Experimental and Numerical Evaluation of the Potential of Improving Oil Recovery from Shale Plugs by Nitrogen Gas Flooding

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Abstract

Production from tight formation resources leads to the growth in U.S. crude oil production. Compared with chemical flooding and water flooding, gas injection is a promising enhanced oil recovery (EOR) approach in shale reservoirs. A limited number of experimental studies concerning gas flooding in the literature have focused on unconventional plays. This paper presents experimental work for applying an immiscible N₂ flooding process in oil-saturated shale plugs. To investigate the effect of injection pressure on recovery performance, multiple core-flood tests were performed at the injection pressures of 1,000 psi, 3,000 psi, and 5,000 psi, respectively. A lab-scale numerical simulation model was built to match the experimental data. Based on this model, we conducted sensitive studies and analyzed the recovery process.

The potential of N₂ flooding for improving oil recovery from shale core plugs has been demonstrated by the experimental observations and simulation results. Under a certain injection pressure, the results show that the oil was produced with a high and stable production rate at the initial period of the recovery process, before gas breakthrough. After that, the incremental RF decreased with the increase of a flooding period, and a much longer time had less effect on extracting more oil. We also examined the effect of injection pressure on gas breakthrough time, ultimate RF, and oil recovery history. This study illustrates that gas flooding could be considered as an improved oil recover (IOR) approach in shale oil reservoirs.

Keywords:

Gas flooding; Shales; Improved oil recovery; Enhanced oil recovery

1. Introduction

Gas injection is a promising IOR method beyond the primary recovery stage. It has been developed as a mature and extensively employed IOR technique for recovering crude oil from conventional reservoirs. The injected gas phase may include hydrocarbon gas, CO₂, N₂, or a mixture of gases. The optimum selection of the gas source depends on reservoir conditions, gas availability, and economic factors. The benefits of nitrogen include its low cost, simple production process, and non-corrosive factor. It has thus become a substitute for natural gas or carbon dioxide, especially in cases where those gases are scarce.

Nitrogen injection has been demonstrated as an effective IOR/EOR approach by many published theoretical and experimental studies as well as by the successful field cases reported globally. The study history can be dated back to the 1970s. Clancy et al. (1981) summarized the potential applications of nitrogen in enhanced oil and gas recovery, which range from the simplest process of pressure maintenance to the most complex technique of miscible displacement. Ahmed et al. (1983) conducted laboratory tests for displacing crude oil using a

high-pressure, N₂ injection. They determined the miscible pressure for the system and also investigated the compositional changes taking place during the displacement process. In a follow-up study, Alcocer and Menzie (1984) examined the effect of temperature and gas-oil ratio in solution on crude oil recovery and the miscibility process. Simulation studies showed a positive IOR potential: N₂ can be used effectively as an injection gas to facilitate maximized oil recovery in the fields of Trinidad (Sinanan and Budri, 2012) and the South East Asset (Belhaj et al., 2013). Ulrich (2015) assessed the IOR potential of N₂ injection for oil fields in North Africa and highlighted the advantages and feasibility of such technology.

Over the past decade, U.S. crude oil production has grown rapidly, which has been primarily driven by resources from tight formations (EIA, 2015). Those areas represent low-permeability reservoirs, including shale and chalk formations. It is projected that stimulation treatments operated in the initial stage of production will become less effective with the depletion of reservoir pressure. Improved oil recovery methods must be applied to shale reservoirs to maintain and extend the production growth, in addition to the current use of horizontal wells with multiple transverse fractures. Researchers are considering gas injection as an IOR solution in tight formations. Gas can be injected in subsurface media continuously or cyclically, known as flooding or huff-n-puff processes. Cyclic gas injection (CGI) recovery has shown encouraging potential from blooming physical and numerical simulation studies (Song and Yang, 2013; Wan et al., 2013; Gamadi et al., 2013; Yu et al., 2014; Sheng, 2015; Yu and Sheng, 2015; Sanchez-Rivera et al., 2015; Wan et al., 2015). The action of injecting gas in the flooding mode has mainly been evaluated by reservoir modeling work. Sheng and Chen (2014) initially simulated gas and water flooding in a simple fractured shale model with the base matrix permeability of 0.1 μ D. They concluded that the injection of gas greatly outperforms water. With a similar injection scheme in well-to-well flooding, Zhu et al. (2015) built a compositional reservoir model with a matrix permeability of 10 μ D and 1 μ D. Their results suggested there is the potential of CO₂ flooding to improve recovery in shale oil. Limited core-flood experiments have been implemented to test gas flooding IOR potential using shale core plugs. Kovscek et al. (2008) and Vega et al. (2010) tested the performance of CO₂ injection in a fractured siliceous shale core with a permeability of 0.02-1.3 mD. To the best of our knowledge, few tests have been operated under ultra-low permeability (less than 1 μ D) conditions.

In this work, the oil recovery potential of N₂ flooding processes was evaluated in the Eagle Ford shale plugs with a permeability of less than 1 μ D. Core-flooding tests were conducted to mainly investigate the effects of the flooding time and injection pressure on recovery performance. By performing numerical simulation on experimental tests, we have a better understanding of the gas flooding process and production history in shale reservoirs.

2. Experimental Work

2.1 Materials

The core plugs used in this study were cut from the Eagle Ford shale outcrop parallel to the bedding planes with a dimension of 1.5-inch diameter and 2-inch length. The measured average helium porosity was 5% and the nitrogen permeability was about 80 nD. Permeability was determined using a complex transient measurement system (AutoLab 1000) developed by NER Inc., USA. There was no observed natural fracture or fissure inside of the plugs from CT images (Figure 1). The oil sample used for core plug saturation was the dead shale oil with a low density

of 0.815g/cc and a viscosity of 8.5 cp under 71°F and atmospheric pressure. N₂ with a high purity of 99.999% was used as the gas source in the flooding tests.

Figure 1. The plug samples CT image in 3D and slice view

2.2 Experimental Setup

The experimental work consists of two parts: (a) core plug saturation and (b) the gas flooding process, as the setup diagram shows in Figure 2. The apparatus used for core saturation contains a vacuum pump, a vessel, an accumulator, and a Quizix pump (QX-6000). For gas flooding tests, a core holder with a maximum operating pressure of 10,000 psi was used. Tap water, pressurized by Quizix pump, was used to supply confining pressure to the plug, which was 500 psi higher than the injection pressure. The injected gas came from a high-pressure (6,000 psi) compressed N₂ cylinder. A gas mass flow meter (SmartTrak 100) with a readability of 0.02 sccm (standard cubic centimeters per minute) was installed at the outlet to monitor the gas flow rate.

(a)

Figure 2. Schematic diagram of experimental setup used for (a) oil saturation and (b) gas flooding tests

2.3 Experimental Procedures

In general, core samples were saturated with dead oil followed by the N2 flooding tests. Firstly, the helium porosity of plug samples were measured by using a gas porosimeter and were calculated with Boyle's Law. An analytical balance with the readability of 0.0001g was used to measure the plug weight when it was dry, when it was oil-saturated, and after the tests. Such high quality sensitive balance is required because the weight difference is very small when measuring plugs at various conditions.

For the saturation process, the cleaned core plugs were placed in an oven for drying 24 hr with the temperature of 248°F (120°C), and then the dried samples were placed in a vessel and vacuumed for 24 hr. After that, the oil was delivered into the vessel with a constant operating pressure of 1,000 psi for 24 hr for maximum saturation. The relief valve was then opened and the test plug was taken out of the vessel (other plugs were put in oil before operating the flooding test). After removing the outside liquid, the plug was placed in an empty container for a few hours to equalize its pressure and stabilize the weight. The above procedure was repeated multiple times on each plug as the flooding tests were performed under different operating conditions. Comparing the results of oil-saturated weight of the plug indicated that the saturation results were almost the same. After the saturation, the flooding test could be performed by placing the test plug in the core holder with a rubber sleeve, applying confining pressure, and then injecting the gas into the plug.

2.4 Experimental Design

A total of three scenarios of N2 flooding processes were performed at different injection pressures under immiscible conditions. Scenario #1 was conducted with a constant injection pressure of 1,000 psi for 5 days. Scenarios #2 and #3 were operated with a constant injection pressure of 3,000 psi and 5,000 psi, respectively. Since the recovery process becomes faster when higher injection pressure applied, we only monitored the recovery history of 2 days for

scenarios #2 and #3, which saved the experiment operation time and allowed us to understand the recovery characters as well. To minimize the experimental errors and eliminate the impact of sample difference, the same core plug was kept for use under different scenarios. Though samples were not precisely the same, they were cut from the same area and presented similar rock properties. In each scenario, two core samples were designed to experience the same test scheme. The purpose was to avoid errors, ensure accuracy, and validate conclusions.

The shale plug samples used in this study had an ultra-low porosity (about 5%), which led to a small amount of oil (about 2.5 grams) existing in the plug after full saturation, and less than 1 gram of total oil was yielded at the end of the test. Therefore, it is impossible to monitor the oil production history conventionally by collecting data from a graduated cylinder or a scale that is placed at the outlet of the core holder. An alternative way, which we adopted, is to measure the plug weight before and after the test. Thus, applying a certain injection pressure, multiple tests were performed on the same plug when studying the recovery history during the flooding process (the relationship between flooding time and recovery factor). The operating conditions for each plug are shown in Table 1. The RF of each test is calculated from Eq. 1:

$$RF = \frac{W_{sat} - W_{exp}}{W_{sat} - W_{dry}} \quad (1)$$

where W_{sat} is the weight of the core sample maximally saturated with oil, W_{dry} is the weight of the dried core sample, and W_{exp} is the weight of the core sample measured after the N2 flooding test.

To achieve the maximum oil production, the backpressure was atmospheric pressure. As the effect of temperature on RF is not our focus in this study, and to simplify the operation process, all tests were operated at the room temperature of 72°F.

Table 1. Operating conditions for N2 flooding tests

Scenario No.	Core No.	Injection pressure	Flooding period
1	GF_4 GF_6	1,000 psi	Conduct core-flood tests under 6-hr, 12-hr, 18-hr, 1-day, 2-day, 3-day, 4-day, and 5-day, respectively.
2	GF_6 GF_7	3,000 psi	Conduct core-flood tests under 0.25-day, 0.5-day, 1-day, and 2-day, respectively.
3	GF_6 GF_7	5,000 psi	Conduct core-flood tests under 0.25-day, 0.5-day, 1-day, and 2-day, respectively.

3. Simulation Model Description

A core-scale numerical model was built using a commercial simulator, CMG-GEM, to simulate the N2 flooding processes in shale plugs. The domain was discretized into 34×1×11 Cartesian grid blocks with the dimension of 2-in × 1.5-in × 1.5-in. Figure 3 shows the 2-D II cross and 3-D view of the reservoir simulation model. The model has 34 layers in I direction to present the fluids motion behavior during the gas injection period. K direction was divided into 11 layers that allowed gas to be injected into, and gas and oil could be produced from each layer,

as the performance of the physical core-flood test. The dead oil compositional analysis results are shown in Table 2. The reservoir and operational conditions of the base model are given in Table 3, with a matrix permeability of 80 nano-Darcy and injection pressure of 1,000 psi. The distribution of porosity, absolute permeability, and oil saturation are assumed to be homogeneous in the shale matrix.

The preliminary input relative permeability data are referred to in previous simulation work (Wan et al., 2015), which simulated the N₂ huff-n-puff processes in shale rocks. Combined with the experimental results from three scenarios, relative permeability typical curve for each plug is tuned to match the corresponding oil production history. Thus we generated a total of three base models. The model which matched the experiments for plug GF_6 is selected to further interpret experimental results, predict the ultimate oil recovery, and conduct further sensitive analysis. The relative permeabilities that were tuned to match different experiments for the chosen model are shown in Figure 4.

Table 2. Input fluid composition

Component	C3-nC4	iC5-C8	C9-C19	C20-C40	C41-C42
Mole Frac. (%)	0.018	2.64	36.66	45.32	15.36

Table 3. Reservoir properties and recovery conditions of the base model

Property	Value	Units
Shale matrix permeability	80	nD
Shale matrix porosity	4.8%	fraction
Initial oil saturation	100%	fraction
Initial core pressure	14	psi
Reservoir temperature	72	°F
Injection pressure P_{in}	1000	psi
Production pressure P_{out}	14	psi
Compressibility of shale	5×10^{-6}	psi ⁻¹
Injected gas	N ₂	N/A
Injected period	5	day

Figure 3. 2-D and 3-D reservoir simulation model (blue area represents shale core plug)

4. Results and Discussion

In this study, a total of 32 sets of N2 flooding tests were operated using three shale plug samples. The results of the helium porosity (ϕ_{gas}) of each plug, fluid saturation porosity (ϕ_{sat}) and oil recovery factor (RF) in each test are given in Table 4. ϕ_{gas} is used as a reference value of porosity. By comparing it with ϕ_{sat} , we can evaluate the oil saturation level prior to operating the flooding test, as the analysis in Table 5. Overall, ϕ_{gas} is gently greater than ϕ_{sat} because gas has much smaller molecules and lower viscosity than those of liquid, which make it easier for gas to flow into spaces of nano-pore size. After each saturation process, we observed that more than 90% of pore areas were saturated with oil; thus, it could be assumed that the sample was fully oil saturated. For each single plug, considering all obtained ϕ_{sat} as a group, we calculated the average ϕ_{sat} , and standard deviation (SD) of the ϕ_{sat} group, as shown in Table 5. All three cases have a very small SD, which indicates that they are clustered closely around the mean value. So we can conclude that each oil saturation process was conducted properly and successfully. The purpose of analyzing saturation performance is to ensure that the plug presented the same oil saturation prior to each flooding test, thus improving the accuracy and reliability of the obtained RF results.

Table 4. Measured oil recovery factor of operated N2 flooding tests

Core No.	W_{dry} , g	ϕ_{gas}	P_{in} , psi	t_{exp} , day	W_{sat} , g	W_{exp} , g	ϕ_{sat}	RF
GF_4	150.9424	5.48%	1,000	0.25	153.3844	153.1982	5.08%	7.62%
				0.5	153.3885	153.0702	5.09%	13.01%
				0.75	153.3869	152.9977	5.08%	15.92%
				1	153.3902	152.9296	5.09%	18.82%
				2	153.3660	152.8011	5.04%	23.31%
				3	153.4028	152.7658	5.12%	25.89%
				4	153.4416	152.6877	5.20%	30.17%
				5	153.4498	152.6581	5.22%	31.57%
				0.25	153.8688	153.7411	4.79%	5.52%
				0.5	153.8723	153.6622	4.79%	9.07%
GF_6	151.5559	5.27%	1,000	0.75	153.8741	153.5843	4.80%	12.50%
				1	153.8622	153.5140	4.77%	15.10%
				2	153.8638	153.4078	4.78%	19.76%
				3	153.8658	153.3555	4.78%	22.09%
				4	153.8702	153.2817	4.79%	25.43%
				5	153.8697	153.2293	4.79%	27.68%
			3,000	0.25	153.8676	153.6254	4.78%	10.48%
				0.5	153.8600	153.4321	4.77%	18.57%
				1	153.8735	153.2605	4.80%	26.45%
				2	153.8709	153.1467	4.79%	31.28%
			5,000	0.25	153.8793	153.4668	4.81%	17.75%
				0.5	153.8712	153.2575	4.79%	26.51%

				1	153.8846	153.1257	4.82%	32.59%
				2	153.8865	152.9644	4.82%	39.56%
			3,000	0.25	154.8026	154.6281	3.97%	9.11%
				0.5	154.7977	154.4850	3.96%	16.37%
				1	154.8110	154.3397	3.98%	24.50%
				2	154.8121	154.2344	3.99%	30.02%
GF_7	152.8876	4.12%	5,000	0.25	154.8078	154.5045	3.98%	15.79%
				0.5	154.7911	154.3666	3.94%	22.30%
				1	154.8134	154.1849	3.99%	32.64%
				2	154.8154	154.0408	3.99%	40.18%

Table 5. Plug samples oil saturation evaluation

Core No.	ϕ_{gas}	Avg. ϕ_{sat}	$\phi_{\text{sat}} / \phi_{\text{gas}}$	Standard deviation of ϕ_{sat}
GF_4	5.48%	5.11%	93.34%	6.09E-04
GF_6	5.27%	4.79%	90.96%	1.52E-04
GF_7	4.12%	3.97%	96.48%	1.77E-04

The experiment measured oil RF for all flooding tests, which can be found in Table 4. According to the RF data of Scenario #1 ($P_{\text{in}} = 1,000$ psi), water-oil and gas-oil relative permeability curves for the base model of each plug sample are tuned to history-match the experimental measurements, as an example of GF_6 show in Figure 4. The experimental and simulated oil recovery histories are depicted in Figure 5, which present an excellent match between the two profiles. Using the tuned base model, the injection pressure is changed to simulate Scenarios #2 and #3, and oil recovery history-matching results are shown in Figures 6 and 7, respectively. The viability of the established model is confirmed, and an agreement between measured and simulated RF data is achieved from those three scenarios.

Figure 4. Relative permeability curves for (a) water-oil system and (b) gas-oil system used in the simulation model

In Scenario #1, for each sample, eight flooding tests were conducted under 1,000 psi of injection pressure to collect RF at different points in time. The results show that after a 5-day flooding process, the cumulative RF of GF_4 and GF_6 were 31.6% and 27.7%, respectively. Although it gave different cumulative RF for two samples, which was greatly caused by differences in the properties, we find a consistent tendency from the oil production history plot.

The simulated RF profiles show that the oil production rate is high at the beginning of the flooding processes, which lasts less than one day for three cases. According to the average reservoir pressure profiles in Figures 5 to 7, there are three stages that can be observed based on the changes in the slope: 1. P_{ave} increases with flooding period in an extremely high rate; 2. P_{ave} continues to increase but with a slower rate until the peak value reached; 3. After a slight drop, P_{ave} becomes stabilized and remains a constant value. In stage one, the pressure near the injector area, grid (1, 1, 1-11), is built up to the target P_{in} in a short time as a high gas injection rate is applied. During the second stage, gas flows from the injector to the producer, diffuses in the shale matrix, and results in the increase of the average system pressure. The third stage represents the period after gas breaks through the plug. The slope of the recovery curve reflects the oil production rate. Since the flooding process began, the oil is produced fastest during stages I and II, until gas appears in the producer and P_{ave} arrives in peak status. Subsequently, the rate occurs suddenly with a sharp decline in the third stage, which implies the onset of major N2 breakthrough. As presented in Figures 5 to 7, the major gas breakthrough time of the three scenarios are about 16.5 h, 5.0 h, and 3.5 h, respectively, indicating that it takes much less time for gas to break through the plug when a higher P_{in} is applied.

Figures 8 to 10 present the simulated distribution of pressure, oil saturation, and gas saturation in plug GF_4 during the flooding process, which was operated under the injection pressure of 1,000 psi for 5 days. At the beginning of the test (0-day), the oil-saturated ($S_o = 100\%$) plug was placed in the core holder at the atmospheric pressure (14.7 psi). When a gas source was provided, the plug pressure was built up from injector and quickly spread to the producer. With the increasing of S_g at the injector area, S_o started to decrease. Driven by the injected gas, oil came out of the producer. We observed that 0.625-day is a critical time during the designed flooding period: the distribution of pressure in the plug becomes stabilized as it has no change in the following days. At this point, S_o is less than 1 at the producer and the injected gas has just been transferred into this area ($S_g > 0$), which reveals that gas flowed through the plug. After gas breakthrough, until the end of the test (5-day), S_o decreased progressively in stepped distribution from the injector to the producer, which was a response to the increasing volume of gas portion in the shale matrix.

When pressurized gas was injected into plug, it displaced oil to the area with low pressure and less flow resistance. Once the flow channel was established throughout the plug, it provided a major flow path for the media of gas, thus weakening the performance of gas drive with a longer operation.

Figure 5. Measured and simulated oil recovery history for Scenario #1

Figure 6. Measured and simulated oil recovery history for Scenario #2

Figure 7. Measured and simulated oil recovery history for Scenario #3

Figure 8. Pressure variations during the 5-day N2 flooding process

Figure 9. Oil saturation variations during the 5-day N2 flooding process

Figure 10. Gas saturation variations during the 5-day N2 flooding process

Table 6 shows the experimental observations of gas breakthrough (BT) time and stabilized outlet gas flow rate for different injection pressure (P_{in}). This BT time was recorded as the time when gas bubbles were present in the water at the outlet. The gas outlet flow rate was very low at the beginning and then increased to a stabilized value when the major BT was generated. Therefore, the simulated BT time is longer than the observed one. When $P_{in} = 1,000$ psi, the stabilized flow rate was so small (less than $0.5 \text{ cm}^3/\text{min}$) that it could not be identified from the gas mass meter. With the increase of P_{in} , gas broke through the plug earlier with a higher stabilized flow rate. It was observed that when $P_{in} = 5,000$ psi, gas flowed through the plug in two hours, more than 10 hours faster compared with the condition of $P_{in} = 1,000$ psi.

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Table 6. Gas BT time and outlet flow rate at different P_{in}

Injection pressure, psi	GF_6		GF_7	
	t_{BT} , hr	q, sccm	t_{BT} , hr	q, sccm
1,000	13	< 0.5	-	-
3,000	3	12.2	2.8	13.6
5,000	2	18.33	1.75	18.77

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Figure 11. Effect of injection pressure on oil recovery of 5-day N2 flooding

345 Based on the simulation model of core GF_6, Figure 11 investigated the effect of injection
346 pressure on recovery performance of the N2 flooding for a period of 5 days, with a constant P_{in}
347 ranges from 500 psi to 5,000 psi. It shows that P_{in} can affect oil recovery throughout the flooding
348 process. Before gas BT, recovery rate increases with the increase of P_{in} , which is obviously
349 reflected in the medium-low pressure range (500 psi to 3,000 psi). The turning point position of
350 each recovery curve illustrated that a higher P_{in} not only makes gas flow faster through the plug
351 but also contributes to a greater RF at the BT point. The incremental RF is based on the greater
352 pressure gradient, which creates extended flow channels (enlarge the stimulated area) and
353 improves the plug conductivity. Therefore, injection pressure is a sensitive factor that influences
354 the oil recovery greatly in the N2 flooding process.

355 In order to further examine the role of flooding period in the recovery process and find out the
356 ultimate RF for three scenarios, we extended the operation period to 300 days. Again applying
357 the GF_6 model, the simulated oil recovery history is presented in Figure 12. As it is unrealistic
358 to conduct a core-flood test for such a long period, we do not have experimental data for so long.
359 The simulated results show that the ultimate RF of the N2 flooding tests at injection pressure of
360 1,000 psi, 3,000 psi, and 5,000 psi are 80.5%, 82%, and 85%, respectively. The corresponding
361 times that the ultimate RF achieved are about 60 d, 140 d, and 220 d. We found that when

increasing P_{in} from 1,000 psi to 5,000 psi, an increment of only 4.5% oil RF is yielded from the lab-scale simulation results. The distinct advantage of employing high P_{in} is to increase the oil recovery rate and shorten the development period, while it will increase the cost of injecting the high pressure gas. By contrast, the utilization of a lower P_{in} is more suitable for the shale plays that need to be a long-term, sustainable development. Therefore, the optimum selection of injection pressure for flooding recovery is of significance in order to maximize oil recovery as well as the economic benefit, which should take into account many factors such as production cost, daily output, and oilfield developing time.

Figure 12. Estimation of the ultimate oil recovery for three scenarios

This experimental study initially explored the possibility of gas flooding in nano-Darcy shale reservoirs. Along with the simulation work, both results showed a positive potential of oil recovery, especially before the gas breakthrough. More efforts need to be made on operating gas flooding tests at real reservoir and production conditions, optimizing the simulation model, in order to increase our understanding of the recovery mechanism and effectiveness of gas flooding in the field-scale cases.

5. Conclusions

This study focused on evaluating the IOR performance of N₂ flooding in shale core plugs. From the experimental data and simulation results, we analyzed the oil recovery history and discussed the injection pressure effect during the flooding period. The following conclusions can be drawn from this study.

- The feasibility and potential of gas flooding in nano-permeability shale oil plays have been investigated by both experimental data and a simulation approach. Continuous gas injection

could be applied as an IOR solution in shale reservoirs.

- N₂ flooding presented the greatest recovery potential and produced oil rapidly during the early injection period until gas breakthrough. The oils that had been recovered at the BT were 16.8%, 17.9%, and 19% from the simulated data under the injection pressures of 1,000 psi, 3,000 psi, and 5000 psi, respectively. After the breakthrough, the production rate declines sharply and the outlet gas rate became stabilized gradually.
- Gas injection pressure is an important factor in the flooding process. Injecting gas with a higher pressure can shorten the breakthrough time, which will achieve a higher RF at BT, generate a higher stabilized outlet flow rate, and also cause a rise in the ultimate RF.
- The simulation results show that P_{in} has no significant effect on the ultimate RF: an incremental of 4.5% oil was yielded when increasing P_{in} from 1,000 psi to 5,000 psi. But it influenced the recovery history greatly: under a higher P_{in} , oil was produced more quickly throughout the recovery process. Thus, the ultimate RF will be achieved much earlier.

Acknowledgments

This work was supported by the U.S. Department of Energy under Award Number DE-FE0024311. The financial support is greatly appreciated.

Nomenclature

W_{dry}	weight of dry core plug sample, g
W_{sat}	weight of core sample saturated with dead oil, g
W_{exp}	weight of core sample measured after the N ₂ flooding test, g
T_{exp}	designed gas injection period, day
ϕ_{gas}	porosity measured from gas porosimeter
ϕ_{sat}	porosity measured from oil saturation (weight difference)
P_{in}	injection pressure, psi
P_{out}	production pressure, psi
P_{ave}	average reservoir pressure, psi
S_g	gas saturation
S_o	oil saturation
RF	recovery factor
BT	breakthrough

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