# Pore-Level Simulation of Heavy Oil and Bitumen Recovery Using the Steam Assisted Gravity Drainage (SAGD)

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## Abstract:

A CFD-based numerical solver is developed to simulate the pore-scale behaviour of SAGD process, including phase change phenomena (i.e., condensation and vaporization). During the simulation a complete set of mass conservation and Navier-Stokes momentum and energy equations under non-isothermal condition are solved simultaneously. In addition to take phase change phenomena into account, the flow pattern in porous media is well-demonstrated. Then, the solver is validated against visualization experimental studies of SAGD process available in the literature. The results include a demonstration of a series of pore-scale events particularly in the vicinity of the bitumen-steam interface. The results of this study are a part of the larger investigation the objective of which is to understand deeply physics of complex multiphase flow in heterogeneous structures.

## Introduction:

Due to its high recovery, stable oil production rate and reduced environmental footprint, Steam Assisted Gravity Drainage (SAGD) recovery is one of the promising approaches developed to enhance oil recovery in heavy oil and bitumen resources (Butler, 1997; Butler *et al.*, 1981). However, pore-scale physics and interactions between steam, condensed water and oil in the SAGD process are not yet fully-understood (Lee *et al.*, 2015). Thus, pore-level studies of the fundamentals of complex transport phenomena (including flow pattern and heat transfer) in porous media can result in a significant improvement in understanding the field-scale macroscopic observations (Al-Bahlani and Babadagli, 2009).

The viscosity of heavy oil is very high, typically over million centipoise (Meyer and Attanasi, 2003). In order to produce heavy oil, it has to be mobilized in the reservoir. Because of extremely high viscosity, i.e. resistance to flow, fundamental recovery techniques are not applicable to improve the oil recovery factor (Hart, 2014). The key to mobilize heavy oil is to decrease its viscosity. There are two general ways to reduce heavy oil viscosity: first, heat heavy oil and second, dissolve solvent in heavy oil (Butler, 1997). The steam injection is a common way to enhance heavy oil recovery in unconventional oil resources. During steam injection, the heavy oil temperature increases sufficiently and consequently the viscosity of heavy oil drops rapidly. In contrast to non-thermal methods where viscosity reduction is very slow and depend on the diffusion and dispersion of the fluids. When steam is contact with cold heavy oil, another phase (condensate phase) is produced at the interface between the steam and heavy oil. The effect of the layer of condensate phase on the heavy oil recovery is not yet fully understood. Numerical simulation technique can be used to tackle this problem (Mohammadmoradi, 2016). Most of the previous works on the simulation of fluid flow in porous media deal with a single phase (either gas or liquid) or two phase flow. In this study a new solver is developed to study flow pattern in a porous media when the phase change occurs. The volume of fluid (VOF) approach is used to perform phase change in this study. Easy capturing of the interface during the phase change and inherent mass conservation property are two main advantages of the VOF method (Gueyffier *et al.*, 1999).

*Governing equations:*

To use the VOF method a volume fraction term α is defined. The volume fraction term lies between 0 and 1 and

$$\sum_{i=oil,water,steam} \alpha_i = 1$$

The continuity equation for each phase is given by (Kartuzova and Kassemi, 2011):

$$\frac{\partial(\alpha_i\rho_i)}{\partial t} + \nabla.(\alpha_i\rho_i\boldsymbol{v}) = S_i, i = oil, water, steam$$

Where ρ, **v** and t are density, velocity and time, respectively. Note that $\dot{m}$ stands for the mass transfer between phases. There are many equations to express mass transfer term. In this study, we use an empirical relation to quantify the interfacial heat and mass transfer (Lee *et al.*, 2015).

$$S_{\alpha_v} = -S_{\alpha_l} = r_l\alpha_l\rho_l\frac{T-T_{sat}}{T_{sat}} \quad T > T_{sat} \quad \text{evaporation process}$$

$$S_{\alpha_l} = -S_{\alpha_v} = r_v\alpha_v\rho_v\frac{T_{sat}-T}{T_{sat}} \quad T < T_{sat} \quad \text{condensation process}$$

Where $S_{\alpha_v}$ is the interfacial mass transfer rate from liquid to vapor, $S_{\alpha_l}$ is the interfacial mass transfer rate from vapor to liquid. $r$ denotes the mass transfer intensity factor with unit $S^{-1}$. The value of $r$ is recommended to be such as to maintain the interfacial temperature reasonably close to the saturation temperature, and to avoid divergence issues. As an empirical coefficient, $r$ is given different values for different problems. Researchers have used a very wide range of values, depending on flow regime, geometry, mesh size and time steps. (Alizadehdakhel et al., 2010; De Schepper et al., 2009; Wu et al., 2007) set $r_v = r_l$ =0.1 in their simulations for investigation of evaporation and condensation in a thermosiphon, simulating flow boiling in a hydrocarbon feedstock and flow boiling in serpentine tubes respectively.(Goodson et al., 2010; Yang et al., 2008)

For pore-scale simulation, we used $r = 100$ for both condensation and vaporization process in order to numerically maintain the consistency between saturation and temperature profiles i.e. keep the interfacial temperature around $T_{sat}$. It is founded that as $r$ goes to very small values, interfacial temperature start deviating from saturation temperature and increasing $r$ helps maintain interfacial temperature close to $T_{sat}$. Note that extremely large values of $r$ cause numerical convergence problems(Yang *et al.*, 2008).

The momentum equation is expressed as follow:

$$\frac{\partial(\rho\boldsymbol{v})}{\partial t} + \nabla.(\rho\boldsymbol{v}\boldsymbol{v}) = -\nabla P + \nabla.[\mu(\nabla\boldsymbol{v} + \nabla\boldsymbol{v}^T)] + \rho g + F$$

Where P is the pressure. The viscosity is denoted by μ. F and g are surface tension term and gravity respectively. Note that

$$\rho = \sum_{i=oil,water,steam} \rho_i \alpha_i$$

$$\mu = \sum_{i=oil,water,steam} \mu_i \alpha_i$$

To implement the effect of surface tension in our calculations, F is defined as follow:

$$F = \left[\sigma\kappa\boldsymbol{n} + \frac{d\sigma}{dT}\left(\sigma T - \boldsymbol{n}(\boldsymbol{n}.\nabla T)\right)\right]|\nabla\alpha|\frac{2\rho}{\rho_1 + \rho_2}$$

Where $\kappa = -\nabla.\mathbf{n}$ and $\sigma$ are the curvature and surface tension terms, respectively. By T and **n**= $\nabla\alpha/|\nabla\alpha|$, the temperature and the surface normal vector are respectively defined. The energy equation is written as follow:

$$\frac{\partial(\rho C_p T)}{\partial t} + \nabla.\left(\rho\boldsymbol{v}C_p T\right) = \nabla.(k\nabla T) + Q$$

Where Q is the volumetric heat sources, k is the thermal conductivity term given by

$$\rho = \sum_{i=oil,water,steam} k_i \alpha_i$$

Using these equations, a new solver is developed in OpenFOAM solver in order to address the phase change problem.

## Conclusion and Results:

Figure 1 shows a typical porous medium which is used in our study. The porous medium is fully saturated by heavy oil (T=300 K) while steam (T=400K) is injected. The saturation temperature is 373 K.

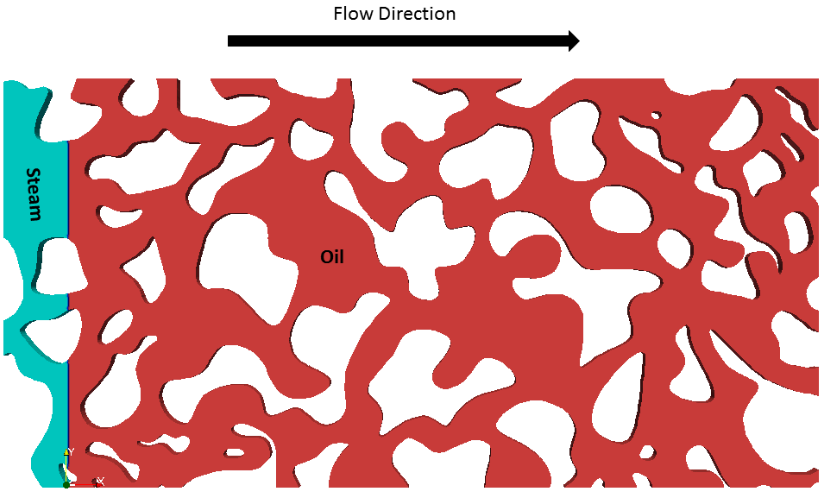

**Figure 1. porous media saturated by oil and steam**

The viscosity ratio and density ratio in our studies are 10000 and 1000, respectively. Material properties of water, steam and oil is provided in the table below:

**Table 1. Properties of water, steam and oil**

| | $\rho\ [kg/m^3]$ | $\mu\ [pa.s]$ | $c_p\ [kj/(kg\ K)]$ | $k\ [w/(m\ K)]$ |
|---|---|---|---|---|
| Steam | 1 | 0.0001 | 2100 | 0.02 |
| Oil | 1000 | 1 | 1900 | 0.3 |
| Water | 1000 | 0.01 | 4200 | 0.6 |

As illustrated in Figure 2, at the interface between oil and steam, the temperature of injected steam drops and the condensate phase is produced. Dark blue is used to present the condensate phase.

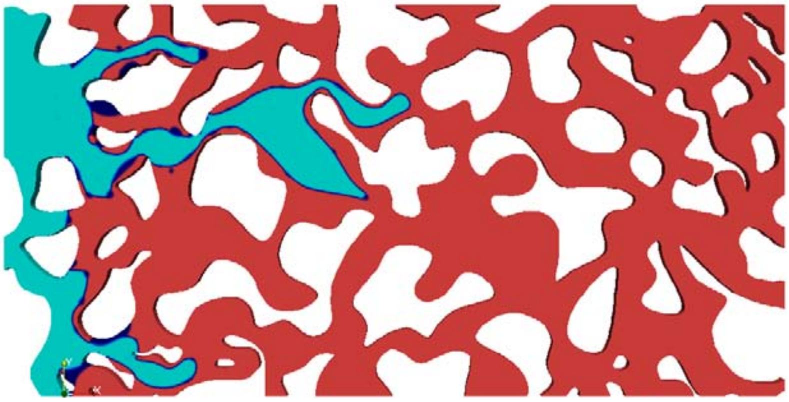

**Figure 2. Displacement of oil by the injected steam. The dark blue represents the condensate phase**

In the second case, a more complex medium is used to examine the oil production as a result of viscosity reduction (Figure 3). During the process starting from **a** to **f**, oil phase is heated and the production continues from the bottom face. The aqueous phase (blue color in Figure 3b) forms and disappears quickly due to condensation and evaporation phenomena.

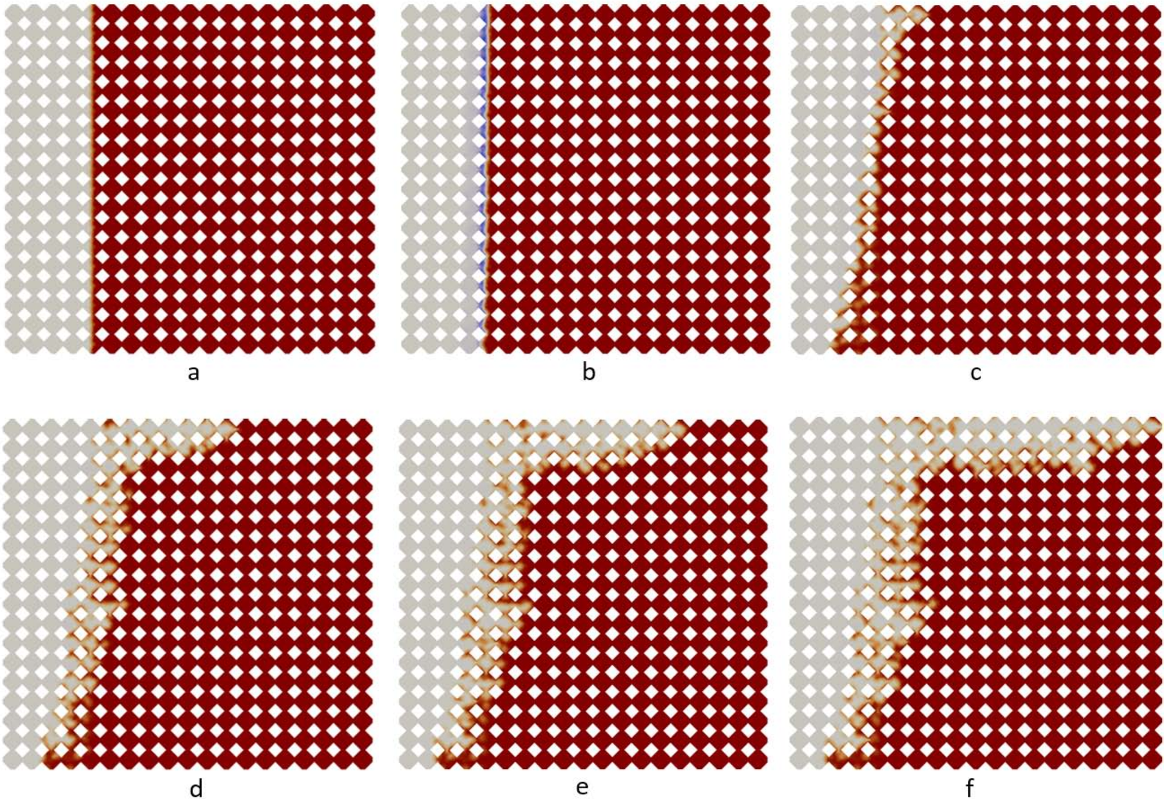

**Figure 3 Simulated steam-oil interface development from (a) to (f)**

The results are in a good agreement with a similar process which is conducted experimentally (Mohammadzadeh 2015) (Figure 4).

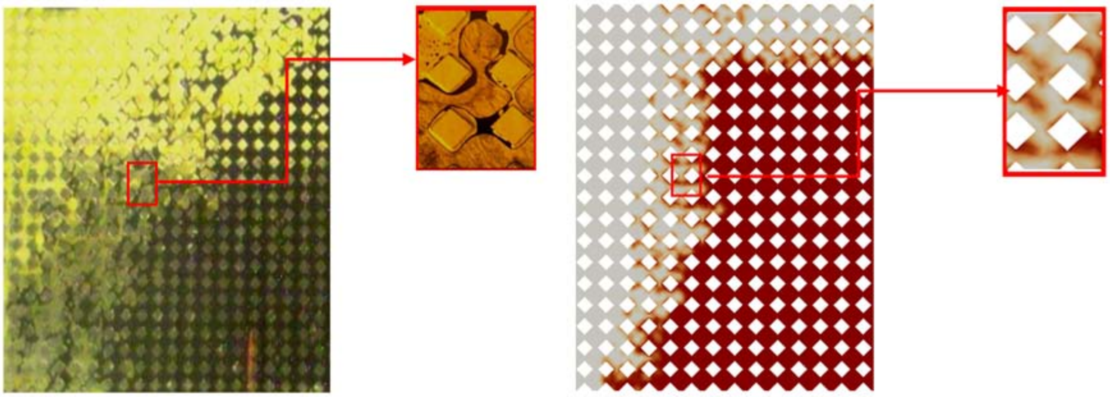

**Figure 4 Residual oil pattern, (experimental (left), and simulation(right) results)**

To sum up, a new solver has been developed to study phase change in porous media. This solver can help to understand complex physics which are dominated in thermal recovery approaches. Using this solver, the influence of material properties such as viscosity, density, thermal conductivity, heat capacity, interfacial tension and wettability on the phase change and consequently oil recovery can be addressed. This solver will be further modified to capture the heat transfer in grains.

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