

High Resolution Prediction of Gas Injection Process Performance for Heterogeneous Reservoirs

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Abstract

This report outlines progress in the first 3 months of the first year of the DOE project “High Resolution Prediction of Gas Injection Process Performance for Heterogeneous Reservoirs.”

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1 Executive Summary

Gas injection in oil reservoirs offers huge potential for improved oil recovery. However, successful design of a gas injection process requires a detailed understanding of a variety of different significant processes, including the phase behavior of multicomponent mixtures and the approach to multi-contact miscibility in the reservoir, the flow of oil, water and gas underground, and the interaction of phase behavior, reservoir heterogeneity and gravity on overall performance at the field scale. This project attempts to tackle all these issues using a combination of theoretical, numerical and laboratory studies of gas injection, as described below.

The aim of this work is to develop a set of ultra-fast compositional simulation tools that can be used to make field-scale predictions of the performance of gas injection processes. To achieve the necessary accuracy, these tools must satisfy the fundamental physics and chemistry of the displacement from the pore to the reservoir scales. Thus this project focuses on four main research areas:

- Determination of the most appropriate methods of mapping multicomponent solutions to streamlines and streamtubes in 3D,
- Development of techniques for automatic generation of analytical solutions for one-dimensional flow along a streamline,
- Experimental investigations to improve the representation of physical mechanisms that govern displacement efficiency along a streamline, and

- Theoretical and experimental investigations to establish the limitations of the streamline/streamtube approach.

In this report we briefly review the status of the research effort in each area. We then give a more in depth discussion of our development of a CT scanning technique which can measure compositions in a two-phase, three-component system in-situ.

2 Introduction

Newly arrived M.S. student Linda Chizoba Sam-Olibale has begun working with Professor Tom Hewett on the comparison of streamtube and streamline models. Ph.D. student Jichun Zhu and Professor Lynn Orr are in the processes of extending the analytical solutions of compositional flows to include variations in temperature. In January 2001, Kristian Jessen will join us as a post-doctoral associate and begin work on the automatic generation of analytical solutions. Research associate Charles Schaefer is characterizing a system of fluids which can be used to study four-phase flow, and crossflow between streamlines. All of this research will be detailed in later reports. In this report, we concentrate on our progress in using CT scanning to study compositional systems in-situ.

3 Experimental

3.1 Experimental Measurements of Compositional Flows

During a displacement in which the displacing phase is not at chemical equilibrium with the displaced phase, the chemical state of the system will vary in space and time. This variation can be described as a path through the composition space. In 1D displacements, the path through the composition space, and the saturation profiles in real space has been solved under certain simplifying assumptions [4, 3]. These solutions are in excellent agreement with measurements of the effluent of slim-tube experiments.

There are many situations when the simplifying assumptions are not valid: gravity drainage [8], when gravity and capillary forces are non-negligible, viscous fingering [9], capillary driven crossflow [6], etc. In these cases the effluent from a column study will not capture the relevant physics and chemistry happening during the displacement.

In-situ measurements of the composition during the displacement are thus highly advantageous. Along with giving a saturation profile of the displacement, the compositional information will yield a profile of phase behavior, and thus profiles of the densities, viscosities, and interfacial tensions. From in-situ measurements, we can begin to compare experimentally how capillary crossflow, gravity, and viscous effects alter the displacement.

3.2 Analog Ternary System

In reservoirs, the transfer of hydrocarbon components between the gaseous and liquid phases takes place at high temperature and pressures. The phase behavior of a model three-component/two-phase hydrocarbon system at reservoir conditions is depicted in Fig. 1. CO_2 is the primary component of the gaseous phase, C_{10} is the primary hydrocarbon component

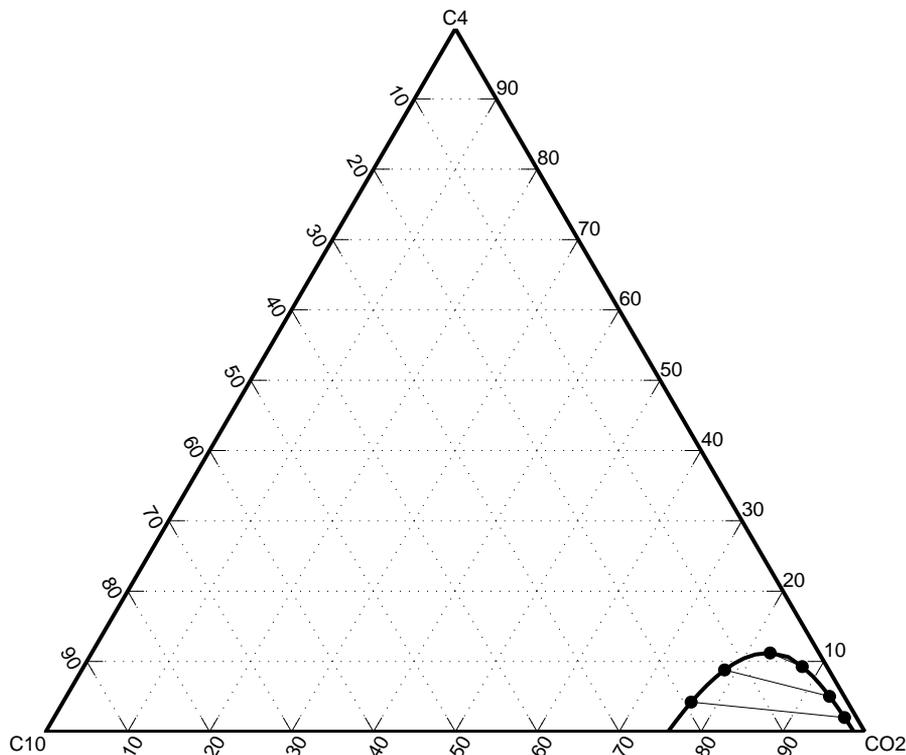


Figure 1: Phase diagram for the $C_{10}/C_4/CO_2$ ternary system at $160^\circ F$ and $1600 PSIA$.

of the liquid phase, and C_4 is the intermediate hydrocarbon component. Outside the thick curved line is the single phase region, and inside is the two-phase region, with tie lines depicted by the straight thin lines. Under certain limiting assumptions, and from this phase diagram and analytical calculations, the displacement of a C_{10} rich phase by a CO_2 rich phase can be calculated.

These calculations assume that the capillary and gravity forces are negligible in the displacement, which will not be true for many gas injection processes. To experimentally focus on how capillary and gravity forces affect the flow and transfer, we use an analog compositional system consisting of isopropanol (IPA), iso-octane (IC_8), and a 10% NaBr brine. This is similar with the system developed by Morrow *et al.*[5], except for the more concentrated brine. The room temperature/room pressure phase diagram has been measured and is depicted in Fig. 2. In this system, the iso-octane represents the light hydrocarbons, and is the primary constituent of the non-wetting (gaseous) phase. The brine represents the heavy hydrocarbons, and is the primary constituent of the wetting (liquid) phase. The isopropanol represents the intermediate size hydrocarbons, and can transfer between the wetting and non-wetting phases. The analogies between the reservoir system and laboratory system are apparent with the major difference between these two being a much larger two-phase region in the laboratory system.

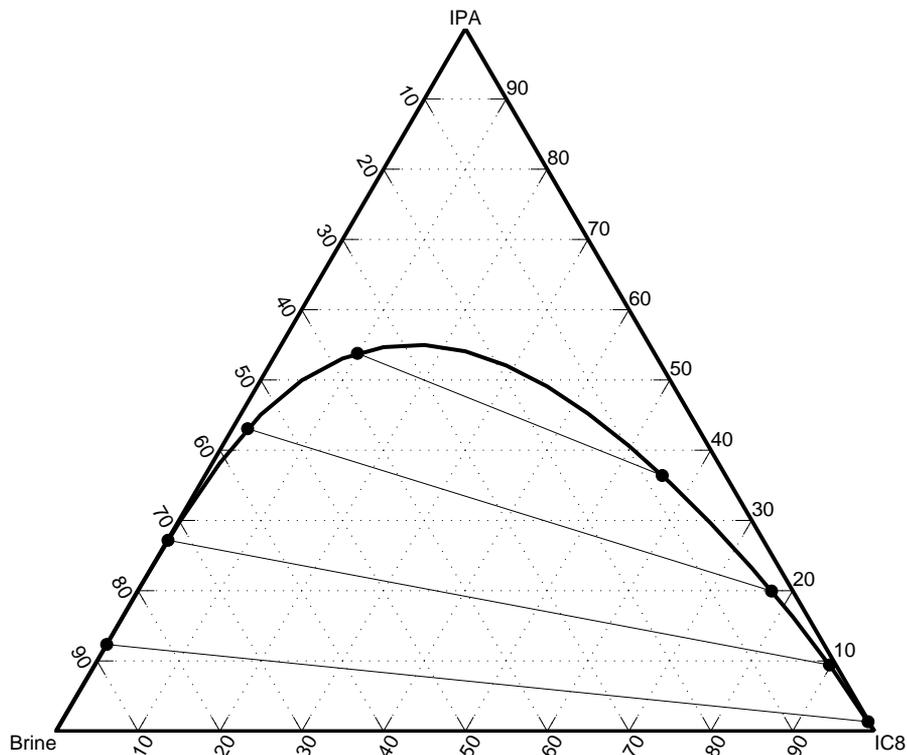


Figure 2: Phase diagram for the brine/isopropanol (IPA)/iso-octane (IC8) ternary system at room temperature and pressure.

4 Results and Discussion

4.1 CT scanning

CT scanning has been used widely to image saturation profiles within a porous medium such as unconsolidated sand and/or sandstone [2, 7]. During the previous DOE grant, we were interested in the in-situ oil, water and gas saturation of three-phase (water/oil/gas) gravity driven displacements [1]. Using a CT scanner operating at two different energies, we obtained two separate measurements of the attenuation of the core, and using the knowledge that the saturations must sum to one, we were able to the in-situ saturations. We found the in-situ saturations to be accurate to ± 0.01 in saturation for all three phases.

We review how three-phase saturations are measured using dual-energy CT scanning, and then we report on our developments extending this to the three-component, two-phase compositional system.

CT scanning measures the overall attenuation in small control volumes (voxels). This attenuation is the linear sum of the attenuation caused by each substance in that voxel. For a three-phase (water/oil/gas) system in a porous medium, the attenuation (CT) in Hounsfield units is given by

$$CT = \alpha_o m_o + \alpha_w m_w + \alpha_g m_g + \alpha_r m_s, \quad (1)$$

where m_i is the mass (g) of oil, water, gas, and solid, in the voxel, and α_i is the attenuation coefficient of each phase in Hounsfield units per gram.

The attenuation coefficients depend on the energy of the radiation, and the particular component, so they must be calibrated beforehand. We obtain the calibration constants by

scanning the porous medium when it is dry, when it is fully saturated with water, and when it is fully saturated with oil. Using CT_i to describe the measured CT number when the core is full of phase i , and assuming that the porous medium is fixed, we can re-write Eq. 1 as

$$CT = CT_o S_o + CT_w S_w + CT_g S_g, \quad (2)$$

where S_i is the saturation of phase i .

By scanning at high and low x-ray tube energies (which gives different calibration coefficients), and using the fact that the saturations must sum to 1, the in-situ saturations can be calculated from the measured attenuations. The matrix equation to solve for the saturations is

$$\begin{pmatrix} CT_o^H & CT_w^H & CT_g^H \\ CT_o^L & CT_w^L & CT_g^L \\ 1 & 1 & 1 \end{pmatrix} \begin{pmatrix} S_o \\ S_w \\ S_g \end{pmatrix} = \begin{pmatrix} CT^H \\ CT^L \\ 1 \end{pmatrix}, \quad (3)$$

where the superscripts H and L are for the high and low energy measurements.

4.2 Accuracy

The accuracy of the in-situ saturations (or, alternatively the mass fractions) from the dual energy technique is proportional to the determinant of the left hand side matrix in Eq. 3. This determinant is large if a) the oil, water, and gas all have different attenuation strengths, and b) the water preferentially attenuates low-energy x-rays and the oil preferentially attenuates high-energy x-rays (or vice-versa). For the oil/water/gas system condition a) is easily met, and condition b) can be enhanced by doping the water phase with 10% NaBr.

Although we can estimate the saturation accuracy from the fluid CT properties, a more definitive method is to do the measurements in an actual porous medium. This in-situ method is implemented as follows. The porous medium which we image consists of homogeneous sand pack with a diameter of 7.5 cm and a length of 65 cm. Since there are small variations in packing along the core, the calibration needs to be done separately at each imaged interval which is typically every 2 cm along the length of the core. The calibration scans at the high (140KeV) and low (80 KeV) energies are taken when the core is dry, when it is fully saturated with water, and when it is fully saturated with oil. Each position thus has its own calibration matrix. The saturation accuracy now can be measured by filling the core with known amounts of fluid, and observing the scatter in the measured amounts.

For oil/water/gas systems, we obtain a relatively uniformly saturated porous medium by displacing a oil-saturated pack with 5 pore volumes of water, leaving a small amount of residual oil. In the center of the core, away from the end effects, the oil saturation should be relatively constant, and the measured gas saturation should be zero. Fig. 3 shows these measured water, oil, and gas saturations in a ternary diagram. The scatter in the plot gives an estimate of the saturation accuracy, which is ± 0.01 in the direction of the gas saturation. The larger scatter in the water/oil direction is caused by variations in the trapped oil more than saturation accuracy, and other measurements show that the saturation accuracy is roughly ± 0.01 for the water and oil phases also.

This can be extended to a compositional system which has 3 components and 2 phases. The calibration and the calculations are similar to the oil/water/gas system with

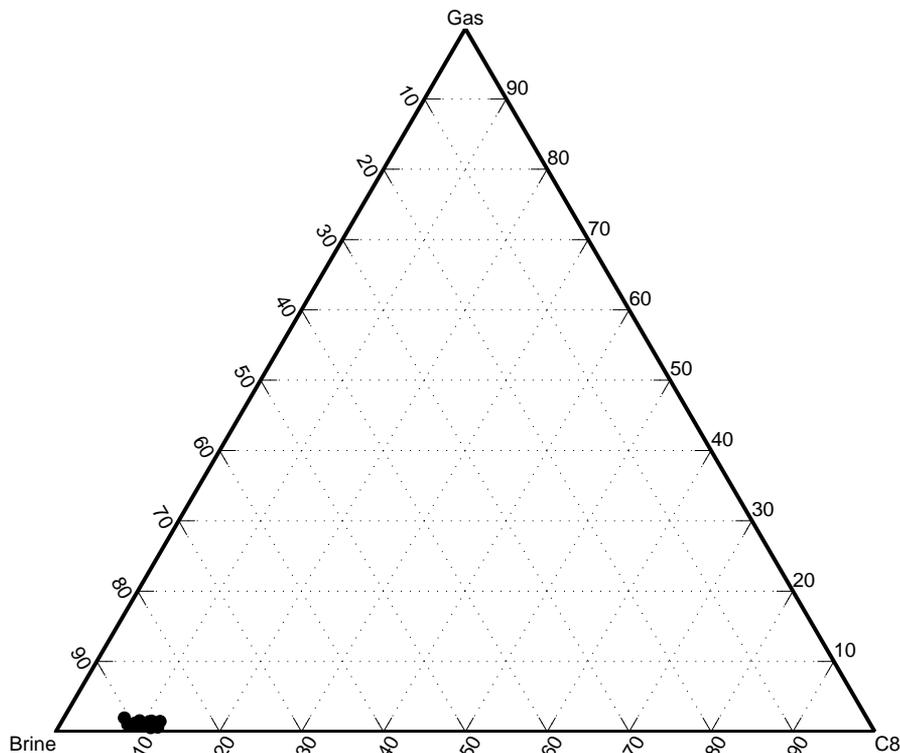


Figure 3: Measured three-phase saturations along a uniformly saturated section of core. The scatter in the data roughly gives the saturation accuracy of the in-situ measurements.

the isopropanol replacing the gas, and mass fractions are used instead of saturations. The difficulty lies within the change in accuracy of the technique. The matrix equation which determines the mass fractions is now

$$\begin{pmatrix} CT_o^H & CT_w^H & CT_a^H \\ CT_o^L & CT_w^L & CT_a^L \\ 1 & 1 & 1 \end{pmatrix} \begin{pmatrix} m_o \\ m_w \\ m_a \end{pmatrix} = \begin{pmatrix} CT^H \\ CT^L \\ 1 \end{pmatrix}, \quad (4)$$

where a is for alcohol and the m_i are the mass fractions of each phase.

For this water/oil/alcohol system, the determinant of the matrix is much smaller than it is in the water/oil/gas system. This occurs because the density of the isopropanol ($\rho_a = 0.782$) is close to the density of the iso-octane ($\rho_o = 0.688$). This can substantially reduce the accuracy of the oil and alcohol mass fractions.

We recently completed experiments testing the accuracy of dual-energy scanning for this compositional system. The core was scanned dry, and then subsequently scanned full of iso-octane, isopropanol, and brine. After the calibration scans the core was flooded with a mixture of brine and alcohol at mass fractions of $m_a = 0.6$ and $m_w = 0.4$. Figure 4 shows the measured mass fractions from scanning all the positions along the core.

The scatter in the data lies mostly on the oil-alcohol axis, which shows that it is harder to distinguish these components from each other than from the brine. This is not surprising as the brine has a much different density ($\rho_w = 1.070$), and also preferentially attenuates the low-energy x-rays. From the data, we estimate the mass fraction accuracy to be ± 0.01 for the brine component and ± 0.05 for the alcohol and oil components.

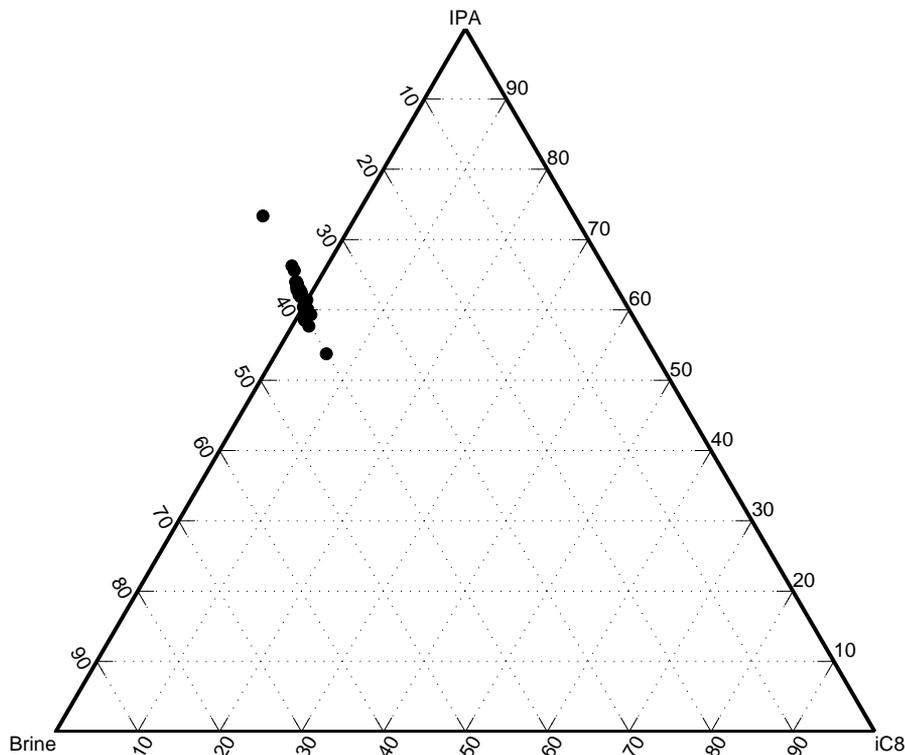


Figure 4: Measured three-component mass fractions along a uniformly saturated section of core. The scatter in the data roughly gives the mass fraction accuracy of the in-situ measurements.

5 Conclusion

The accuracy obtained will be adequate enough to discern the composition of the fluids at each position during the displacement. We are currently performing a gravity driven displacement where pure iso-octane is displacing a brine/IPA mixture. This is equivalent to gravity drainage of a hydrocarbon mixture during a CO_2 injection. Since the composition of the fluids must change during the displacement, the interfacial tension between the phases and the density difference will also change along the column. The in-situ CT measurements will tell us under what conditions the capillary forces dominate, and when the buoyancy forces dominate in compositional gravity drainage.

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