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Network modeling of asphaltene deposition during two-phase flow in carbonate

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A B S T R A C T

A network model is modified to compute formation damage resulting from asphaltene deposition in porous media containing two-phase flow. The model predictions are compared to experimental data of six core samples under similar reservoir conditions. The model is applied to study the effect of asphaltene deposition on throat size distribution, wettability alterations from water-wet to oil-wet, water and oil relative permeability, and capillary pressure in two mechanisms of drainage and imbibition. The asphaltene induced damage is considered by two mechanisms; the smaller throats are plugged owing to large asphaltene particles and the larger throats diameter is decreased.

1. Introduction

The crude oil can be divided into two main parts: (1) The first part contains the components with high boiling point and polar asphaltenic components. This part of crude oil is the source of organic deposition in reservoir formation and (2) the second part called deasphaltenic oil or maltenes acts as a solvent of the first part.

Asphaltenes are not dispersed in maltenes, but are suspended by hydrogen bonds between resin and asphaltene molecules. Light to medium crude oils containing small amounts of asphaltene may create more asphaltene precipitation problems during primary production. So, heavier crudes that contain a larger amount of asphaltene have very little asphaltene precipitation problems as they can dissolve more asphaltene (De Boer et al., 1995; Nghiem et al., 1998).

Asphaltene deposition in porous media causes two types of alterations as follows: (1) Alterations of porous media morphology: the precipitated asphaltenes are fine particles that may form aggregates, which are large enough to be retained at small pore throat and reduce the absolute permeability. So, the main reason of absolute permeability reduction is plugging of the throats. Asphaltene deposition causes more permeability reduction than porosity reduction. (2) Changes in surface specifications of porous media: the precipitated asphaltene adsorbed on the rock surface causes changes of wettability. Asphaltene on rock surface is the most important parameter to change the rock wettability from water-wet to oil-wet. Studies show that while increase in asphaltene deposition enhances pore throats plugging and reduces absolute permeability which induces desirable alterations in relative permeability and improves displacement efficiency.

The formation damage model is a mathematical expression to predict the alterations of porous media such as absolute permeability reduction. Despite much experimental researches performed on porous media formation damage, minor works are conducted on the subject of modeling of formation damage in porous media.

Studies show that most works on formation damage of porous media owing to deposited asphaltene are based on empirical or semi-empirical correlations to express absolute permeability reduction and the porous media morphology is not considered. Most of the models represent the porous media as a set of parallel pathways, some of which pluggable and the others non-pluggable and connectivity between the pathways as an important porous media specification has not been taken into account (Gruesbeck and Collins, 1982; Civan, 1995; Ali and Islam, 1997, 1998; Minssieux et al., 1998; Leontaritis, 1998; Nghiem et al., 1998; Wang et al., 1999; Nghiem et al., 2000; Kocabas et al., 2000; Qin et al., 2000; Wang xxxand Civan, 2001; Monteagudo et al., 2002, 2003; Almehaideb, 2004). Based on these models the effect of asphaltene deposition on porous media morphology is negligible. However, according to percolation theory, connectivity affects permeability.

Monteagudo et al. (2002, 2003) for the first time proposed a simulator for one phase flow in porous media near a wellbore coupled with a thermodynamic model and a network model in

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Nomenclature

AC	asphaltene content, wt%
AD	after deposition
BD	before deposition
DF_K	permeability damage factor, dimensionless
DF_ϕ	porosity damage factor, dimensionless
IPV	initial pore volume, cm^3
K_d	absolute permeability after deposition, md
K_0	initial absolute permeability, md
NR	number of network realizations
PC	capillary pressure
PC_{max}	maximum capillary pressure
PC_{min}	minimum capillary pressure

Greek symbols

Φ_d	porosity after deposition, dimensionless
Φ_o	initial porosity, dimensionless

order to predict the change in oil flow under asphaltene deposition. The network model is used to predict formation damage resulting from asphaltene deposition. The fluid flow is considered single phase. However the flow in wellbore is more complicated and is multiphase during oil production. The throats are cylinders with circular cross-sections. So, the effect of some parameters such as contact angles, relative permeability, capillary pressure, and wettability are not considered.

In this paper for the first time, a network model is modified to predict asphaltene deposition effects on petrophysical properties containing absolute permeability, porosity, throat and pore size distribution, also its influence on two-phase fluid flow including capillary pressure and water and oil relative permeability in drainage and imbibition. The model results are compared to adopted experimental data from literature.

2. Network model

In drainage, the non-wetting fluid displaces the wetting fluid. Conversely, in imbibition the wetting fluid displaces the non-wetting fluid. The mechanisms of these two displacements are completely different.

The network model proposed by Blunt (1997, 1998, 2001), Blunt et al. (2002), Piri and Blunt (2005a, 2005b) and Patzek (2001) is used in this paper. The Blunt model is modified to predict asphaltene deposition that is described later in this paper.

The displacements in network models are based upon capillary equilibrium between phases. At each step, the displacement is conducted in one element. It is assumed that capillary forces control the fluid displacement at pore scale. The phases are considered incompressible. So, the phase saturation is not a function of phase pressure but varies as a function of oil–water interface curvature.

In drainage, piston type is the only mechanism, but in imbibition as part of the network has been invaded beforehand, the displacement is much more complicated and contains piston type, snap-off and pore body filling mechanisms. This classification has been proposed by Lenormand (1983, 1986).

2.1. Drainage

In drainage, at first all pores and throats are filled with water. The outlet and inlet throats are connected to a water and oil reservoir, respectively. The water is considered at a constant pressure. The pores and throats are filled in order of capillary pressure. At each step one element is filled with oil. This element is adjacent to the inlet or already oil-filled element and has the lowest entry capillary pressure. During the displacement capillary pressure is increased. But it should be noted that while filling a pore after an adjacent oil-filled throat, capillary pressure decreases. In drainage water remains in corners. In order to calculate the amount of water remained in corners, the capillary pressure of the last filled element is applied to obtain the curvature of oil–water interfaces for all elements.

2.2. Imbibition

This displacement occurs after drainage. The oil pressure is constant and water is injected from inlet. The capillary pressure decreases. In imbibition, water displaces oil; wettability is changed to mixed-wet. The change of wettability during imbibition is controlled by the composition of the oil and water, the mineralogy of solid surface, and the capillary pressure imposed during drainage.

The wettability of those areas which are contacted by oil will be changed from water-wet to oil-wet.

There are three main mechanisms in imbibition: piston-type, snap-off, and pore body filling.

2.2.1. Piston-type mechanism

This is opposite of invasion. If there is contact angle hysteresis, the contact point of water–oil–solid will be pinned and the contact angle increases. Piston-type displacement in imbibition can be spontaneous or forced occurred in a positive and negative capillary pressure, respectively.

2.2.2. Snap-off mechanism

If there is no adjacent water-filled element, piston-type mechanism is not feasible. In this condition when the water layers in two corners meet, the oil–water interface is unstable and the element fills with water and snap-off takes place. This mechanism is divided into two parts: spontaneous and forced.

2.2.3. Pore body filling

The threshold capillary pressure for pore body filling depends on the number of adjacent oil-filled throats. There are several models to compute the capillary pressure of this mechanism (Lenormand et al., 1983; Blunt, 1997, 1998; Oren et al., 1998).

3. Model applications: the influence of asphaltene deposition on water and oil relative permeability and wettability

To assess the model, experimental data of low permeability carbonate core samples reported by Shedid (2001) is applied. The data are achieved using actual reservoir crude oil and brine, flowing through actual carbonate cores under similar reservoir conditions of temperature and pressure. The data are divided into two groups: capillary pressure; and oil and water relative permeability. Three core samples are used in each group. The initial porosity range is from 0.1623 to 0.2120 and initial absolute permeability range is from 4.89 to 7.20 md. Table 1 shows petrophysical properties of the used samples. As it can be seen the samples petrophysical properties are rather different. Permeability and porosity damage factors