Miscible WAG-CO$_2$ Light Oil Recovery from Low Temperature and High Pressure Heterogeneous Reservoir

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Abstract

Brazilian pre-salt oils should contain a variable concentration of dissolved CO$_2$ which is produced in the gas phase. A sustainable production of these oils requires a destination for the produced gas. As offshore fields have limitations associated to gas manipulation, storage and exportation, miscible CO$_2$ flooding is an Enhanced Oil Recovery (EOR) method with great potential to be employed in pre-salt reservoirs. In fact, miscible CO$_2$ injection in highly heterogeneous reservoirs should increase the oil production. As CO$_2$ flooding is related to high gas mobility, an alternative EOR method is water-alternating-gas injection (WAG). The WAG with CO$_2$ (WAG-CO$_2$) is advantageous in this scenario due to the sea water available apart from enabling the control of gas mobility. In addition, using CO$_2$ as an injection fluid is a viable solution for the GHG problem. Before implementation of WAG injection in a field, the prediction of the oil production through reservoir simulation is recommended. Simplified Black-Oil modeling is not appropriate to simulate a reservoir with light oil and miscible CO$_2$ injection. The rigorous simulation of WAG injection requires a compositional model. Also, hysteresis of relative permeability should be implemented in the simulation model to consider the cyclic hysteresis of the three-phase relative permeability. The case studied has analogous characteristics of pre-salt reservoirs such as light oil with 8% molar of CO$_2$ and initial reservoir conditions of low temperature and high pressure. The phase behavior of the oil and CO$_2$ mixture is represented by an Equation of State that contemplates the swelling resulting from the CO$_2$ dissolution in the oil. As hysteresis modeling requires some uncertain experimental parameters, a sensitivity analysis is carried out to determine the influence on oil recovery. The importance of using the reservoir simulation as a tool to predict the oil recovery before implementing WAG injection in practice is evidenced. It also demonstrated that the sensitivity analysis of the required uncertain parameters to consider the hysteresis is a viable approach to give the pessimistic and optimistic scenarios of light oil recovery prediction under WAG injection.

Introduction

Brazilian light oil from pre-salt reservoirs should contain some dissolved carbon dioxide (CO$_2$) in variable concentrations and the recovery of these oils is associated with CO$_2$ production. The CO$_2$ discharge into the atmosphere is prohibited in order to preserve the environment and avoid the greenhouse effect. Therefore, light oil production requires a sustainable destination for the produced CO$_2$. In fact, CO$_2$ is an attractive gas, which can be used in Enhanced Oil Recovery (EOR) methods and contribute to the increase of oil recovery. This is due to three main mechanisms: swelling, viscosity reduction and reduction of residual oil saturation (Nasrabadi et al., 2009). The CO$_2$ diffusion should also contribute to a substantial increase of oil recovery in highly heterogeneous and fractured reservoirs (Hoteit and Firoozabadi, 2009).

It is well known that gas injection has high microscopic displacement efficiency due to the low interfacial tension between the oil and gas phases. In cases where the miscibility is reached, the value of the interfacial tension approaches zero and complete oil recovery can occur in the swept area. Even when miscibility is not achieved, the mass transfer between the oil and gas phases leads to smaller values of interfacial tensions compared to water injection. In such cases, independently of residual saturation values, gas injection represents an important recovery process and satisfies environmental issues.

Gas injection can be successful in different reservoir production stages, independently of the mass transfer mechanisms that can occur between the oil and gas phases. For example, the CO$_2$ injection is not restricted to reservoirs that were firstly depleted by waterflooding. It is possible to inject CO$_2$ from the beginning of the reservoir life or later on. The unfavorable mobility of the gas can significantly reduce the sweep efficiency in heterogeneous reservoirs (Egermann et al., 2006).
As CO₂ flooding is related to the high mobility of the gas, the water-alternating-gas method (WAG) is an alternative method since the water controls the gas mobility, avoiding the viscous fingers. In fact, the WAG was firstly proposed by Caudle and Dyes (1958) as a goal to improve the sweep efficiency of the gas injection process. Gas mobility control is one of the most important factors that contribute to the success of the oil recovery process by gas injection. The WAG process combines the favorable aspects of gas injection and waterflooding, better oil displacement and better macroscopic sweep, respectively (Christensen et al., 2001). The WAG process also possesses economic advantages due to the reduction in the amount of gas injected into the reservoir (Pariani et al., 1992).

Recently, the interest in WAG injection has increased for one main reason: the gas produced during the oil recovery can be recycled and re-injected into the reservoir. The re-injection of produced gas in the WAG should be a viable alternative for offshore operations due to the limitations of gas manipulation, storage and exportation. Its use is mainly attractive if the offshore field produces CO₂, as is expected in Brazilian pre-salt oil reservoirs. Also, WAG-CO₂ should be an effective recovery method in the pre-salt scenario: ultra-deep offshore reservoirs, available sea water and gas production during oil production. In fact, Pizzarro and Branco (2012) mentioned that in the initial stages of the Brazilian pre-salt development projects, studies were conducted in order to evaluate recovery methods of the light oil. EOR methods were considered during the entire life cycle. WAG injection was considered an effective method in the scenario of pre-salt reservoirs. Also, the potential of the WAG-CO₂ process for recovering of the Brazilian light oil was analyzed through reservoir simulation. According to Beltrão et al. (2009), the WAG injection resulted in excellent oil recovery when the CO₂ was miscible in the oil reservoir. Almeida et al. (2010) demonstrated through numerical simulation results that WAG injection duplicated the oil recovery compared to waterflooding. Preliminary tests in pre-salt reservoirs also indicated that WAG-CO₂ injection can increase the oil recovery in approximately 50% when compared to waterflooding (Vigliano, 2011). For these reasons, reservoir simulation is an important tool to be used in order to predict light oil recovery under WAG-CO₂ from reservoirs with conditions analogous to Brazilian pre-salt.

The miscible WAG-CO₂ process simulation is complex. This injection method modifies the fluid and rock-fluid properties simultaneously. The rigorous manner to simulate the WAG is through compositional simulation in substitution to the usual, simplified Black-Oil formulation. An Equation of State (EOS) is required to adequately represent the phase behavior resulting from the CO₂ dissolution in the oil. As a result of cyclic injection of WAG, the relative permeability of each phase depends on the saturation path and saturation history and this path dependence or irreversibility is referred to as hysteresis (Spiteri and Juanes, 2006). Consequently, it is fundamental to adequately represent the hysteresis of relative permeability in the reservoir simulation model employed to represent the light oil recovery under miscible WAG-CO₂.

**Objective**

The main goal of this work was to predict light oil recovery from a highly heterogeneous reservoir, in conditions analogous to Brazilian pre-salt, in terms of CO₂ content in the oil and unusual high pressure and low temperature. The miscible WAG-CO₂ was the recovery method employed since the beginning of the reservoir production. The hysteresis of relative permeability was implemented in the compositional reservoir simulation model using the three-phase Larsen and Skauge model (1998) due its superiority compared to two-phase hysteresis models. However, it requires some parameters that are measured experimentally. As these parameters are unknown for the case studied, a sensitivity analysis was executed to determine the impact of each parameter on the oil recovery.

**WAG Hysteresis**

WAG involves drainage and imbibition processes and the hysteresis effects that occur sequentially due to cyclic injection. Different from two-phase displacement, where the saturation of a phase can only increase or decrease, permeability in WAG can follow an infinite number of paths, since two saturations are independently changed in three-phase displacement. The usual manner to calculate the three-phase relative permeability is through empirical correlations based on two-phase relative permeability data. Usually, when these correlations are used, it is assumed that water is the wetting phase and oil is the intermediate-wetting phase. The oil saturation is a function of water and gas saturations. The gas and water phase relative permeabilities depend only on their own saturations (Shahverdi, et al., 2011).

Several WAG injections have described cycle-dependent hysteresis for relative permeability through three-phase hysteresis models such as the Larsen and Skauge model (1998), which was developed for both wetting and non-wetting phase relative permeability. The main characteristics of the three-phase hysteresis models are summarized by Element et al. (2003). The three-phase model includes trapping of gas and reduction of the wetting-phase permeability in the presence of trapped gas. The intermediate wetting phase permeability is obtained through an interpolation formula, which is altered to consider the effect of the trapped gas. The main purpose of the three-phase model is the prediction of the reduced gas permeability and increased trapping of gas on the second and subsequent cycles of gas injection.

The Larsen and Skauge model (1998) is capable of predicting the non-reversible hysteresis loops for the gas phase. The gas and water permeability is typically reduced in each saturation cycle as the trapped gas saturations are increased. The trapped gas saturation is evaluated by Land’s equation. All phenomena occurring in the presence of hysteresis in a water-wet system that are supported by the Larsen and Skauge model (1998) were listed by Element et al. (2003). Besides the trapping of gas by the injected water, reduction of the gas relative permeability following the gas trapping, reduction of water permeability in the presence of gas and the irreversibility of hysteresis cycles, the Larsen and Skauge model (1998) also
predicts the reduction in the residual oil saturation with the gas trapping and the variation in the fractional flow with the trapped gas saturation. Hysteresis should increase oil recovery in WAG injection since, after the gas injection, water mobility is reduced (Spiteri et al., 2008). Water injection after gas injection traps part of the gas in the porous media and the gas mobility is reduced. The trapping of the gas is considered a favorable characteristic of WAG injection, resulting in a better sweep efficiency and the oil recovery occurs with a lesser gas-oil ratio, increasing the WAG injection efficiency.

The literature indicates the necessity to validate and adjust, through experimental data, the required parameters to use the three-phase hysteresis models (Element et al., 2003; Karkooti et al., 2011). In the ideal case, these parameters should be obtained experimentally in conditions as close as possible to the reservoir conditions.

In addition to the hysteresis of relative permeability, some authors reported injectivity loss during the WAG injection (Goodyear et al., 2003; LaForce and Orr, 2008). For this reason, the WAG hysteresis model should predict it. According to Pergoraro (2012), the Larsen and Skauge model (1998) is capable of representing the injectivity loss in the WAG.

Considering the Lasen and Skauge model (1998), four parameters are required in order to predict the hysteresis of relative permeability: (1) maximum residual gas saturation ($sgmax$) that is used to calculate Land’s constant (C) and to determine the imbibition curve as a function of the drainage curve; (2) exponent alpha ($alpha$) that corresponds to the reduction factor of gas relative permeability in function of the water saturation in the drainage curves, representing the water impact on the gas relative permeability and allowing the modeling of the cycles of hysteresis; (3) parameter ($a$) that modifies the residual oil saturation in function of the trapped gas saturation; and (4) three-phase relative permeability to water ($krw3$).

For water-wet systems, there is little data available, reported in literature, for the parameters of the Larsen and Skauge model (1998). According to Christensen et al. (2001), parameter ($a$) is comprehended between 0.25 and 1, depending on the wettability. The authors used a value equal to 1 for parameter ($a$), alpha exponent was considered as 2.0 and three-phase relative permeability to water ($krw3$) was considered to be 1/10 of the two-phase water relative permeability ($krw$). Larsen and Skauge (1998) reported that the parameter ($a$) was equal to 1, the alpha exponent was 4.9 and also considered the three-phase relative permeability to water ($krw3$) to be 1/10 of the two-phase water relative permeability ($krw$). Skauge et al. (1999) defined ranges for the parameters of the Larsen and Skauge model: the limits to $a$ parameter and alpha exponent were 0.25 to 1 and 0 to 5.0. Kamath et al. (1998) and Rogers and Grigg (2000) reported that the three-phase relative permeability to water ($krw3$) should be represented by multiplying the two-phase water relative permeability ($krw$) by 0.50 or 0.25.

**Methodology**

The methodology was proposed in order to facilitate the analysis of the case studied and the sequence of the simulation runs. The first step was the adjustment of the injection and production rates to ensure that the average reservoir pressure profile was constant after the decline period. The results of WAG-CO$_2$ injection without hysteresis were considered as a reference in order to analyze the effects of considering hysteresis of relative permeability in the simulation models.

The three-phase relative permeability was predicted considering the Stone 1 model (1970). Commercial simulators normally adopt the Stone 1 model modified by Aziz and Settari (1979). The data necessary to execute these simulations were oil-water and oil-gas relative permeability curves. This model was implemented in the WAG simulation models without and with hysteresis.

A sensitivity analysis was executed to determine the influence of the hysteresis of relative permeability in light oil recovery from a highly heterogeneous reservoir. The hysteresis of relative permeability was modelled based on the three-phase hysteresis Larsen and Skauge model (1998). The gas and water phase hysteresis were incorporated simultaneously in the reservoir simulation, since they occur sequentially due to cyclic injection. The required parameters of Larsen and Skauge model (1998) are exponent alpha ($alpha$), ($a$) parameter, maximum residual gas saturation ($sgmax$) and three-phase relative permeability to water ($krw3$). Except of ($a$) parameter, the three others were considered as uncertain variables in the sensitivity analysis.

The main field objective functions analyzed were the oil recovery factor, cumulative oil, gas and water production and the gas-oil rate to analyze the influence of the gas trapping and the changing in the gas and water relative permeability during the WAG injection. In order to investigate if the hysteresis had some impact on water and gas injectivity, their cumulative injections were also considered as objective functions.

Some suppositions were adopted to realize this work. The pure CO$_2$ was the gas injection fluid, since the EOS did not contemplate any impurity in the CO$_2$. A unique EOS was used to represent the phase behavior and the reservoir temperature was equal to that of the experimental PVT data and swelling tests. It was supposed that a sufficient amount of CO$_2$ was available to attend the gas demand in the WAG process. Operational conditions of the WAG did not intend to maximize the economic return or the oil production. The injector wells were operated at a constant rate and the producer wells were operated above the bubble point of the fluid. Although it is recognized that the capillary pressure may also have an important effect on a WAG injection, this phenomenon was not considered in this work.

**Application**

The reservoir simulation model was based on Model 2 of the Tenth SPE Comparative Solution Project (Christie and Blunt, 2001). The main characteristics of the reservoir model were high heterogeneity in porosity and permeability. The 3D model was represented by a regular Cartesian grid with 20x80x14 cells (197 ft x 197 ft x 19.7ft), Figure 1.
The reservoir fluid was light oil with about 8% molar of CO₂ (Moortgat et al., 2010). The Equation of State (EOS) employed to represent the phase behavior was constituted by seven pseudocomponents and was adjusted by Scanavini et al. (2013), using the experimental data of Moortgat et al. (2010). As the EOS contemplated the swelling, it adequately represented the phase behavior resulting from the CO₂ dissolution in the oil, Figure 2. The initial reservoir conditions were high pressure (about 6400 psi) and low temperature (138°F). These conditions were similar to those of the Lula field, initially known as the Tupi field (Beltrão et al., 2009; Formigli et al., 2009; Nakano et al., 2009; Almeida et al., 2010).

The rock-fluid properties were represented by the relative permeability curves of a grainstone rock, a type of carbonate, Figure 3. According to Craig (1971), this system is classified as water-wet.

The field production strategy consisted of 20 wells: 12 producers and 8 injectors disposed in a line drive scheme (Figure 1). The value of bottom-hole pressure (BHP) of producers was higher than the bubble point of the fluid (5580 psia). Injector wells were operated at constant rates and their values of BHP were higher than the initial reservoir pressure. Also, the BHP wells were controlled to maintain the reservoir average pressure higher than the minimum miscibility pressure (MMP) of CO₂ in the oil, ensuring a CO₂ miscible displacement. The predicted MMP was about 3700 psia (Yuan et al., 2004).

To represent WAG, injector wells were alternately shut-in and shut-off to change the injection fluid: water or pure CO₂. The WAG cycle was considered as the sum of one period of water injection plus one period of CO₂ injection. Water was the first fluid injected in each WAG cycle and its injection period was always 360 days. The CO₂ injection period was also 360 days. The sequence of injection fluids, water and gas, was followed during the entire simulation time, 10,080 days (almost 28 years). The simulation runs were executed in a commercial compositional reservoir simulator.

For the case studied, the parameters for the use of the Larsen and Skauge model (1998) are unknown. In order to execute the sensitivity analysis, a range of values was admitted to the \( \alpha \) exponent, maximum residual gas saturation and three-phase relative permeability to water. Considering that the system is water-wet, uncertainties of these parameters were defined according to the values found in the literature. The value of \( \alpha \) parameter was constant and equal to 1. Three values were considered for the \( \alpha \) exponent: 0.01, 2.5 and 5.0. The three-phase relative permeability to water \( (krw) \) was represented by multiplying the two-phase water relative permeability \( (krw_3) \) by 0.50, 0.25 and 0.10. The maximum residual gas saturation was comprehended between 0.05 and 0.55.

![Figure 1 - Highly heterogeneous reservoir: absolute permeability in x direction.](image1)

![Figure 2 - Phase behavior for the light oil with 8% molar of CO₂ (adapted from Scanavini et al., 2013).](image2)

### Results

The operational conditions of WAG-CO₂ models employed to the recovery of light oil were defined considering that the period of water injection was 360 days and the period of CO₂ injection also 360 days. The WAG cycle, the sum of the two injection periods, was constant and equal to 720 days during all the WAG injection. To ensure CO₂ miscible displacement and operation above the oil saturation pressure, the average reservoir was controlled as indicated in Figure 4(a). Figure 4(b) showed that injection rates of water and CO₂ were maintained constant in the WAG model without hysteresis (reference model) and also illustrated the constant periods of water and gas injection. For the operational conditions defined in Figure 4, the WAG ratio, considered as the ratio of injected water volume to CO₂ volume in each cycle and reservoir conditions, was equal to 1:1. The CO₂ slug size in this condition was about 17%.

As a second step, the hysteresis of water and gas relative permeability was implemented in the reservoir simulation model. To better represent this phenomenon, the three-phase Larsen and Skauge model (1998) was employed. The simultaneous effects of the hysteresis of the wetting (water) and non-wetting phase (gas) were implemented simultaneously in the simulation models with hysteresis, since these effects occurred together during a WAG injection and there was no physical meaning to consider one separated from the other. The same operational condition defined in the reference model was applied to the reservoir models with hysteresis.
Figure 3 - Two-phase relative permeability curves for a grainstone rock: (a) oil-water and (b) oil-gas.

Figure 4 - Operational conditions of WAG: (a) average reservoir pressure and (b) water and CO2 injection rate.

The effect of hysteresis in light oil recovery under the conditional operations specified in Figure 4 was analyzed in terms of cumulative oil production and oil recovery. As expected, the implementation of the hysteresis of relative permeability in the WAG-CO2 injection was favorable to the increase of oil production, Figure 5. The sensitivity analysis illustrated in Figure 5 was executed in terms of the alpha exponent related to the gas phase hysteresis model and the maximum residual gas saturation (sgrmax), representing the trapped gas. The value of (a) parameter, also necessary for the gas phase hysteresis, was not changed in the sensitivity analyses and maintained equal to unity. The water phase hysteresis was implemented through the three-phase relative permeability to water (krw3), whose curve was considered to be the two-phase water-relative permeability curve (krw) multiplied by 0.10. There was no variation of the three-phase relative permeability curve during this sensitivity analysis.

Figure 5 shows the parameter that most influenced the oil production was the maximum residual gas saturation (sgrmax). The higher the amount of trapped gas, the higher was the cumulative oil production, Figures 5(a) to (c). Consequently, the increase of trapped gas resulted in a higher oil recovery, Figures 5(d) to (f). It is possible to observe that values of maximum residual gas saturation above 0.35 did not greatly influence the oil recovery. Also, Figure 5 shows the three values of the alpha exponent that comprehend the two extremes of the range of possible values to alpha: 0.01 (near zero) and 5.0 and the middle value in this range, 2.5, practically did not influence the oil production. This was evidenced by the curves of cumulative oil production and also by the values of oil recovery.

An analogous sensitivity analysis to the one represented in Figure 5 was realized for two other three-phase relative permeability to water (krw3) curves: the two-phase water relative permeability (krw) multiplied by 0.50 and 0.25. The cumulative oil curves were practically identical to the ones presented in Figure 5. The oil recoveries for these two scenarios of three-phase relative permeability are shown in Figure 6. Neither these two three-phase relative permeability to water curves (krw3), nor the alpha exponent equal to 2.5 and 5.0, Figures 6(a) and(b), respectively, had any impact on the oil recovery compared to the oil recovery from Figure 5.
Figure 5 - Effect of hysteresis on light oil production – Sensitivity analysis of alpha (gas phase hysteresis) and trapped gas saturation (sgrmax). The three-phase relative permeability to water curve (khw3) (water phase hysteresis) was not changed: (a) to (c) cumulative oil production and (d) to (f) oil recovery.
Figure 6 - Effect of hysteresis in light oil recovery – Sensitivity analysis of trapped gas saturation ($s_{gr_{max}}$), three-phase relative permeability to water ($k_{rw3}$), and alpha exponent equal to (a) 2.5 and (b) 0.01.

For the sensitivity scenarios analyzed in Figures 5 and 6, there was no observed injectivity loss in any reservoir simulation model with hysteresis. The imposed operational conditions in the simulation model were sufficient to maintain constant water and gas injection rates in all models with water and gas hysteresis of relative permeabilities independently of the values of parameters of the Larsen and Skauge model (1998). The absence of injectivity loss in the models with hysteresis was represented by water and gas cumulative injection, Figures 7(a) and (b), respectively. For this case, the unfavorable aspect of injectivity loss associated to the WAG method was overcome by imposed operational conditions to the producer and injector wells of the reservoir simulation models.

According to what is expected in WAG injection, the mobility of the gas phase was reduced when the hysteresis of relative permeability was modeled by the three-phase Larsen and Skauge model (1998). For all scenarios of the sensitivity analysis, the hysteresis reduced gas production, Figures 8(a) to (b). Analogous to the oil production, the effect of the trapped gas saturation ($s_{gr_{max}}$) was more expressive than the effect of the alpha exponent. The higher the residual gas saturation, the higher was the gas produced independently of the value of alpha.

A favorable behavior observed for the case studied was the significant reduction of the gas-oil ratio when the hysteresis was modeled. As there was no injectivity loss in the reservoir models with hysteresis, the same amount of CO$_2$ was injected in all models. The reduction of the gas-oil rate was exclusively related to the variation of oil and gas production for the different scenarios considered in the sensitivity analyses. Figures 8 (c) to (d) evidenced that the gas-oil ratio was greatly influenced by the value of the maximum residual gas saturation: the higher the trapped saturation, the lesser was the gas-oil ratio. Consequently, the higher the amount of trapped gas in the porous media, the more favorable was the condition to the WAG process. As observed for the oil and gas production, the gas-oil ratio was poorly influenced by different values of alpha exponent.

The WAG method is also associated with the reduction of water mobility. The influence of hysteresis of water relative permeability was investigated. Analogous to the analyses realized for cumulative gas production, the hysteresis of the water relative permeability was considered simultaneously with the gas relative permeability. However, in this case, the sensitivity analyses were focused on the parameter with direct effect on water relative permeability: the three-phase relative permeability of water ($k_{rw3}$). As the maximum residual gas saturation had no effect on the cumulative water production, the value of 0.35 was considered as representative of the trapped gas saturation. Although the rock considered in this work was a type of carbonate, its wettability was highly preferential to water. For this reason, the amount of water produced in the reservoir model without hysteresis was very low, however, was not null, as illustrated in Figure 9. When the hysteresis was implemented in the reservoir simulation models and the multiplier of the two-phase water relative permeability ($k_{rw}$) was increased from 0.10 to 5.0, independently of the value of alpha exponent, the higher the values of the three-phase relative permeability to water ($k_{rw3}$), the higher was the cumulative water production.

Different from that observed for the cumulative oil and gas produced, in which the alpha exponent had practically no influence in those production parameters, Figure 9 shows the opposite. The cumulative water production was greatly influenced by the value of alpha. Figure 9(a) shows that when the $k_{rw3}$ was obtained by multiplier 0.50 and associated with the inferior limit of alpha, 0.01, the amount of produced water was highly superior compared to the others scenarios. Otherwise, when the superior limit of alpha 5.0 was considered, Figure 9(b), the model without hysteresis presented cumulative water production greater than the models with hysteresis. This fact evidenced that the water and gas phase hysteresis should be considered simultaneously in the simulation model, since these effects were correlated.
Figure 7 - Effect of water and gas phase hysteresis: (a) cumulative water injection and (b) cumulative CO$_2$ injection.

Figure 8 - Effect of water and gas phase hysteresis: (a) to (c) cumulative gas production and (d) to (f) gas-oil ratio.
Figure 9 - Cumulative water production as a function of the three-phase relative permeability to water (krw:3) for maximum residual gas saturation (sgrmax) equal to 0.35 and the alpha exponent equal to (a) 0.01 and (b) 5.0.

Conclusions

The interest in WAG injection has increased since the gas produced during oil recovery can be recycled and re-injected in the reservoir. The re-injection of gas in the WAG should be a viable alternative for offshore operations due to the limitations of gas manipulation, storage and exportation. Its use is particularly attractive if the offshore field produces CO2, as is expected of Brazilian pre-salt oil reservoirs. Also, WAG-CO2 should be an effective recovery method in the pre-salt scenario: ultra-deep offshore reservoirs, available sea water and gas production during operation.

WAG has, as a principle, the cyclic injection of fluids during the recovery process. Consequently, hysteresis of relative permeability is associated with this EOR method. For this reason, when a reservoir model with WAG injection is submitted to reservoir simulation, it is fundamental to implement the hysteresis phenomenon in the reservoir models.

The case studied was represented by a highly heterogeneous reservoir with light oil and the recovery process was WAG-CO2. The impact of the hysteresis of relative permeability was investigated in the oil production forecasting through the three-phase Larsen and Skauge model (1998). The gas and water phase hysteresis were incorporated simultaneously in the reservoir simulation models, since these phenomena cannot be considered if one is isolated from the other. As hysteresis modeling requires some experimental parameters that were unknown for the case studied, a sensitivity analysis was carried out to determine their influence on oil recovery.

The hysteresis of relative permeability in the WAG-CO2 was favorable to the increase of oil production. As the hysteresis reduced gas and water mobility, gas and water productions in the models with hysteresis were inferior to those of the model without hysteresis. A favorable behavior observed for the case studied was the significant reduction of the gas-oil ratio when the hysteresis was modelled. Maximum residual gas saturation was the parameter with more expressive influence on the sensitivity analysis for the case studied. The unfavorable aspect of injectivity loss associated with the WAG was overcome by operational conditions imposed on the producer and injector wells of the reservoir simulation models. However, there are some cases in which it is not possible to maintain constant injection rates, and the effect of injectivity loss can be significant. Its effect is higher than the sweep efficiency, resulting in a lower oil recovery when the hysteresis of relative permeability is implemented in the reservoir simulation model. Some studies showed this behavior and it will be presented in future works.

The importance of using the reservoir simulation as a tool to predict the oil recovery before implementing WAG injection in practice was evidenced. Also, it was demonstrated that the sensitivity analysis of the required uncertain parameters to consider hysteresis is a viable approach to give the pessimistic and optimistic scenarios of light oil recovery prediction under WAG-CO2 injection.

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