Technology Program of the Korea Institute of Energy Technology Evaluation and Planning (KETEP) granted financial resource from the Ministry of Trade, Industry & Energy, Republic of Korea (no. 20122010200060).

References

[1] T. B. Reid and H. J. Robinson, "Lick creek meakin sand unit immiscible CO_2 waterflood project," *Journal of Petroleum Technology*, vol. 33, no. 9, pp. 1723–1729, 1981.

[2] K. Kantar, D. Karaoguz, K. Issever, and L. Varana, "Design concepts of a heavy-oil recovery process by an immiscible CO_2 application," *Journal of Petroleum Technology*, vol. 37, no. 2, pp. 275–283, 1985.

[3] W. E. Kerr, "Retlaw upper mannvile "V" pool unit experimental carbon dioxide flood," *Journal of Canadian Petroleum Technology*, vol. 24, no. 1, pp. 275–283, 1985.

[4] A. Spivak, W. H. Garrison, and J. P. Ngugen, "Review of an immiscible CO_2 project, tar zone, fault block V, Wilmington field, California," *SPE Reservoir Engineering*, vol. 5, no. 2, pp. 155–162, 1990.

[5] W. S. Fong, R. W. Tang, A. S. Emanuel, P. J. Sabat, and D. A. Lambertz, "EOR for California diatomites. CO_2, flue gas and water corefloods, and computer simulations," in *Proceedings of the Western Regional Meeting*, pp. 159–170, Bakersfield, Calif, USA, April 1992.

[6] K. Issever, N. A. Pamir, and A. Tirek, "Performance of a heavy-oil field under CO_2 injection, Bati Raman, Turkey," *SPE Reservoir Engineering*, vol. 8, no. 4, pp. 256–260, 1993.

[7] T. D. Ma and G. K. Youngren, "Performance of Immiscible Water-Alternating-Gas (IWAG) Injection at Kuparuk River Unit, North Slope, Alaska," in *Proceedings of the SPE Annual Technical Conference and Exhibition*, pp. 415–420, New Orleans, La, USA, September 1994.

[8] D. N. Rao, S. C. Ayirala, M. M. Kulkarni, and A. P. Sharma, "Development of gas assisted gravity drainage (GAGD) process for improved light oil recovery," in *Proceedings of the SPE/DOE Symposium on Improved Oil Recovery*, Tulsa, Okla, USA, April 2004.

[9] B. H. Caudle and A. B. Dyes, "Improving Miscible displacement by gas-water injection," *Petroleum Transactions of the AIME*, vol. 213, pp. 281–284, 1958.

[10] L. W. Lake, *Enhanced Oil Recovery*, Society of Petroleum Engineers, Richardson, Tex, USA, 2010.

[11] Y. Zhang, S. Huang, and P. Luo, "Coupling immiscible CO_2 technology and polymer injection to maximize EOR performance for heavy oils," *Journal of Canadian Petroleum Technology*, vol. 49, no. 5, pp. 27–33, 2010.

[12] S. Majidaie, A. Khanifar, M. Onur, and I. M. Tan, "A simulation study of chemically enhanced water alternating gas (CWAG) injection," in *Proceedings of the SPE EOR Conference at Oil and Gas West Asia*, pp. 242–250, Muscat, Oman, April 2012.

[13] W. Li, Z. Dong, J. Sun, and D. S. Schechter, "Polymer-alternating-gas simulation: A Case Study," in *Proceedings of the SPE EOR Conference at Oil and Gas West Asia*, Muscat, Oman, March 2014.

[14] S. X. Ning, B. S. Jhaveri, N. Jia, B. Chambers, and J. Gao, "Viscosity reduction EOR with CO_2 & enriched CO_2 to improve recovery of Alaska North Slope viscous oils," in *Proceedings of the SPE Western North American Region Meeting*, Anchorage, Alaska, USA, 11.

[15] D. Y. Peng and D. B. Robinson, "A new two-constant equation of state," *Industrial and Engineering Chemistry Fundamentals*, vol. 15, no. 1, pp. 59–64, 1976.

[16] H. Dykstra and R. L. Rarsons, "The prediction of oil recovery by waterflood," in *Secondary Recovery of Oil in the United States*, pp. 160–175, 1950.

[17] S. E. Buckley and M. C. Leverett, "Mechanism of fluid displacement in sands," *Transactions of AIME*, vol. 146, no. 1, pp. 107–116, 1942.

[18] F. F. Craig Jr., T. M. Geffen, and R. A. Morse, "Oil recovery performance of pattern gas or water injection operations from model tests," *Transactions of AIME*, vol. 204, pp. 7–15, 1955.

[19] F. I. Stalkup Jr., *Miscible Displacement*, Society of Petroleum, Richardson, Tex, USA, 1983.

[20] Computer Modelling Group Ltd, "STARS: Advanced Process and Thermal Reservoir Simulator," Calgary, Canada, 2012.

[21] J. J. Sheng, *Modern Chemical Enhanced Oil Recovery: Theory and Practice*, Gulf Professional Publishing, Burlington, Mass, USA, 2010.

[22] R. R. Jennings, J. H. Rogers, and T. J. West, "Factors influencing mobility control by polymeric solutions," *Journal of Petroleum Technology*, vol. 23, no. 3, pp. 391–401, 1971.

[23] E. L. Ligero, S. F. Mello, E. O. Muñoz Mazo, and D. J. Schiozer, "An approach to oil production forecasting in a WAG process using natural CO_2," in *Proceedings of the SPETT Energy Conference and Exhibition*, pp. 109–118, Port of Spain, Trinidad and Tobago, June 2012.