Predicting oil recovery through CO₂ flooding simulation using methods of continuous and water alternating gas

M T Fathaddin¹*, M M Thomas¹ and U Pasarai²

¹ Faculty of Earth Technology and Energy, Univeritas Trisakti, Jakarta, Indonesia
² PPPTMGB Lemigas, Jakarta, Indonesia

*mtfathaddin@gmail.com

Abstract. In this study, CO₂ Flooding simulation models were used to predict oil recovery. The models were previously validated by laboratory experiments of continuous injection and water Alternating Gas (CO₂) injection for miscible condition. Sensitivity test was performed to attain the effect of injection rate parameters. The simulation experiments indicated that the optimal performance for both methods obtained at injection rate of 0.09 cuft/day. The scenarios of continuous CO₂ injection showed that the maximum recovery factor was 21.1%. While the maximum recovery factor of the scenarios of water alternating gas was 37.9%. Based on the results of the whole scenarios used, Walter Alternating Gas flooding resulted in more effective recovery factor than Continuous CO₂ Flooding, within the range of injection rate studied.

1. Introduction

CO₂ flooding is known as a method of Enhanced Oil Recovery (EOR) which is able to reduce the residual oil volume through several mechanisms such as crude vaporization, oil swelling, viscosity reduction, interfacial tension (IFT) reduction, and miscible displacement. In order to apply the method, several problems should be handled for a suitable reservoir candidate such as CO₂ supply, reservoir heterogeneity, reservoir pressure, temperature, fluid composition, salinity, and fracture pressure of reservoir rock [1-5]. The objective of this research is to model and assess the recovery of oil with CO₂ injection in limestone at a laboratory scale. Two types of CO₂ flooding models were conducted, continuous miscible CO₂ injection and CO₂-WAG injection using a reservoir simulator. The effect of injection rate on the overall performance of the flood was investigated. The laboratory test was conducted under conditions of pressure and temperature corresponding to field conditions.

Continuous CO₂ injection involves injecting a certain amount of CO₂ continuously until the required slug size is reached. One major problem faced by this technique is gravity segregation and the formation of viscous fingers that propagates through the displaced fluid leaving much of the hydrocarbon not contacted. This is due to the fact that CO₂ has a lower viscosity compared to oil and it results in an adverse mobility ratio. Significant cross-flow of mobilized oil occurs as a result of fluid pressure gradients and the effects of buoyant and capillary forces between porous layers in a reservoir where vertical permeability exists [6,7].

The WAG or Water-Alternate-Gas injection comprising of injection of water and gas slugs simultaneously or in the form of cyclic alternation. The main objective is to reduce CO₂ channeling by filling the highly permeable channels with water to improve sweep efficiency during CO₂ injection. Optimum conditions of oil displacement by WAG processes are achieved when the velocities of the gas
and water are the same in the reservoir. Some advantages of the WAG process include higher CO\textsubscript{2} utilization, reduced CO\textsubscript{2} production and greater ultimate recovery. Some of the complications faced by WAG are slower oil response, gravity segregation due to density difference between CO\textsubscript{2} and water, interruption by water on the continuity of the extraction process by the CO\textsubscript{2} slug and loss of injectivity [7,8].

2. Method

In research, a compositional reservoir simulator reservoir was used to perform miscible CO\textsubscript{2} flooding namely continuous CO\textsubscript{2} injection and water alternating gas (WAG) injection in a laboratory scale. The model was validated by laboratory experiment. The data of fluid and rock (core) sample are given in Table 1. The components of reservoir fluid are listed in Table 2. The core sample was taken from a limestone formation in South Sumatera Province.

| Parameters | Values |
|------------|--------|
| Initial Pressure, \(p_i\) | 700 psi |
| Temperature, \(T_r\) | 158 °F |
| Oil viscosity, \(\mu_o\) | 0.3 cp |
| Rock Compressibility, \(c_r\) | 4.0E-6 psi\(^{-1}\) |
| Oil Gravity, SGO | 41.5 °API |
| Initial Water Saturation \(S_w\) | 0.235 |
| Permeability, \(k\) | 140 mD |
| Porosity, \(\phi\) | 0.215 |
| Core diameter, \(D\) | 0.8872 in. |
| Core Length, \(L\) | 12.792 in. |

The base 3D model for cylindrical core with diameter of 0.8872 in. and length of 12.792 in. The dimension is 33x1x30 yielding a total number of 990 gridblocks. Using this as the base model, the optimum injection mode for WAG and continuous were determined and compared to yield the most effective CO\textsubscript{2} injection mode.

The aim of CO\textsubscript{2} WAG injection simulation was to analyze the effect of CO\textsubscript{2} and water injection rate for WAG injection on the recovery factor and to determine the optimum CO\textsubscript{2} WAG injection rate. Using the base model, two CO\textsubscript{2} slugs and two water slugs were alternately injected into the core sample. The duration of each slug was two hours. The rate of CO\textsubscript{2} was the same as that of water. Four injection rates were modeled. They were 0.03 cuft/day, 0.06 cuft/day, 0.07 cuft/day, and 0.09 cuft/day.

The aim of Continuous CO\textsubscript{2} injection simulation was to analyze the effect of CO\textsubscript{2} injection rate on the recovery factor and to determine the optimum CO\textsubscript{2} injection rate. Using the base model, CO\textsubscript{2} was continuously injected into the core sample. The duration of CO\textsubscript{2} injection was the same as the total duration of WAG injection (8 hours). Four equal injection rates were modeled. They were 0.03 cuft/day, 0.06 cuft/day, 0.07 cuft/day, and 0.09 cuft/day.

| Component | Mol % |
|-----------|-------|
| CO\textsubscript{2} | 0.15 |
| N\textsubscript{2} | 0.02 |
| C\textsubscript{1} | 0.29 |
| C\textsubscript{2} | 0.24 |
| C\textsubscript{3} | 3.02 |
| iC\textsubscript{4} | 1.24 |
| nC\textsubscript{4} | 2.23 |
| iC\textsubscript{5} | 1.56 |
| nC\textsubscript{5} | 1.49 |
| C\textsubscript{6} | 6.68 |
| C\textsubscript{7}+ | 83.08 |
| Total | 100.00 |
3. Results and discussion

The validation of the simulation model was conducted by matching the cumulative oil produced curve of simulation result to that of the experimental result as shown in Figure 1. For this purpose, the same procedure of WAG injection experiment was performed. The figure indicates that the simulation result was well agreed to the laboratory experimental result, where the difference of maximum cumulative oil produced between those two curves was 0.3%.

![Figure 1](image)

**Figure 1.** Comparison of experimental and simulation curves of cumulative oil produced.

Table 3 shows recovery factor resulted from continuous and WAG injection for various injection rates. The table indicates that recovery factor is proportional to the injection rate. However, the effect of injection rate is much less sensitive to continuous CO2 injection than to WAG injection. The result agrees with the study performed by Nasir and Chong [7] for various models of CO2 flood process, the recovery factor of oil was observed to be proportional to the injection rate. Other information obtained from the table is the recovery factor of WAG injection method is higher than that of continuous injection for various injection rates studied. Since WAG is able to reduce CO2 channeling, the higher injection rates the greater the recovery factor difference of the two methods. Figure 2 shows the cumulative oil produced both for continuous and WAG injection. The figure show that cumulative oil produced is proportional to injection rate. But it increases slightly for continuous injection. The increase of injection rate may result in pressure increase that can affect the cumulative of oil produced. Since the pressure is above MMP, the oil recovery tends to flat as the pressure increases [9, 10].

| Injection Rate (cuft/day) | Continuous | WAG  | Δ     |
|--------------------------|------------|------|-------|
| 0.03                     | 20.3       | 22.9 | 2.6   |
| 0.06                     | 20.6       | 28.1 | 7.5   |
| 0.07                     | 20.9       | 36.1 | 15.2  |
| 0.09                     | 21.1       | 37.9 | 16.8  |

**Table 3.** Recovery factor for continuous and WAG injection.
Figure 2. Cumulative oil produced for continuous and WAG injection.

4. Conclusions
Based on the simulation results and analyses shown above, several statements are made as follows. Recovery factor is proportional to the injection rate. However, the effect of injection rate is much less sensitive to continuous CO2 injection than to WAG injection. Recovery factor of WAG injection method is higher than that of continuous injection for various injection rates within the range studied.

References
[1] Suarsana I P, Marhaendrajana T, Gunadi B 2015 Gas Injection Programs in PERTAMINA West Java to Obtain Better Recovery: Field Screening, Laboratory and Simulation Study, SPE International Improved Oil Recovery Conference, SPE 97507 MS, Kuala Lumpur, December 2005
[2] Karimaie H, Nazarian B, Aurdal T, Nøkleby P H, and Hansen O 2017 Simulation Study of CO2 EOR and Storage Potential in a North Sea Reservoir Energy Procedia 114 Elsevier 7018-7032
[3] Amin M E A 2012 Optimization of CO2 WAG Processes in a Selected Carbonate Reservoir: Laboratory Study (Al Ain: United Arab Emirates University)
[4] Longyu H 2015 Optimum Water-Alternating-Gas (CO2-WAG) Injection in the Bakken Formation (Saskatchewan: University of Regina)
[5] Zekri A, Al-Attar H, Al-Farisi O, Almheaidet R, Lwisa E G 2015 Experimental investigation of the effect of injection water salinity on the displacement efficiency of miscible carbon dioxide WAG flooding in a selected carbonate reservoir J Petrol Explor Prod Technol 5 363–373
[6] Chen B and Reynolds A C 2015 Ensemble-Based Optimization of the WAG Injection Process, SPE Reservoir Simulation Symposium SPE 173217 MS, Houston, February 2015.
[7] Nasir F M and Chong Y Y 2012 The Effect of Different Carbon Dioxide Injection Modes on Oil Recovery International Journal of Engineering and Technology 9(10)
[8] Anuar N A M, Yunan M H, Sagala F, and Katende A 2017 The Effect of WAG Ratio and Oil Density on Oil Recovery by Immiscible Water Alternating Gas Flooding American Journal of Science and Technology 4(5) 80-90
[9] Hawez H and Ahmed Z 2014 Enhanced Oil Recovery by CO2 Injection in Carbonate Reservoirs WIT Transactions on Ecology and The Environment 186 547–558
[10] Verma M K 2015 Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO2-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO2-EOR Associated with Carbon Sequestration (Reston, Virginia: U.S. Geological Survey)