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Assessing the effects of CO_2/methane mixtures on gas-oil interfacial tension and fluid flow using compositional simulation

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Abstract
In CO_2-enhanced oil recovery (CO_2EOR) processes, the gas-oil interfacial tension (IFT) affects rock wettability, capillary pressure, relative permeability, oil flow, and oil recovery (OR) factor. Thus, IFT is a key property when addressing the flow assurance issues in CO_2EOR processes. Usually, methane-rich gases mix with CO_2 for injection. Although the literature reports some studies about the effect of methane concentration on the properties of CO_2-oil systems, investigation of this effect on IFT and fluid flow still lacks, which is the primary motivation for the present work. Compositional simulations were carried out for different scenarios with varying methane concentration, pressure, and flow rate focused on the variation of these properties with IFT. The results show how the methane content alters the CO_2 dissolution in oil, the light hydrocarbons extraction from the oil, the reservoir pressure, the phase densities, the oil saturation, the gas-oil IFT, and the OR factor. At the beginning of the process, an optimal methane concentration provides the maximum OR. However, the EOR process achieves the highest recovery in the long term by injecting only CO_2.

Keywords
CO_2EOR; interfacial tension; reservoir simulation

Introduction
Among the EOR techniques, the CO_2 injection (CO_2EOR) is one of the most established and used worldwide. This technique reduces oil viscosity and the CO_2-oil interfacial tension, increases oil swelling, oil mobility, oil extraction, sweep efficiency, and the maintenance of the high internal reservoir pressure [1–7], in addition to an associated low cost [8]. These factors together generate a high displacement efficiency and decrease residual oil volume, thus improving the oil flow and recovery factor. Although it is not within the scope of this work, the asphaltene and wax precipitation phenomena, as well as hydrate formation, dramatically affect the flow assurance in CO_2 injection processes [9] and should be appropriately addressed.
Injecting gases such as methane and nitrogen for EOR purposes does not provide the same positive effects as injecting CO_2 because these gases have a much lower solubility in oil [10]. Therefore, it is preferable to use CO_2 as the injection gas. Moreover, CO_2 injection is quite beneficial for the environment since keeping it in the reinjection cycle and storing it in the reservoir mitigates greenhouse gas emissions. It is also helpful in the case of Brazilian pre-salt reservoirs, which naturally have a high-CO_2 content, reaching 40% (mol) in the produced gas [11,12].
CO_2 injection into the reservoirs maximizes the advantageous effects of the gas dissolution into the oil, such as the CO_2-oil interfacial tension reduction and the increase of the capillary number (N_c). On the other hand, the high CO_2 dissolution in oil leads to asphaltene precipitation. From the flow assurance point of view, a trade-off between oil displacement and asphaltene precipitation due to CO_2 dissolution requires the technical and economic assessment of the process.
In practice, the injected CO_2 often mixes with various components due to the different sources of the injection gas, such as light hydrocarbons, sulfur, and nitrogen compounds, which affect the performance of the injection process. As the purification of the CO_2 streams is quite expensive, the injection of CO_2 mixed with some other components leads to a significant cost reduction in the CO_2EOR processes [13]. Among these components, methane gas is a product of primary, secondary and tertiary oil extraction processes and can be used as a reinjection gas for EOR. Therefore, the present work aims to assess the effects of CO_2/methane mixtures on interfacial tension and fluid flow. It is imperative to understand the effects of these mixtures' composition on the performance of the EOR process to determine whether CO_2 injection with methane removal is appropriate, ensuring the fluid flow inside the reservoir [14].

In the literature, to our knowledge, no work compares the injection of CO_2 with and without methane, analyzing the impact of the methane content on the system's properties, especially on the gas-oil IFT and on the oil recovery factor. Cho et al. (2020) [15] performed a similar analysis for the cycles of a water alternating gas (WAG) process but not for a gas-only injection. Jin et al. (2017) [14] also assessed a WAG process without evaluating the effects of the systems' properties. The experimental measurements of IFT reported in the literature and the studies about the impact of this property on the gas-oil system generally consider only motionless systems typical of the experimental setups. The present work assesses these issues, considering the IFT effects on the oil flow inside the reservoir, which is novel in the literature, aiming for a more representative description of the CO_2EOR process.

The main objective of this work is to evaluate, using compositional simulation, the effect of the methane content on the CO_2-oil IFT, the fluid flow issues, and the oil recovery factor. A series of simulations were carried out considering different methane concentrations in the injection gas, ranging from 0 to 50% molar of methane in a mixture with CO_2. In addition, other injection conditions were tested, such as gas injection at constant pressure, considering pressure values above and below the experimental minimum miscibility pressure (MMP), and gas injection at a constant flow rate. These different conditions were chosen because, for injection below the MMP, phenomena like fingering and gas breakthrough influence the process [16]. For each simulation, the behavior of various properties of the gas-oil system, along with the flow, is compared, such as density, pressure, phase composition, oil saturation, IFT, and oil recovery. The focus is on how the variation of these properties affects the IFT and which mechanisms are involved. This assessment is quite necessary due to the role of IFT on fluid displacement in a porous medium and its intimate relationship with the properties of the CO_2-oil system, besides the flow assurance issues.

Methodology

In the present work, EOR simulation by injecting CO_2 and different mixtures of CO_2 and methane was performed using the Builder, WinProp, and GEM packages, developed by the Computer Modelling Group (CMG). The oil data were taken from Sequeira et al. (2008) [17], and the reservoir model from Killough et al. (1987) [18] was used for the simulations. No other work in the literature reports both PVT and CO_2-oil IFT data, which is the property of major interest in the present work.

The PVT characterization of the oil was carried out using experimental data of saturation pressure, separator test, constant composition expansion, differential liberation, swelling test, and MMP, all provided by Sequeira et al. (2008) [17] for CO_2-oil systems using the WinProp 2019.1 module. The Peng-Robinson equation of state described the liquid and gas phases. The numerical grid and the gas injection conditions were defined using the Builder package. The grid used to describe the reservoir has 7:7:3 dimensions. The injector and producer wells were positioned in blocks (1, 1, 3) and (7, 7, 1), respectively, so there is the most significant possible distance between them.

GEM calculates the CO_2-oil IFT using the Parachor method, where the equation developed by Firoozabadi et al. (1988) [19] allows calculating the Parachor parameter of the system's pseudo components. However, Nobakht et al. (2008) [20] analyzed the Parachor method and pointed out the difficulty of using it for multicomponent mixtures, as in the case of the gas-oil system. It is due to a need to calculate the parachor parameters for each system component, using equations developed considering the pure components. Consequently, this consideration makes the Parachor method more accurate for pure components than for mixtures.

After defining the conditions related to the reservoir model and establishing the injection restrictions, three different simulation sets of CO_2 injection were carried out: the first one was the CO_2 injection above the MMP, the second one was below the MMP, and the third one was the CO_2 injection at a constant flow rate. Various injection process restrictions were selected for each simulation set, as shown in Tab. 1. Besides, for each set, the following CO_2 streams were chosen to compare the injection simulation results: low-methane content CO_2 stream (100% CO_2), medium-methane content CO_2 stream (75% CO_2 and 25% methane), and high-methane content CO_2 stream (50% CO_2 and 50% methane), all in molar fraction.

Table 1. Simulation conditions.

	First set	Second set	Third set
Injector STG* (MCF/day)	–	–	12,000
Injector BHP** (psi)	7,000	6,000	–
Producer BHP (psi)	6,500	5,500	6,500
Simulation time (years)	30	30	30

*Surface gas rate
**Bottom hole pressure

Results and Discussion

A block of the reservoir grid (7:7:3) was first observed over time. After the grid discretization, the intermediate block in position (4, 4, 2) was chosen, located precisely in the center of the reservoir. Figure 1 illustrates the reservoir grid, highlighting the position of the injector and producer wells and the intermediate block under analysis. Unfortunately, as Sequeira et al. (2008) [17] did not perform an experimental investigation of methane-CO_2-oil IFT, it was impossible to compare the results obtained in this work with experimental data from the literature.

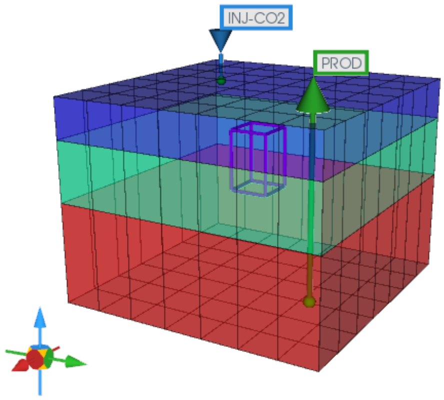

Figure 1. Grid used for the reservoir modeling, indicating the positions of the injector and producer wells and the intermediate block.

Results show the CO_2 molar fraction in oil over time for the three sets of simulations, which states that CO_2 gradually dissolves in the oil until it reaches saturation. The higher the methane content in the injected CO_2, the lower the molar fraction of CO_2 dissolved into the oil. Analysis of reservoir pressure reveals that the higher the methane content in the injected gas, the higher the pressure in the block (4, 4, 2). It occurs because methane has lower compressibility than CO_2, thus keeping the reservoir pressure stable.

The behavior of the density of the liquid phase depends directly on the composition of the injected gas, so the pure CO_2 injection promotes an increase in oil density. In contrast, the injection of the mixture of CO_2 + methane promotes a reduction in this property. Under high pressures, CO_2 reaches the supercritical state (above 1070 psi), and an abrupt increase in density occurs, with values typical of a liquid phase. This phenomenon causes the supercritical CO_2 to have a higher density value than the oil. Then, when dissolution occurs, the oil density increases. However, when mixed with methane, the gas phase density and the mixed CO_2 solubility decrease because methane is a lighter and less soluble gas than CO_2.

Figure 2 presents the gas-oil IFT curve over time for the three sets of simulations and the different methane concentrations in the CO_2 injection stream. It is possible to notice that, at the beginning of the injection, all the IFT curves present null values because there is no gas on the block and, consequently, no interface. However, after leaving the null value, the IFT curves stabilize quickly. After the gas reaches the block, the IFT does not vary significantly over time, except for pure CO_2 injection in Fig. 2.c.

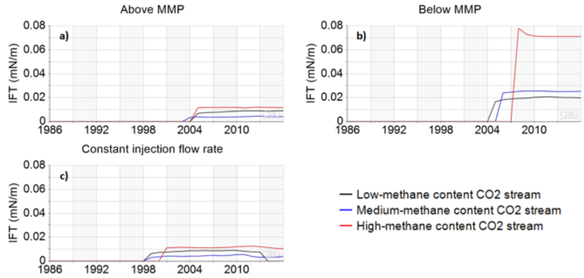

Figure 2. Gas-oil interfacial tension over time in the block (4, 4, 2), being a) the first set results, b) the second set and c) the third set.

When observing Fig. 2.a, Fig. 2.b and Fig. 2.c, it is clear that the results diverge concerning the stream leading to the lowest IFT, although the figures show that injection of CO_2 with 50% methane causes the highest IFT. Fig. 2.b shows a clear trend that the higher the methane concentration in the injection stream, the higher the gas-oil IFT. However, Fig. 2.a and Fig. 2.c show that the lowest IFT is achieved by injecting CO_2 with 25% methane, indicating that there may be an optimal concentration that provides the maximum recovery. Based on the apparent contradiction described above, it may be concluded that, in the case under study, the IFT depends on two significant variables: the block pressure, which increases as the methane content in the injection gas increases, and the CO_2 dissolution in oil, which decreases with the increase in methane concentration. So, there is an offset effect on the system because the block pressure and the CO_2 dissolution in oil both cause a decrease in the IFT. They are oppositely affected by the increase in methane concentration.

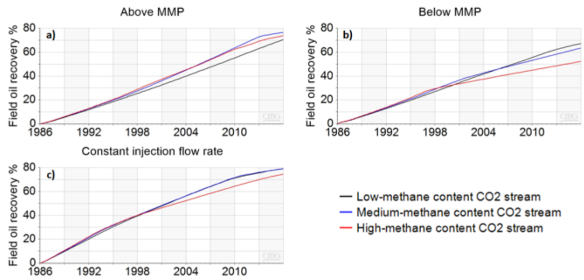

Figure 3. Field oil recovery over time for the three sets of simulations and the different methane concentrations, being a) the first set results, b) the second set and c) the third set.

Figure 3 presents the field oil recovery over time for the three sets of simulations and each of the different compositions of the injection gas. All the field oil recovery curves over time show an upward behavior, which was expected since, as time goes on, the amount of oil produced from the reservoir increases due to the gas injection process. However, in the first ten to twenty years of the injection process, it is possible to notice that the greatest recovery is achieved by using CO_2 with 50% methane. According to Figs. 3.a and 3.b, which show the gas injection process at constant pressure, more significant recovery is favored by higher injection pressure due to the increased CO_2 dissolution in oil, and consequently, the decrease in the IFT, which also leads to an increase in the capillary number [21]. The highest oil recovery observed in this work is achieved considering a constant injection flow rate, Fig. 3.c, when the injection gas is either 100% CO_2 or CO_2 with 25% methane. Comparing Figs. 2 and 3, regardless of the methane content, the recovery curves tend to agree with the IFT curves, so the lower the IFT, the greater the recovery. Figure 3.c shows that the values achieved by oil recovery considering pure CO_2 (black curve) and CO_2 with 25% methane (blue curve) are the highest ones and close to each other, even with a difference in the values of IFT. The system with 100% CO_2 injection achieved miscibility in 2013, which caused the black curve to drop to zero, although the IFT of the black curve generally presents higher values than the blue curve. The IFT drop brings the two oil recovery curves to such close values.

Conclusions

The present work performed an extensive analysis of the effect of the methane content in the CO_2 injection stream on relevant variables of EOR processes, stressing the interfacial tension's role and its relationship with the fluid flow through the reservoir. The results allow us to conclude that the effect of the methane content on the gas-oil IFT in a CO_2 injection process is somewhat tricky. An offset was observed between the effects of an increase in the methane content on many properties during the gas injection. For instance, an increase in the methane content leads to a higher internal pressure of the reservoir that causes a reduction in the IFT and a lower CO_2 dissolution in oil that raises the IFT. The balance between these opposite effects is the primary explanation that the IFT presents a lower value either for 100% CO_2 injection or a mixture of CO_2 + methane injection. The methane content effect on oil recovery varies over time so that, in the long term, the highest recovery is achieved by injecting CO_2 with as least methane as possible. Nonetheless, an optimal methane concentration provides the maximum recovery at the beginning of the injection process. Furthermore, methane injection along with CO_2 is supposed to help guarantee fluid flow during the process, leading to lower asphaltene precipitation.

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Responsibility Notice

The authors are the only responsible for the paper content.

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