PREDICTION OF GAS INJECTION PERFORMANCE FOR HETEROGENEOUS RESERVOIRS

SEMI-ANNUAL TECHNICAL

REPORTING PERIOD: 10/01/1997 - 03/31/1997

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REPORT ISSUE DATE: 04/30/1997

DE-FG22-96BC14851

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Introduction

The current project is a systematic research effort that will lead to a new generation of predictive tools for gas injection processes in heterogeneous reservoirs. The project is aimed at quantifying the impact of heterogeneity on oil recovery from pore level to reservoir scales. This research effort is, therefore, divided into four areas:

- Laboratory Gas Injection Experiments
- Network Modeling of Three-Phase Flow
- Benchmark Simulation of Gas Injection Processes
- Streamline Simulator Development

The status of the research effort in each area is reviewed briefly in the following section.

Project Status

Laboratory Gas Injection Experiments

Gravity drainage of oil in the presence of gas and water has been found to result in high recovery efficiency [4]. Numerical representation of the high recovery efficiency requires a good understanding of three-phase relative permeabilities, especially at low oil saturations. Ph.D student Akshay Sahni has analyzed experimental results of selected three-phase displacements in the literature and compared them with the newly developed mathematical theory of three-phase flow in porous media [1, 2]. He approximated the relative permeability of each phase as a polynomial function of the saturation of that phase. An excellent agreement has been obtained between the measured and the calculated saturation paths. The analytical solution has also been checked by performing numerical simulations. Fig. 1 is an example of the comparisons of experiments, mathematical theory and numerical simulations. Fig. 1 shows a situation in which gas is injected into a system with high oil saturation and the formation of an oil bank is observed.

The experiments in the literature were generally conducted at relatively high oil saturations. We have designed a series of gravity drainage experiments to measure three-phase relative permeability at low oil saturations. The CT scanner in the Petroleum Engineering Department at Stanford has been modified to measure in-situ saturations of vertically-placed samples, which is necessary in gravity drainage experiments. Akshay Sahni has finished a series of gravity drainage experiments in sand packs using different model oils to calibrate the scanner and to investigate the effect of spreading coefficient on three-phase relative permeability. A procedure has been developed for calculating relative permeabilities from measured in-situ saturations.
Figure 1: Predicted and measured saturation paths for Grader and O’Meara’s run #8
Research Associate Dr. Dengen Zhou has conducted a series of gravity drainage experiments on mixed-wet sand packs to investigate the effect of wettability on three-phase gravity drainage. The mixed-wet sand packs were prepared by mixing different proportions of water-wet and oil-wet sands. Experimental results suggest that the connectivity of flow pathways is controlled by the wettability, which would alter the magnitude of relative permeabilities and residual oil saturations at the end of a gravity drainage process. These experiments identify the mechanisms that control the displacement in mixed-wet systems and will be used in network simulations of three-phase flow in mixed-wet reservoir rocks.

The next step of the research in this area is to process the experimental data and extract information on relative permeabilities. We will perform gravity drainage experiments on consolidated samples, which have higher capillary pressures than sandpacks for a given fluid system.

**Network Simulation of Three-Phase Flow**

A significant effort has been made to understand three-phase flow in pores and pore networks. Experiments and theoretical studies have shown that the existence of corners and crevices in the pore space enhances the stability oil layers in the medium and hence increases the oil relative permeability. Stability criteria and conductance of oil layers in corners have been proposed to represent the effect of pore geometry on relative permeabilities. Ph.D Student Darryl Fenwick has constructed a three-dimensional network model to study the flow of water, oil and gas in pore networks. A three-dimensional regular network is employed to represent a porous medium. The stability criteria and the conductance of oil layers in the corners of pores have been incorporated in the network model. Primary simulation results suggest that for spreading systems the residual oil saturation could be close to zero as oil layers are stable even at very low saturations. Fig. 2 shows the calculated oil relative permeabilities for gas injection processes with different initial oil saturations. At high oil saturations, the relative permeabilities differ. However, oil flows mainly through oil layers at low saturations, and the relative permeability curves become similar. For systems with negative spreading coefficient the residual oil saturation is a strong function of displacement history and the spreading coefficient. The details of pore geometry affect the simulation results more significantly for nonspreading systems than for spreading systems.

We continue our effort in understanding multiphase flow in single pores. The conductance of an oil layer in the pore space depends on the boundary conditions at the interfaces of the fluids [5]. We designed an experimental effort to identify the boundary conditions at the fluid interfaces. MS Student Tuba Firincioglu has measured the drainage rates of water and oil in triangular capillaries. Comparisons of measured and calculated drainage rates would reveal the boundary conditions at the water/oil and oil/gas interfaces.

Research in this area will continue to extend the network model for simulations of different displacement processes. We will also experimentally examine the stability criteria of oil layers in corners for nonspreading systems.
Benchmark Simulation of Gas Injection Processes

Simulations of a gas injection process in reservoir scales using conventional simulation technique require significant amount of CPU time even on the most advanced computers available now. The development of streamtube/streamline simulation methods in our research group provides the opportunity for large scale simulations of gas injection processes with accurate representation of the displacement mechanisms in reservoir scales. Prof. Marco Thiele has performed a series of numerical simulations of gas injection using a code developed by the University of Texas at Austin (UTCOMP) and an early version of the streamline simulator developed at Stanford to compare the accuracy and the efficiency of the two types of simulation techniques. For reservoirs in which flow is dominated by permeability heterogeneity, the streamline simulator gives accurate results in a significantly reduced time. Fig. 3 shows a comparison of the productions curves from UTCOMP and the streamline simulator with different number of recomputations of the pressure field. It is clear that the streamline simulator needs only about 40 updates which is significantly smaller than the number used in the conventional simulators.

The research in this area will continue along with the development of the streamline simulator. We will use the revised versions of the streamline simulator to study various gas displacement processes in heterogeneous systems.

Figure 2: Calculated oil relative permeabilities for gas injection processes with different initial oil saturations.
Streamline Simulator Development

The streamline simulation method under development at Stanford has evolved from the streamtube simulation technique developed by Prof. Marco Thiele at Stanford [3]. The streamtube concept is very convenient for two-dimensional systems. However, for three-dimensional heterogeneous systems defining a streamtube is fairly complex. Thus, streamtubes are replaced by streamlines which are easy to define in both two and three dimensions spaces. The early version of the streamline simulator handles systems in which gravity forces are insignificant, that is, the flow is dominated by the reservoir heterogeneity. Recently Ph.D student Rod Batcykey has extended the technique to include gravity effects for first contact miscible and two-phase displacements in three-dimensional systems. Fig. 4 is an example of the simulated solvent distribution profile in a three-dimensional system (50×50×20 gridblocks). The injection well is located in the upper two blocks in the center of the model, the production wells are located in the lower two blocks in each corner of the model. Fig. 4 clearly shows that adding gravity to this three-dimensional model increases the amount of solvent in the top of the model. Each streamline model required 2 CPU hours, as against approximately 50 days for each ECLIPSE (a commercial finite-difference simulator) run if they were obtained using our current computer resources. The streamline method is several orders of magnitude faster than the conventional simulation methods.

The large speedup factor of using the streamline method enables us to conduct multiple-realization reservoir studies. Prof. Marco Thiele used the early version of the streamline simulator to quantify the uncertainty in reservoir performance. Fig. 5 shows an example use of streamline method to assess the uncertainty related to 100 equiprobable
Figure 4: Solvent distribution in a heterogeneous medium at $t_D = 0.52$, without gravity ($N_g = 0$) and with gravity ($N_g = 0.1$), as predicted by the streamline model. An injection well is located in the top two gridblocks in the model center, production wells are located in the lower two gridblocks in each corner of the model.
permeability realizations (125×50) and four different displacement mechanisms: (1) tracer flow, (2) two-phase immiscible flow, (3) first-contact miscible (FCM) flow, and (4) a four-component vaporizing-condensing gas drive. $t_d$ and $x_d$ are dimensionless time and distance, $C_d$ is the dimensionless concentration, $S_w$ is water saturation, $M$ is end-point mobility ratio, $Pe$ is Peclet number, and $\lambda$ is total mobility. It is clear that the uncertainty in the recovery is a combined effect of the reservoir heterogeneity and the displacement mechanisms: the permeability field are the same for all four displacement mechanisms, yet the uncertainty in cumulative recovery is notably different. Constructing Fig. 5 using conventional reservoir simulation techniques would have taken substantial computing resources and, in fact, the 100 recovery curves for the four component vaporizing-condensing gas drive would have been impossible to construct with our current computational resources.

The streamline method decouples each mechanisms that influences flow, solving them separately then combining the results. Mechanisms that result in transverse flow, such as capillary effects and diffusion, are hard to incorporate in the streamline method. More fundamental research is need to include the transverse flows from capillarity and molecular diffusion.

Summary

Since the initiation of the research project, significant progress has been made in the four research areas defined. A series of three-phase gravity drainage experiments have been performed to measure relative permeability and to investigate the effect of wettability on three-phase flow. A three-dimensional network model has been constructed to study the behavior of three-phase relative permeabilities. A streamline simulation technique is under development, which makes it possible to conduct full field reservoir simulations with accurate representation of displacement mechanisms.

References


Figure 5: Uncertainty in cumulative recovery for 100 equiprobable permeability fields and four different displacement mechanisms.