

## **Pore-Level Modeling of Carbon Dioxide Sequestration in Oil Fields: A study of viscous and buoyancy forces**

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Underground injection of carbon dioxide for enhanced oil recovery (EOR) is a common practice in the oil and gas industry and has often been cited as a proven method of sequestering CO<sub>2</sub> (US DOE, 1999). Of all sequestration methods, this is probably the best understood, as carbon dioxide has been used in the oil industry for many years. Additionally, most oil fields have been relatively well characterized geologically, and often have impermeable layers above them, which will act as traps for sequestered CO<sub>2</sub>. Miscible CO<sub>2</sub> flooding is particularly favorable for both EOR and sequestration because the absence of capillary forces increases the efficiency of the displacement. Of course, the goals of enhanced oil recovery and CO<sub>2</sub> sequestration are not the same, so a flooding process optimized for sequestration will be somewhat different than one for oil recovery.

There are still some difficulties with CO<sub>2</sub> sequestration in oil fields. For example, it has long been known that displacing connate oil by a less-dense, less-viscous fluid produces flow stratification and unstable fingering patterns in the displacement fronts. These phenomena reduce the oil production of the reservoir, as well as the available space for sequestration. Gravity override and viscous fingering are still not well understood, even in the oil recovery industry. A better understanding of these processes could lead to reduced capital and operating costs for CO<sub>2</sub> sequestration in oil fields and for enhanced oil recovery.

We have developed a pore-level numerical model of the miscible injection of one fluid (CO<sub>2</sub>) into a porous medium saturated with another fluid (oil). The model incorporates a distribution of "pore-throat" radii, fluid viscosities, and fluid densities to mechanistically represent the physical flow situation. This model has been used, with experimental values of viscosities and densities, to study the high-pressure injection of liquid carbon dioxide into oil-saturated porous media. Results are presented for a number of viscosity and density ratios.

### *Introduction*

Two-phase flow in porous media has long been important to scientists and engineers in the environmental and petroleum industries. Most modeling of two-phase flow is done on large reservoir simulators meant to predict general flow properties, such as saturation and total recovery (Blunt et al., 1992). These simulators typically rely on a form of Darcy's law to describe the movement of each phase through the medium. However, for nearly twenty years, it has been known that in certain well-defined limits, the compact flow assumptions of the Buckley-Leverett equations are not accurate.

The physical processes that contribute to the inaccuracies in Darcy's law and the Buckley-Leverett equations manifest themselves on a pore-level. These are the same processes that cause flow phenomena such as viscous fingering. We believe that the best way to understand this type of flow behavior is to create pore-level models that capture these flow phenomena. The models may then be used to scale up flow properties to field size and inform modifications in reservoir simulators. A number of pore-level analytical and computer models, such as diffusion-limited aggregation and invasion percolation, have been developed to describe the fractal growth patterns known to occur in special two-phase flow situations (Feder, 1988; Ferer and Smith, 1994).

We have developed a mechanistic pore-level network model to describe miscible and immiscible, incompressible, non-wetting fluid invasion into porous media. This model generates random distributions of pore radii to simulate porous medium properties and incorporates fluid viscosities and fluid densities. This is an extension of previous models (Ferer and Smith, 1994; Ferer et al., 2001) that did not include buoyancy forces.

### *Objective*

The main objective of this work is to use the mechanistic model to simulate miscible displacement of oil by carbon dioxide. The displacement is horizontal, so gravity forces are considered to be in the transverse direction, as opposed to being in the direction of flow. We study the relationship between viscosity and density differences and CO<sub>2</sub> displacement efficiency for the case of miscible displacement of oil. The viscosity ratio ( $M=\mu_1/\mu_2$ ) and the density ratio ( $D=\rho_1/\rho_2$ ) are common dimensionless numbers that we relate to saturation and fractal dimension.

### *Approach*

Using the mechanistic model, we simulate the horizontal infiltration of liquid carbon dioxide into a porous medium saturated with oil. Since oil fields exist under a variety of temperatures and pressures, ranges of density and viscosity are taken from experimental values and used as input parameters for the model. At all relevant depths, carbon dioxide is significantly less viscous and less dense than oil. In some cases, the carbon dioxide will be a supercritical fluid and therefore compressible. Nevertheless, we assume fluid incompressibility in our model, which is a conservative assumption for CO<sub>2</sub> sequestration.

All simulations have been run on a 50x50 diamond lattice of pores and throats. Simulations were run for a range of viscosities and densities that would correspond to liquid and supercritical CO<sub>2</sub>. The values used in the simulations are shown in Table 1. Experimental values for density and viscosity of oil were also used to calculate the input parameters. Physical properties of the oil may vary almost as much as those of carbon dioxide. However, to simplify, only average values of oil viscosity and density were used:  $\mu=50\text{cP}$  and  $\rho=1.1\text{g/cm}^3$  (Lake, 1989).

Table 1. Physical properties of oil under low, average, and high pressure.

Pressure	Density <sup>1,2</sup> (g/cm <sup>3</sup> )	Viscosity <sup>2</sup> (cP)
low	0.15	0.01
average	0.50	0.05
high	0.90	0.09

<sup>1</sup>Angus et al. (1976) <sup>2</sup>Chun and Wilkinson (1995)

### Model Description

The model described here is essentially an extension of the model by Ferer and Smith (1994). Capillary forces are included in the model, but they are not used in this work because the displacement is miscible. The model is a diamond lattice of pores and throats as shown in Figure 1. Flow through each throat is determined by the conductance of the throat (depending on throat radius) and the pressure gradient between the pores (depending on the pressure in each pore, the capillary pressure, and the gravitational gradient). An excellent description of the model without gravity can be found in Ferer et al. (2001), so we will be concentrating on a description of how buoyancy forces are added here.

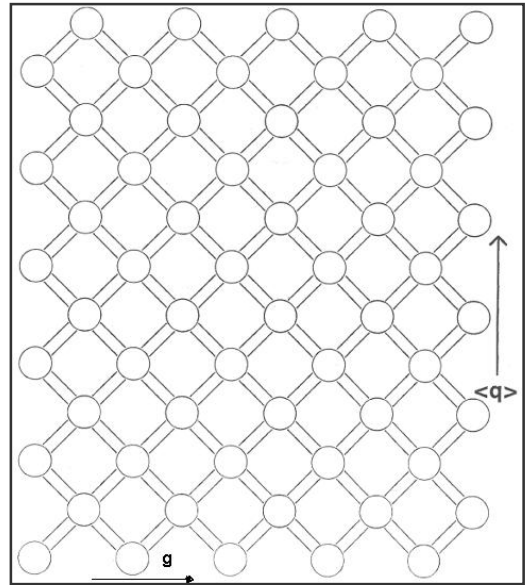


Figure 1. Diamond lattice of pores and throats; cross-current gravity.

To determine the flow in each throat, the value of the pressure gradient must be calculated for each time step. One component of the pressure gradient comes from the pressure differential between the pores on each side of the throat. Absent capillarity, the only other component is due to gravity. When a single fluid is in a pore and throat, the calculation is fairly simple:

$$P_G = \rho g x \sin \psi , \quad (1)$$

where  $P_G$  is the pressure gradient due to gravity,  $\rho$  is the density,  $g$  is the acceleration due to gravity,  $x$  is the distance from the center of one pore to the other, and  $\psi$  is the angle that the throat makes with respect to the horizontal. The direction of this pressure gradient is always in the same direction (downward in the transverse direction to the flow).

When two fluids are in the pores and throats, however, the situation becomes more complex. Basically, the pore-throat system can be split up into two sections, the section filled with invading fluid and the section filled with displaced fluid. Once you find the length of each section, you can use Equation 1 for each distinct part and sum

them to get the total pressure gradient. If two fluids are in the throat, then the pressure gradient in the throat is:

$$P_G = \rho_1 g a x \sin \psi + \rho_2 g (1-a) x \sin \psi , \quad (2)$$

where  $a$  is the volume fraction of the invading fluid (fluid 1) in the throat.

For each pore, the invading fluid is assumed to be in the center of the spherical pore in a ball, while the defending (wetting) fluid surrounds it and stays next to the pore wall. Spheres in the model have a unit volume of 1, so the pressure gradient along the pore would be:

$$P_G = \rho_1 g \left( \frac{3a}{4\pi} \right)^{1/3} \sin \psi + \rho_2 g \left[ \left( \frac{3}{4\pi} \right)^{1/3} - \left( \frac{3a}{4\pi} \right)^{1/3} \right] \sin \psi , \quad (3)$$

where  $a$  is the volume fraction of invading fluid in the pore.

Including gravitational forces in the model also requires a distinct pressure distribution around the boundary of the modeled flow cell. Figure 3 shows what that pressure distribution would look like for the cell. Notice that this is the pressure distribution that would envelope the cell if it were surrounded by oil in hydrostatic equilibrium moving from left to right.

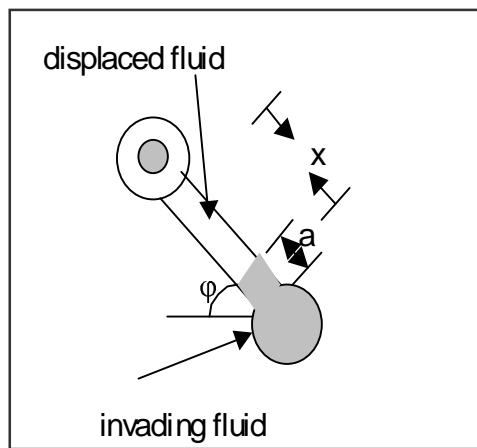


Figure 2. Diagram of a pore-throat system; invading fluid is gray.

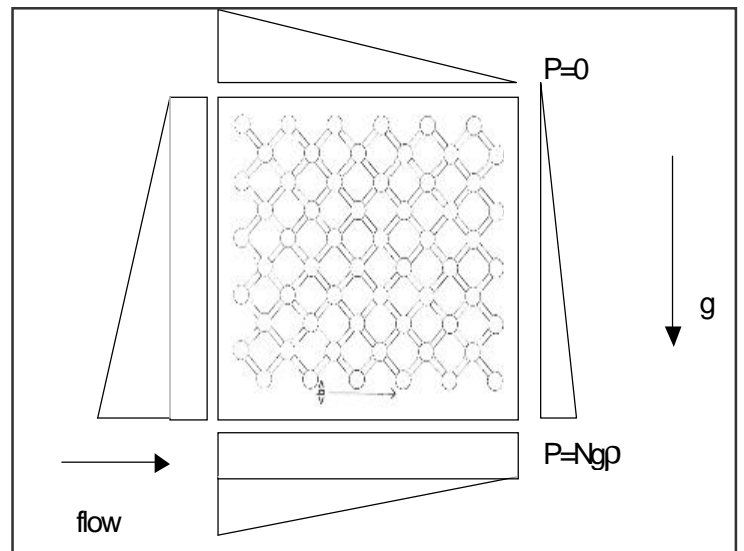


Figure 3. Diagram of pressure field around cell.

### Results

In this section, results from simulations of size 50x50 pores are presented. Table 2 shows the saturations and fractal dimensions for the simulations that were run and how they relate to the viscosity and density ratios. The general relationship between these variables is fairly clear and is consistent with what is known about the effects of gravitational and viscous forces on two-phase miscible displacement. Saturation and fractal dimension both decrease with decreasing viscosity ratio and decreasing density ratio. Notice also that a difference in density causes a greater change in saturation than an equivalent change in viscosity, at least for the ranges tested here. Whereas saturation varies by about 25% for about an 85% change in density, it changes by only about 10% for a similar change in viscosity.

Table 2. Saturation and fractal dimension as related to viscosity and density ratios.

	<b>D=0.1</b>		<b>D=0.4</b>		<b>D=0.7</b>	
	<b>Sat</b>	<b>D<sub>f</sub></b>	<b>Sat</b>	<b>D<sub>f</sub></b>	<b>Sat</b>	<b>D<sub>f</sub></b>
<b>M=0.0003</b>	15.7	1.69	18.8	1.73	20.5	1.74
<b>M=0.0010</b>	16.3	1.70	19.1	1.73	21.3	1.74
<b>M=0.0018</b>	17.2	1.70	19.8	1.75	23.1	1.76

It is important to place these results in context. While the values of the density ratio are within one order of magnitude from unity, the values of viscosity ratio are much less. Other studies have suggested that the further from unity the viscosity ratio is, the less relative difference is found in the corresponding saturations (Lenormand et al, 1988). This means that the viscosity ratio is probably as significant a factor in determining the saturation as the density ratio, only not as important for this range of values. Nonetheless, these results are only preliminary, and a final determination of the relative importance of viscosity and density must wait for more information.

### Conclusion & Application

Practically, these results tell us two things. First, within the range of temperatures and pressures that one would find in oil fields, the saturation can vary significantly. This suggests that some fields will be better suited for sequestration than others, i.e., the ones that correspond to higher CO<sub>2</sub> viscosities and densities. This, of course, does not necessarily mean the lowest depths, as in some of these cases, the CO<sub>2</sub> is in a supercritical state, wherein the viscosity can vary widely.

A second practical consideration is that the viscosity seems to be significantly less important than the density within this region of the M-D parameter space. Thus, adding viscosifiers to the CO<sub>2</sub> to make it “thicker” would not be very useful. More important would be the addition of some substance that would increase the CO<sub>2</sub> density without significantly increasing the mass. This would not necessarily be true, however, for other CO<sub>2</sub> sequestration situations, such as in brinefields, where changes in the viscosity ratio may have much more significant effects.

Of course, the results presented here are fairly preliminary, and it is difficult to make any final practical conclusions until these simulations are run on larger systems to determine what kind of scaling effects we can observe. Because of the sizes of the systems, it is not clear how well the flow will scale up with these parameter values. Preliminary fractal dimension calculations are consistent, but better estimates should come with larger systems.

### *Future Activities*

The first area of future work is to generate more random fields of pores and run the simulations with the same parameters to help determine how robust the system is. Following this, of course, we would like to simulate using larger pore networks (70x70 and 100x100) for the same range of parameters. This would give us some idea of the scaling properties of the system (Ferer and Smith, 1994).

Ideally, we would vary the values of viscosity and density outside the range of those practical in oil field sequestration to better understand the relationship between these variables and determine if the viscosity ratio becomes more significant as it increases. Then, we could create a parameter space for viscous and buoyancy forces similar to the one suggested by Lenormand et al. (1988) for capillary number and viscosity ratio. Such a diagram would allow us to place the relative importance of viscosity and density into some larger context.

Another plan for the future is to expand this model to allow flow in three dimensions. Two dimensional models can be good at determining the relative importance of viscous and density forces, but to truly scale up to large three-dimensional systems requires at least some testing on 3-D networks.

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