

Effect of CO₂ Concentration in Injecting Gas on Minimum Miscibility Pressure: Compositional Model and Experimental Study

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ABSTRACT: For technical and economic success of miscible gas injection projects, an accurate laboratory measurement of Minimum Miscibility Pressure (MMP) at reservoir conditions is essential. On the other hand, compositional reservoir simulator is a useful tool in gas injection studies and prediction of MMP. The main goal of this paper is to describe a procedure to generate a three phase sequential type of compositional reservoir simulator. The solution method is completely addressed. A compositional thermodynamic program for equilibrium calculation, and pseudo-component determination was developed. Another purpose of this study is to prepare an experimental setup for investigating the effect of CO₂ concentration in injecting gas on oil recovery and MMP. Some displacement tests using slim tube apparatus were performed and recoveries and MMPs were measured. Finally, experimental results were compared with the model predictions. A good agreement was achieved between the experimental data and model predictions.

KEY WORDS: Compositional simulation, Gas injection, Minimum miscibility pressure, Recovery.

INTRODUCTION

Today, reservoir simulation is a mature technology, and it is widely used in reservoir management. Nearly all major reservoir development are based on simulation results [1]. These simulators are based on the simultaneous solving of flow equations in porous media. These are categorized into two types of black oil and compositional models. The selection is usually based on the volatility of

the oil. In black oil models, phase behavior is simply represented by Bo and Rs, which are only function of pressure, and flash calculations are not needed. In the case of compositional simulation, phase behavior is represented by an Equation of State (EOS) and phase equilibrium relations, and this requires flash calculations. From the formulation point of view several compositional

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formulations are published in the literature. They may be classified as IMPECS (Implicit in Pressure, Explicit in Composition and Saturation), Semi Implicit or IMPSEC (Implicit in Pressure and Saturation, Explicit in Composition), Sequential type and FIM (Fully Implicit Method) formulations.

The first compositional simulators of general application were developed by *Kazemi et al.* [2] in 1978 and by *Fussel & Fussel* [3] in 1979. *Young & Stephenson* [4] classified IMPECS type. *Watts* [5] in 1983 based on the ideas of *Acs et al.* presented another approach, the sequential implicit method to solve the compositional flow difference equations. An attempt was made of combining the advantages of IMPECS while retaining some of stability characteristics of the implicit method. *Wang et al.* [6] presented a fully implicit EOS compositional simulator for large scale reservoir simulation. Their simulator uses a multi block, domain decomposition approach. Recently, compositional stream line simulators for assessment of miscible/near miscible gas injection process performance are widely used. These simulators have significant potential to accommodate requirement for accurate and reliable production forecasts. These requirements include high resolution descriptions of permeability heterogeneity and appropriate representation of the phase behavior including a sufficient number of components in the equation of state representation of reservoir fluid [7]. Numerous authors have contributed to the development of stream line simulator [8-11]. This Paper describes an iterative sequential compositional formulation. Basically it uses the ideas of *Nghiem et al.* [12], but in this work the implicit transmissibilities have been used.

THEORITICAL SECTION

Multicomponent and multiphase flow in a porous medium can be described using three different types of equations when temperature is constant:

- Partial differential, component-mass balances describing component flow, in which Darcy's law is used to govern the transport of phases from one cell to another

- Phase equilibrium equations dealing with equilibrium component mass transfer between phases.

Mass balance equation

The material balance for each hydrocarbon component and water are written as follow:

$$\nabla \cdot \left[\xi_o x_i \frac{k k_{ro}}{\mu_o} \nabla \Phi_o + \xi_g y_i \frac{k k_{rg}}{\mu_g} \nabla \Phi_g \right] + q_i = \quad (1)$$

$$\frac{\partial}{\partial t} \left(\phi \left(\xi_o S_o x_i + \xi_g S_g y_i \right) \right) \quad i = 1, 2, \dots, n$$

$$\nabla \cdot \left[\xi_w \frac{k k_{rw}}{\mu_w} \nabla \Phi_w \right] + q_w = \frac{\partial}{\partial t} \left(\phi \xi_w S_w \right) \quad (2)$$

In the above equations, Φ 's are phase potentials. The molar continuity equation for the hydrocarbon system is obtained by summing Eq. (1).

$$\nabla \cdot \left[\xi_o \frac{k k_{ro}}{\mu_o} \nabla \Phi_o + \xi_g \frac{k k_{rg}}{\mu_g} \nabla \Phi_g \right] + q_t = \quad (3)$$

$$\frac{\partial}{\partial t} \left(\phi \left(\xi_o S_o + \xi_g S_g \right) \right) \quad i = 1, 2, \dots, n$$

where :

$$q_t = \sum_{i=1}^n q_i \quad (4)$$

Writing the above equations in the finite difference form results the following equations:

$$\frac{V_b}{\Delta t} \left(N_i^{n+1} - N_i^n \right) = \Delta \left(T_o^{n+1} x_i^{n+1} \left(\Delta P_o^{n+1} - \gamma_o^n \Delta h \right) \right) + \quad (5)$$

$$\Delta \left(T_g^{n+1} y_i^{n+1} \left(\Delta P_o^{n+1} + \Delta P_{cog}^n - \gamma_g^n \Delta h \right) \right) + q_i V_b$$

$$\frac{V_b}{\Delta t} \left(N_w^{n+1} - N_w^n \right) = \quad (6)$$

$$\Delta T_w^{n+1} \left(\Delta P_o^{n+1} - \Delta P_{cow}^n - \gamma_w^n \Delta h \right) + q_w V_b$$

$$\frac{V_b}{\Delta t} \left(N^{n+1} - N^n \right) = \Delta \left(T_o^{n+1} \left(\Delta P_o^{n+1} - \gamma_o^n \Delta h \right) \right) + \quad (7)$$

$$\Delta \left(T_g^{n+1} \left(\Delta P_o^{n+1} + \Delta P_{cog}^n - \gamma_g^n \Delta h \right) \right) + q_t V_b$$

Where T is transmissibility and:

$$N_i = \phi \left(\xi_o S_o x_i + \xi_g S_g y_i \right) \quad (8)$$

$$N_w = \phi \xi_w S_w \quad (9)$$

Phase equilibrium equation

The condition for thermodynamic equilibrium is established by the equality of the oil and gas phase chemical potentials or fugacity for each component

$$f_i^o(T, P, x_i) = f_i^g(T, P, y_i) \quad (10)$$

From a material balance on the oil and gas phases, the following equation is obtained

$$Fz_i = Lx_i + Vy_i, \quad i = 1, 2, \dots, n \quad (11)$$

And we have some constraint equations from definitions of mole fraction and saturation.

Adding Eqs. (6) and (7) results in the pressure equation:

$$\frac{V_b}{\Delta t} \left[(N + N_w)^{n+1} - (N + N_w)^n \right] = \quad (12)$$

$$\Delta \left(T_o^{n+1} (\Delta P_o^{n+1} - \gamma_o^n \Delta h) \right) +$$

$$\Delta \left(T_g^{n+1} (\Delta P_o^{n+1} + \Delta P_{cog}^n - \gamma_g^n \Delta h) \right) +$$

$$\Delta \left(T_w^{n+1} (\Delta P_o^{n+1} - \Delta P_{cow}^n - \gamma_w^n \Delta h) \right) + V_b (q_t + q_w)$$

Each grid block has its set of above equations. The pressure equation is solved using the iterative biconjugate gradient method. After finding the pressure of each grid block, composition of each component and the saturations are calculated using the following equations:

$$z_i^{l+1} = \frac{N_i^{l+1}}{N^{l+1}} \quad (13)$$

$$S_w^{l+1} = \frac{N_w^{l+1}}{(\phi \xi_o)^{l+1}} \quad (14)$$

$$S_g^{l+1} = \frac{V \xi_o^{l+1} (1 - S_w^{l+1})}{\xi_g^{l+1} + V (\xi_o + \xi_g)^{l+1}} \quad (15)$$

EXPERIMENTAL SECTION

The recoveries and MMP obtained in this study were determined using slim tube apparatus. The oil sample in this work was selected from an Iranian oil reservoir. Also a gas sample from a gas reservoir of Iran was used as displacing agent. Compositional analyses of oil, gas and characterization of plus fraction are given in Tables 1 and 2.

Miscible gas injection process is started by saturating the tube with oil sample at reservoir temperature above the bubble point pressure and preceded at each step by enriching the injecting gas by adding a certain amount of CO₂ to the injecting gas to meet the objective concentration. In each test, the oil is displaced by injecting enriched gas into the tube at a constant injection rate. In each run,

Table 1: Analysis of oil, gas sample.

Component	Reservoir Fluid	Injection Gas
H2S	0.0012	0.0047
N2	0.0004	0.0414
CO2	0.0125	0.0217
C1	0.2530	0.8490
C2	0.0570	0.0516
C3	0.0471	0.0174
IC4+NC4	0.0440	0.0086
IC5+NC5	0.0217	0.0030
C6	0.0398	0.0013
C7	0.0351	0.0010
C8	0.0330	0.0003
C9+	0.4553	0.0000
Solution GOR, m ³ /m ³	82	-
Bubble Point Pressure (kPa)	11,925	-

Table 2: Characterization of C9⁺.

Molecular Weight	194
Specific Gravity	0.8897

approximately 1.2 pore volume of enriched gas is injected through the slim tube, so that we can monitor the effects of miscible contact of oil and gas samples instantaneously. During different displacement test, the amount of produced oil and gas should be measured. Referring to the measured volumes of the produced oil and gas, different factors such as gas oil ratio and recovery factor could be calculated accurately. Back pressure regulator is used to keep the outlet pressure of the slim tube constant.

RESULTS AND DISCUSSION

A study was done to determine the effect of adding CO₂ to injecting gas on ultimate recovery and MMP. The results of this experimental study are shown in Figs. 1 and 2. This effect on ultimate recovery has been depicted in Fig. 1. As it is clear from its trend, increasing CO₂ concentration in the injecting gas causes increase in ultimate oil recovery

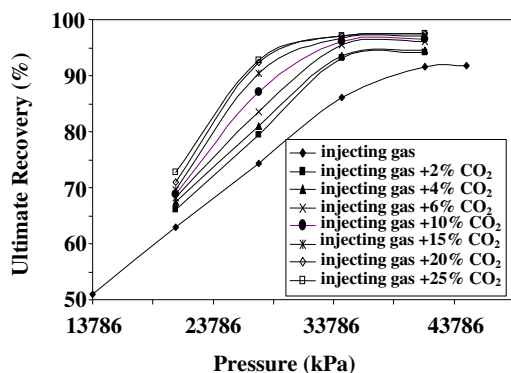


Fig. 1: Ultimate Recovery vs. test pressure in different CO₂ concentration.

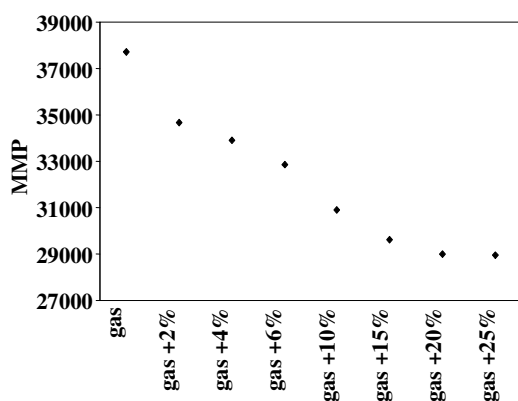


Fig. 2: The effect of CO₂ Concentration in injecting gas on experimental MMP.

at specified pressure. It can be also observed that the increasing rate of ultimate recovery is considerable in low CO₂ concentration, but it diminishes at high CO₂ concentration. In other words before reaching to maximum efficient CO₂ concentration (20%), adding more CO₂ improves recovery factor considerably, but after passing the peak point enriching injected gas is neither helpful nor economic. Fig. 2 indicates MMP values for different CO₂ concentration in injected gas. It can be seen that the MMP decreases as more CO₂ is added to the injected gas. This decrease will be continued up to the optimum CO₂ concentration, (In this study it was found to be about 20%), but enrichment beyond this point had negligible effect on MMP. The results of Figs. 1 and 2 are in good agreement with each other.

For checking the validity of developed model the results of model were compared against experimental data which are depicted in Fig. 3. In this figure the results of ultimate recovery vs. pressure are compared with

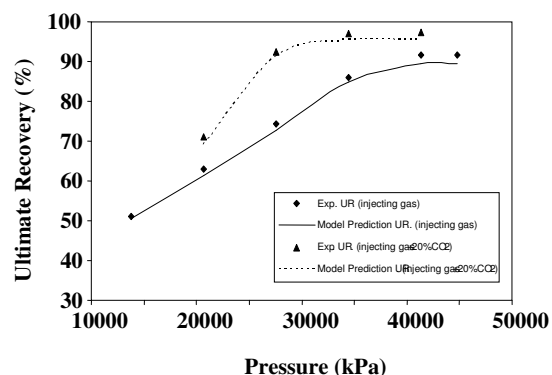


Fig. 3: Ultimate recovery curve (Comparison of experimental results and model prediction).

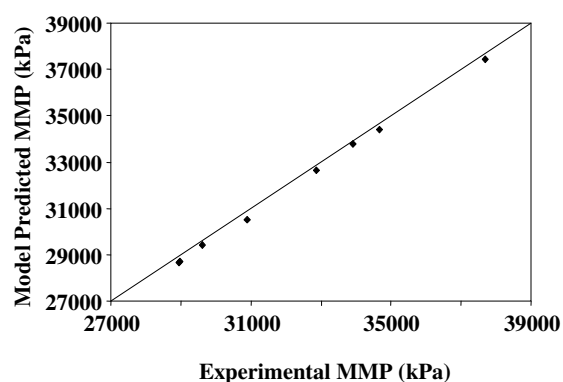


Fig. 4: Comparison of Experimental MMP and MMP predicted by model.

corresponding simulated results for two cases. The first case is the base case and the other one is the case in which injecting gas is enriched with 20% CO₂. (Optimum CO₂ concentration).

Also, the error values of calculated and experimental recovery were calculated and it was found that the average error is 2.25% and this value shows the accuracy of compositional model in predicting oil recovery. Finally it was tried to compare the experimental results of MMP with MMP predicted by model. This comparison is shown in Fig. 4. As it can be seen in that figure, the obtained points are scattered around 45° line and to some extent this indicates the accuracy of the model. Generally Figs. 3-4 confirm the validity of developed model. Mean absolute error of the final MMP data was calculated which was around 255 kPa. Comparing the calculated error with reservoir pressure, it can be inferred that this model is able to predict the MMP for engineering purpose.

CONCLUSIONS

This paper presents a procedure to formulate a three phase compositional reservoir simulator. Also, the solution method is described in detail.

The main aim of this study was to determine the optimum CO₂ concentration for enriching the injecting lean gas. However, the main effect of enriching of injecting gas is decreasing of MMP that is a key parameter for designing a gas injection projects. To do so, the slim tube setup was utilized and some displacement tests were performed in order to measure MMP. Experimentally measured MMP values showed that adding CO₂ to the primary lean gas leads to decrease in MMP.

The optimum CO₂ concentration was founded to be around 20% in this particular study. Beyond this limit enrichment had negligible effect on MMP. Finally, the experimental results compared with the model predictions and as a good agreement between them was found which in turn showed the possibility of employing a well tuned simulation model.

Nomenclature

F	Feed
f_i^j	Fugacity of component i in phase j, atm
k	Absolute permeability, mdarcy
k_{rj}	Relative permeability of phase j, immiscible condition
L	Moles in liquid phase
P	Pressure of mixture at equilibrium, kPa
P_j	Pressure of phase j, kPa
q_i	Molar injection / production rate of component i per unit volume, mole / m ³ .s
q_t	Molar injection / production rate of hydrocarbon per unit volume, mole / m ³ .s
q_w	Molar injection / production rate of water per unit volume, mole / m ³ .s
S_j	Saturation of phase j
t	Time, s
T_j	Transmissibility of phase j, mole / kPa.s
V	Moles in vapor phase
V_b	Block volume, m ³
x_i	Mole fraction of component i in oil phase
y_i	Mole fraction of component i in gas phase
z_i	Mole fraction of component i in hydrocarbon

Greek symbols

ϕ	Porosity
μ_j	Viscosity of phase j, kg/m.s
ξ_j	Molar density of phase j, mole/m ³
Δ	Difference operator
∇	Gradient operator
$\nabla \cdot$	Divergence operator
Φ_j	Potential of phase j, kPa

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