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A Systematic Experimental Study to Understand the Performance and Efficiency of Gas Injection in Carbonate Reservoirs

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Summary

Gas injection is the most widely applied recovery method in light, condensate, and volatile oil carbonate reservoirs. Gas has high displacement efficiency and usually results in a low residual oil saturation in the part of the reservoir that is contacted with gas. The displacement efficiency increases when the injected gas is near-miscible or miscible with the oil. In addition to nitrogen and hydrocarbon gas projects, carbon dioxide (CO_2) enhanced oil recovery (EOR) has been the dominant gas EOR process. Gas-based EOR has been implemented in both mature and waterflooded carbonate reservoirs.

In this paper, we present the results of a detailed experimental study aimed at understanding the performance and efficiency of gas injection in carbonate reservoirs. A series of immiscible and miscible gas injection coreflood experiments were performed using limestone reservoir cores under different injection strategies. To minimize laboratory artifacts, long cores were used in the experiments, and to observe the effect of gravity, both 2 in. diameter and 4 in. diameter (whole core) were used. The experiments were performed under reservoir conditions using live crude oil. The core wettability was restored by aging the core in crude oil for several weeks under reservoir temperature. Hydrocarbon gas (methane) was used as the immiscible injectant, and both CO_2 and a mixture of 50% C_1 and 50% CO_2 were used as miscible injectant. All gas injection experiments were performed using vertically oriented cores, and the gas was injected from the top unless it is stated otherwise.

The main parameters investigated in this study are as follows:

1. The effect of miscibility on oil recovery for both continuous gas injection and water alternating gas (WAG).
2. The effect of gravity on gas sweep efficiency compared to waterflooding.
3. The effect of gas-oil interfacial tension (IFT) on oil recovery when using the same oil.
4. The effect of oil type on oil recovery using the same injected gas at miscible and immiscible conditions.
5. The effect of immiscible gas injection on subsequent miscible gas injection performance.
6. Impact of CO_2 cycle length on ultimate oil recovery.
7. The impact of the order of fluid injection where multiple WAG injection cycles were performed in separate experiments after water or gas injection.

The main conclusions of this study are as follows:

1. As expected, miscibility has a significant impact on displacement efficiency and oil recovery where miscible gas recovered more than 20% extra oil compared to immiscible gas.
2. A significant variation in oil recovery is observed for miscible gas injection (i.e., more than 10 saturation units difference) depending on the minimum miscibility pressure (MMP) between the injected gas and crude oil, even when both experiments are performed at miscible conditions using the same injected gas.
3. The performance of tertiary CO_2 flood was adversely affected by the slug of immiscible gas injected. Therefore, it is not recommended to have immiscible gas injection before miscible gas injection.
4. Regardless of injected gas type, gas injection with similar IFTs achieved similar oil recovery.
5. During WAG experiments, starting the injection cycles with water or gas did not have any impact on the ultimate oil recovery for both miscible and immiscible cases for one of the reservoirs, while WAG_G (WAG starting with gas injection) recovered more oil for another reservoir.
6. Gravity has a significant impact on oil recovery for both miscible and immiscible gas injections. A significant difference is observed in oil recovery when comparing CO_2 injection on 2-in.- and 4-in.-diameter core samples or when comparing horizontal vs. vertical immiscible gas injection and WAG experiment.
7. The longer the CO_2 slug size, the higher the oil recovery observed in gas injection experiments.

The results of this study provide a rich and rarely available set of experimental data that can help improve and optimize gas and WAG injection in oil-wet carbonates.

Introduction

Carbonate reservoirs contain more than 50% of the world's hydrocarbon reserves and, on average, have recovery factors between 30 and 40%. Carbonate reservoirs are, in general, geologically more complex than clastic reservoirs as they have more complex pore systems, are highly heterogeneous, and often have dual porosity systems (in addition to fractures). Most carbonate reservoirs also show mixed-wet

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to oil-wet characteristics. The surface chemistry of calcite as one of the primary minerals of carbonates increases its potential to become oil-wet (Hirasaki and Zhang 2004). Both geological heterogeneity and wettability have a strong impact on remaining oil saturation and its distribution and hence on oil recovery and sweep efficiency and on the choice of EOR options to be applied in such reservoirs. Due to these challenges, it is not surprising that a recent literature review has revealed that most EOR applications have been in sandstone reservoirs. Based on an international EOR project database containing 1,507 projects (Manrique et al. 2010), only 18% of the EOR projects have been implemented in carbonates. The small fraction of EOR projects in light oil carbonate reservoirs are mainly gas (CO_2) injection in the US (either continuous miscible gas or WAG).

Gas injection (especially CO_2) is a proven EOR method, and it is the most widely applied EOR technique, especially in light oil carbonate reservoirs. In addition to pressure maintenance, the primary objective for gas injection is to improve displacement efficiency (or microscopic sweep efficiency) and reduce residual oil saturation below the values usually obtained in waterflooding. The displacement efficiency and hence recovery of gas injection schemes is further improved when the process is operated under miscible or near-miscible conditions. On the other hand, gas injection suffers from poor sweep efficiency due to low gas viscosity (high mobility), geological heterogeneity, gravity override, and viscous fingering leading to unfavorable mobility ratio and premature gas breakthrough. The macroscopic sweep of gas injection is further reduced for highly heterogeneous reservoirs.

This challenge has long been recognized and possible solutions, such as WAG and simultaneous injection of water and gas, were initially proposed to overcome the shortcomings and to improve the sweep efficiency of the gas injection process (Surguchev et al. 1996; Rossen et al. 2006; Stone 2004). More recently, other processes have been developed to control gas mobility and improve sweep efficiency in more heterogeneous or stratified reservoirs, such as foam or simultaneous injection of miscible gas and polymer, SIMGAP [see Masalmeh et al. (2014)].

Miscible gas or WAG injection (CO_2 or rich hydrocarbon gases) can theoretically achieve 100% microscopic displacement efficiencies. However, gas availability, cost, reservoir pressure, lack of gas processing capacities, and environmental constraints (especially in offshore platforms) can be limiting factors imposing the design of near-miscible or immiscible WAG injection (lean gas, e.g., natural gas). Moreover, even 1D laboratory experiments reported residual oil saturation to miscible gas of sometimes up to 5% or higher [see Lange (1998)]. Therefore, it is essential to study the performance of gas and WAG injection scenarios in immiscible, near-miscible, and multiple-contact miscible conditions.

A number of experimental studies are available in the literature to investigate oil recovery by gas injection schemes in both sandstone and carbonate. Egermann et al. (2006) performed secondary and tertiary gas injection and simultaneous injection of water and gas in composite carbonate cores. Rich gas was injected below MMP. They reported ultimate oil recoveries as high as 90% regardless of the injection history. Negligible water blocking was observed during tertiary gas injection. This was explained by the oil-wet nature of the core samples.

Kalam et al. (2011) performed miscible WAG and tertiary gas injection in composite oil-wet carbonate reservoir cores. They studied the effect of injection gas as well as injection history. They also concluded that the tertiary CO_2 injection was superior compared to tertiary hydrocarbon (HC) gas injection and HC-WAG, although both gasses were injected at miscible conditions.

Duchenne et al. (2014) carried out flooding experiments on intermediate-wet carbonate cores from the Middle East. The experiments were designed to investigate the microscopic sweep efficiency of continuous CO_2 and WAG CO_2 far above MMP. They concluded that WAG experiments performed better than CO_2 injection due to better sweep efficiency and slower gas breakthrough.

Stern (1991) carried out a series of tertiary multiple-contact miscible CO_2 coreflood experiments to study the effect of flow rate, core length, oil viscosity, wettability, WAG ratio, and initial water saturation on displacement mechanisms. The study concluded that the amount of bypassed oil increases as the solvent/oil viscosity ratio decreases and where the displacement is more unstable. Moreover, the study concluded that wettability has a significant effect on oil recovery by WAG after waterflooding, where a significant water blocking effect is observed in water-wet rocks compared to mixed-wet or oil-wet rocks. Water shielding was also investigated in several other studies such as Holm (1986), Shyeh-Yung (1991), Rao et al. (1992), and Yeh et al. (1992). They all concluded that a significant water blocking effect is observed for water-wet Berea cores and the effect decreases for mixed-wet and oil-wet cores.

The study by Shyeh-Yung (1991) also showed that for CO_2 flood, S_{orm} increases linearly (oil recovery decreases) as the pressure decreases. No dramatic loss of recovery is observed below the MMP as suggested by slimtube test results. Therefore, reservoir condition coreflood should, whenever possible, replace slimtube tests as laboratory screening tests for determining the effects of pressure on CO_2 gas-injection processes as these tests also provide more realistic S_{orm} values.

The length of the core sample to be used in miscible gas injection experiments was also investigated in the literature. Both Stern (1991) and Shyeh-Yung (1991) concluded that using extra-long cores or a slimtube for miscibility development is not required at pressures well above the MMP. In such experiments, the miscibility is developed over a distance smaller than 1 ft.

The impact of a number of parameters on displacement efficiency and oil recovery of gas-based EOR was investigated in this study such as (i) the impact of CO_2 cycle length followed by waterflood, (ii) the impact of methane cycle length on subsequent miscible gas injection, (iii) the impact of gas-oil IFT on oil recovery, (iv) the impact of injection history (injection order) on immiscible and miscible WAG injection, and (v) the impact of gravity on gas EOR efficiency. The experiments were performed using carbonate rock from three different reservoirs (Reservoirs A, B, and G). Note that, in this study, the effect of the size of the WAG cycle was not investigated. Therefore, the WAG cycles in the different experiments presented in this paper were continued until minimal or no extra oil was produced.

Core Materials and Fluids Properties

Reservoir Cores. Four reservoir cores (2 in. and 4 in. diameter) used in the coreflood experiments were obtained from carbonate reservoirs A, B, and G. The core samples were cut vertically to obtain long-enough core samples. The reservoir cores were relatively high-purity limestone, typically containing less than 2% clay and 4% silica contents, respectively. The selected cores were uniform limestone with no visible fractures with adequate length to minimize the capillary end effects often seen in small core plugs. The properties of the reservoir cores are listed in **Table 1.** The composition of the rocks was measured by X-ray diffraction. **Table 2** shows the detailed composition of the rock samples used for the coreflood experiments.

To prepare the cores for the experiments, first, each of the reservoir cores was thoroughly cleaned with toluene and methanol injected in cycles before drying and weighing the core. Each core was then loaded in a high-pressure core holder, and its pore volume (PV) was measured. Later, the cores were fully saturated with formation water (FW) and permeability measurements were performed.

Properties	A1 Core	A2 Core	B Core	G Core
Diameter (cm)	5.1	10.2	5.1	5.1
Length (cm)	30	30	25.4	24.3
Porosity, ϕ (%)	24.93	19.33	19.50	29.95
Permeability to brine, K (md)	1.1	1.5	1.8	16.2

Table 1—Properties of Cores A, B, and G used in this work.

Core	A1	A2	B	G
Identified Phases	Concentration (wt%)			
Calcite	95.7	96.1	88.4	98.2
Gypsum	1.1	1.6	5.8	0.8
Quartz	3.1	1.6	3.9	0.6
Aluminum	0.1	0.7	1.9	0.4
Total	100	100	100	100

Table 2—X-ray diffraction analysis of the core samples.

Fluids. The crude oils from three different reservoirs (herein labeled A, B, and G) were centrifuged to separate possible water content before injecting the crude oils into the core. The formation brines for all mentioned reservoirs were prepared volumetrically at atmospheric conditions, stirred, and degassed before testing. The compositions and properties of all brines (A, B, and G) are given in **Table 3**, respectively.

The composition (mole fraction) of the produced gases for Reservoirs A and B is shown in **Table 4.** Methane was used as the produced gas for coreflood experiments on Reservoir G. The live oil was prepared by recombining the dead crude oil and produced gas.

Dead crude oils were mixed with the corresponding associated gas to make the recombined reservoir crude oils. The mixing process was performed at the corresponding reservoir pressure and temperature of each reservoir. It was performed in a manner to match gas/oil ratio (GOR), oil formation volume factor, bubblepoint, and viscosity of the live fluid for the cases of Reservoirs A and B. As shown in **Table 4**, the produced gas contains light and intermediate components (C_2–C_{10}). Therefore, the recombined oils were representative of the real reservoir fluids. As for Reservoir G, the crude oil was prepared by fully saturating dead oil with methane. The original reservoir fluids were fully saturated, and the produced gas composition contained more than 98% methane.

Table 5 lists the results of pressure/volume/temperature (PVT) properties experimentally measured for the recombined live oils at reservoir conditions. Note that Fluid G has the lowest GOR due to the different oil compositions and lean-produced gas (methane) compared to other gases produced for Reservoirs A and B (rich in intermediate components). The miscibility pressures of CO_2 and methane with the reservoir fluids are shown in **Table 6**; the data were measured using slimtube experiments (Alshuaibi et al. 2019). Methane (C_1) equilibrated with crude oil was used as the immiscible injectant, and CO_2 was considered in the multiple-contact miscible experiments. For Reservoir B, an additional miscible injection experiment was performed using a mixture of 50% C_1 and 50% CO_2. The MMP of this mixture and Crude Oil B is also shown in **Table 6**. Moreover, two hydrocarbon-rich gases (Rich Gases 1 and 2) were used in experiments to investigate the impact of IFT on oil recovery. The two gases were designed by adding intermediate components to methane, and a gas-oil IFT of 1.1 and 0.45 mN/m was achieved for Rich Gas 1 and Rich Gas 2, respectively.

Salt Component (ppm)	A	B	G
NaCl	27,900	49,898	48,667
$CaCl_2 \cdot 6H_20$	3,210	14,501	20,792
$MgCl_2 \cdot 6H_20$	950	3,248	1,368
Barium	0	0	0
Strontium	0	0	0
KCl	2,320	1,990	0
Na_2SO_4	2,260	234	373
$NaHCO_3$	74	162	180
Total dissolved solids	88,550	179,853	186,747

Table 3—Formation brine compositions used in coreflood experiments on Reservoirs A, B, and G.

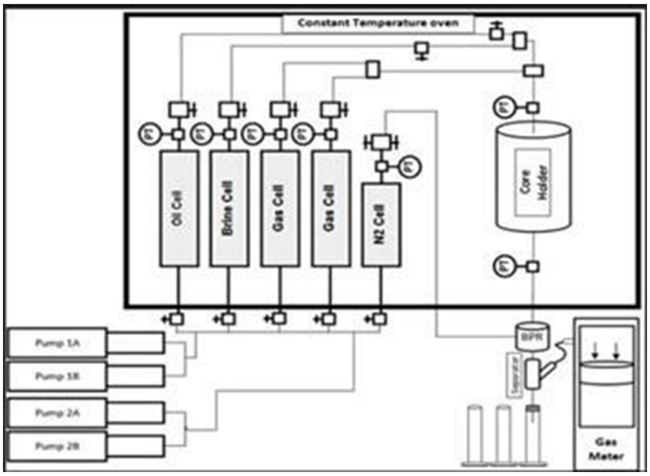

Fig. 1—Schematic of the coreflood rig.

	A	B	G
Component	Concentration (mol%)		
CO_2	5.10	6.13	0
C_1	58.91	66.5	100
C_2	12.37	12.19	0
C_3	9.81	7.59	0
i-C_4	2.41	1.49	0
n-C_4	5.11	2.64	0
i-C_5	1.10	0.87	0
n-C_5	2.60	0.85	0
C_6	1.44	0.69	0
C_7	0.73	0.98	0
C_8	0.29	0.05	0
C_9	0.13	0.02	0

Table 4—Composition of the produced gases of Reservoirs A and B used in this work.

Experimental Setup and Procedures

Experimental Setup. A sketch of the experimental setup is shown in **Fig. 1.** In the high-pressure coreflood rig used in this study, a temperature-controlled air oven is used to house the core holder, injection fluids, the backpressure regulator (BPR) lines, and connections at a constant temperature. The apparatus has three storage cells containing the injection fluids (i.e., crude oil, gas, and water). Two pairs of pumps are used to flow fluids around the flow system (core and bypass lines) and also to apply overburden pressure on the core and supply pressure to the BPR.

In the experiments reported here, the orientation of the core was vertical, and the overburden pressure was kept 500 psig above the pore pressure (pressure at BPR). To measure and record the differential pressure across the core, two very accurate pressure transducers are connected to the inlet and outlet of the core. A BPR is used to maintain the pressure of the core outlet and deliver the core effluent at atmospheric pressure. While running an experiment, the effluent from the BPR flows into a dual outlet separator, where the liquid would be collected in a graduated cylinder. A CO_2 analyzer was connected to the production line for detecting CO_2 and recognizing CO_2 breakthrough in the produced gas.

Experimental Procedure. The core samples were first cleaned under reservoir temperature and then dried in an oven at 40°C to evaporate any possible solvent that remained after cleaning. The next step was to weigh the core at room temperature. Then, the core was loaded into the core holder and vacuumed for approximately 24 hours to remove any air from the core pores. Helium and brine (FW) PV tests were carried out with an overburden pressure of 500 psi higher than the core pressure.

Brine permeability measurement was performed at room temperature and reservoir pressure. FW was used for this measurement. The net pressure was kept at 500 psi. FW was injected through the core in ascending multiple rates, while the pressure difference between the inlet and the outlet was recorded. Darcy's law for the laminar and linear flow was used for calculating the rock's brine permeability. The initial water saturation (S_{wi}) was established by injecting a series of mineral oils. Using mineral oil would prevent emulsification.

Parameter	A	B	G
GOR (std cm^3 gas/std cm^3 oil)	132.70	160.22	127.15
Oil viscosity (cp)	0.328	0.361	0.381
Water viscosity (cp)	0.35	0.404	0.39
CO_2 viscosity (cp)	0.046	0.051	0.047
C_1 viscosity (cp)	0.021	0.022	0.022
Formation volume factor (res cm^3/std cm^3)	1.45	1.55	1.28
Bubblepoint (psig)	2,430	2,507	4,800
Pressure (psig)	4,230	4,485	4,800
Temperature (°C)	121	121	133

Table 5—PVT properties of the recombined fluids (A, B, and G) used in these coreflood experiments.

Moreover, using viscous mineral oil helps to achieve the S_{wi}. After establishing S_{wi}, the viscous mineral oil was displaced sequentially with lighter mineral oils to reach a viscosity close to crude oil viscosity.

The core holder was moved into the oven, and crude oil was injected through the core. During the injection, the pressure in the core was increased to reservoir pressure as the net stress was kept at 500 psi. The temperature was increased gradually to corresponding reservoir temperatures. With a rate of 1 PV per week, the aging process was carried out for 4 weeks under reservoir conditions using dead crude oil.

Having prepared the live crude oil, the recombined fluid was transferred into the oven. Live crude oil was first injected through the bypass, BPR, and gas meter to measure GOR and formation volume factor (swelling factor). Subsequently, the live oil was pumped through the core for 4 PV until the GOR calculated from the core effluent had reached the initial value measured from the recombined oil through the bypass and PVT tests.

Experimental Results and Discussions

In this section, the experimental results are summarized and discussed. A series of immiscible and miscible gas injection coreflood experiments were performed using limestone reservoir cores under different injection strategies. To minimize laboratory artifacts, long cores were used in the experiments, and to observe the effect of gravity, both 2 in. and 4 in. diameters (whole core) were used. The experiments were performed under reservoir conditions using live crude oil. The core wettability was restored by aging the core in crude oil for 4 weeks under reservoir temperature. Hydrocarbon gas was used as the immiscible injectant, and CO_2 and a mixture of 50% C_1 and 50% CO_2 were used as miscible injectants. Moreover, to investigate the IFT impact on oil recovery, different enrichment of the hydrocarbon gas was used. All gas injection experiments were performed using vertically oriented cores and the gas was injected from the top unless it is stated otherwise.

Secondary Waterflood. Secondary waterflood was performed to establish the baseline for the subsequent gas injection experiments. The core was first 100% saturated with water, and then the initial oil and the irreducible water saturations were established. A waterflood was performed to determine and measure the residual oil saturation to water (S_{orw}) using different core samples from the three different reservoirs. For each experiment, the value of initial water, the composition of injection water and crude oil, and the core sample were all selected from the same reservoir. The waterflooding procedure is as follows:

1. Saturate the sample with 100% water.
2. Initialize the sample at S_{wi} of around 10%.
3. Age the sample for 4 weeks to restore wettability.
4. Start waterflooding with a low rate of 1 ft/D until no further oil is produced.
5. The waterflooding rate is then increased in steps to overcome the capillary end effect [see Masalmeh (2013)]. The injection rate started using a rate equivalent to 1 ft/D and increased by at least an order of magnitude in the subsequent steps.

Fig. 2 shows the waterflood results using fluids and core samples from Reservoirs A, B, and G. More oil was produced during the bump rates (where the injection rate was increased), especially in the core from Reservoir G, while the samples of lower permeability (Reservoirs A and B) did not produce much during the bump flood as capillary end effect is more dominant in the higher permeability samples. As shown in **Fig. 2** and **Table 7,** both Reservoirs A and B showed 10–15% higher oil recovery than Reservoir G. Moreover, water breakthrough was much earlier in Reservoir G than in A and B. Note that there is no correlation between basic rock properties (porosity and

	Reservoir A	Reservoir B	Reservoir G
Experimental pressure	4,230 psi	4,485 psi	4,800 psi
CO_2 MMP	2,850 psi	2,570 psi	4,800 psi
C_1 MMP	≈6,000 psi	>5,500 psi	>7,500 psi
50% C_1+ 50% CO_2 MMP	–	4,050 psi	–

Table 6—MMP values for CO_2 and C_1 with crude oils from Reservoirs A, B, and G.

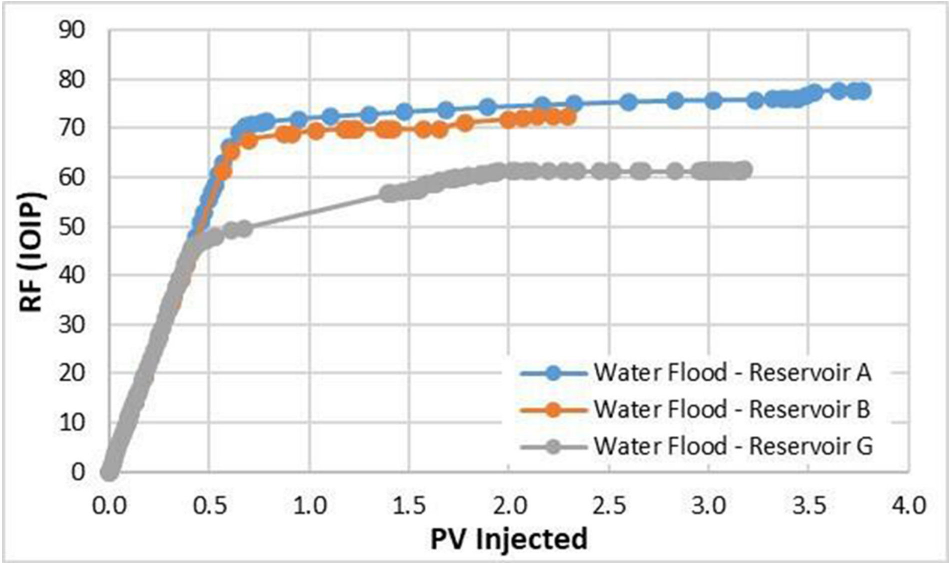

Fig. 2—Comparison of the oil recovery profile (IOIP%) of waterflood on different core samples from three different reservoirs. RF = recovery factor; IOIP = initial oil in place.

permeability) and the residual oil saturation. Reservoirs A and B have an order of magnitude lower permeability than Reservoir G and showed lower residual oil saturation.

Reservoir	S_{wi}	S_{orw}	k_{ro} at S_{wi}	k_{rw} at S_{orw}
A	0.10	0.20	0.789	0.141
B	0.12	0.25	0.881	0.305
G	0.11	0.34	0.556	0.362

Table 7—k_{ro} at S_{wi} and k_{rw} at S_{orw} of different waterflood experiments.

Both oil relative permeability endpoint [$k_{ro}(S_{wi})$] and the water relative permeability endpoint [$k_{rw}(S_{orw})$] are reported in **Table 7**. Note that the rock from the different reservoirs showed little or no water spontaneous imbibition; hence, the rock is nonwater-wet. However, from the production curve and the relative permeability endpoints, it seems Reservoir G is more oil-wet than Reservoirs A and B. Moreover, the core from Reservoir G is more heterogeneous than the cores from Reservoirs A and B. The combination of those two factors (wettability and heterogeneity) may have affected the residual oil saturation values measured on those samples. Further investigation is ongoing to understand the variation in the S_{or} data.

Effect of Miscibility on Oil Recovery for Both Continuous Gas Injection and WAG Flood. The primary objective of the experiments presented in this section is to study secondary gas injection performance, both miscible and immiscible, and compare it with that of the waterflood. The experiments were performed on core samples from two different reservoirs (Reservoirs B and G). Moreover, miscible and immiscible WAG experiments were also performed on the same core sample from both reservoirs. The experiments were performed in a vertical direction where gas was injected from the top of the core. The gas injection started with the aged core at similar initial oil and irreducible water saturations of the waterflood experiment. For the immiscible gas injection experiment, the injected gas was pre-equilibrated with oil to minimize mass transfer during the injection. The pre-equilibration process was performed at the same pressure and temperature as the experiment (4,800 psig and 133°C), and both gas and oil were separated after the process. As a result, there was a mass transfer between oil and gas and, therefore, a change in both compositions. However, both fluids were still immiscible as the pre-equilibrium pressure (4,800 psig) was well below the oil and methane MMP. Moreover, the results of the gas injection experiments, as will be discussed below, show that the oil recovery is still much lower than the miscible gas injection experiments. The fluid properties of both reservoirs are presented in **Table 5**. The MMP of the methane and CO_2 with the crude oils from both reservoirs is presented in **Table 6**. Moreover, the table also shows the pressure at which the laboratory experiments were performed.

The oil recovery during the immiscible (C_1) and miscible (CO_2) secondary gas injection experiments performed using rock and fluids from Reservoir G is shown in **Fig. 3.** For the immiscible gas injection experiment, gas injection from top to bottom was performed at the same injection rate of 20 cm^3/h, and it was continued for more than 4 PV at which the pressure drop curve was almost flat. The gas breakthrough took place after injecting 0.34 PV, significant oil production continued, and oil recovery increased to 47% after 4.5 PV. The experimental data show the poor performance of the secondary immiscible gas injection and high remaining oil to gas is evident.

Note that immiscible gas displacing oil experiments may suffer from experimental artifacts such as capillary end effect and viscous fingering. Gas has low viscosity and, therefore, high mobility which leads to an unfavorable mobility ratio during gas displacing oil experiments. Hence, viscous fingering is expected which leaves behind high remaining oil saturation. Moreover, for gas displacing oil experiments, gas is nonwetting and oil is strongly wetting to gas. Therefore, a strong end effect is expected, especially the pressure drop during these experiments is quite low due to the low gas viscosity. To minimize the capillary end effect, the experiments were performed using a 1-ft-long core. However, at the end of the first rate during the gas injection experiment, the pressure drop was 1.4 psi which is in

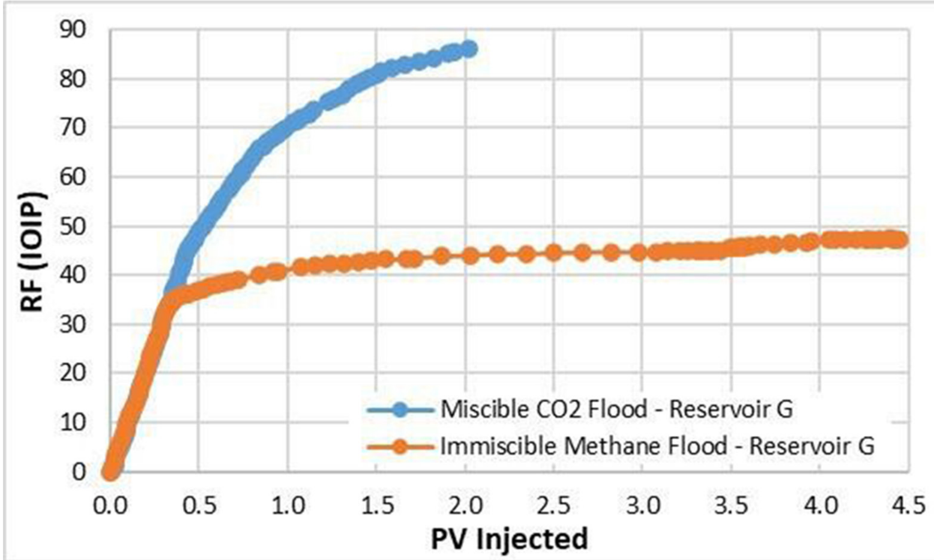

Fig. 3—Oil recovery (IOIP%) of miscible and immiscible secondary gas injection vs. PV of injected gas.

the same order as gas-oil capillary pressure. A bump rate was used to overcome the capillary end effect, where the gas injection rate was increased up to 100 cm^3/h. However, only 2.5% of extra oil was produced during the bump rates. The reason is that a well-established bath was formed during the low rate due to viscous fingering, and upon increasing the rate, the gas will still mainly flow through the fingers and bypass most of the oil. Therefore, oil recovery during immiscible gas displacing oil experiments may not be representative and leads to poor sweep efficiency even in 1D experiments.

As shown in **Fig. 3**, the oil recovery of the miscible gas injection was much higher compared to the immiscible gas injection experiment. As discussed by Shahrokhi et al. (2018), a close look at the GOR in this miscible experiment showed that CO_2 breakthrough took place after 0.48 PV. A significant oil volume was still recovered, and the recovery factor after 2 PV of gas injection was 86%. More oil could have been recovered if the gas injection continued. While a higher recovery factor is expected for miscible gas injection, the significant difference between the two experiments is partly due to the experimental artifacts that the immiscible gas injection experiment suffers from. The miscible gas injection experiment does not suffer from the experimental artifacts discussed above. The displacement is more stable (higher viscosity of CO_2 compared to C_1) and no capillary end effect due to the low gas-oil IFT during the miscible injection. Note also that while miscible gas injection had high recovery factor compared to immiscible gas injection, the remaining oil after injecting 2 PV of CO_2 was 12%, which is relatively high for miscible gas injection. This issue will be discussed later in this paper.

Following the secondary gas injection experiments, three cycles of WAG experiments were performed for both immiscible and miscible scenarios. The oil recovery curves of both experiments are shown in **Fig. 4.** The vertical dashed lines separate the injection of each injected slug. For the immiscible gas injection case, the first water injection experiment showed a steep and significant increase in recovery. This demonstrates that the oil left after the first immiscible gas injection cycle is not a trapped oil; it was bypassed due to an unfavorable mobility ratio and therefore water displaced that mobile oil. The remaining cycles produced only 4% extra and the total oil recovery was 67.5%.

For the miscible WAG experiments, the first water cycle produced about 3%, and the ultimate recovery at the end of the experiment is 92%. As demonstrated in **Fig. 4**, during miscible WAG experiments, most of the recovery took place in the first gas injection cycle, which is expected in 1D laboratory experiments.

Effect of Gas-Oil IFT on Oil Recovery. Laboratory immiscible gas displacing oil experiments suffer from the experimental artifacts discussed above. First, the displacement is unstable, which leads to viscous fingering and early gas breakthrough. Second, the gas is nonwetting and the displacement suffers from a strong capillary end effect. Both effects lead to low oil recovery as observed in **Figs. 3 and 4** discussed in the previous section. Increasing the gas injection rate does not help as it enhances viscous fingering and gas will flow through the established fingers. To minimize the end effect and improve the mobility ratio, five gas injection experiments using gases of different gas-oil IFT values were performed. The gas-oil IFT values of the different gases vary between 3.3 and 0.45 mN/m in addition to the miscible case where the gas-oil IFT is close to zero. The oil recovery curves of the different experiments are shown in **Fig. 5.** The main conclusions of these experiments are as follows:

1. As expected, the oil recovery increases with reducing IFT, and the highest oil recovery is achieved at miscible conditions. For more details on the effect of IFT on oil recovery and relative permeability curves, see Jahanbakhsh et al. (2016) and the references therein.
2. Reducing gas-oil IFT from 3.3 to 1.1 mN/m improved oil recovery by only 5%. This could be explained by reducing the capillary end effect, and the flow is still immiscible flow.
3. A big jump in recovery is observed once the gas-oil IFT is reduced from 1.1 to 0.45 mN/m. This big jump cannot be explained by reducing the end effect only as a reduction in the capillary pressure by a factor of two cannot explain such an increase in oil recovery. This shows that reducing gas-oil IFT to 0.45 mN/m changes the flow regime to near miscible and that contributes to the extra oil recovery observed in the experiment. Moreover, by enriching the gas, the gas mobility will reduce and that may lead to more stable displacement, which also improves oil recovery.
4. Regardless of the injected gas type, gas injection with similar gas-oil IFT achieved similar oil recovery. This can be shown by comparing the rich hydrocarbon gas injection of low IFT (0.45 mN/m) and the pre-equilibrated CO_2 injection where gas-oil IFT is 0.55 mN/m.

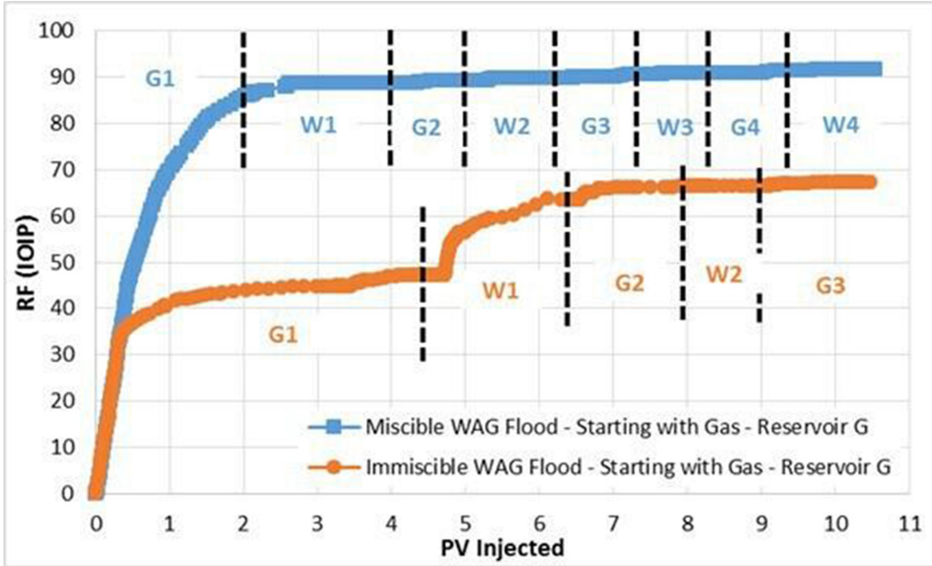

Fig. 4—Oil recovery (IOIP%) of miscible and immiscible WAG flood starting with gasflood vs. PV of injected fluids.

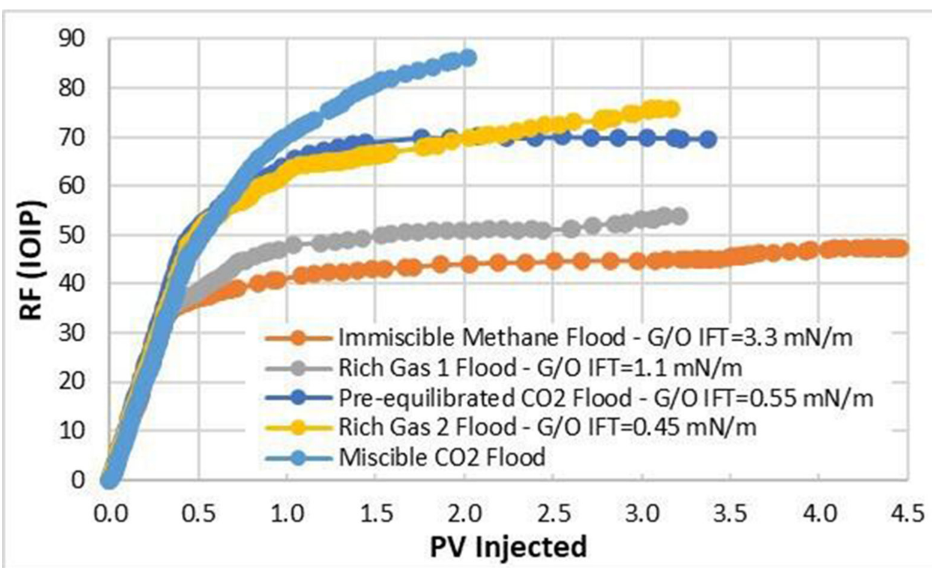

Fig. 5—Oil recovery (IOIP%) of secondary gasflood at different IFTs vs. PVs of injected gas.

5. The oil recovery of the immiscible gas injection is still affected by the experimental artifacts mentioned above. Therefore, the displacement efficiency measured in these experiments, except for the miscible case, may not be representative of field cases.

Effect of Gravity Segregation on Oil Recovery on Immiscible and Miscible Gas and WAG. Gas has high displacement efficiency; however, it suffers from poor sweep efficiency due to gravity segregation, channeling, and viscous fingering. Laboratory experiments are usually focused on displacement efficiency as they are 1D experiments. In this study, we performed two types of experiments to quantify how gravity segregation affects immiscible and miscible gas injection and WAG: (1) vertical and horizontal immiscible gas injection and WAG using 2-in.-diameter core samples from Reservoir G and (2) miscible gas injection on 2-in.- and 4-in.-diameter core samples from Reservoir A where the gas injection was performed in the horizontal direction. In addition, waterflood experiments were performed on the same 2-in.- and 4-in.-diameter core samples from Reservoir A to compare the impact of gravity on miscible gas injection and waterflood.

The results of both horizontal and vertical (gravity stable) gas and WAG injection experiments are compared in **Fig. 6.** The vertical dashed lines separate injection of each injected slug. The ultimate oil recovery of the vertical gas injection was about 10% higher than the horizontal gas injection. This shows that horizontal gas injection experiments suffer from gravity effects (i.e., override) and are not representative. The recovery factor of the secondary vertical gas injection experiment was less than 50%, which is too low and indicates that even vertical gas injection experiments may suffer from experimental artifacts, such as viscous fingering and capillary end effect, as discussed above. The ultimate recovery factor after WAG injection cycles of the vertical coreflood is about 8% higher than that of the horizontal coreflood, which shows that the WAG cycles could not mitigate the impact of gravity during the horizontal gas injection experiment.

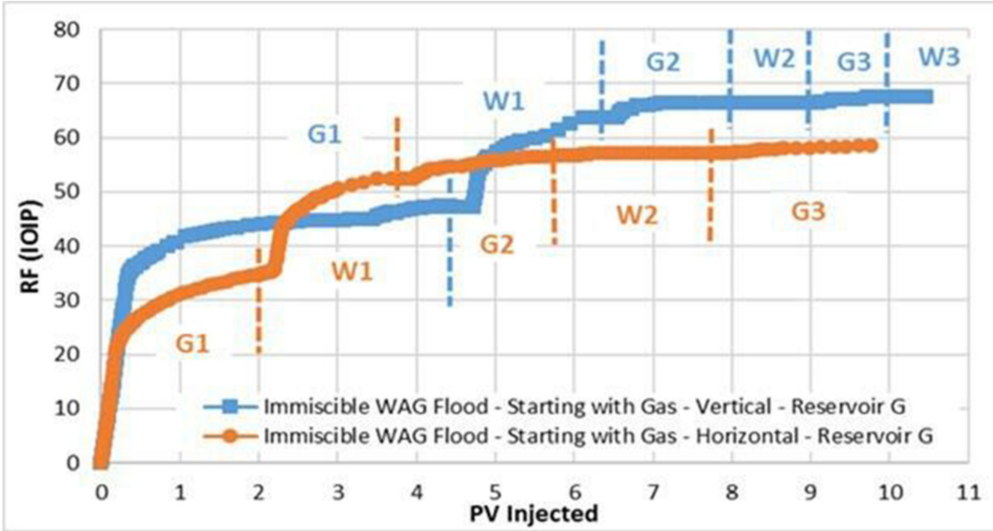

Fig. 6—Oil recovery (IOIP%) of immiscible secondary gas and WAG injection vs. PV injected for horizontal and vertical experiments.

The miscible gas injection and waterflood experiments performed using 2-in.- and 4-in.-diameter core samples are shown in **Fig. 7.** The experiments were performed using fluids and core samples from Reservoir A. The data indicate that the ultimate oil recovery of the miscible CO_2 injection is reduced by 14% when comparing the results of the 2-in.-diameter core with the 4-in.-diameter core. On the other hand, waterflood recovery is reduced by 4% only. This is within the spread in the data obtained from other coreflooding experiments performed on other core samples from this reservoir (see the waterflooding curve on core samples from Reservoir A in **Fig. 2**). The data demonstrate that even on the laboratory scale, the sweep efficiency of the miscible gas is significantly reduced when increasing the core diameter by a factor of two. Therefore, the problem will be more dominant on the reservoir scale, where the reservoir section can be up to 100 or 150 ft thick. In addition, the problem will become worse with increasing well spacing. Note also that these experiments are performed on low-permeability (1–2 md) samples, gravity override will increase for high-permeability reservoirs. Therefore, the results demonstrate that continuous gas injection on a reservoir scale will always need mobility control to improve sweep efficiency.

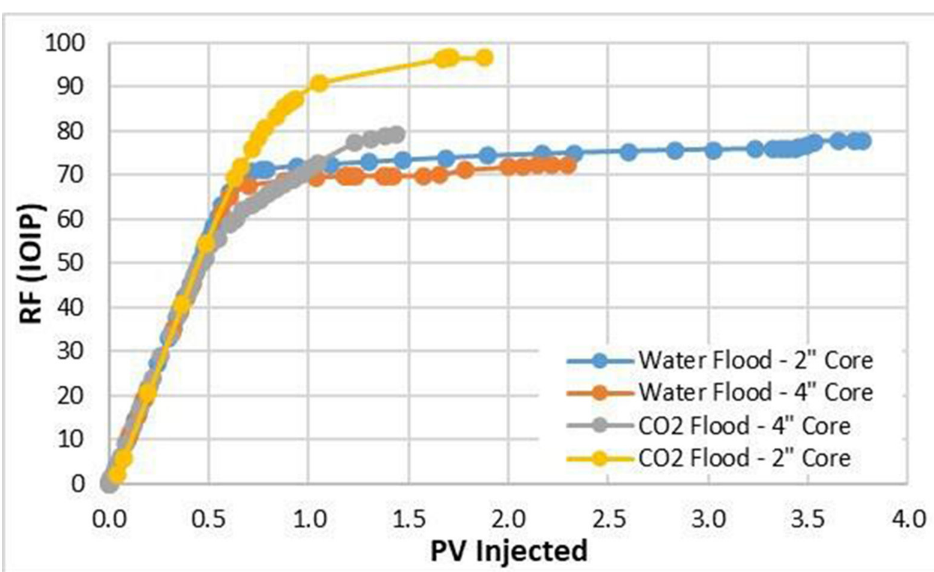

Fig. 7—Oil recovery (IOIP%) of miscible gas injection and waterflood vs. PV injected performed on 2-in.- and 4-in.diameter core samples.

A more detailed investigation of sweep efficiency of gas-based EOR should be performed by numerical simulation using properly calibrated models, and the results will be case-specific based on the interplay between gravity, heterogeneity, and fingering.

Effect of Crude Oil Composition on Oil Recovery by Gasflood. To investigate the impact of crude oil composition on the gasflood performance, two coreflood experiments were performed. In the first experiment, Crude Oil G was pre-equilibrated with methane, whereas in the second experiment, the intermediate components (C_6–C_{12}) of Crude Oil G were removed and then it was pre-equilibrated with methane. It is worthwhile to mention that the viscosities of the live crude oils were almost similar. As for the injection gas, methane was pre-equilibrated with crude oil to minimize mass transfer during the gasflood experiment. The results confirm that the higher gasflood performance was observed for the case of Crude Oil G with the intermediate components compared to the case where the intermediate components were removed **(Fig. 8).** The significant increase in the oil recovery performance for the crude oil with the intermediate components could be attributed to the lower IFT between this crude oil and the injected gas, as the effect of intermediate components has an enormous impact on the gas/oil IFT and hence the performance of gasflood. This result would be important when reinjection of gas is considered.

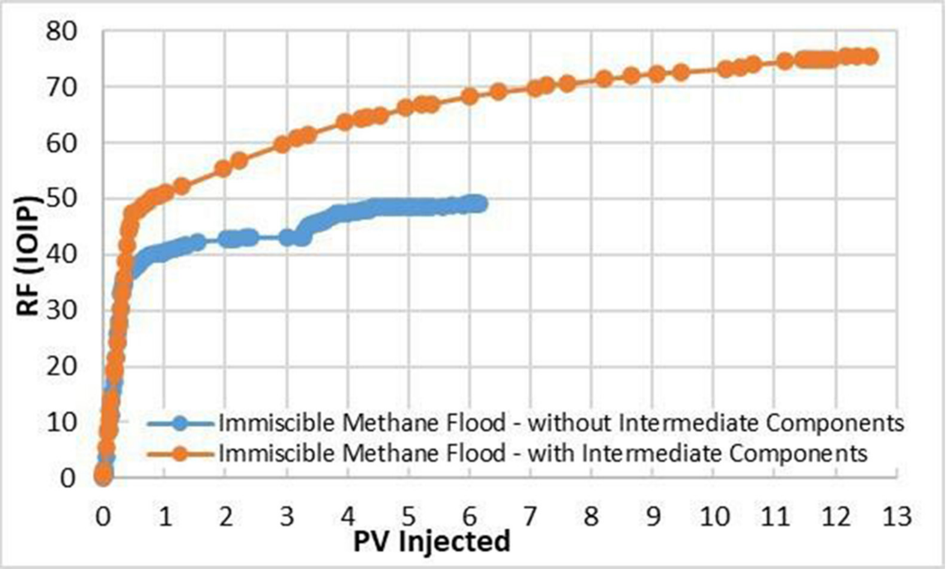

Fig. 8—Oil recovery (IOIP%) of secondary gasflood with the different levels of intermediate components in the crude oil vs. PV of injected gas.

Effect of Injection Pressure on Oil Recovery by Immiscible and Miscible Gasfloods. To investigate the impact of injection pressure on the performance of the immiscible gasflood, methane injections were compared for the cases of Reservoirs G and B. The results indicate that a higher oil recovery by injecting C_1 is observed in Reservoir B compared to Reservoir G **(Fig. 9).** This is because of much higher C_1 MMP for Reservoir G (see **Table 6**). In other words, the injection pressure is closer to the C_1 MMP in Reservoir B. The ultimate oil recovery of the methane flood in the Reservoir B experiment was about 20% higher than methane injection in the Reservoir G experiment. This shows that the immiscible gas injection in Reservoir G experiments suffers from an unproductive vaporization mechanism due to the greater gap between the injection pressure and C_1 MMP. Therefore, as the injection pressure increases, the ultimate oil recovery of the immiscible gas would increase. However, the optimal injection pressure should take the pressure of formation fracture and the economic value of the project into account.

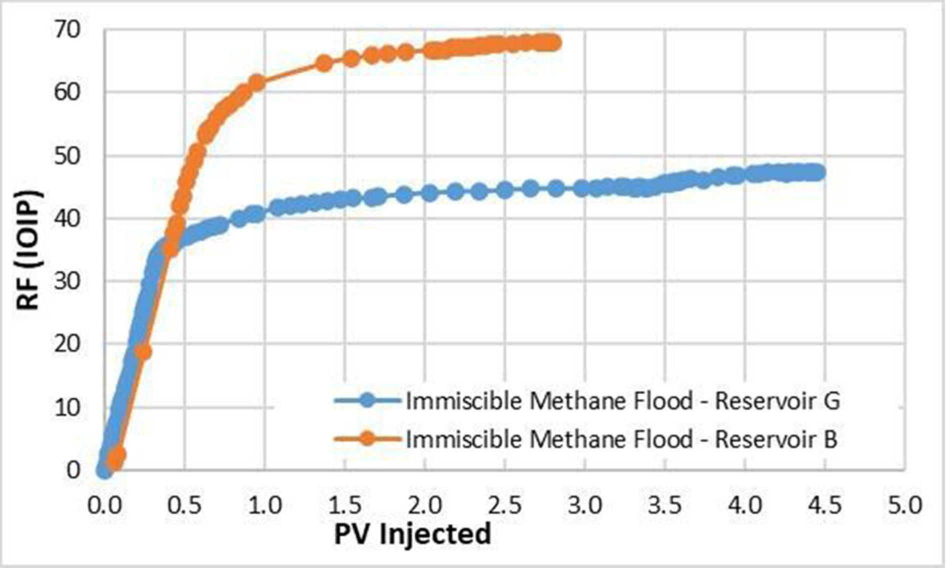

Fig. 9—Oil recovery (IOIP%) comparison of immiscible gasflood under the conditions of Reservoirs B and G vs. PV of injected gas.

For the miscible gas injection, three different experiments were performed:

1. Miscible CO_2 injection using Reservoir B core and crude oil samples.
2. Miscible CO_2 injection using Reservoir G core and crude oil samples.

3. Miscible mixture of 50% C_1 and 50% CO_2 injection using Reservoir B core and crude oil samples.

The MMP and the reservoir pressure of the three different experiments are shown in **Table 6**.

In the case of miscible CO_2 injection, a higher oil recovery was observed in Reservoir B compared to the similar injection scenario (CO_2 injection) in Reservoir G **(Fig. 10).** Comparable to the immiscible gas injection process, much higher CO_2 MMP was measured for Reservoir G, and consequently, the closer injection pressure to MMP (for Reservoir G) resulted in lower oil recovery by CO_2 injection compared to Reservoir B. Comparing the experiments performed on Reservoir B, although both experiments are performed under miscible conditions, the oil recovery of the CO_2 injection is higher than that of the 50% C_1 and 50% CO_2 mixture. The oil saturation at the end of the three experiments (after 2 PV injection) was 2%, 12%, and 11%, respectively. This shows that the S_{orm} (residual oil saturation to miscible gas) is strongly dependent on the difference between MMP and reservoir pressure (i.e., S_{orm} increases as the difference between P_{res} and MMP decreases). This is in line with the conclusion of Shyeh-Yung (1991) who reported that residual oil saturation to CO_2 flood (S_{orm}) decreases linearly as pressure increases. A similar conclusion was also presented by Lange (1998), where S_{orm} decreases as the pressure increases.

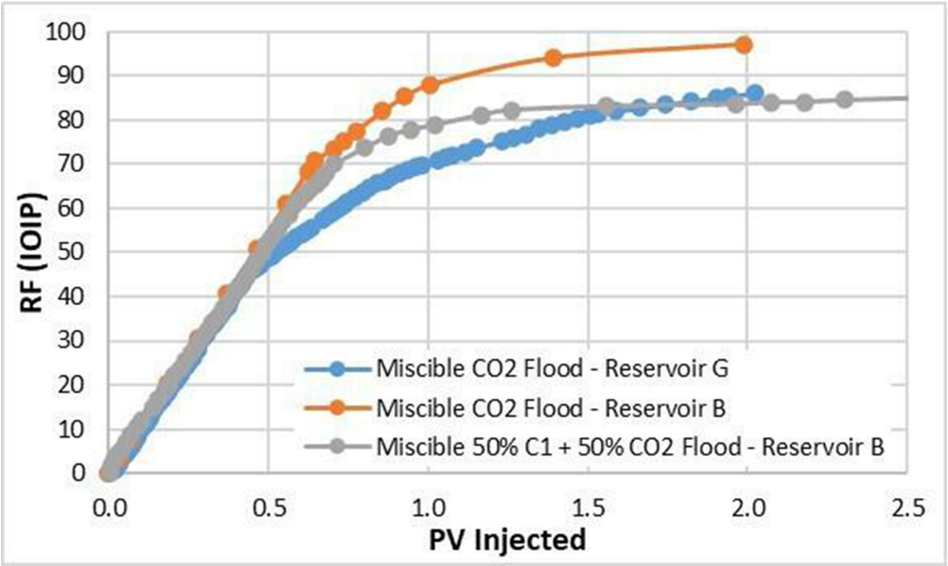

Fig. 10—Oil recovery (IOIP%) comparison of three miscible gas injection experiments under the conditions of Reservoirs B and G vs. PV of injected gas.

Impact of CO_2 Cycle Size on Oil Recovery. As demonstrated above, the miscible gas injection has high displacement efficiency but poorer sweep efficiency. CO_2 injection is the most frequently used gas injection EOR process. CO_2 cost is one of the most critical parameters affecting the economics of CO_2 injection EOR projects. Improving the utilization factor of CO_2 will improve the commerciality of the CO_2 projects. In this section, we investigated the impact of the CO_2 cycle length on the oil recovery in 2-in.-diameter vertical core experiments. **Fig. 11** compares the oil recovery factor of five different experiments using rock and fluids from Reservoir B:

1. Continuous CO_2 injection.
2. Waterflood.
3. 0.2 PV CO_2 injection followed by water flooding.
4. 0.4 PV CO_2 injection followed by waterflooding.
5. 0.6 PV CO_2 injection followed by waterflooding.

The main objective of these experiments is to investigate whether a short slug of CO_2 followed by waterflood would lead to the same or comparable displacement efficiency as continuous CO_2 injection. This could be the case if water will push the CO_2 slug, which will displace the oil. The main observations from **Fig. 11** are as follows:

1. Continuous CO_2 injection has the highest recovery factor (RF = 97%), i.e., the highest displacement efficiency.
2. The recovery factor of waterflood is 72%.
3. The shorter the CO_2 slug is, the lower the ultimate recovery after the waterflood cycle.
   a. The recovery factor of the 0.2 PV of CO_2 followed by waterflooding is the same as waterflood, which is 72%.
   b. The recovery factor of the 0.4 PV of CO_2 followed by waterflooding is 79%; this shows a 7% increase on top of the waterflood case.
   c. The recovery factor of the 0.6 PV of CO_2 is 85%, which is 13% on top of the waterflood.
   d. Comparing the five experiments at 1 PV of injected fluid shows that the recovery factor is 90% for continuous CO_2, 79% for both 0.4 and 0.6 PV of CO_2 injection, and 70% for both 0.2 PV of CO_2 injection and waterflood.

The above shows that the ultimate recovery increases as the CO_2 slug increases. However, this only demonstrates that the displacement efficiency is adversely affected by shorter CO_2 slug. Proper assessment of sweep efficiency can only be done by reservoir simulation using fine-grid models. While shorter CO_2 slugs adversely affect displacement efficiency, longer CO_2 slugs may adversely affect sweep efficiency (i.e., CO_2 will override due to gravity effects). The optimal CO_2 slug length should consider the sweep efficiency and economic value of the project.

Impact of Immiscible Gas Injection on Subsequent Miscible Gas Injection. Gas-based EOR is an important part of ADNOC EOR ongoing and future plans. Some of the reservoirs that are planned to be developed by miscible gas injection (continuous gas or WAG) are currently developed by immiscible gas injection. Moreover, during miscible gas injection in the reservoir, hydrocarbon gas may come out of the solution if the reservoir pressure is not maintained above saturation pressure. Therefore, it is crucial to investigate the impact of immiscible gas injection on subsequent miscible gas injection. **Fig. 12** compares the ultimate oil recovery of five different experiments:

1. Continuous CO_2 injection.
2. Continuous C_1 injection (2.8 PV) followed by CO_2 injection.
3. 0.2 PV C_1 injection followed by CO_2 injection.
4. 0.4 PV C_1 injection followed by CO_2 injection.
5. 0.6 PV C_1 injection followed by CO_2 injection.

The data in **Fig. 12** show that the ultimate oil recovery is reduced from 97% for continuous CO_2 injection to 86%, 85%, 83%, and 81% for injecting 0.2 PV of C_1, 0.4 PV of C_1, 0.6 PV of C_1, and 3 PV of C_1, respectively. The data demonstrate that the displacement efficiency of CO_2 injection is significantly reduced by a small slug of methane. The immiscible slug has two negative effects on the subsequent miscible gas injection. First, the miscible gas is first contact miscible with methane and hence will follow the same flow path as methane (i.e., the immiscible gas will create a flow path for the subsequent miscible gas). Second, the presence of the immiscible gas in the porous medium will increase the miscibility pressure of the new mixture (methane and CO_2). Both effects will lead to reducing the displacement efficiency of the subsequent CO_2 injection and lead to lower ultimate oil recovery. Therefore, it is not recommended to have immiscible gas injection in reservoirs where a miscible gas injection is planned. Moreover, gas coming out of the solution will have the same negative impact on miscible gas injection. In short, in any miscible gas injection development, it is important to maintain the reservoir pressure above saturation pressure.

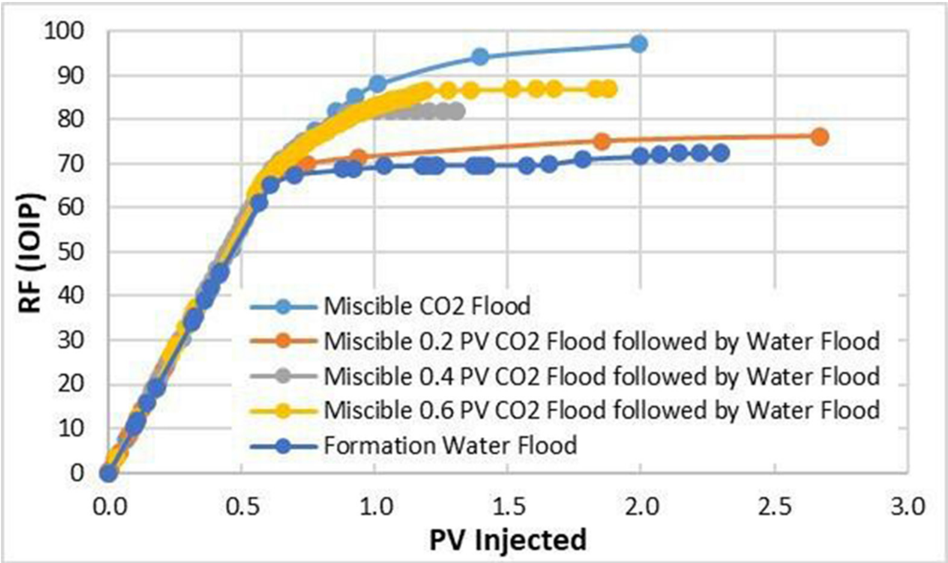

Fig. 11—Oil recovery (IOIP%) of five different CO_2 and waterflood experiments vs. PV injected (see text in the paragraph above for a description of the various experiments).

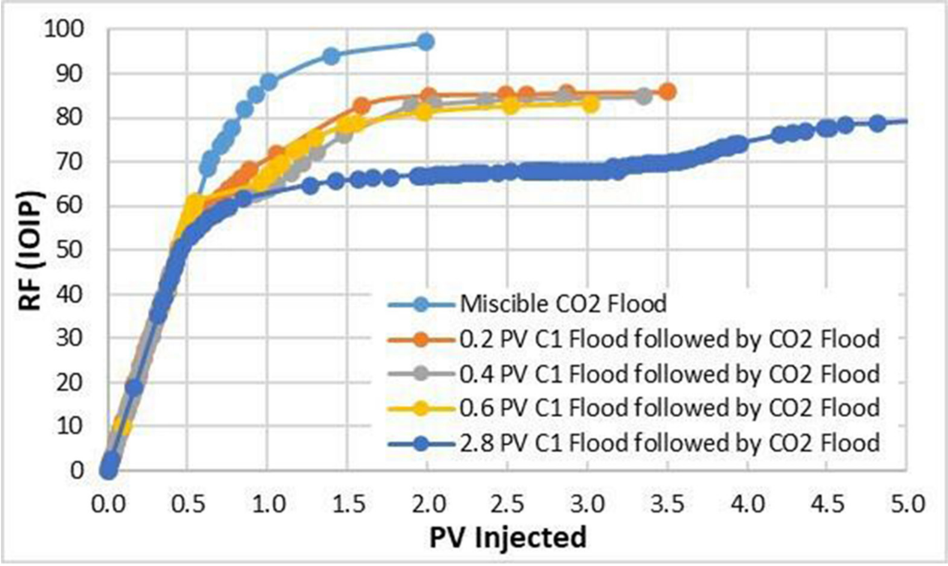

Fig. 12—Oil recovery (IOIP%) of five different C_1 followed by CO_2 injection experiments vs. PV injected (see text in the paragraph above for a description of the different experiments).

One more experiment was also performed; a mixture of 50% C_1 and 50% CO_2 was injected in the same core, and using the same reservoir fluids, the recovery factor is shown in **Fig. 13.** The ultimate recovery is 87%, which is similar to the experiments with the slug of 0.2 PV C_1 injection. This indicates that using the same volume of immiscible gas in a mixture with CO_2 is much more efficient than performing a sequence of immiscible gas followed by CO_2 injection. The slug of immiscible gas will establish the flow path and hence adversely affect the subsequent miscible gas injection. However, injecting a mixture of C_1 and CO_2 does not suffer from such an effect and leads to better displacement and sweep efficiency. The main conclusion of this section is that immiscible gas injection has a negative impact on subsequent miscible gas injection, even if the immiscible gas slug is very short. Injecting a mixture of miscible gas with immiscible gas is better than injecting a slug of immiscible gas, followed by miscible gas. Comparing the results of the six experiments presented in **Figs. 12 and 13** at 1 PV injected shows that the recovery factor is 90%, 80%, 69%, 62%, 61%, and 61% for the continuous CO_2, continuous 50% C_1 and 50% CO_2, 0.2 PV C_1 then CO_2, 0.4 PV C_1 then CO_2, 0.6 PV C_1 then CO_2, and continuous C_1 injection, respectively.

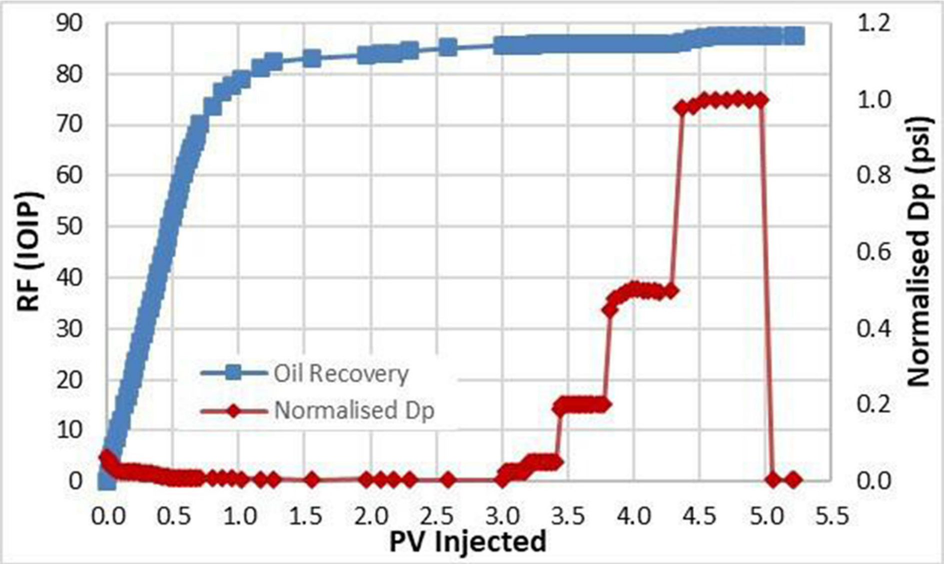

Fig. 13—Oil recovery (IOIP) of miscible secondary gas injection (50% C_1 and 50% CO_2) and pressure drop vs. PV of injected gas.

Oil Recovery by Immiscible and Miscible WAG Injection Scenarios (Effect of Injection History). WAG starting with waterflood (WAG_W) and WAG starting with gas injection (WAG_G) experiments were performed to study the effect of saturation history on immiscible and miscible gas injection scenarios in mixed-wet carbonate rocks. Injection of each WAG slug continued until oil production was almost zero. Two different reservoirs have been used in this part of the study (Reservoirs B and G) where the immiscible gas is methane, and the miscible injectant is CO_2. We have also used another miscible injectant for Reservoir B, which is a mixture of 50% C_1 and 50% CO_2.

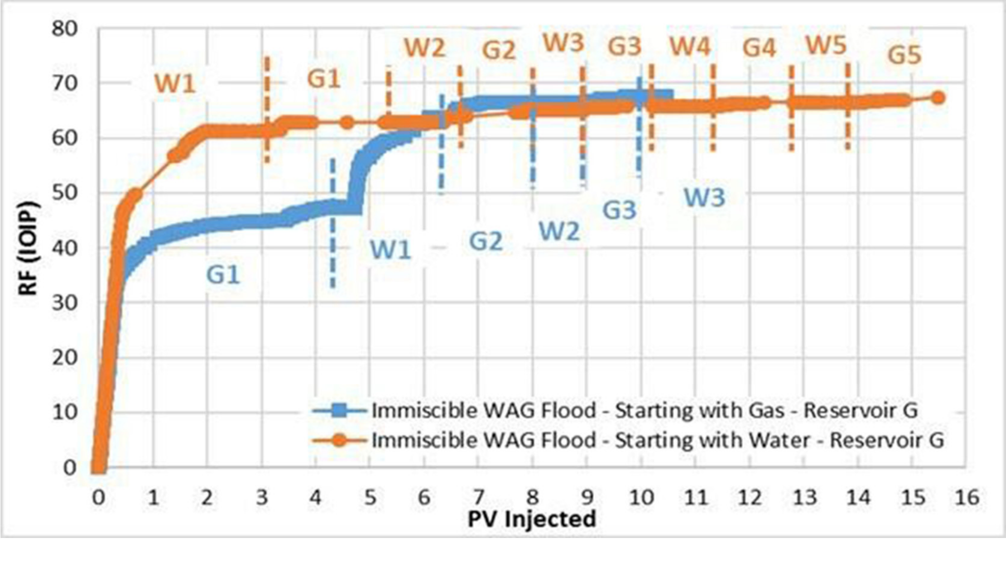

Fig. 14—Oil recovery (IOIP%) of immiscible WAG experiments after gas injection (WAG_G) and waterflood (WAG_W) vs. PV injected.

Oil Recovery by Immiscible and Miscible WAG Injection Scenarios (Effect of Injection History) for Reservoir G. Fig. 14 compares the oil recovery profile of two immiscible WAG experiments (WAG_W and WAG_G) for Reservoir G. The MMP of CO_2 and C_1 with the reservoir fluid is provided in **Table 6**. After 10 PV of alternate water and gas injection, WAG_W experiment shows similar oil recovery compared to the WAG_G experiment. The oil was mainly recovered within the first gas and water cycles (or water and gas cycles), and the additional recovery for further alternate slug injection was only 5% regardless of saturation history. WAG-G (WAG starting with gas injection) shows that during the first gas injection cycle, the oil recovery is 47% only and increased to 62% after the water injection cycle. It is important to notice that except for the first water injection after the secondary gas injection where the remaining oil saturation was high, no oil was produced during water injection periods. The alternation of water and gas in the subsequent cycles mobilized residual oil to gas by forming new gas flow paths in the core; however, the extra recovery was limited (5%).

The effect of injection history on miscible WAG injection in mixed-wet carbonates was studied by performing similar WAG injection scenarios using CO_2 as an injectant and the same reservoir fluids and core samples as those used in the immiscible WAG experiments presented above. Injection of each WAG slug continued until oil production was almost zero.

Fig. 15 compares the oil recovery of the miscible WAG injection scenarios. As demonstrated in the figure, the ultimate oil recovery in both cases (WAG_G or WAG_W) is the same, 92%. Note that in the WAG_G scenario, most of the oil is recovered during the first gas injection cycle, which is expected for miscible gas injection. On the other hand, for the WAG_W scenario, the miscible CO_2 injection recovered 30% more oil than waterflood (i.e., injection of the first gas slug significantly decreased S_{orw}).

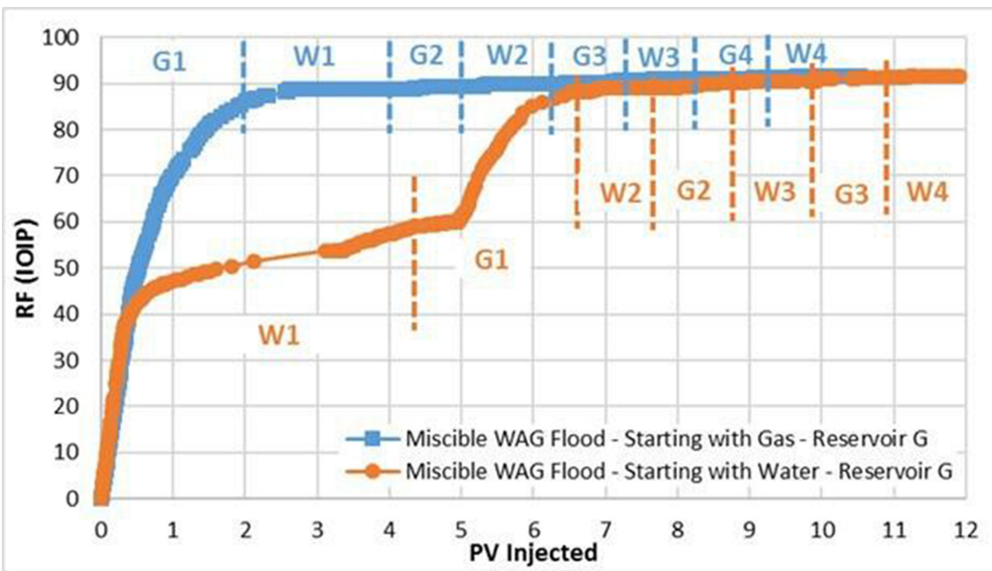

Fig. 15—Oil recovery (IOIP%) of miscible WAG experiments after gas injection (WAG_G) and waterflood (WAG_W) vs. PV injected.

The results of both miscible and immiscible experiments for this reservoir showed that water shielding is negligible. As already documented in the literature (Holm 1986; Shyeh-Yung 1991; Stern 1991; Rao et al. 1992; Yeh et al. 1992), for mixed- to oil-wet rocks, water shielding (or blocking) has a much lower effect on oil recovery compared to that for water-wet rocks. This is due to the continuity of the oil layers through the core in a more oil-wet system. The last two cycles of both WAG injections produced only 2% additional oil. Similar to immiscible WAG injection, no significant oil recovery was observed during water injection periods.

Oil Recovery by Miscible Gas Injection Scenarios (Effect of Injection History) for Reservoir B Using Two Different Miscible Gases (CO_2 and a Mixture of 50% C_1 and 50% CO_2). Similar to the experiments discussed in the above sections, the effect of injection history was investigated for miscible gas injection scenarios in mixed-wet carbonate using fluids and core material from Reservoir B. The miscible injectants were CO_2 and a mixture of 50% C_1 and 50% CO_2. Injection of each WAG slug continued until oil production was almost zero.

Fig. 16 compares the oil recovery profile of different gas injection scenarios for the 50% C_1 and 50% CO_2 mixture. As demonstrated in the figure, the ultimate oil recovery in both cases (WAG_G or WAG_W) is 88% and 85%, respectively. As expected in the WAG_G scenario, most of the oil is recovered during the first gas injection cycle. However, for the WAG_W scenario, the miscible injectant recovered 14% more oil than waterflood (i.e., injection of the first gas slug significantly decreased S_{orw}). Similar to the two cases presented in **Figs. 14 and 15**, no significant oil recovery was observed during subsequent water injection cycles, and most of the oil recovery was obtained during the first two cycles.

As shown in the figure, the WAG_G recovered 3% more oil than the WAG_W scenario, and this could be due to water shielding. The sample used in these experiments is not water-wet, as we did not see any water spontaneous imbibition; however, very little oil is recovered during waterflood after water breakthrough. This is different from the case of Reservoir G, where about 15% of oil in place was recovered after water breakthrough. Moreover, the ratio of the water to oil relative permeability endpoint for Reservoirs B and G is 0.34 and 0.65, respectively. This demonstrates that Reservoir G is more oil-wet and hence no or less water shielding is expected, while some water shielding is possible for Reservoir B.

Fig. 17 shows the data of the miscible CO_2 gas injection case. Note that we only show a continuous gas injection case and WAG_G case. The CO_2 injection case recovered 97% of the oil in place, so there was no space to perform any water injection cycles as the residual oil was only 2%. For the WAG_W scenario, the waterflood cycle recovered 71%, and the miscible gas (CO_2) cycle increased the recovery factor to 90%. The continuous gas injection scenario recovered 7% more of oil in place compared to the WAG_W scenario. This

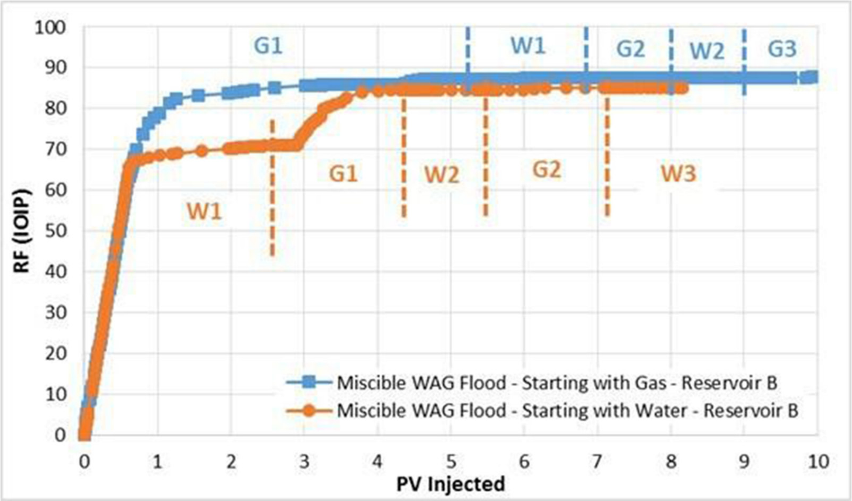

Fig. 16—Oil recovery (IOIP%) of miscible WAG experiments after gas injection (WAG_G) and waterflood (WAG_W) vs. PV injected.

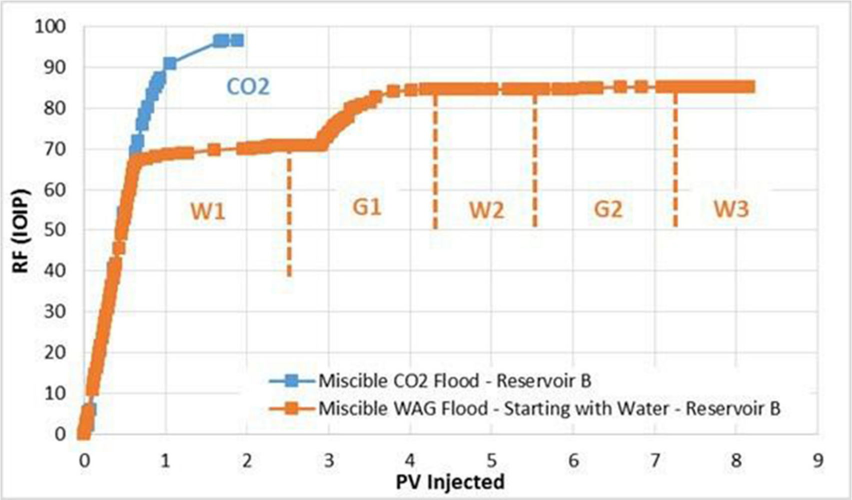

Fig. 17—Oil recovery (IOIP%) of miscible WAG experiments after gas injection (WAG_G) and waterflood (WAG_W) vs. PV injected.

demonstrates that for this reservoir, some water shielding is observed and it is more significant for the miscible CO_2 gas injection than the miscible 50% C_1 and 50% CO_2 mixture case.

Conclusions

In this paper, we presented the results of a series of coreflood experiments in mixed to oil-wet carbonate rock. The corefloods were performed to investigate and understand the displacement efficiency of gas injection under different injection scenarios for immiscible and miscible cases. Based on the results, the following conclusions can be drawn:

- The performance of waterflood experiments on mixed-wet carbonate reservoir rock showed significant variation in residual oil saturation. More investigation is required to understand the results.
- The performance of waterflood in the laboratory is significantly higher than immiscible gas injection in mixed-wet carbonates. However, laboratory immiscible gas injection experiments are affected by experimental artifacts such as adverse mobility ratio and capillary end effects, which are difficult to mitigate for gas injection experiments.
- Immiscible WAG injection after gas injection does reduce the residual oil saturation below residual oil saturation to waterflood for Reservoir G.
- During WAG experiments, starting the injection cycles with water or gas did not have any impact on the ultimate oil recovery for both miscible and immiscible scenarios for Reservoir G, so no water shielding is observed. However, miscible WAG_G (WAG starting with gas injection) recovered more oil for Reservoir B. This could be due to water shielding.
- As expected, the oil recovery increases with reducing IFT, and the highest oil recovery is achieved at miscible conditions.
- The experiments performed with different gas-oil IFT values show that at an IFT of 1.1 mN/m, the flow is still immiscible. However, the flow was near miscible for the experiments performed using a gas-oil IFT of 0.55–0.45 mN/m, with enhancement of oil recovery.
- Regardless of the injected gas type, gas injection with similar gas-oil IFT achieved similar oil recovery. This can be shown by comparing the rich hydrocarbon gas injection of low IFT (0.45 mN/m) and the pre-equilibrated CO_2 injection where gas-oil IFT is 0.55 mN/m.
- As expected, miscibility has a significant impact on displacement efficiency and oil recovery. However, a considerable variation in oil recovery is observed (i.e., about 10 saturation units difference) depending on the oil properties, even when both experiments are

performed at miscible conditions using the same injected gas. This is demonstrated by comparing CO_2 injection experiments in **Figs. 3 and 7** or **Fig. 10**.

- The performance of tertiary CO_2 flood was adversely affected by the slug of immiscible gas injected. The displacement efficiency was reduced by up to 15 saturation units, depending on the length of the immiscible gas slug.
- Gravity has a significant impact on oil recovery for both miscible and immiscible gas injections. A significant difference is observed in oil recovery when comparing CO_2 injection on 2-in.- and 4-in.-diameter core samples or when comparing horizontal vs. vertical immiscible gas injection and WAG experiments. This demonstrates that gas-based EOR will require mobility control to improve sweep efficiency and the gravity effect will be significantly higher on the reservoir scale.
- The longer the CO_2 slug size, the higher the oil recovery observed in gas injection experiments.
- In miscible gas (CO_2) slug injection experiments followed by waterflood, the shorter the CO_2 slug is, the lower the ultimate recovery will be. Injecting a short CO_2, such as 0.2 PV or lower, had no positive impact on oil recovery after the waterflood cycle compared to secondary waterflood. Therefore, in WAG development starting with gas injection, a longer gas injection cycle could be beneficial.
- However, the above conclusion only demonstrates that the displacement efficiency is adversely affected by shorter CO_2 slug. Proper assessment of sweep efficiency can only be done by reservoir simulation using fine-grid models. While shorter CO_2 slugs adversely affect displacement efficiency, longer CO_2 slugs may adversely affect sweep efficiency (i.e., CO_2 will override due to gravity effects). The optimal CO_2 slug length should take into account the sweep efficiency and economic value of the project.

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