

Experimental Investigation of Continuous N₂ and Enriched N₂ Gas Flooding under Multicontact Miscible (MCM) and First Contact Miscible (FCM) Displacements

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Abstract

Paper presents an analysis of the effects of high-pressure N₂ and enriched N₂ injection on oil recovery under multicontact miscible and first contact miscible conditions. Phase equilibrium experiments, slim-tube, and core displacement tests were carried out at the reservoir conditions to study miscible N₂ flooding. Utilizing the phase equilibrium and PVT data, pseudoternary diagrams were constructed to determine the minimum enrichment required for FCM displacement. It emerged that methane vaporization is one of the main characteristics of N₂ flooding, and this characteristic amplifies clearly as more N₂ dissolves in the crude oil. Moreover, the coreflood results indicated that the oil recovery by enriched N₂ injection is higher than that by N₂ injection at the early stage of production. This was probably due to the fact that there is no interfacial tension between the enriched N₂ and oil when they contact each other under FCM displacement.

Keywords: Enhanced oil recovery; N₂ gas flooding; Enriched gas drive; Minimum miscibility pressure (MMP); Minimum miscibility enrichment (MME); MCM; FCM.

1. Introduction

The efficiency of enhanced oil recovery (EOR) methods meet the increasing global oil demands at the present time as oil reservoirs approach to a stage of their life cycle, in which no more oil could produce after secondary flooding. Gas flooding, as one of the most widely practiced methods for EOR [1], is conventionally considered to move oil from the reservoirs through injecting various gases, typically screening by operators based on different circumstances of the reservoirs for desired profits [2-3]. It should be mentioned that selecting the type of injection gas highly depends on the economic evaluations and also its availability in that specific area [4]. Among different kinds of gases, methane, air, CO₂, and N₂ have been in use for a long time in the petroleum industry. Regardless of the merits of these gases in different situations, they have their drawbacks compare to N₂, leading to choose N₂ as a particularly viable alternative in gas flooding.

According to oil displacement through N₂ injection, the displacement can be divided into two main types of immiscible and miscible displacements, relying on reservoir pressure, reservoir temperature and crude oil composition. More specifically, one of the essential factors adjusting the miscibility of N₂ with oil is minimum miscible pressure (MMP), typically applying as a benchmark to determine under which process oil displacement occurs either through miscible or immiscible displacement. Generally, MMP is defined as the minimum pressure at

which two or more substances mix in any proportions together to form one single-phase at reservoir temperature [5-6]. If the oil is displaced by gas at the injection pressure lower than the MMP, the displacement is considered immiscible; in contrast, in the case of injection pressure at or higher than MMP, the miscible displacement occurs in the reservoir. In the literature, there are various ways to determine MMP, such as empirical equations, theoretical models, numerical simulations, or laboratory experiments. Pseudoternary diagrams, as one of the theoretical methods, have been traditionally used to determine the MMP, minimum miscibility enrichment (MME), and also the behavior of gas drive processes [7-8]. Aside from their limitations, MMP and MME can be readily estimated by drawing a tangent line on the phase envelope of the pseudoternary diagram at constant reservoir pressure and reservoir temperature. Accordingly, MMP corresponds with a pressure at which a tangent line at the critical point of phase envelope passes through the point representing oil composition; in addition, MME can be determined as a result of an intersection point of the tangent line on a phase envelope at the critical point on the intermediate components' side of the ternary diagram [8-9].

Generally, the miscible gas injection has been conveniently classified into two main processes: First contact miscible (FCM) and multicontact miscible (MCM), where MCM consists of vaporizing gas drive (VGD), condensing gas drive (CGD), and condensing/vaporizing gas drive (CVD) [10-11].

Regarding the enriched gas injection, two processes of MCM (particularly CVD) or FCM will occur in the reservoir, depending on the level of gas enrichment above the MME. In the interval between MME to minimum enrichment for FCM, the dominant process is MCM, and after that FCM process takes the lead in increasing oil recovery [6]. Numerous literature has shown that oil recovery factor does not change significantly above MME [12-13]; in contrast, some authors show that injecting a richer gas at the enrichment required for FCM maybe surpasses MCM process regarding to oil recovery for following reasons: (1) Disappearance of flowing gas effect [14] (2) absence of IFT and capillary pressure because of single-phase flow, which is a crucial matter for at least high heterogeneity reservoirs [15-16].

This paper is concerned with the impact of N₂ and enriched N₂ injection on oil recovery, particularly under FCM and MCM conditions at elevated pressures and temperature. The FCM displacement by N₂ injection, to the best of the authors' knowledge, has not been studied in literature before. The main reason behind the lack of technical information on this topic is that this kind of displacement is not achievable in most of the reservoirs. However, because of the particular conditions of the reservoir in this study, it was tried to achieve this goal according to the theory of minimum enrichment required for FCM in pseudoternary diagrams.

2. Materials and methods

2.1. Materials

In this study, first-stage separator oil and gas samples were collected from one of the southwest Iranian oilfields. The separator pressure and temperature were 1.78 MPa and 82°C during sampling. The gas chromatography compositional analysis of the separator oil, separator gas, and original reservoir oil were tabulated in Table 1. The reservoir oil has a molecular weight of 108.05 gr/mol, C₇₊ molecular weight of 256 gr/mol, and C₇₊ specific gravity of 0.9015. For the recombination process of the first-stage separator oil and gas samples, the GOR matching method was chosen, in which the GOR of the recombined oil measured at the laboratory was matched with the reported GOR of 600 scf/stb. The bubble point pressure (P_b) of the recombined oil was determined by conducting a standard constant composition expansion (CCE) experiment at the reservoir temperature, which was measured to be 18.41 MPa. The viscosity of recombined oil was measured at different pressures by connecting a capillary viscometer to the PVT apparatus. To do so, the viscosity of recombined oil was measured to be 1.5521 mPa.s at the initial reservoir pressure of 34.47 MPa and temperature of 102.78°C. The density of the recombined oil was equal to 0.7887 gr/cm³ under reservoir conditions. N₂ with a mole fraction purity of 99.99% was used as injection gas in all tests.

Table 1. Compositional analysis of the separator oil, separator gas, and original reservoir oil.

Component	First-stage separator gas (mole%)	First-stage separator oil (mole %)	Reservoir oil (mole%)
H ₂ S	0.00	0.00	0.00
N ₂	0.00	0.00	0.00
CO ₂	0.90	0.17	0.51
C ₁	76.47	6.37	38.61
C ₂	14.11	5.88	9.67
C ₃	5.55	6.53	6.08
iC ₄	0.65	1.44	1.08
nC ₄	1.33	4.93	3.27
iC ₅	0.32	2.67	1.59
nC ₅	0.29	2.64	1.56
C ₆	0.26	5.33	3.00
C ₇₊	0.12	64.04	34.63
Total	100.00	100.00	100.00

The reservoir limestone whole core was obtained from Asmari formation from the same oilfield where oil and gas were collected. The core plugs were drilled from this whole core in one direction to ensure a consistent permeability anisotropy. The porosity and the permeability of these core plugs were in the range of 4-8% and 8-12 mD, respectively. Three out of ten core plugs were selected according to the screening process, which consisted of fluid transmissibility and lacking an extremely high permeability fracture. Finally, these three core plugs were put on top of each other to form a stacked core for conducting coreflood tests. The basic dimensions, the porosity and the permeability of the stacked core are listed in Table 2.

Table 2. Dimensions and properties of the stacked core

Core	Height (mm)	Diameter (mm)	Porosity (%)	Permeability (mD)	Pore Volume (mL)
Stacked core	147.3	38	6.526	9.561	10.90

2.2. Phase equilibrium experiments

The main objective of phase equilibrium experiments conducted in this study was to shed some light on the behavior of the equilibrium gas and equilibrium oil at different pressures, in particular below MMP and above MMP when N₂ is injected in a single contact with live oil. Moreover, these data were used to tune an equation of state to simulate the multicontact process with commercial PVT software. In the phase equilibrium experiments, there are mainly two ways to simulate the injection gas proceeding through the real reservoir in the laboratory conditions with all limitations therein, one way with only one single contact [17] and the other one with multiple contacts [17-18]. In the case of the single contact experiment, the lean gas can be injected either at the specific volumetric fraction or at the particular concentration (mol %) into the PVT cell. In all experiments performed in this section, the injection of N₂ was implemented at the specific volumetric fractions under various pressures and constant reservoir temperature.

2.2.1. Experimental setup and procedure

Fig. 1 depicts a diagram of the experimental setup used for phase equilibrium experiments, which is mainly composed by the following components: 1) a PVT cell (Ruska Instrument Corporation, USA) equipped with a front window which permitted to see the fluids and measure their volumes was used to provide the contact of live oil and gas at reservoir temperature and high pressures; 2) three mercury pumps (DBR, JEFRI Equipment, Canada) were used to pressurize the PVT cell, to inject live oil, and to pressurize the storage cylinder; 3) a live oil transfer cylinder and an N₂ cylinder; 4) a sampling cylinder was used to sample the equilibrium gas and subsequently to connect to the gas chromatography apparatus in order to analyze the gas components; 5) a storage cylinder was used to collect the equilibrium gas at the end of each experiment and also to pressurize the N₂ during the test.

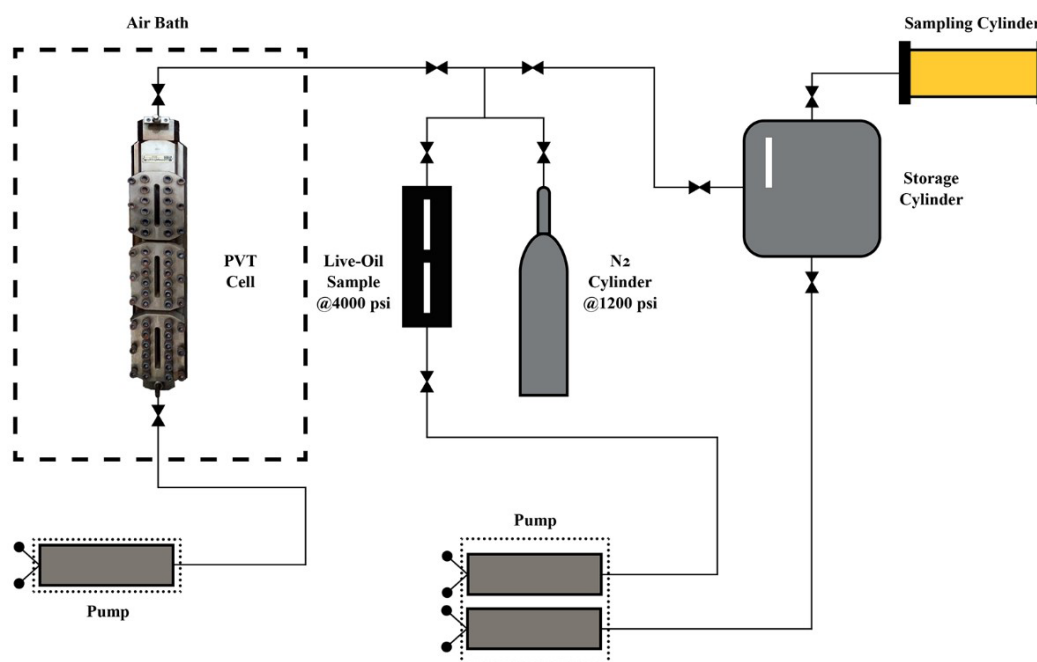


Fig. 1. Schematic diagram of the experimental setup used for the N₂-live oil single contact phase equilibrium measurements.

A brief description of the experimental procedure is outlined as follows: A batch of pure N₂ was introduced into the PVT cell at the containing pressure of the gas cylinder, which was at 8.27 MPa. Then, the N₂ was pressurized to the experimental pressure at the reservoir temperature, and its volume was measured. When the volume of N₂ in the cell was lower than a predetermined volumetric fraction, which it was defined as the cumulative volume of the injection gas divided by the PVT cell volume, an amount of N₂ from the N₂ containing cylinder was introduced into the storage cylinder and pressurized to the experimental pressure and then was injected into the PVT cell. Alternatively, when the volume of the N₂ at the PVT cell was higher than a predetermined volumetric fraction, the excess N₂ was vented from the cell to the storage cylinder and then was released to the room atmosphere. After preparing the precise volumetric fraction of N₂ at the cell, the live oil was pressurized in its transfer vessel at the experiment pressure. In the next step, a determined volume of live oil, which was calculated precisely using the thermal expansion coefficient, was injected into the PVT cell to fill the rest of the cell. Afterward, the PVT cell containing a predetermined volumetric fraction of live oil and pure N₂ was isolated in the oven to reach equilibrium at the reservoir temperature for six hours. Meanwhile, the cell was continuously moved to the left and right position so as to mix the fluids during the rocking and ensure equilibrium establishment in this step. Thereafter, the cell was mounted in the vertical position for about 24 hours, permitting the separation of the equilibrium gas and oil to occur. At this point, the equilibrium gas was withdrawn to the storage cylinder to fill the sampling cylinder, which was in vacuum condition, and the equilibrium oil was purged from the PVT cell. Subsequently, the sampling cylinder was connected to a gas chromatography apparatus to obtain the equilibrium gas composition at the predetermined volumetric fraction. Using the convergence pressure method, the composition of equilibrium oil was calculated at the reservoir temperature and the selected pressure.

It is to be noted that each phase equilibrium experiment was terminated at the predetermined volumetric fraction after the corresponding equilibrium gas was sampled, and then another experiment was started with the subsequent specified volumetric fraction at the same test pressure. This procedure was repeated for different volumetric fractions at different pressures.

2.2.2. Simulation of pseudoternary diagrams

An equation of state was tuned by using the single contact phase equilibrium data alongside the PVT tests such as the standard constant composition expansion test (CCE) and separator test, etc. The Peng-Robinson equation was utilized in the numerical simulation of multicontact process during N_2 injection [19]. Then, the grouping based on the volatility of components was employed as follows: 1) N_2 , as the injection gas, was added to methane to form pseudo-component one 2) ethane to hexane was grouped together to form pseudo-component two 3) C_{7+} fraction was assigned as pseudo-component three. It is to be noted that the simulation of pseudoternary diagrams was implemented with cell to cell approach. Finally, the pseudoternary diagrams were obtained at three different pressures (27.58 MPa, 34.47 MPa, and 41.37 MPa) and constant reservoir temperature of 102.78°C.

2.3. Slim-tube displacement tests

Fig. 2 shows the schematic of the slim-tube setup used in this study. It is consisted of a stainless steel tube, with 122 mm length and an internal diameter of 4.57 mm. The slim-tube was packed with glass beads to a porosity of 35% and a permeability of 5.7 D. The measured pore volume (PV) was equal to 75.22 mL. Two mercury pumps were used to inject fluids into the slim-tube. The experimental setup was also equipped with a gas cell to mix N_2 with separator gas for enrichment, a back pressure regulator to maintain a desired pressure during the tests, a glass separator to collect produced oil, and a gas meter to measure produced gas.

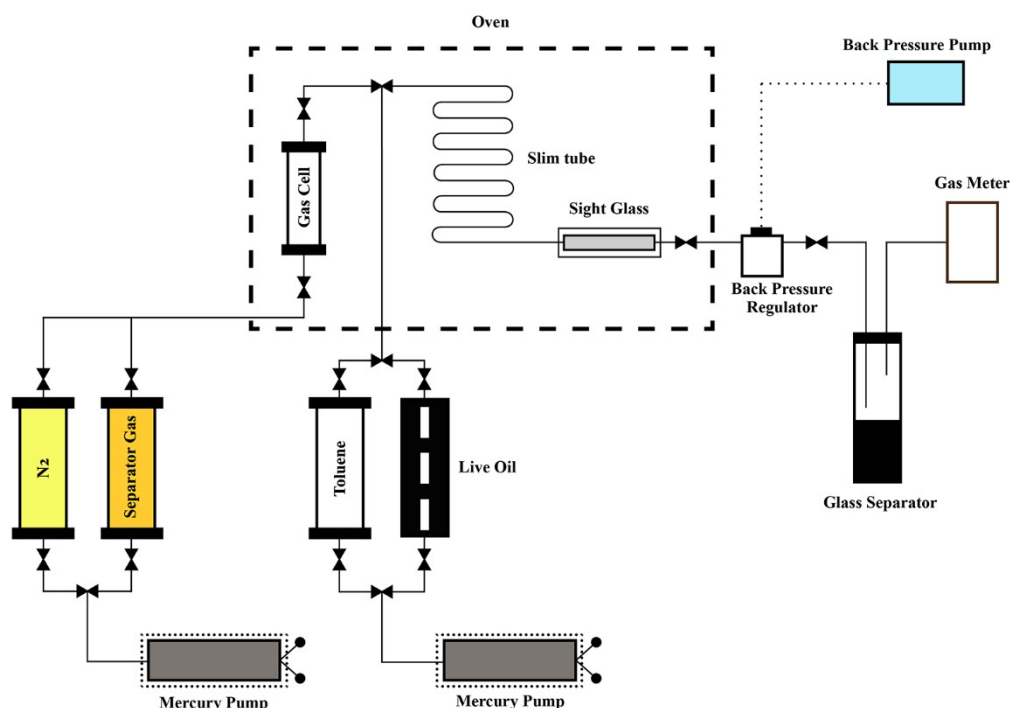


Fig. 2. Schematic diagram of the slim-tube setup.

Slim-tube tests were performed in three steps comprising cleaning, saturation, and displacement. Prior to each test, toluene was continuously injected to the slim-tube until the color of toluene at the outlet was clear, and then N_2 was purged to dry it. After cleaning the system, slim-tube was initially saturated with toluene, and more than 2 PV of live oil was then flooded at a pressure above the bubble point pressure to displace the toluene. In the next step, the slim-tube was aged for 4 hrs. in the oven at reservoir temperature of 102.78°C to reach the system equilibrium. The backpressure regulator was set at the desired pressure, and the continuous gas injection was conducted under different displacement situations.

In this study, the slim-tube displacements were divided into two main sections: the MMP measurement of the crude oil with pure N_2 and the determination of oil recovery by injecting enriched N_2 . Regarding the MMP measurement, the N_2 was injected into the slim-tube at different test pressures, and the produced oil and gas were recorded at every 2 mL of injected gas. Each test was terminated after injecting a total of 1 PV of N_2 and also ensured that no more oil was produced. In the case of enriched N_2 injection, a specific amount of N_2 and first-stage separator gas, which were calculated in the phase equilibrium section, were injected into the gas cell to mix with each other. After reaching equilibrium, enriched N_2 was injected into slim-tube at a constant flow rate of 0.13 mL/min under reservoir conditions, and the produced oil was recorded.

2.4. Coreflood displacement tests

A schematic of the coreflood setup for N_2 and enriched N_2 flooding is shown in Fig. 3. The experimental setup mainly consisted of three transfer cylinders for live oil, pure N_2 and first-stage separator gas, two displacement pumps, a high-pressure stainless steel core holder, a back pressure regulator, a back pressure pump, a gas meter, and a glass separator. It is worth mentioning that conducting N_2 injection at high temperature and pressures simultaneously needed a special rubber-sleeve to prevent the leakage during the coreflood experiments so that a strong rubber-sleeve was used to constrain the stacked core. Dealing with this difficulty is the most common issue in such conditions, where Hudgins also reported that they had to fabricate a rubber-sleeve for this reason [20]. In addition, water was used to apply overburden pressure on the stacked core due to eliminating the leakage, which usually happened by gas diffusion through the rubber-sleeve. The oven, which was used to mimic the reservoir temperature, had a limited space to place all of the transfer cylinders, so only the core holder and a gas cell were placed into the oven.

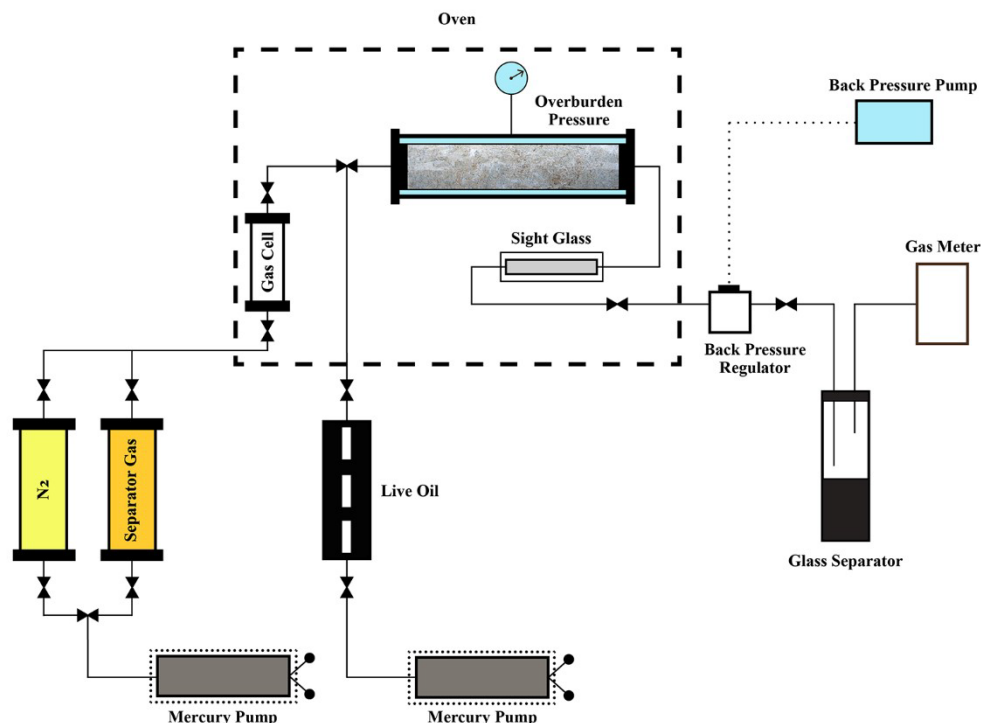


Fig. 3. Schematic diagram of the coreflood apparatus applied for N_2 and enriched N_2 flooding.

Prior to each coreflood, the cores were cleaned by a Soxhlet extractor for 48 hrs. with toluene and were dried in an oven at 100°C for 24 hours. Then, the stacked core was mounted in the core holder and vacuumed for 48 hours. Thereafter, toluene was injected into the core at a constant pressure to measure the effective pore volume, and as a result of that porosity

was calculated. Toluene injection was continued until the steady state was reached, and the pressure drop variation through the stacked core was recorded to calculate absolute permeability using Darcy's law. Afterward, 2 PV of live oil was injected into the core at a constant flow rate of 0.1 mL/min, and the saturated stacked core was maintained for 24 hrs. at reservoir temperature of 102.78°C to reach the equilibrium state.

A total of two coreflood tests were conducted in this investigation under different conditions. In the first test, N₂ was injected at a constant flow rate of 0.13 mL/min at MMP and reservoir temperature of 102.78°C. After the outlet fluid passed through the back-pressure regulator, it was separated into two phases of oil and gas at the glass separator. The volume of produced oil was then recorded to determine the oil recovery factor by dividing the oil volume by the stacked core pore volume. The test was terminated when no more oil was produced. In the second test, pure N₂ was initially mixed with a calculated volume of first-stage separator gas in the gas cell to form an enriched N₂. After reaching the equilibrium at reservoir temperature, the enriched N₂ was injected into the stacked core at a constant flow rate of 0.13 mL/min at reservoir pressure, and the volume of produced oil was recorded. It is worth noting that the initial oil saturation of the stacked core was one (i.e., no connate water saturation was included) in order that the circumstances of coreflood tests become identical to slim-tube tests except the dispersivity.

3. Results and discussion

3.1. Phase equilibrium experiments

A total of 12 experiments were carried out to determine the influence of pressure on oil and gas compositional changes at reservoir temperature of 102.78°C. By implementing a slim-tube pretest, the MMP between recombined oil and pure N₂ was measured in order to determine the pressures at which the phase equilibrium should be conducted. Based on the measured MMP of 38.93 MPa, three pressures of 27.58 MPa, 34.47 MPa, and 41.37 MPa were chosen to perform the phase equilibrium experiments under different conditions. In addition, the volumetric fractions of 15%, 35%, 50% and 75% of N₂ were selected to inject the gas into the PVT cell.

3.1.1. Distribution of intermediate components in intermediate group (C₂-C₆) in equilibrium oil and equilibrium gas

Fig. 4 illustrates the ratio of each intermediate component to the intermediate group for equilibrium gas and equilibrium oil at different experiment pressures in terms of different volumetric fractions of pure N₂ injection into the PVT cell. As can be seen from Fig.4, more ethane concentrates in the equilibrium gas compared to the oil phase, which is attributed to its high volatility, and in return, high amounts of hexane remains in equilibrium oil at the specific volumetric fraction. In fact, the difference in the distribution of each intermediate component in each phase depends on the volatility of each component [21]. Furthermore, intermediate components gradually increase in the gas phase as the system pressure increases, owing to the fact that the interaction between the oil and N₂ becomes slightly stronger at higher pressures. By increasing N₂ injection volume, the process of dissolution and extraction between N₂ and oil also continuously increases, resulting in more vaporizing of intermediate hydrocarbon components and increasing the ratio of heavy components in the oil phase [22].

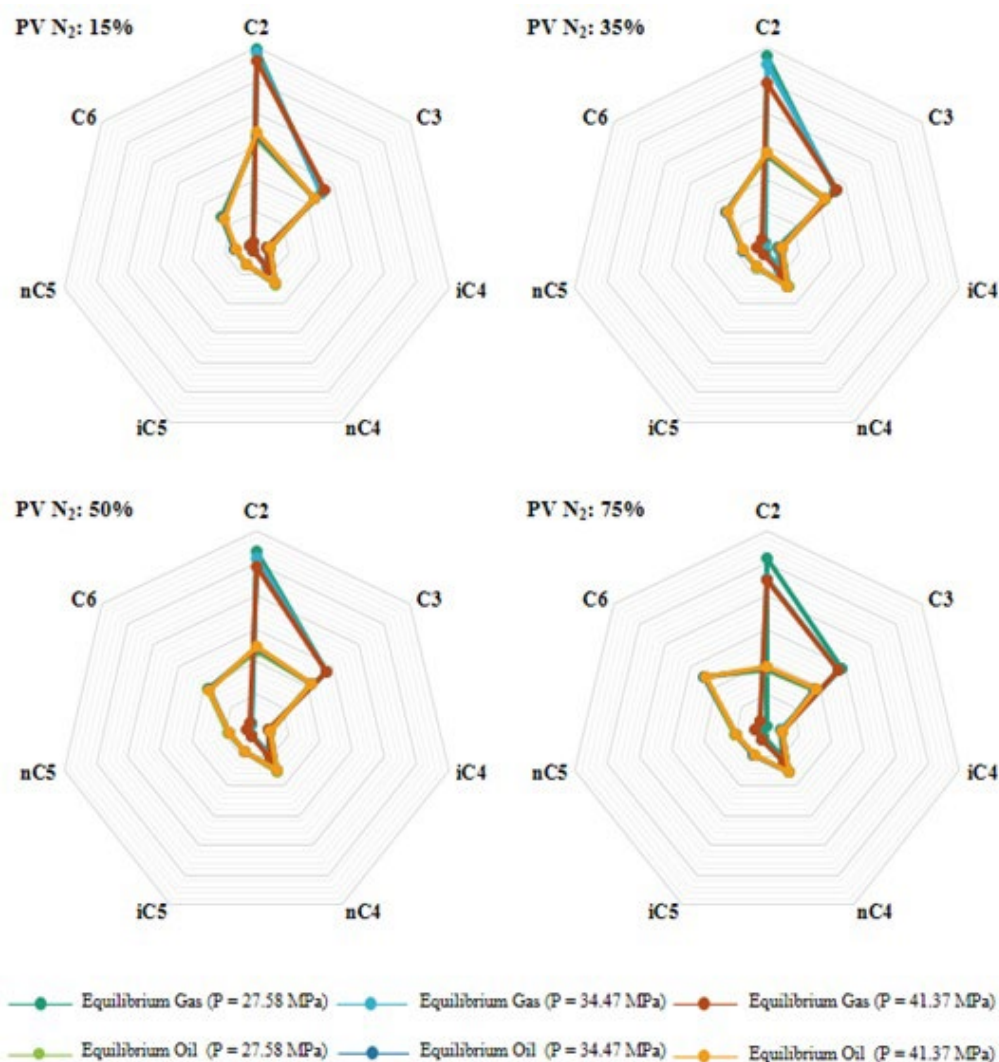


Fig. 4. Distribution of each intermediate components in intermediate group (C₂-C₆) in equilibrium oil and equilibrium gas in terms of different volumetric fractions of N₂ injected (PV N₂ = 15%, 35%, 50%, and 75%) at three different pressure (27.58 MPa, 34.47 MPa, and 41.37 MPa) and T = 102.78°C.

3.1.2. Effect of pressure on the variation of C₁ and C₂-C₆ components in equilibrium oil

Fig. 5 compares the variation of methane (C₁) component in the equilibrium oil phase at three different pressures and constant reservoir temperature. As can be observed in Fig. 5, methane component of the oil phase decreases for all three pressures by increasing the PV N₂ injected; however, this reduction deviates before the 35% of PV N₂ injected for these pressures such that vaporization of methane at 41.37 MPa is slightly lower than that of other pressures. This behavior can be related to this point that the solubility of methane in a liquid hydrocarbon, especially containing volatile hydrocarbons, increases as the pressure increases [23-24]. In the case of C₂-C₆ vaporization, the variations of these components in the oil phase are shown in Fig. 6. It can be observed from Fig. 6 that decreasing of C₂-C₆ in the oil phase follows the same trend for all pressures when the PV N₂ injected increases, and also the amount of these components in the oil phase is lower at 41.37 MPa. In other words, increasing pressure leads to more N₂ dissolution in the oil phase, stronger mass transfer between N₂ and the oil phase, and thereby higher intermediates components' extraction from the oil phase. Thus, it can be concluded that the vaporizing gas process acts stronger as the system pressure increases.

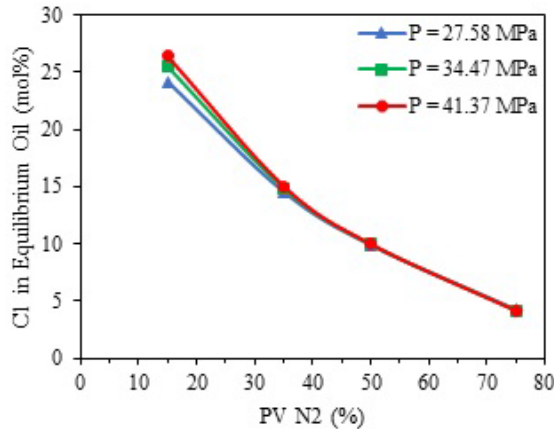


Fig. 5. Variation of methane (C₁) in equilibrium oil versus the PV N₂ injected at P = 27.58, 34.47 and 41.37 MPa and T= 102.78°C.

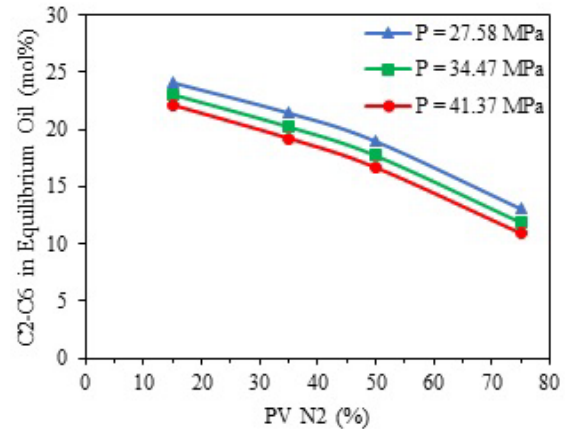


Fig. 6. Variation of intermediate components (C₂-C₆) in equilibrium oil vs the PV N₂ injected at P = 27.58, 34.47 and 41.37 MPa and T=102.78°C.

3.1.3. MME and FCM determination

Figs. 7-9 show the pseudoternary phase behavior diagrams for the recombined oil and N₂ injection gas at three different pressures. As expected, the size of the two-phase region shrinks when the system pressure increases [9]. By drawing limiting tie line at the approximate critical point for these diagrams, it can be observed that the point representing the reservoir oil composition places on the left side of this line for pressures of 27.58 MPa and 34.47 MPa, which means that N₂ injection displaces the reservoir oil under immiscible condition; in contrast, for the pressure of 41.37 MPa, the reservoir oil composition point places on the right side of limiting tie line, leading to miscible displacement of the reservoir oil after multiple contacts with N₂. These results are in good agreement with the measured MMP in slim-tube tests.

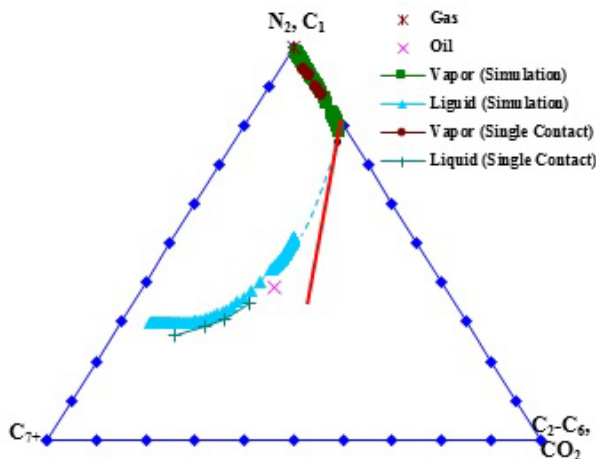


Fig. 7. Pseudoternary diagram for the recombined oil and N₂ injection gas at P = 27.58 MPa.

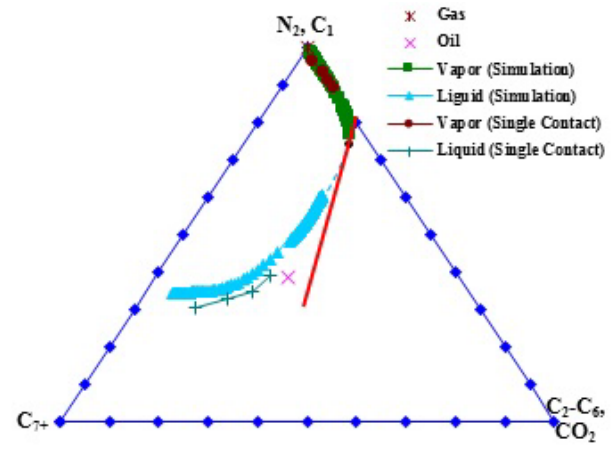


Fig. 8. Pseudoternary diagram for the recombined oil and N₂ injection gas at P = 34.47MPa and T=102.78°C.

With regard to the reservoir pressure lower than the MMP, miscibility will not be achieved when a lean gas (N₂ or CH₄) is injected into the reservoir, in which vaporizing gas drive process occurs, because reservoir rock cannot endure high-pressure gas injection required for this situation [12,21]. Therefore, one way to address this problem is to reverse the vaporizing gas drive process by enriching the lean gas with intermediate components. In this study, N₂ was enriched with intermediate components to achieve miscibility, since the reservoir pressure was lower than the MMP. To determine what quantity of intermediates should be mixed with

N_2 , two lines, including the limiting tie line and the tangent line from the point representing the reservoir oil composition to the two-phase envelope, were drawn on the two-phase envelope of the pseudoternary diagram at the reservoir pressure of 34.47 MPa. Consequently, MCM and FCM regions can be distinguished for an enriched gas drive when these lines intersect the right side of the triangle, as shown in Fig. 10. The MME, in which the dominant displacement is condensing/vaporizing gas drive, occurs at approximately 19% (C_2-C_6 and CO_2) for this system, and the minimum miscible enrichment for FCM occurs roughly at 21% (C_2-C_6 and CO_2). In order to further investigate the impact of enriched gas injection under FCM condition on oil recovery, the pure N_2 was enriched with first-stage separator gas, which contained an amount of 23.41% (C_2-C_6 and CO_2), for the slim-tube and coreflood experiments. At 23.41% (C_2-C_6 and CO_2), it would be expected that single-phase flow occurs where the oil recovery primarily depends on the level of dispersion in the system [13].

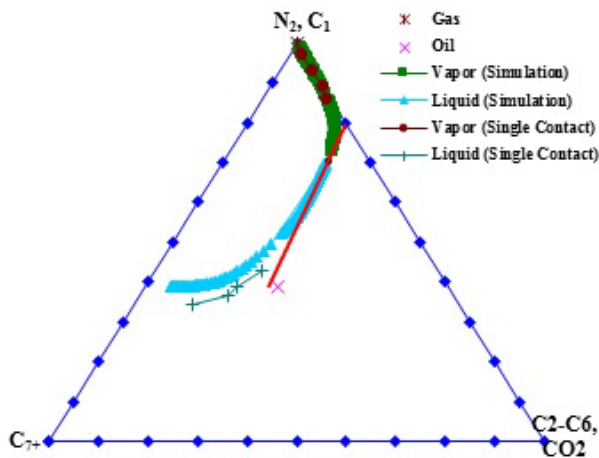


Fig. 9. Pseudoternary diagram for the recombined oil and N_2 injection gas at $P = 41.37$ MPa and $T = 102.78^\circ\text{C}$.

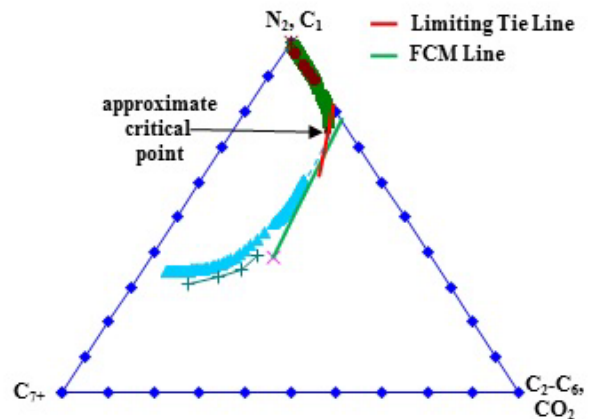


Fig. 10. Pseudoternary diagram for the recombined oil and N_2 injection gas at $P = 34.47$ MPa and $T = 102.78^\circ\text{C}$ (with limiting tie line and FCM line).

3.2. Slim-tube tests

To determine the MMP between the recombined oil and N_2 , five slim-tube tests were conducted at pressure ranges from 28.96 to 44.81 MPa and a constant reservoir temperature of 102.78°C . Fig. 11 shows the oil recovery factor versus the PV N_2 injected at different test pressures. It is noted that the PV N_2 injected defined as the cumulative volume of N_2 injected divided by the PV of the slim-tube. As expected, the ultimate oil recovery increases when the test pressure rises. This is due to the fact that by increasing the system pressure, the interfacial tension (IFT) between oil and N_2 decreases linearly until the IFT reaches zero at miscible condition, resulting in higher oil recovery [25-26]. The oil primarily produces under three different displacement conditions from the slim-tube when a lean gas is injected: 1) immiscible displacement under which the two-phase flow occurs, and a clear interface between oil and gas can be observed from the sight glass 2) near miscible displacement, which is a transition from immiscible to miscible condition and displacement occurs at pressures slightly below MMP, in which the recovery efficiency is higher than immiscible displacement and less than miscible displacement due to the minimum value of IFT 3) [27-28] miscible displacement under which one phase flow occurs so the oil recovery is significantly high and also no interface can be observed between oil and gas. Therefore, it is inferred that the oil may be produced under immiscible condition at 28.96 MPa and 34.47 MPa, and under miscible condition at 41.37 MPa and 44.81 MPa. The ultimate oil recoveries at 1 PV of N_2 injected are then plotted versus test pressures, and the intersection between two linear fitting curves can be termed as the MMP [29]. Thus, as shown in Fig. 12, the MMP between recombined oil and pure N_2 was measured to be approximately 38.93 MPa in this study.

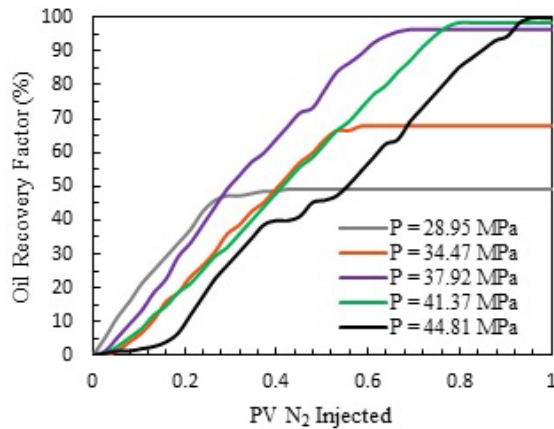


Fig. 11. Oil recovery factor versus the PV N₂ injected from slim-tube at different test pressures and reservoir temperature.

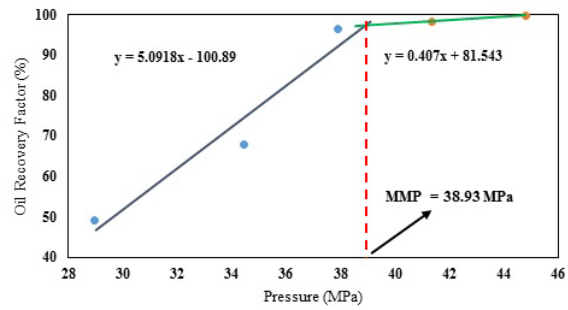


Fig. 12. MMP measurement for the N₂-live oil system.

Due to the fact that the reservoir pressure ($P_{\text{res}} = 34.47$ MPa) was lower than the MMP, the N₂ was enriched with first-stage separator gas to achieve miscibility under reservoir conditions. According to the determined MME in the previous section and an accurate calculation, an amount of 415.12 L of N₂ was mixed with 3665.62 L of first-stage separator gas at reservoir conditions to obtain an enriched N₂ gas, which produces oil under FCM condition. **Fig. 13** show the oil recovery factor of N₂ under immiscible and enriched N₂ under FCM displacements in the slim-tube at reservoir conditions. The results show that the ultimate oil recovery of enriched N₂ injection is higher than that of N₂ injection, with a difference of about 25.11% of the original oil in place (OOIP). This can be attributed to this fact that the IFT between oil and gas and capillary pressure becomes zero under miscible conditions ^[30], thereby leading to higher oil recovery for enriched gas injection. Moreover, it can be observed that more than 1 PV of enriched N₂ is injected until the oil reaches its ultimate recovery, whereas no more oil is produced after 0.58 PV of N₂ injected. The main reason behind this behavior is that interaction between enriched N₂ and oil under FCM condition is much stronger than the immiscible condition, causing more consumption of the injected gas.

3.3. Coreflood tests

In this section, the effect of continuous N₂ and enriched N₂ injection are evaluated on the oil recovery of the stacked core. For the first test, the N₂ flood was conducted at approximately MMP of 38.95 MPa, which was measured in the slim-tube section, and the reservoir temperature of 102.78°C. For the second test, after pure N₂ was mixed with the first-stage gas separator in the gas cell, enriched N₂ flood was carried out at the reservoir conditions ($P_{\text{res}} = 34.47$ MPa and $T_{\text{res}} = 102.78^\circ\text{C}$). The oil recovery factor for continuous N₂ injection at MMP and enriched N₂ at P_{res} are shown in Fig. 14. It should be mentioned that the oil displacement mechanisms are different in either test: in the first test, the oil displaces by N₂ injection under vaporizing gas mechanism or MCM, whereas, in the second one, the enriched N₂ displaces the oil under FCM condition. As can be observed from Fig. 14, the ensuing enriched N₂ injection, the oil recovery grows faster than that of N₂ injection at the beginning of production in the stacked core. This outcome is caused by lacking the entry capillary pressure in enriched N₂ injection during FCM flood and the effect of flow resistance of the two-phase flow in N₂ injection under MCM condition ^[16,31], which affects the oil recovery at the early stage of production. Concerning the N₂ injection, the more contacts of N₂ with oil causes intermediate components to vaporize from the oil phase to the gas phase and as a result of that miscibility between N₂ and oil achieves, leading to a remarkable ultimate oil recovery of 88% OOIP. In the ensuing the enriched N₂ injection, the oil production gradually increases until it reaches the ultimate oil recovery of 85% OOIP. The minor difference between the ultimate oil recovery for N₂ and

enriched N_2 can be attributed to higher injection pressure for N_2 injection (i.e., the difference between injection pressures about 4.48 MPa), which leads to a denser solvent. Comparing the number of pore volumes injected gas showed that more gas was injected for enriched N_2 (1.4 PV) than that for N_2 (0.92 PV), indicating the stronger interaction between enriched N_2 and oil. This behavior may be explained by the fact that a small content of CO_2 in the enriched gas increases the gas dissolution in oil [32], and components mix in all proportions under FCM condition [6], resulting in more gas consumption.

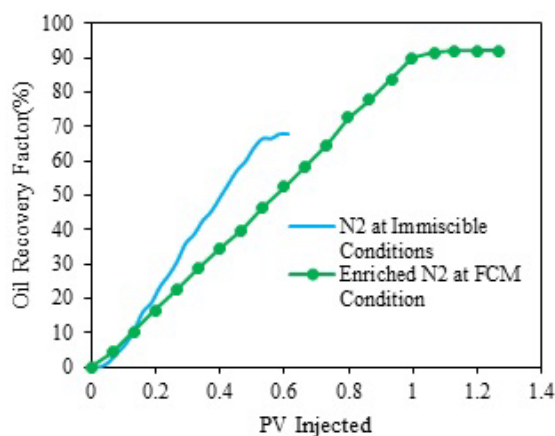


Fig. 13. Comparison between oil recovery factor of slim-tube versus the PV N_2 injected under immiscible and enriched N_2 injected under FCM displacements at the reservoir conditions.

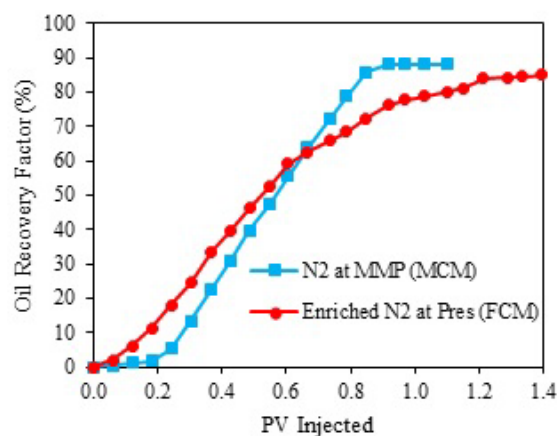


Fig. 14. Oil recovery factors of the stacked core versus the PV N_2 injected under MCM displacement at MMP and enriched N_2 under FCM displacement at reservoir pressure.

Besides, comparing the oil recovery from slim-tube and stacked core reservoir by enriched N_2 injection at reservoir conditions, the ultimate recovery in the slim-tube is 7% higher than in the coreflood, although both experimental results were under FCM condition. Several authors have shown that dispersion controls the oil recovery in one-dimensional displacement as the gas enrichment increases above the MME [13,33-35]. To be precise, the increasing of dispersion (a lower Peclet number) leads to lower oil recovery when the enriched gas above MME is injected, owing to the fact that dispersion causes the decreasing concentration of the enriching components [34, 36]. For an ideal slim-tube, the oil displacement is a one-dimensional dispersion free flow [37]; however, the dispersion measurement for slim-tube shows a low range of 3.048 to 15.24 mm at laboratory conditions [34]. In contrast, the dispersion throughout the stacked core is obviously higher than that in the slim-tube because of existing pore structure complexity and diverse permeability throughout the core. Therefore, the magnitude of dispersivity differences in these tests contributes to reducing the oil recovery from the stacked core in comparison to the slim-tube. It can be seen that the ultimate oil recovery for N_2 injection under FCM condition is sensitive to the dispersivity of the system. Nevertheless, comparing FCM and MCM displacements in the case of heterogeneity suggest that FCM displacements may be superior to the MCM displacements regarding the oil recovery, which was also confirmed by Al-Wahaibi [15].

4. Conclusions

Phase equilibrium experiments reveal that the amount of the more volatile intermediate components decreases in the oil phase as the more N_2 dissolves into it. Conversely, by increasing the N_2 volumetric fraction, the heavy hydrocarbon components concentrate significantly in the oil phase, and consequently, the oil becomes heavier. The methane in the oil phase vaporizes significantly to the gas phase as the dissolution of N_2 increases into the oil phase. This shows that methane vaporization is one of the main characteristics of N_2 injection during a single contact process.

Regarding the FCM displacement in stacked core reservoir, the lack of IFT and capillary pressure in the enriched N₂ flooding can lead to improving oil recovery at the early stage of production, in comparison to MCM displacement. Beyond that stage, the ultimate oil recovery achieves 85% of OOIP in the porous media during FCM displacement.

Comparing the experimental results of slim-tube and coreflood, as two systems with different dispersivity, shows that the ultimate oil recovery is so sensitive to the dispersion in these systems when enriched N₂ is injected under FCM displacement. However, the difference in dispersivity of these porous media may not affect the early stage of oil production. Apart from the limitations of pseudoternary diagrams, the high oil recovery through slim-tube and porous media shows that one can still rely on these diagrams in order to determine the FCM point.

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