

A NEW STUDY ON FLUID FLOW IN POROUS MEDIA BASED ON CYLINDRICAL COORDINATES

T. Jafari Behbahani, A. Dahaghin

*Refining Technology Development Division, Research Institute of Petroleum
Industry(RIPI), P.O.Box 14665-1998, Tehran, Iran, jafarit@ripi*

Received February 20, 2015, Accepted May 11, 2015

Abstract

Permeability reduction in porous media during primary oil recovery and using the enhanced oil recovery methods are complicated. In this work, a modified model based on cylindrical coordinates and four phase black oil model (oil, water, gas, and asphaltene) was developed to account permeability reduction in porous media. The developed model was verified using data given in literature. The existing models are based on Cartesian coordinate and use only two material balance equations based on asphaltene and oil phases in the porous media sample. Subsequently, this model has been used for examining the effect of well production rate and the initial reservoir permeability on the asphaltene deposition behavior in a typical reservoir during flooding injection process. The results show that the developed model based on cylindrical coordinates and four phase black oil is more accurate than those obtained from previous models and is in good agreement with the experimental data reported in literature.

Also, the results of proposed model indicate that at a fixed permeability, with increase in the production rate, the amount of asphaltene deposits will increase. However, an increase in the reservoir permeability will decrease the deposition rate because of the existence of further channels for flow.

Keywords: cylindrical coordinates; porous media; fluid flow.

1. Introduction

The processes of asphaltene precipitation and deposition in porous media have a substantial effect on oil flow during primary oil production and enhanced oil recovery processes.

The oil flows through regions with the minor resistance during primary production stage of a reservoir. Ali and Islam [1] investigated the effect of asphaltene deposition on carbonate rock permeability in single-phase flow. A model was coupled to deposition and adsorption mechanisms and the results were compared to experimental data of carbonate rocks. Also, CO₂ flooding is one of successful EOR (Enhanced Oil Recovery) methods applied in oil fields. CO₂ can improve oil production by reducing the interfacial tension and viscosity or increasing mobility. One common problem during CO₂ injection is asphaltene instability, which induce deposition and adsorption of asphaltene and may cause pore-throat-plugging or wettability alteration [25]. Field and laboratory data confirm that the asphaltene solubility is lower in the light oil. Asphaltenes tend to precipitate more easily in light oils rather than in heavy oils. For instance, the Venezuelan Boscan crude with 17.2 wt% asphaltene was produced with nearly no troubles whereas Hassi-Messaoud in Algeria has numerous production problems with only 0.15 wt% asphaltene [17]. Since light-oil reservoirs are more often candidates to gas injection processes, the danger is even bigger. Due to the complexity of asphaltene deposition phenomena during CO₂ injection, very little experimental results currently exist on asphaltene deposition under dynamic condition using bottom hole live oil in porous media. The majority of existing works study the asphaltene deposition during CO₂ flooding using the injection of mixture of recombined oil (mixture dead oil and associated gas) and CO₂ to the core and or with static systems and in the absence of a reservoir rocks [23]. Zanganeh *et al.* [28] studied asphaltene deposition during CO₂ injection by a novel experimental set up to employ a high pressure visual cell using synthetic oil. Also, Okwen [22]

studied the chemical influence of formation water in decreasing the rate or amount of asphaltene deposition during CO₂ injection and suggested the relevant parameters necessary to determine the formation type that is appropriate for CO₂ injection. Nobakht *et al.* [21] investigated mutual interactions between crude oil and CO₂ under different pressures and found that the measured crude oil - CO₂ equilibrium inter-facial tension (IFT) is reduced almost linearly with the equilibrium pressure. It is observed that if the equilibrium pressure is high enough, the light components in the original crude oil are quickly extracted from the oil drop to CO₂ phase at the beginning. Wang *et al.* [26] proposed a model for permeability reduction in rock samples. Hamouda *et al.* [7] studied miscible and immiscible flooding and proposed a model based on the solubility theory to account for the effect of CO₂ flooding. The asphaltene deposition is governed by four mechanisms; surface deposition, entrainment, plugging and adsorption. Ali and Islam [1] investigated the effect of asphaltene deposition on carbonate rock permeability in single-phase flow. A model was coupled to deposition and adsorption mechanisms and the results were compared to experimental data of carbonate rocks. Gruesbeck and Collins [6] proposed a model that has been used for mechanical entrapment of solids and developed the equation for the deposition of fines in porous media. Minssieux *et al.* [13] investigated the flow properties of crude oils at reservoir temperature in different rocks. Leontaritis [16] developed a simplified model for prediction of formation damage and productivity decline by asphaltene deposition under saturated conditions in radial flow. The hydraulic diameter was estimated by the ratio of the total pore volume to the total pore surface area of the flow channels. Civan [4] developed a two-phase model to predict paraffin and asphaltene deposition. The permeability of plugging and non-plugging pathways was given by the empirical relationships. Wang *et al.* [27] proposed a deposition model including the static and dynamic pore surface deposition and pore throat plugging. The model incorporates the features of Civan's dual-porosity model for a single-porosity treatment in the laboratory core flow tests. The oil, gas and solid phases were assumed at thermal equilibrium. Nghiem *et al.* [20] proposed a model to study compositional simulation of asphaltene precipitation. They used the developed equation of Kumar and Todd [15] based on Kozeny-Carman equation. Kocabas *et al.* [14] developed a wellbore model coupled to asphaltene adsorption model based on Langmuir equation for linear and radial systems. The coupled model predicts permeability damage owing to mechanical trapping and adsorption. The model proposed by Ali and Islam was used and the equation was solved analytically through Laplace transform. Almehaideb [2] developed a model to simulate asphaltene precipitation, deposition, and plugging of oil wells during primary production. A four-component, four-phase limited compositional formulation was described. The model was implemented in cylindrical coordination to match the flow direction around the well. Monteagudo *et al.* [18] used network modeling to simulate one phase flow in porous media in order to predict the change in petroleum flow by asphaltene deposition. The network model is used to predict formation damage caused by asphaltene deposition. The adsorption of asphaltenes on solids is the result of favorable interactions of the asphaltene species or its aggregates with chemical species on or near the mineral surface, a number interaction forces, individually or in combination with each other, can be responsible for it. The major forces that can contribute to the adsorption process include electrostatic (Coulombic) interactions, charge transfer interactions, Van der Waals interactions, repulsion or steric interactions and hydrogen bonding [19]. The majority of existing models proposed monolayer adsorption behavior of asphaltenes on mineral surfaces that is studied by surface excess or Langmuir theory [3].

In petroleum literature, only limited amounts of experimental data on the permeability reduction under reservoir conditions due to conducting laboratory tests on core samples is time-consuming and expensive. Carrying out field experiments for the recognition of this phenomenon is difficult and even impossible. Further developments of both the modeling and experimental measurements should be conducted to design comprehensive reservoir management strategies. The complexity of the process of permeability reduction and formation damage, make impossible to present a fully predictive model in the short term time frame, and the experimental data will need to be collected and then used to tune the models.

Modeling of the asphaltene deposition in oil reservoirs still has room for further improvements. From a mathematical and numerical point of view, it is important to apply improved solution approaches that produce reliable results with reduced simulator runtime. In this work, a new model based on four phases (oil, asphaltene, gas and water phase) and single well model in a cylindrical coordinate was developed to account permeability reduction on core sample during flooding and the model was verified using experimental data given in literature. A conventional finite difference, implicit pressure–explicit saturation) formulation is used. The objective of developing such model is to obtain an improved black-oil formulation. This formulation is straightforward, requires less arithmetic per time step than other formulations, and has much smaller storage requirements than a fully implicit formulation. The main idea of the present study is to study the influence of the well production flow rate and formation permeability on the permeability reduction caused by asphaltene deposition.

2. Theoretical calculation

In this study, the developed model is formed by combination of thermodynamic and permeability reduction models in a black oil . The various parts of this developed model are:

2.1. Thermodynamic model for asphaltene precipitation

According to Flory- Huggins theory [5], the chemical potential of asphaltene component is calculated as follow:

$$\frac{(\mu_p - \mu_p^0)}{RT} = \ln \Phi_p + \left(1 - \frac{V_p}{V_s}\right) \Phi_s + \frac{V_p}{RT} [(\delta_p - \delta_s) \Phi_s]^2 \quad (1)$$

where μ_p , Φ_p , v and δ are, respectively chemical potential, volume fraction and solubility parameter. The solubility parameter in Eq. (1) is written as below:

$$\delta_i = \left(\frac{\Delta u}{v}\right)^{0.5} \quad (2)$$

where u is internal energy.

The values of Δu and v are calculated by the SRK EOS. In this study, it is assumed that the asphaltene phase is as a pure liquid pseudo-component in which asphaltene precipitation has no effect on liquid–vapor equilibrium. Also, crude oil is considered as a binary homogeneous mixture of asphaltene and solvent. By equating the fugacity of asphaltene in liquid and solid phase we have:

$$\Phi_p^L = \exp\left(\frac{V_p^L}{V^L} - 1\right) \Phi_s - \frac{V_p^L}{RT} (\delta_p - \delta_s)^2 \Phi_s^2 \quad (3)$$

The weight fraction of asphaltene precipitation is calculated as below:

$$W_{SAL} = \frac{(1 - \Phi_p^L)(M_w^L/V^L)}{(1 - \Phi_p^L)(M_w^L/V^L) + (\Phi_p^L)(M_{wp}/V_p)} \quad (4)$$

where M_w is molecular weight.

2.2. Asphaltene deposition modeling

There are the two permeability reduction mechanisms on porous media, adsorption and mechanical plugging.

The asphaltenes adsorption mechanism, which is related to the interactions between the asphaltenes functional groups and the rock surface, involves surface polarity, affinity or others attractive forces. Asphaltene is a polar component therefore formations have ability to adsorb asphaltene. The asphaltene adsorption was modeled using Zhu and Gu (ZG) model [29] based on multilayer theory of asphaltene adsorption. Although the model proposed by Zhu and Gu was used for hemimicelles of amphiphiles, it will be shown here that the model is justified for the asphaltene molecule as well, due to its amphiphilic character to aggregate and adsorb to rock interfaces. ZG model is as follows:

$$\Gamma = \frac{\Gamma_\infty k_1 C(n^{-1} + k_2 C^{n-1})}{1 + k_1 C(1 + k_2 C^{n-1})} \quad (5)$$

where Γ , k_1 , k_2 and n are, the amount of adsorbed asphaltene, the first adsorption step parameter (this step is taken to be adsorption of asphaltenes in solution to the surface of the rock), the second adsorption step parameter (this step is taken to be the adsorption

of asphaltenes in solution to those asphaltenes already adsorbed to the rock) and the mean aggregation number of the adsorbed asphaltenes .

Also, the asphaltene adsorption was modeled using a Langmuir isotherm equation that shows monolayer type of asphaltene adsorption:

$$W_{sa} = \frac{W_{sa,max} \cdot K_a \cdot C_{sf}}{K_a \cdot C_{sf} + 1} \quad (6)$$

where K_a and c_{sf} are the ratio of adsorption/ desorption rate constants and the mass of suspended asphaltenes per mass of the oil phase.

2.3. The mechanical plugging rate model

The mechanical plugging rate for asphaltene is given according to Wang model based on Gruesbeck and Collins theory as follow^[6]:

$$\partial E_A / \partial t = \alpha S_L C \phi - \beta E_A (v_L - v_c) + \gamma S_L u_L C \quad (7)$$

where the first term represents the surface deposition rate. The second term represents the entrainment of deposited asphaltene by the flowing phase when the interstitial velocity is larger than a critical interstitial velocity. This term shows that the entrainment rate of the asphaltene deposition is directly proportional to the amount of asphaltene deposits present in porous media, and also, the difference between the actual interstitial velocity and the critical interstitial velocity necessary for deposited asphaltene mobilization. The last term indicates the pore throat plugging rate, which is directly proportional to the product of the superficial velocity and the asphaltene precipitate concentration in the liquid phase. The value of β is described as:

$$\beta = \beta_i, \text{ when } v_L > v_c$$

$$\beta = 0, \text{ otherwise}$$

$$v_L = \frac{u_L}{\phi} \quad (8)$$

The value of γ is set as:

$$\gamma = \gamma_i (1 + \sigma E_A), \text{ when } D_{pt} < D_{ptcr} \quad (9)$$

$$\gamma = 0, \text{ otherwise}$$

Thus, the pore throat plugging deposition rate increases proportionally with the total deposits. When D_{pt} is less than D_{ptcr} , pore throat plugging deposition will occur.

In the above equations, E_A , α , β , γ and σ volume of asphaltene deposited per unit initial volume, the surface deposition rate coefficient, the entrainment rate coefficient, the plugging deposition rate coefficient and the snowball-effect deposition constant. Also, v_L , v_c and u_L are the interstitial velocity of liquid phase, the critical interstitial velocity of liquid phase and the flux of the liquid phase.

3. Solution method

A conventional finite difference, (implicit pressure–explicit saturation) (IMPES) formulation is used to solve the proposed model. The IMPES solution scheme is a hybrid method in reservoir simulation which updates the pressure variables and saturation variables of Equation separately, using an implicit method for the pressure update and an explicit method for the saturation update. This is obtained by solving for new pressures based on the saturations from the previous iteration, and then updating the saturation based on these new pressures. The objective of the IMPES method is to obtain a single pressure equation for each grid block by combining all flow equations to eliminate the saturation unknowns. By this method, capillary pressure, and transmissibilities will be evaluated explicitly (at time level n). The key advantage of the IMPES method is that it is more stable than a fully explicit method, but less costly than a fully implicit method. As the saturation update is the only explicit part of the procedure, the previously restrictive condition becomes looser and allows larger time steps for the same spatial discretization size, which is desirable. In this method, first pressure (oil pressure) distribution in the whole of reservoir is determined implicitly. To determine the oil pressure, Eq. (10) – (14) is recombined to obtain one linear equation with only one unknown for each grid block that is the oil pressure. With having all necessary variables in the previous time step and solving the pressure equation, the pressure distri-

butions around a well are calculated. Then, the saturation distributions for all four phases are determined explicitly. With having pressure in all block, thermodynamic model calculates the volume fraction of asphaltene dissolved in the oil and precipitated from oil. Then, the deposition model calculates the amount of deposited asphaltene on the rock. Porosity and permeability distribution are then determined by the plugging model. Finally, other model parameters are calculated and these values of the model parameters are used in the new time step with repetition of the computations. The IMPES Flow Chart is shown in Figure 1.

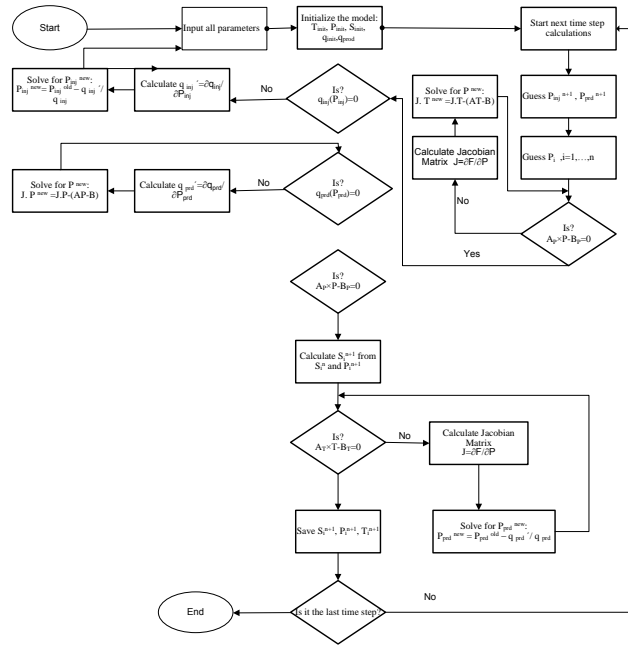


Figure 1 The IMPES method Flow Chart

Iterative coupling was used for coupling of equations. The main objective of the iterative coupling method is to achieve both accuracy and efficiency at the same time. Iterative coupling differs from sequential methods in that saturations are not solved implicitly.

Iterative coupling is an operator-splitting technique that decouples the multiphase system into pressure and saturation equations. At each time step a series of iterations are computed that involve solving both pressure and a linearized saturation equation using specific tolerances that are iteration dependent and sequential. Following convergence of iteration, phase concentrations and mass balances are checked to determine if a time-step convergence is satisfied. If not, nonlinear coefficients are updated and iteration tolerances are tightened. The sequential iteration is then repeated. This concept is illustrated in Figure 1. Also, coupling method of the equations was presented in Figure 2.

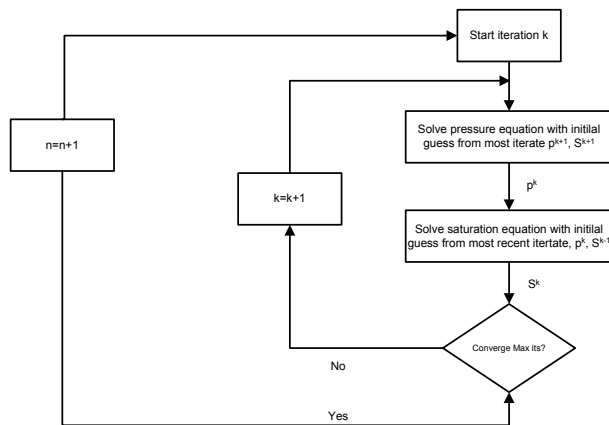


Figure 2 The iterative coupling approach for solving pressures and saturations

4. Result and discussion

In the majority of previous models, the permeability reduction during flooding is modeled based on Cartesian coordinate and two material balance equations. In this work, a modified model based on cylindrical coordinate and four phase black oil model (oil, water, gas, and asphaltene) was developed to account permeability reduction during flooding around a well in a reservoir and the model was verified using data given in literature. Figures 3 to 6 compare the results of the permeability reduction in the rock, remaining asphaltene concentration in the flowing oil, permeability and porosity profiles at various times using the proposed model with those obtained from the Wang [26] model and the model based on monolayer adsorption equilibrium mechanism.

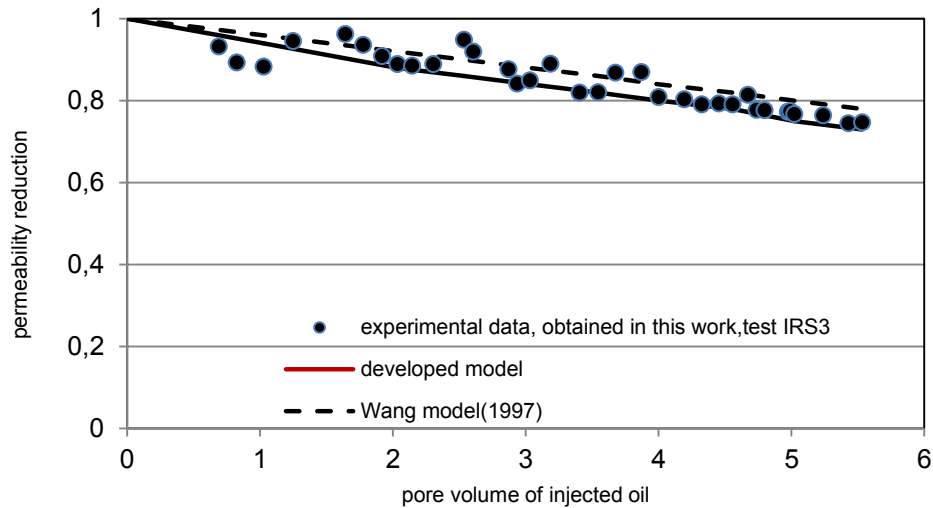


Figure 3 Permeability reduction versus pore volume oil injected for oil IRS3

As shown in results; modified model can predict better the experimental permeability reduction data during flooding in comparison to those obtained using previous model. Table 3 shows average absolute deviation of the predicted permeability reduction from the experimental data based on developed and previous model. As shown in Figures, the permeability reduction behavior is far from two phase black oil model and is closer to modified model which is based on four phase black oil. The asphaltenes adsorption mechanism, which is related to the interactions between the asphaltenes functional groups and the rock surface, involves surface polarity, affinity or others attractive forces. It is known that asphaltenes surface groups may be acidic (carboxylic, benzoic, phenolic), and/or basic (pyridine, pyrazine, dimethylsulfoxide).

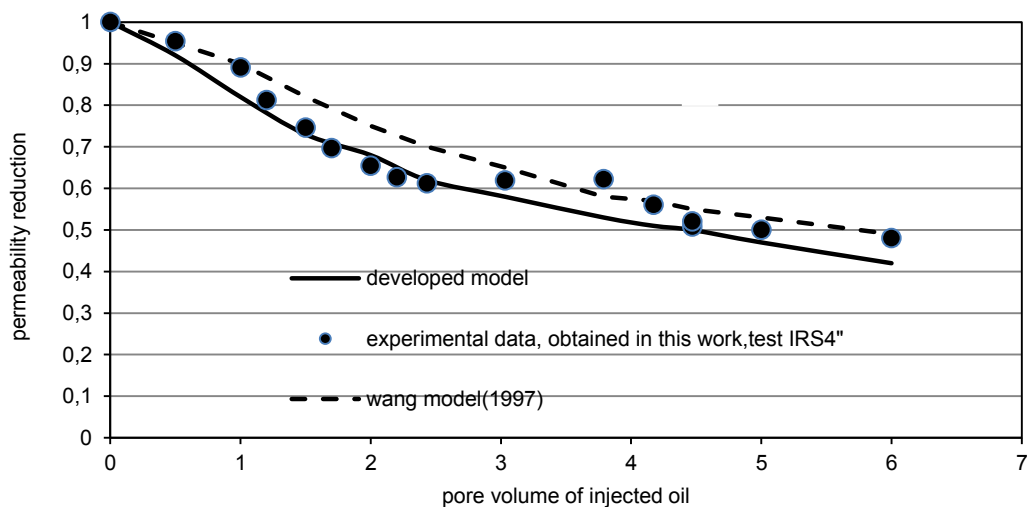


Figure 4 Permeability reduction versus pore volume oil injected for oil IRS4

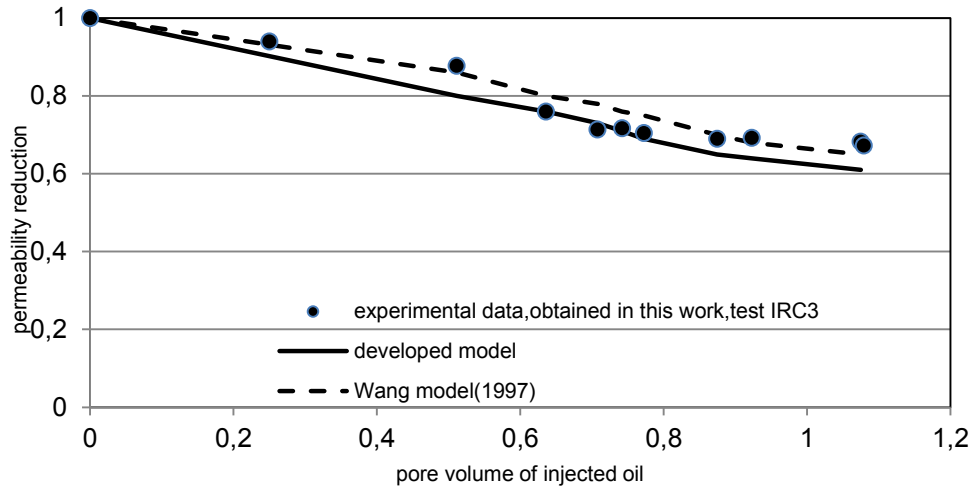


Figure 5 Permeability reduction versus pore volume oil injected for oil IRC3

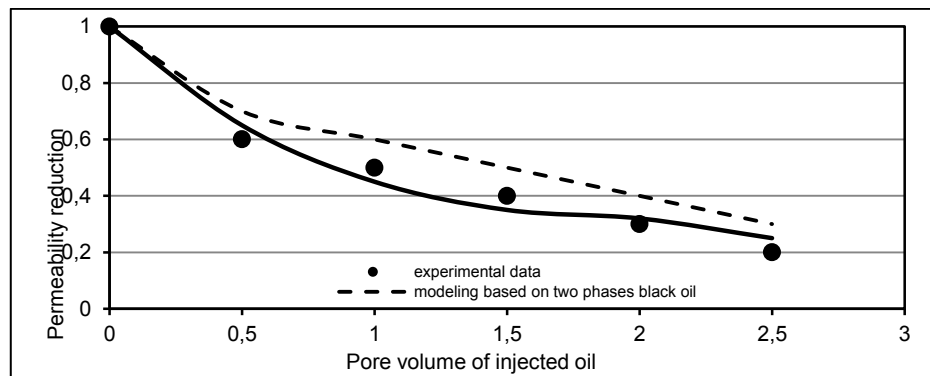
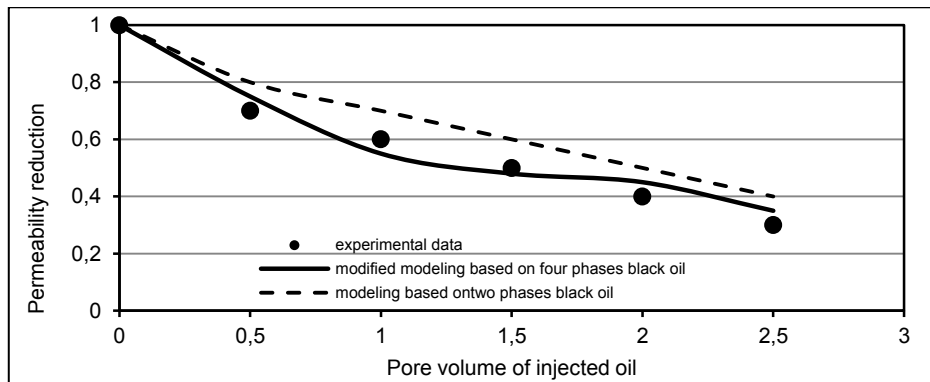
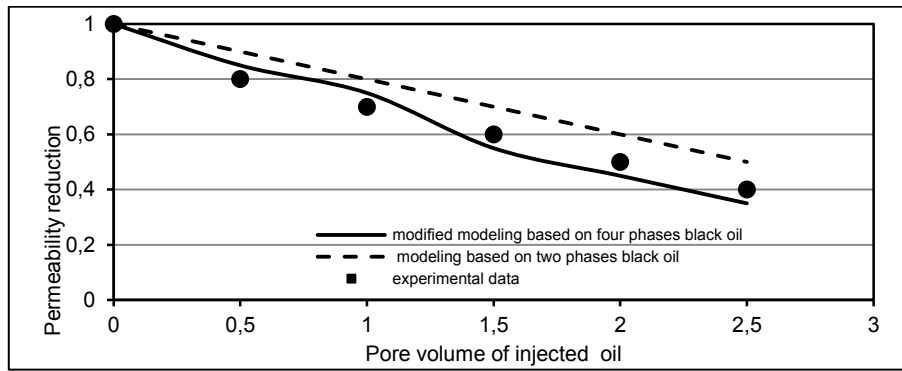


Figure 6 Comparison of the performance of the proposed model and model based on two phases black oil during CO₂ injection flooding

Table 3. Absolute Deviation of the correlated permeability reduction from the experimental results by the modified model and the model based on two phases black oil

Reference	Absolute deviation of asphaltene deposition modeling (%)	
	Modified model	Previous model
Minssieux <i>et al.</i> [13]	3.4	5.3
Jafari Behbahani <i>et al.</i> [8-12]	4.1	7.8
Solaimany-Nazar <i>et al.</i> [2]	5.2	9.8

Also, the results of proposed model indicate that at a fixed permeability, with increase in the production rate, the amount of asphaltene deposits will increase. However, an increase in the reservoir permeability will decrease the deposition rate because of the existence of further channels for flow.

6. Conclusions

In this work, a new model based on cylindrical coordinates and four phases black oil (oil, asphaltene, gas and water phase) was developed to account permeability reduction in porous media. The proposed model was verified using experimental data given in literature.

The results show that the proposed model based on cylindrical coordinates and four phases black oil is accurate than previous model in Cartesian coordinate.

Also, the results of proposed model indicate that at a fixed permeability, with increase in the production rate, the amount of asphaltene deposits will increase. However, an increase in the reservoir permeability will decrease the deposition rate because of the existence of further channels for flow

References

- [1] Ali M A, Islam M R, The effect of asphaltene precipitation on carbonate rock permeability: An experimental and numerical approach, 5-6, October 1997 Annual Technical Conference and Exhibition, San Antonio (SPE 38856).
- [2] Almehaideb RA. Asphaltene precipitation and deposition in the near well region: a modeling approach. *J Petrol Sci Eng.* 2004; 42:157–70.
- [3] Bagheri M B; Kharrat R; Ghotbi C. Experimental Investigation of the Asphaltene Deposition Process during Different Production Schemes. *Rev. Inst. Fr. Pet.* 2011, 66(3): 507-519.
- [4] Civan F, Modeling and simulation of formation damage by organic deposition, First International Symposium on Colloid Chemistry in Oil Production: Asphaltene and Wax Deposition, 26-29, November 1995 Rio de Janeiro, Brazil.
- [5] Flory, P.J. J. Thermodynamics of high polymer solutions. *Chem. Phys.* 1941, 9: 660.
- [6] Gruesbeck C, Collins RE, Entrainment and deposition of the particles in porous media. *Soc Pet Eng.* 1982:847–856.
- [7] Hamouda AA, Chukwudeme EA, Mirza D, Investigating the effect of CO₂ flooding on asphaltenic oil recovery and reservoir wettability. *Energy Fuels*, 2009, 23: 1118–27.
- [8] Jafari Behbahani T, Ghotbi C, Taghikhani V, Shahrabadi A. Investigation on Asphaltene Deposition Mechanisms during CO₂ Flooding Processes in Porous Media: A Novel Experimental Study and a Modified Model Based on Multilayer Theory for Asphaltene Adsorption. *J Energy Fuels.* 2012; 26:5080–91.
- [9] Jafari Behbahani T, Ghotbi C, Taghikhani V, Shahrabadi A. Asphaltene Deposition under Dynamic Conditions in Porous Media: Theoretical and Experimental Investigation. *Energy Fuels.* 2013, 27, 622–639.
- [10] Jafari Behbahani T, Ghotbi C, Taghikhani V, Shahrabadi A. Investigation of asphaltene adsorption in sandstone core sample during CO₂ injection: Experimental and modified modeling. *Fuel.* 2014; 133, 63-72.
- [11] Jafari Behbahani T, Ghotbi C, Taghikhani V, Shahrabadi A. Investigation of asphaltene deposition mechanisms during primary depletion and CO₂ injection, 7-10, June; 2011, European formation damage conference, Noordwijk, The Netherlands (paper 143374).

- [12] Jafari Behbahani T, Ghotbi C, Taghikhani V, Shahrabadi A. A modified scaling equation based on properties of bottom hole live oil for asphaltene precipitation estimation under pressure depletion and gas injection conditions. *Fluid Phase Equilib.* 2013, 358: 212–219.
- [13] Minssieux L, Nabzar L, Chauveteau G, Longeron D, Bensalem R, Permeability damage due to asphaltene deposition experimental and modeling aspects. *Oil Gas Sci.Technol. – Rev. IFP*, 1998, 53(3) :313-327.
- [14] Kocabas I, Islam M R, Modarress H. A wellbore model for field-scale modeling of asphaltene plugging. *J. Pet. Sci. Eng.* 2000; 26:19–30.
- [15] Kumar T, Todd A C, A new approach for mathematical modeling of formation damage due to invasion of solid suspensions, 2-5, October 1988, SPE Annual Technical Conference and Exhibition, Houston, Texas,(SPE 18203).
- [16] Leontaritis K J, Asphaltene deposition: A comprehensive description of problem manifestations and modeling approaches, 13-14, March 1989, SPE Production Operations Symposium, Oklahoma, City.
- [17] Moghadasi J, Kalantari-Dehghani A M, Gholami V, Abdi R, Formation Damage Due to Asphaltene Precipitation Resulting From CO₂ Gas Injection In Iranian Carbonate Reservoirs, SPE Europe/EAGE Annual Conference and Exhibition, 12-15, June 2006 Austria, (SPE 99631).
- [18] Monteagudo JEP, Rajagopal K, Lage PLC. Simulating oil flow in porous media under asphaltene deposition. *J Chem Eng Sci* 2002; 57:323–37.
- [19] Murgich J. INTERMOLECULAR FORCES IN AGGREGATES OF ASPHALTENES AND RESINS. *Pet. Sci. Technol.* 2002, 20: 983–997.
- [20] Nghiem L, Kohse B F; Ali S M F, Doan Q, Asphaltene precipitation: phase behavior modeling and compositional simulation, 25-26, April 2000Asia Pacific Conference on Integrated Modeling for Asset Management, Yokohama, Japan, (SPE 59432).
- [21] Nobakht M, Moghadam S, Gu Y, Mutual interactions between crude oil and CO₂ under different pressures. *Fluid Phase Equilib.* 2008, 265:94–103.
- [22] Okwen R T, Formation damage by CO₂ induced Asphaltene Precipitation. SPE International Symposium and Exhibition on Formation damage control, LA, 15-17, February 2006, Lafayette (SPE 98180).
- [23] Sarma, H K, Can We Ignore Asphaltene in a Gas Injection Project for Light-Oils?, SPE 84877. SPE International Improved Oil Recovery Conference, 20-21, October 2003, Kuala Lumpur, Malaysia.
- [24] Solaimany-Nazar A A, Zonnouri A. Modeling of asphaltene deposition in oil reservoirs during primary oil recovery. *Journal of Petroleum Science and Engineering.* 2011, 75: 251–259.
- [25] Srivastava R K, Huang S S, Mingzhe D, Asphaltene deposition during CO₂ flooding, *SPE Prod. Facil.* 1999, 14: 235-245.
- [26] Wang S, Civan F, Strycker AR. Simulation of paraffin and asphaltene deposition in porous media. SPE international symposium on oilfield chemistry, 16–19, February 1999, Houston, Texas, (SPE 50746).
- [27] Wang S, Civan F, Productivity decline of vertical and horizontal wells by asphaltene deposition in petroleum reservoirs, 13-16, February 2001, SPE International Symposium on Oilfield Chemistry, Houston, Texas (SPE 64991).
- [28] Zanganeh P, Ayatollahi S, Alamdari A, Zolghadr A, Dashti h, Kord S, Asphaltene deposition during CO₂ injection and pressure depletion: a visual study. *Energy Fuels.* 2012, 26: 1412-1419.
- [29] Zhu B Y; Gu T. Reverse hemimicelle formation of 1-decanol from heptane at the solution/graphite interface. *Colloids Surf.* 1990, 46: 339–345