

CARBONATED WATER INJECTION FOR EOR IN ONE DIMENSIONAL FLOW WITH CONSTANT PRESSURE BOUNDARIES

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ABSTRACT

A three component compositional numerical model has been developed to study the performance of carbonated water injection at constant pressure boundaries. This calculation method includes the effects of oil viscosity reduction, oil volume change and interfacial tension variation. Two cases have been studied: High and low interfacial tension conditions using carbonated water injection. The results are compared with simple water injection. Additional oil recovery is attributed to the decrease of oil viscosity and oil-water interfacial tension.

INTRODUCTION

Enhanced oil recovery methods include carbon dioxide (CO₂) flooding where the CO₂ is miscible or immiscible with the oil at reservoir conditions. However, poor sweep efficiency has been reported [1] due to high mobility of gas and gravity driven gas override leading to premature CO₂ breakthrough. Carbonated water injection (CWI) may help alleviate the low sweep efficiency during CO₂ injection, where CO₂ is dissolved in water prior to injection and the CO₂ partitions to the oil phase upon water-oil contact. CWI has two main advantages; 1) the CO₂ dissolved in the oil phase changes the oil viscosity and hence the mobility ratio, and 2) experimentally the interfacial tension (IFT) between the water and oil phases is reduced [2] resulting in an improved overall performance of CWI compared to water injection [3]. Early on, carbon dioxide solvent flooding process was investigated in a laboratory flooding experiment where additional oil was recovered by the carbon dioxide solution drive [4]. A calculation method has been developed for CWI [5]. The solution using this method revealed the crucial effect of viscosity reduction and oil swelling using CWI. Results from high pressure micromodel experiments indicate better oil recovery compared to simple water flooding [6]. Even under the immiscible CO₂-assisted water flooding, the results showed a significant improvement of oil recovery over simple water flooding [6].

In this paper, a one-dimensional three component set of equations is developed to study the reservoir behavior and performance of CWI. A free CO₂ gas phase is not present. The effect of viscosity and interfacial tension as a function of changing pressure and CO₂ concentration is considered, as both are important factors in enhanced oil recovery (EOR).

MATHEMATICAL MODEL

The mathematical model was constructed using the following assumptions: 1) Flow is one dimensional and horizontal; 2) There is no source or sink term between the injector and producer; 3) The reservoir pressure is sufficiently high that no free CO₂ or hydrocarbon gases exist in the reservoir; 4) Initially CO₂ is dissolved in the oil phase and both phases flow simultaneously; 5) CO₂ partitions between the water and oil phases but there is no mass transfer of water and oil components; 6) CO₂ diffusion within the phases is ignored; 7) Equilibrium between oil and water saturated with CO₂ is reached instantaneously; 8) The reservoir formation has constant porosity and permeability; and 9) The injection and production pressures are kept constant.

The compositional model is based on the mass conservation for each component—water, CO₂ and oil. The system of equations representing three components, two phase simultaneous flow (where ϕ is the porosity, S is the saturation, ρ^* is the density ratio between stock tank condition and reservoir condition, c is the mass concentration, ρ is the density, u is the Darcy velocity, K and k_r are the permeability and relative permeability respectively, with subscripts and superscripts CO₂, w = water and o = oil) can be written as:

$$\frac{\partial}{\partial t} \left[\frac{\phi}{\rho_w^*} S_w (1 - c_{CO_2}^w) \right] = \frac{\partial}{\partial x} \left[\frac{u_w}{\rho_w^*} (1 - c_{CO_2}^w) \right] \quad (1)$$

$$\frac{\partial}{\partial t} \left[\frac{\phi}{\rho_o^*} S_o (1 - c_{CO_2}^o) \right] = \frac{\partial}{\partial x} \left[\frac{u_o}{\rho_o^*} (1 - c_{CO_2}^o) \right] \quad (2)$$

$$\frac{\partial}{\partial t} \left[\frac{\phi}{\rho_w^*} S_w c_{CO_2}^w \rho_w^{ST} + \frac{\phi}{\rho_o^*} S_o c_{CO_2}^o \rho_o^{ST} \right] = \frac{\partial}{\partial x} \left[\frac{u_w}{\rho_w^*} c_{CO_2}^w \rho_w^{ST} + \frac{u_o}{\rho_o^*} c_{CO_2}^o \rho_o^{ST} \right] \quad (3)$$

where

$$u_m = K \frac{k_{rm}}{\mu_m} \frac{\partial p}{\partial x}, \quad \rho_m^* = \frac{\rho_m^{ST}}{\rho_m^{RC}}, \quad m = o, w.$$

The sum of the two phase saturations must equal one and the concentration of the CO₂ in the oil ($c_{CO_2}^o$) is a function of the concentration of CO₂ in the water phase and the partition coefficient (γ).

$$S_w + S_o = 1 \quad (4)$$

$$c_{CO_2}^o = \gamma c_{CO_2}^w. \quad (5)$$

The five equations and five unknowns: S_o , S_w , $c_{CO_2}^o$, $c_{CO_2}^w$, p are solved using a block-centred IMPES method by finite differences.

CO₂ transfers from the carbonated water to oil thereby changing the oil properties during the flooding. We assume that the CO₂ in water and oil are at equilibrium based on the

pressure dependent solubility in oil and water. The following relationship describes the partitioning of the CO₂ if water and oil were in equilibrium with a CO₂ gas phase:

$$k_{co_2}^w x_{co_2}^w = k_{co_2}^o x_{co_2}^o = y_{co_2} \quad (6)$$

where y_{co_2} , $x_{co_2}^w$, $x_{co_2}^o$ are the mass fraction of CO₂ in the gas, water and oil phases respectively, and $k_{co_2}^w$, $k_{co_2}^o$ are the mole equilibrium coefficients in water-CO₂, oil-CO₂ systems. In this study, two-phase flow (water and oil) is assumed. We used the correlations given by Emera and Sama [7] and Duan and Sun [8] to predict the CO₂ solubility in crude oil and water. The relationship of CO₂ mass concentrations in liquid phase is given as:

$$\bar{k}_{co_2}^w c_{co_2}^w = \bar{k}_{co_2}^o c_{co_2}^o \quad (7)$$

The partition coefficient (γ) of CO₂ in three-component two-phase fluid system is defined as the ratio between mass equilibrium coefficients $\gamma = \bar{k}_{co_2}^w / \bar{k}_{co_2}^o$ and can be calculated from CO₂ solubility models of water-CO₂ and oil-CO₂ systems. The partition coefficient is a function of total pressure in isothermal carbonated water flooding.

Oil viscosity decreases with increasing CO₂, thus enhancing the oil mobility. In the isothermal reservoir condition, oil viscosity varies mainly due to the change of CO₂ mass concentration and total pressure. We used the correlation presented by Emera and Sama for viscosity as a function of CO₂ concentration [7]. The water viscosity is minimally affected by the dissolved CO₂. Likewise, the water viscosity is a function of temperature, pressure and salt concentration but not CO₂ concentration [10]. We assume that the carbonated water viscosity remains constant.

The oil density increases with increased CO₂ solubility which results from higher pressures [9]. A density correlation [7] has been developed which is calculated from pressure, temperature, oil specific gravity and the oil density at bubble point pressure. The effect of dissolved CO₂ on water density is assumed to be negligible. The pressure dependent water density was generated from a PVT software package.

The water-oil interfacial tension decreases due to the mutual solubility of CO₂. However, due to limited literature available on the effect of interfacial tension in a three-component liquid-liquid system, we assume a simple linear correlation based on reservoir temperature and CO₂ mass concentration. It shows an inverse relationship between interfacial tension and temperature:

$$\sigma_{ow} = -0.025c_{co_2}^o + 0.02 - 0.00243(T - 80). \quad (8)$$

For simplification, the following correlation is assumed between IFT and residual oil saturation at a low interfacial tension region ($0.00015 \text{ N/m} < \sigma_{ow} < 0.002 \text{ N/m}$) [11]:

$$S_{or} = S_{or}^0 \frac{-0.039678 (N/m)}{\sigma_{ow}} . \quad (9)$$

RESULTS & DISCUSSION

Two cases are presented based on two different reservoir temperature conditions. The aim of this study is to evaluate the effects of CWI under both low (case 1) and high (case 2) IFT conditions. The cases were developed under constant pressure boundary conditions and compared to WI. The parameters used in the case study are list in Table. 1. The relative permeabilities used reflect a water wet system.

The saturation profiles of CWI in case 1 (low temperature, high IFT), case 2 (high temperature, low IFT), and WI at breakthrough time (38 days) are shown by Fig. 1. Because the amount of residual oil will not be affected in the high IFT (> 0.002 N/m), the maximum water saturation ($1-S_{or}$) in case 1 is the same as the one in WI. In the high temperature system, IFT decreases with increasing CO_2 concentration; hence, more oil has been recovered under lower IFT conditions. This can be verified by water saturation profile of case 2 where the water saturation in case 2 is much higher close to the injection point. However, after a sharp reduction the curve follows the same saturation profile as it does in case 1 due to a lower CO_2 solubility. The overlapping water saturation profile of the three processes in Fig. 1 implies the same fluid behavior. This confirms the calculation results from previous work [5] which stated that due to the contact with oil the initial carbonated water injected loses its CO_2 and then proceeds as plain water. Thus, the CO_2 moves behind the pure water in CWI.

Although the residual oil saturation stays constant with both CWI and WI under the high IFT, an additional oil recovery is observed with CWI. Fig. 2 shows a comparison between water saturation profiles of case 1 and plain water injection after 200 days at injection. The reservoir rock is saturated with more water using CWI compared to WI, as time progresses. This is mainly because of the oil viscosity reduction with increasing CO_2 concentration which can be seen from Fig. 3.

The temperature in case 2 is much higher than the one in case 1 decreasing the interfacial tension according to eqtn. 8. Fig. 4 shows the change of residual oil with CO_2 solubility in the oil phase. Once the CO_2 mass concentration reaches 56%, low IFT is established leading to lower residual oil saturation. The cumulative amount of oil produced in case 1, case 2 and water flooding are plotted in Fig. 5. The CWI, with a low IFT, has the best result followed by CWI in a high IFT condition. Compared to CWI, less oil can be recovered by water flooding.

CONCLUSION

In this paper a compositional model was developed to study the performance of carbonated water injection with constant pressure boundaries. A comparison was made between carbonated water flooding and plain water flooding. The results show that

additional oil recovery using carbonated water injection is due to the oil viscosity reduction by dissolved CO₂. In addition, if the IFT can be reduced down to a certain region, significant increase in oil recovery will be observed due to reduction in residual oil saturation. However, since this certain region of IFT can hardly be achieved by regular CWI, the oil viscosity reduction plays the main role in oil recovery enhancement.

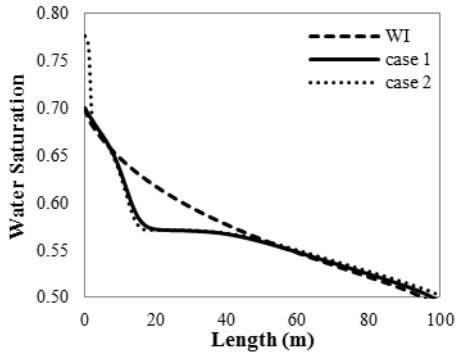


Figure 1. Water saturation after 38 days

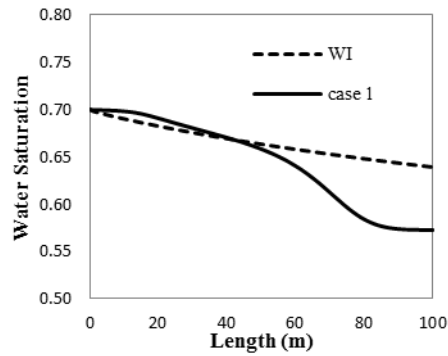


Figure 2. Water saturation after 200 days

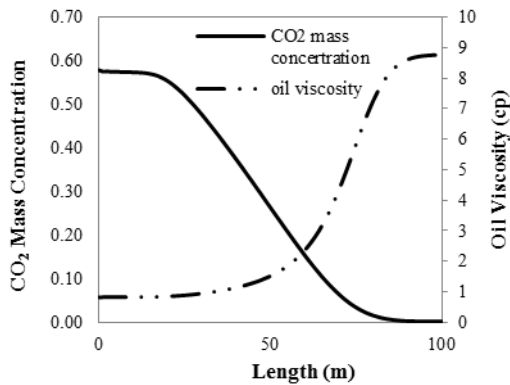


Figure 3. CO₂ mass concentration & oil viscosity after 200 days for case 1

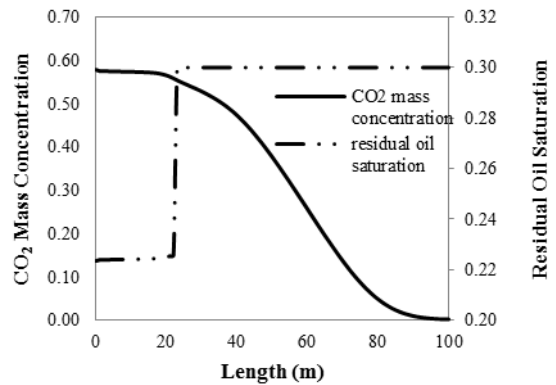


Figure 4. CO₂ mass concentration & residual oil saturation after 200 days for case 2

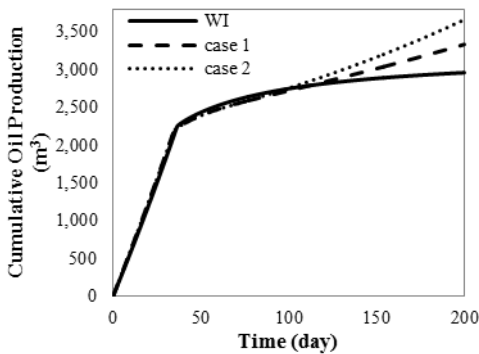


Figure 5. Oil production after 200 days

Table 1. Parameters used in case study

Data	CWI		WI	Data	CWI		WI
	Case 1	Case 2			Case 1	Case 2	
$T (^{\circ}\text{C})$	80	250	80	$\rho_o^{ST} (\text{kg/m}^3)$	874.2		
$C_{CO_2}^{w \text{ in}}$	0.0386		–	$\rho_w^{ST} (\text{kg/m}^3)$	999		
$C_{CO_2}^{o \text{ in}}$	0.5782		–	S_{or}^0	0.3		
$C_{CO_2}^{w \text{ res}}$	0.0018718		–	S_{wc}	0.25		
$C_{CO_2}^{w \text{ res}}$	1.29×10^{-4}		–	$L \text{ (m)}$	100		
k_{ro}	$k_{ro} = 0.8 \left(\frac{1 - S_w - S_{or}}{1 - S_{wc} - S_{or}} \right)^2$			k_{rw}	$k_{rw} = 0.2 \left(\frac{S_w - S_{or}}{1 - S_{wc} - S_{or}} \right)^2$		
$p_{in} \text{ (MPa)}$	3.2		3.3	ϕ	0.18		
$p_{res} \text{ (MPa)}$	3.1			$K \text{ (m}^2\text{)}$	1×10^{-12}		
$p_{out} \text{ (MPa)}$	3.0			$\mu_{oi} \text{ (Pa.s)}$	0.009		
				$\mu_w \text{ (Pa.s)}$	0.001		

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