NIPER/BDM-0326

**Status Report**

# HETEROGENEITY CHARACTERIZATION AND FLOW SIMULATIONS IN NATURALLY FRACTURED RESERVOIRS

**for**

**Management and Operating Contract for the Department of Energy's National Oil and Related Programs**

by

Amit Sarkar and Leon Grossman
BDM Petroleum Technologies
Under Contract to BDM-Oklahoma, Inc.

September 1997

Work Performed Under Contract No.
DE-AC22-94PC91008

Prepared for
U.S. Department of Energy
National Petroleum Technology Office

**NIPER/BDM-0326**
September 1997

# HETEROGENEITY CHARACTERIZATION AND FLOW SIMULATIONS IN NATURALLY FRACTURED RESERVOIRS

**for**

**Management and Operating Contract for the Department of Energy's National Oil and Related Programs**

Work Performed Under Contract No.
DE-AC22-94PC91008

Prepared for
U.S. Department of Energy
National Petroleum Technology Office

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

BDM-Oklahoma, Inc.
P.O. Box 2565
Bartlesville, Oklahoma 74005

# Table of Contents

**1.0 INTRODUCTION** ..... **1**

**2.0 PROJECT DESCRIPTION** ..... **1**

**3.0 RESULTS AND DISCUSSIONS** ..... **1**

3.1 IMBIBITION EXPERIMENTS ..... 1

3.2 CO- AND COUNTERCURRENT FLOW MEASUREMENTS ..... 4

3.3 MULTIPHASE FLOW IN FRACTURES ..... 4

3.4 RESERVOIR CHARACTERIZATION ..... 5

3.4.1 Geostatistical Reservoir Description ..... 5

3.4.2 Fluid Characterization ..... 5

3.4.3 Rock-Fluid Properties ..... 6

3.5 UPSCALING METHODS ..... 7

3.6 RESERVOIR SIMULATION ..... 7

3.6.1 Numerical Simulator ..... 7

3.6.2 Flow Simulation ..... 7

**4.0 CONCLUSIONS** ..... **12**

**5.0 TECHNOLOGY TRANSFER** ..... **12**

**6.0 PLANNED ACTIVITIES** ..... **12**

**7.0 REFERENCES** ..... **13**

# Table

1 Description of Imbibition Experiment for Bainville North (Montana) Core ..... 2

# Figures


1 Schematic of experiment showing fluid flow paths for spontaneous countercurrent and forced cocurrent imbibition processes ..... 2

2 Experimental cumulative oil recovery history during the spontaneous and forced imbibition processes ..... 3

3 Experimental water saturation profiles at different times during spontaneous and forced imbibition processes ..... 3

4 Imbibition and drainage oil-water relative permeabilities for the fracture ..... 4

5 Oil-water relative permeabilities ..... 6

6 Oil-water imbibition capillary pressures ..... 6

7 Schematic showing matrix-fracture system and fluid-flow paths for the matrix blocks (homogeneous or heterogeneous) of size 20 ft ¥ 1 ft ¥ 20 ft ..... 8

8 Experimental cumulative oil recovery history during spontaneous and forced imbibition processes ..... 8

9 Vertical water saturation profiles at different times for columns at distances of 1.5 ft and 19.5 ft from the fracture for the homogeneous matrix ..... 9

10 Horizontal water saturation profiles at 4000 hrs. for the top and bottom layer of the homogeneous matrix ..... 9

11 Vertical pressure (oleic phase) profiles at different times for fracture column and column at a distance of 19.5 ft from the fracture for the homogeneous matrix ..... 10

12 Horizontal pressure (oleic phase) profiles at 5 days for the top and bottom layers of the homogeneous matrix ..... 10

13 Vertical water saturation profiles at different times for the column at a distance of 19.5 ft from the fracture for the homogeneous and heterogeneous matrix blocks ..... 11

## EXECUTIVE SUMMARY

Project progress continues with the successful completion of imbibition and fracture-flow experiments. The imbibition experiments used a limestone core plug from the Bainville North reservoir of the Williston Basin in Montana. The results show that imbibition in the low-permeability, low-porosity limestone core is slower than that in the high-permeability, high-porosity Berea sandstone core. Multiphase flow experiments using a 67-µm-wide fracture model and a low flow rate were conducted to measure imbibition and drainage oil-brine relative permeabilities. Lower flow rates increase residual water saturations and reduce endpoint relative permeabilities. The shapes of the fracture relative permeability curves are sensitive to fluid densities and fluid-flow rates and directions.

Reservoir characterization and flow simulations were conducted using published field data. Rock descriptions for field-size, heterogeneous matrix blocks were generated using conditional simulation techniques. Single-phase upscaling methods were used to estimate representative homogeneous values. Flow simulations of the imbibition processes were conducted using the heterogeneous and homogeneous matrix blocks. The results indicate that gravity forces enhance recovery during imbibition in field-size matrix blocks. For the rock descriptions studied, a homogeneous matrix block with permeability and porosity obtained from geometric and arithmetic averaging, respectively, reproduced the results for the heterogeneous matrix block.

Efforts will be made toward resolving the following issues in the next fiscal year: Modifications of the flow simulator (CMG's IMEX) to estimate capillary pressures for individual grid blocks, and finding good correlations for residual oil saturations which are required for improving simulations in heterogeneous matrix blocks. Experiments on imbibition at pressures below the bubble point are necessary to understand the effects of trapped gas saturations.

## ACKNOWLEDGMENTS

This work was performed for the U.S. Department of Energy (DOE) under Contract DE-AC1005000. The authors thank Dan Maloney and Kevin Doggett for their contributions to the activities of this project. Appreciation is also expressed to Steve George of BDM Petroleum Technologies, Min Tham of BDM-Oklahoma, Inc., and Bob Lemmon of DOE's National Petroleum Technology Office for their encouragement and support.

# 1.0 INTRODUCTION

Spontaneous imbibition is the main oil recovery mechanism during waterflooding of naturally fractured reservoirs. The effects of matrix block heterogeneity, lithology, wettability, and trapped gas saturation on waterflood performance are not fully understood.

The objectives of this project are to characterize naturally fractured reservoirs and to describe relationships that control fluid mobility and oil recovery in fractured rock. The specific tasks are as follows:

- Design and conduct spontaneous imbibition experiments on rock samples of different lithologies and analyze the results.
- Develop techniques for co- and countercurrent fluid flow characterization.
- Perform fracture oil-brine steady-state relative permeability measurements, and analyze the results.
- Develop methodologies for upscaling the media properties such that the dual porosity simulation models can be used for investigating imbibition.

# 2.0 PROJECT DESCRIPTION

Perform research covering oil production from fractured rock. Investigate matrix-to-fracture (including solution gas expansion and imbibition) and fracture-to-fracture (well) multiphase flow using experimental and simulation techniques. Design and conduct spontaneous imbibition experiments on sandstone and limestone rock samples. Analyze results from laboratory measurements on multiphase fluid flow in fractures. History-match experimental results. Generate representative heterogeneous media stochastically and deterministically. Upscale the media properties such that dual-porosity simulation models of the multiple-interacting continua type or the vertical refinement type can be used to investigate imbibition in a reservoir consisting of multiple heterogeneous blocks. Upscaling methods, including wavelet analysis (developed at NIPER/BDM) and renormalization, may be used.

# 3.0 RESULTS AND DISCUSSIONS

## 3.1 IMBIBITION EXPERIMENTS

Experimental investigation of imbibition was conducted. Ambient-condition experiments were conducted using a core plug (N12456) from the Bainville North (Montana) reservoir in the Williston Basin. Although, several plugs were collected from the shallow marine carbonate reservoir, a relatively homogeneous plug was chosen to simplify analysis. Laboratory tests were designed to accomplish the goals of this project, as well as to provide useful data for another DOE-sponsored project. A schematic of the experiment showing the matrix-fracture system and the fluid flow paths during spontaneous countercurrent imbibition and forced cocurrent imbibition appears in Figure 1.

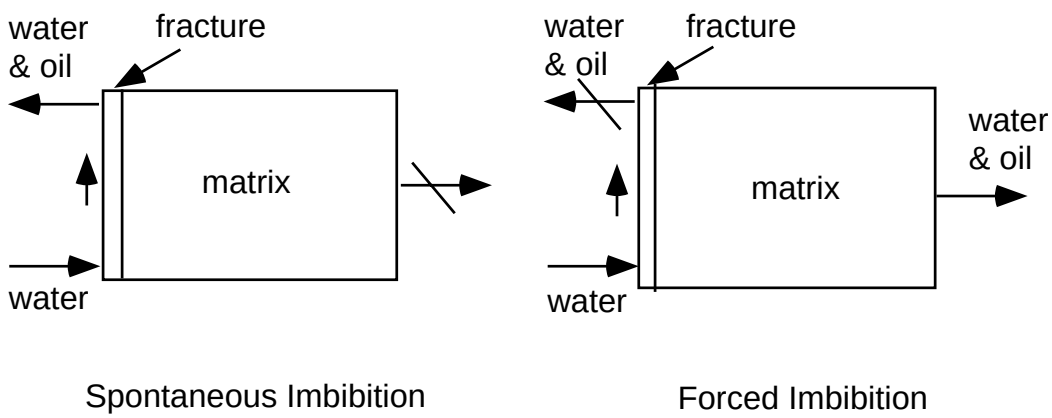


**Figure 1** **Schematic of experiment showing fluid flow paths for spontaneous countercurrent and forced cocurrent imbibition processes**

During spontaneous imbibition, the fracture-side injector and producer were open, and the matrix-side (furthest from the fracture) producer was closed. During forced imbibition, the fracture-side producer was closed, and the matrix-side producer was open. Table 1 lists the basic experimental data.

**Table 1** **Description of Imbibition Experiment for Bainville North (Montana) Core**

| **Parameters** | |
|---|---|
| **Rock Properties** | |
| Length, cm | 7.45 |
| Width, cm | – |
| Height, cm | – |
| Diameter, cm | 3.820 |
| Porosity, % | 17.8 |
| Permeability, md | 8.81 |
| **Fluid Properties** | |
| *Aqueous Phase* | |
| Viscosity, cp | 1.03 |
| Density, g/cc | 1.087 |
| *Oleic Phase* | |
| Viscosity, cp | 1.10 |
| Density, g/cc | 0.787 |

Figure 2 shows cumulative oil recovery history during the spontaneous and forced imbibition processes.

Forced imbibition was started after 142 hours of spontaneous imbibition when recovery was 58% original oil in place (OOIP). Additional recovery during the forced imbibition period was

only 4% OOIP. These results indicated that the rock was mainly water-wet. Figure 3 shows water saturation profiles at different times during the spontaneous and forced imbibition processes.

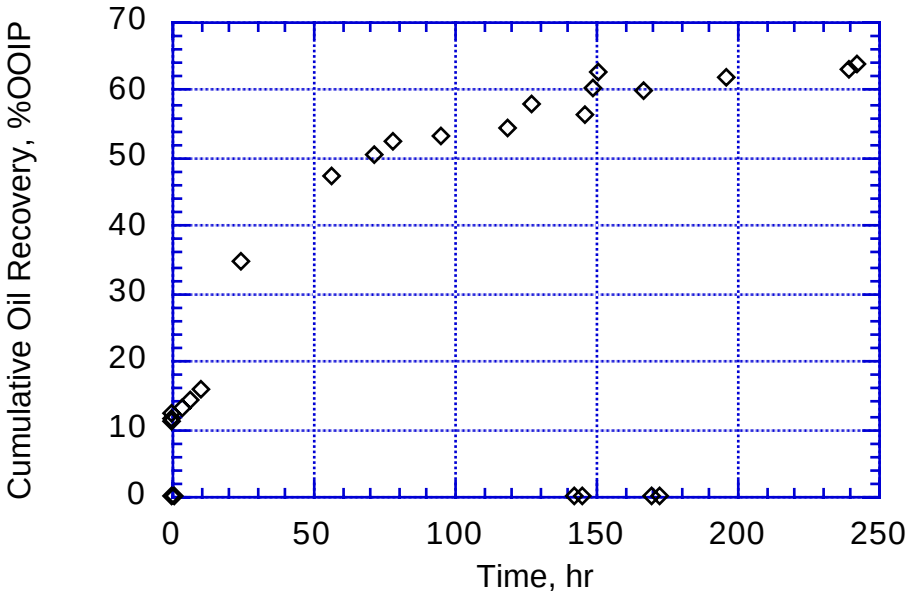


**Figure 2** **Experimental cumulative oil recovery history during the spontaneous and forced imbibition processes**

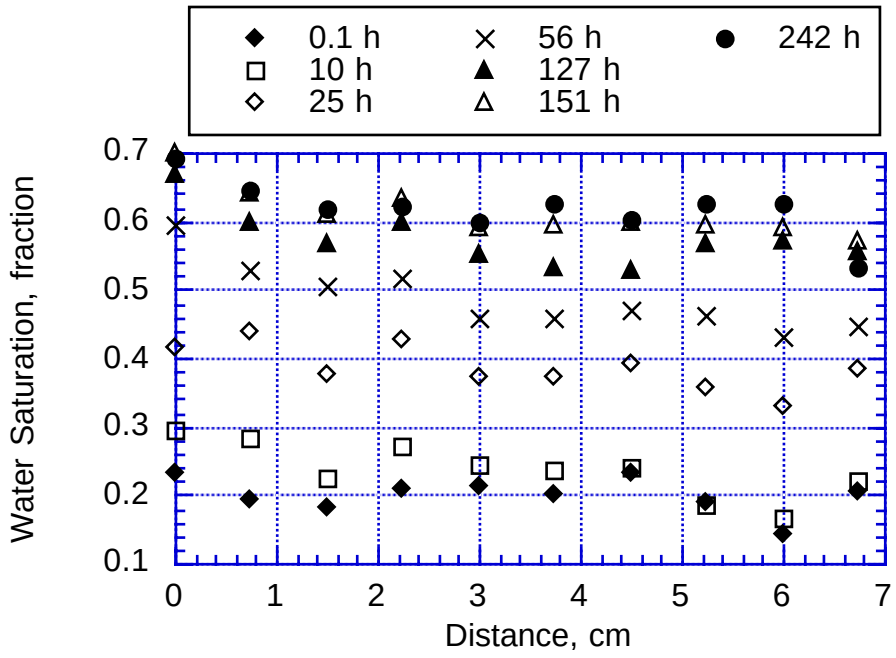


**Figure 3** **Experimental water saturation profiles at different times during spontaneous and forced imbibition processes**

Saturation gradients were low. Imbibition in the low-permeability (9 md), low-porosity limestone core was slower than that in the high permeability (100 md) Berea sandstone core (Maloney et al. 1996).

## 3.2 CO- AND COUNTERCURRENT FLOW MEASUREMENTS

Tests with microporous membranes are in progress to further refine techniques for spontaneous imbibition capillary pressure measurements. No established methods are available for this type of measurement. Modifications of the end pieces are needed for co- and countercurrent flow measurements.

## 3.3 MULTIPHASE FLOW IN FRACTURES

Experimental investigation of multiphase flow in fracture was conducted. The objectives were to examine conditions under which fracture relative permeabilities vary with saturation in a nonlinear manner. Tests were conducted to evaluate the effects of flow rates on oil-brine relative permeabilities. The tests were performed using a 67-µm-wide, smooth-walled plastic fracture cell and a low flow rate of 1.5 ml/hr (35 ft/day).

Figure 4 shows imbibition and drainage relative permeability curves. Imbibition values were higher than drainage values.

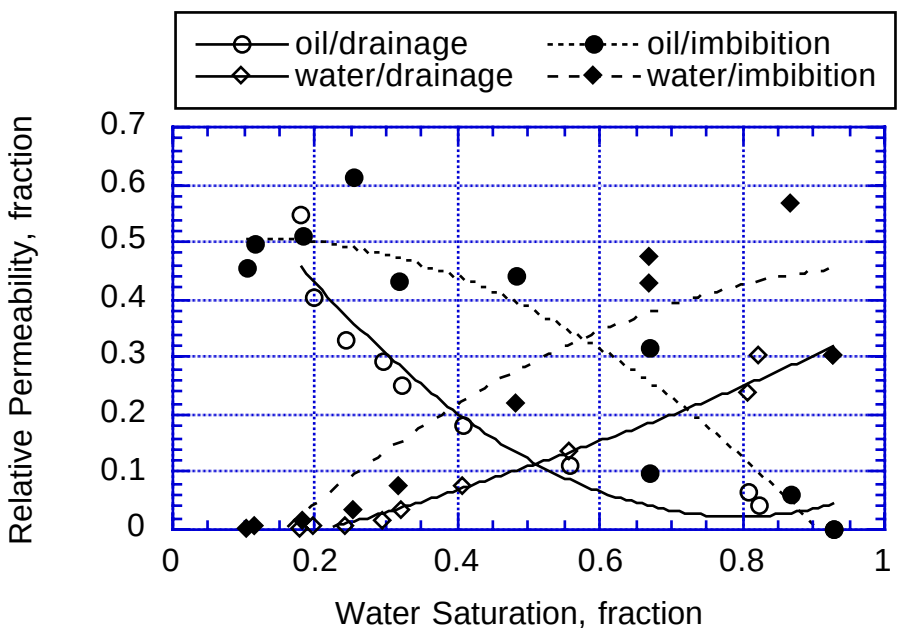


**Figure 4 Imbibition and drainage oil-water relative permeabilities for the fracture**

Maloney et al. (1996) observed that for a 51-µm-wide fracture and high flow rates of 30 ml/hr (920 ft/day), oil and brine relative permeabilities varied almost linearly with saturations. Lower flow rates increased residual water saturations, reduced endpoint relative permeabilities, and moved the cross-over point (saturation where oil and water relative permeabilities are equal) towards higher water saturations. The shapes of relative permeability versus saturation curves are sensitive to fluid densities and fluid-flow rates and directions.

## 3.4 RESERVOIR CHARACTERIZATION

Investigation of imbibition in field-size, large heterogeneous matrix blocks was conducted. Reservoir characterization is described in this section; upscaling methods, and reservoir simulation are described in sections 3.5 and 3.6, respectively.

Geostatistical rock description, fluid characterization, and rock-fluid characterization are described in the subsections that follow. Where specific information was missing, data were collected from the literature (Amyx et al. 1960). Published data on the Ekofisk field were used in this study (Thomas et al. 1987, da Silva 1989).

### 3.4.1 Geostatistical Reservoir Description

For a field-size matrix block, porosity and permeability realizations were generated using conditional simulation techniques. A public-domain geostatistical software package, GSLIB—which was developed by Stanford University—is being used for this application. Sequential gaussian simulation (SGSIM) was used to generate porosity distributions and a Markov-Bayes approach in sequential indicator simulation (MBSIM) was used to create permeability distributions. Published variogram data from a horizontal well in the analogous Dan field (chalk lithology) in the North Sea were used as the conditioning data. Nine porosity and permeability data sets were used as the conditioning data to describe a 6 m x 0.3 m x 6 m (20 ft x 1 ft x 20 ft) matrix block. Within the block, porosities ranged from 20% to 37%, and permeabilities ranged from 0.6 md to 11 md. Logarithm of permeability values were used in the conditional simulation process. Following the variogram data, more continuity exists in the horizontal direction than in the vertical direction.

### 3.4.2 Fluid Characterization

A pressure-volume-temperature program (CMGPROP developed by CMG) was used to characterize the 36□ API oil at 268□F temperature, and to generate pressure volume temperature (PVT) data required for the simulator (Thomas et al. 1987). Compared to the available fluid data, parameters including saturation pressure, viscosity, and density were matched exactly. Only the simulated solution gas ratio was slightly different.

### 3.4.3 Rock-Fluid Properties

Figures 5 and 6 show oil-water relative permeabilities and imbibition capillary pressures.

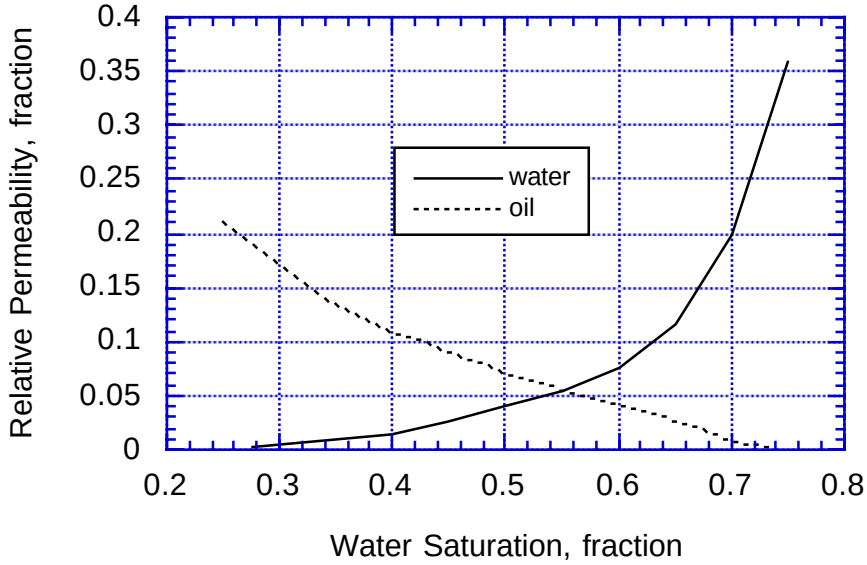


**Figure 5 Oil-water relative permeabilities**

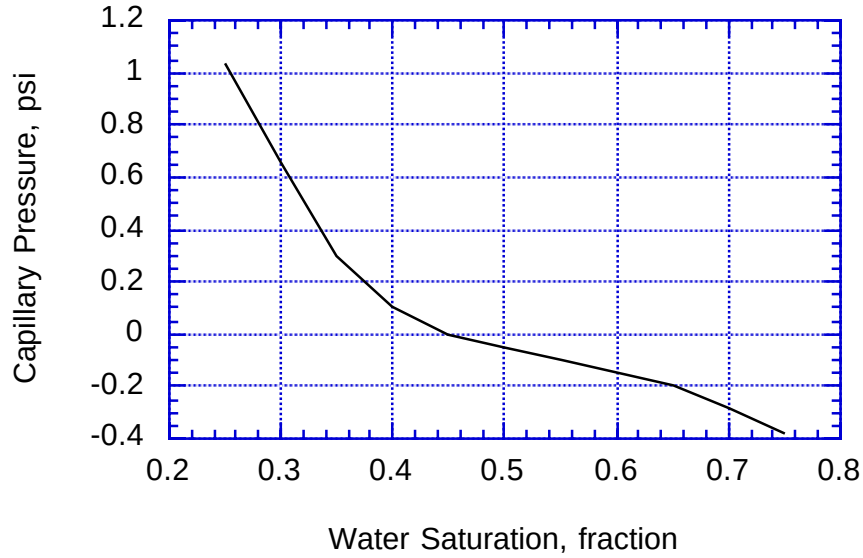


**Figure 6 Oil-water imbibition capillary pressures**

Cocurrent water relative permeabilities were reduced by 30% to obtain values for countercurrent relative permeabilities (da Silva 1989). To history-match two-phase production data, only the oil-water capillary pressures may be adjusted, because the water influx rate is a coupled function of water relative permeabilities and gradients of capillary pressure with

respect to water saturation. Oil recovery from capillary forces only is limited to 40% OOIP, because the critical water saturation at which capillary pressure is zero is 45%.

Residual water saturations for individual grid blocks were estimated using the following correlation for intergranular carbonates (Figure 4–18 in Mattax and Dalton, 1990)

$$S_{wr} = S_{wr,max} - m \log (k/k_{min}) \quad (1)$$

Where $S_{wr,max}$ is the maximum residual water saturation corresponding to the minimum permeability ($k_{min}$) and m is the slope of the linear correlation. The values for $S_{wr,max}$, $k_{min}$, and m were 0.5 md, 0.1 md, and 0.15 md, respectively.

## 3.5 UPSCALING METHODS

Single-phase upscaling methods were used to generate representative values for an equivalent homogeneous matrix block. For porosity, the arithmetic average was 28.6%. For permeability, the geometric average was 4.8 md and the arithmetic average was 6.1 md. For this particular permeability distribution, both averaging techniques produced similar results.

## 3.6 RESERVOIR SIMULATION

### 3.6.1 Numerical Simulator

The IMEX black oil simulator, developed by CMG, was used for conducting numerical experiments. The simulator has limited capabilities to simulate hysteresis. It accepts secondary drainage and imbibition data for oil-water capillary pressures. No option exists for normalizing the capillary pressure data and estimating these for individual grid blocks. Hysteresis in gas relative permeabilities are considered using a matching parameter of maximum residual gas saturation on the imbibition cycle (Killough 1976). A SUN SPARC 20 UNIX workstation and a DEC ALPHA computer were used for running simulations.

### 3.6.2 Flow Simulation

**Field Data.** To study the effects of heterogeneity on imbibition, two reservoir-condition spontaneous imbibition simulations were conducted: one with the heterogeneous matrix block and the other with the equivalent homogeneous block described in Section 3.5. The same grid system (21 ∞ 1 ∞ 20 ) was used for both the blocks. The fracture, represented by 1 ∞ 1 ∞ 20 grid column, was initially filled with oil. The reservoir/core pressure was 7,000 psi, which was above the bubble point pressure of 5,560 psi (Thomas et al., 1987). The residual water saturations for the homogeneous blocks were 25%, and those for the heterogeneous blocks were estimated using Equation 1.

Figure 7 shows a schematic of the fracture-matrix (homogeneous or heterogeneous) system and the fluid flow paths for the blocks of size 20 ft ∞ 1 ∞ 20 ft. Figure 8 shows cumulative oil recovery histories for the homogeneous and heterogeneous matrix blocks. The good match of recovery results indicated the validity of the upscaling techniques used.

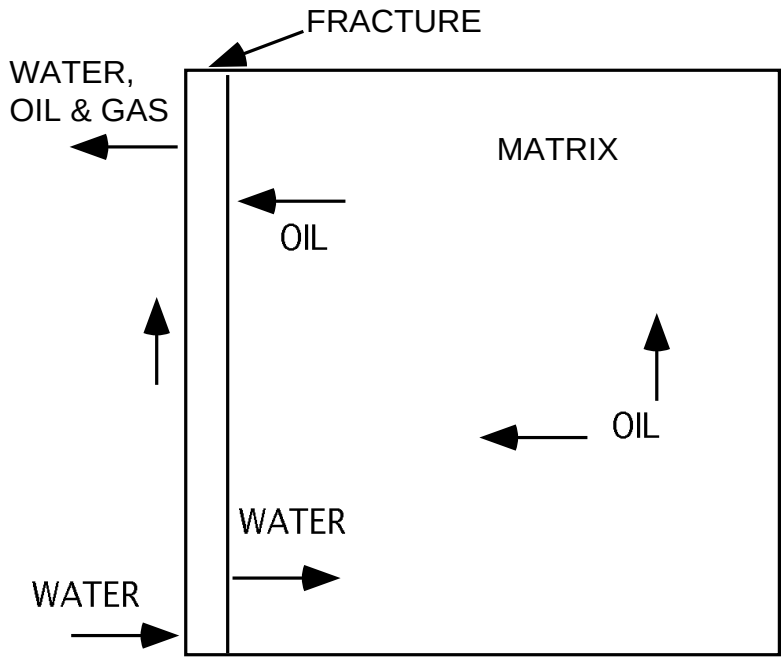


**Figure 7** **Schematic showing matrix-fracture system and fluid-flow paths for the matrix blocks (homogeneous or heterogeneous) of size 20 ft ∞ 1 ft ∞ 20 ft**

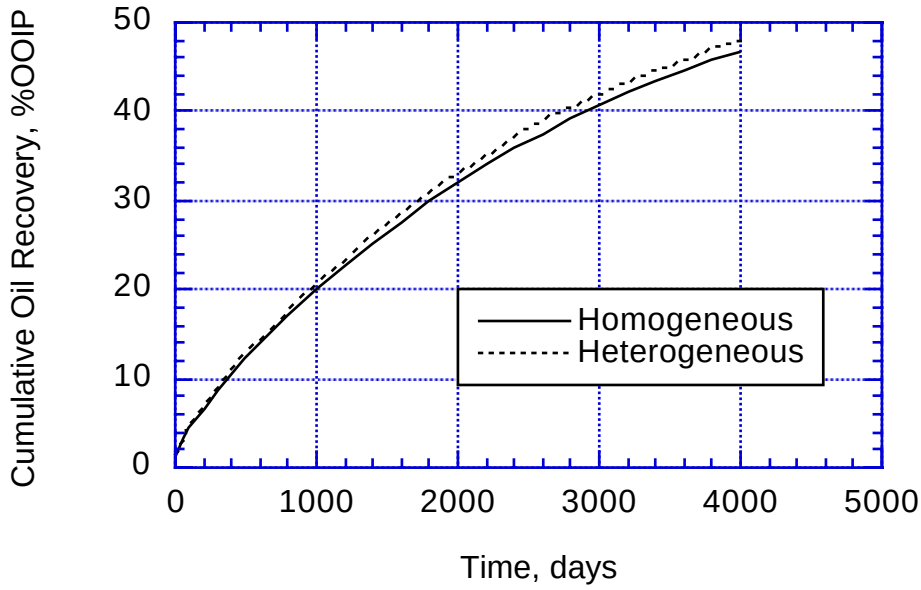


**Figure 8** **Experimental cumulative oil recovery history during spontaneous and forced imbibition processes**

For the homogeneous matrix block, Figures 9 and 10 show vertical and horizontal water saturation profiles at different times.

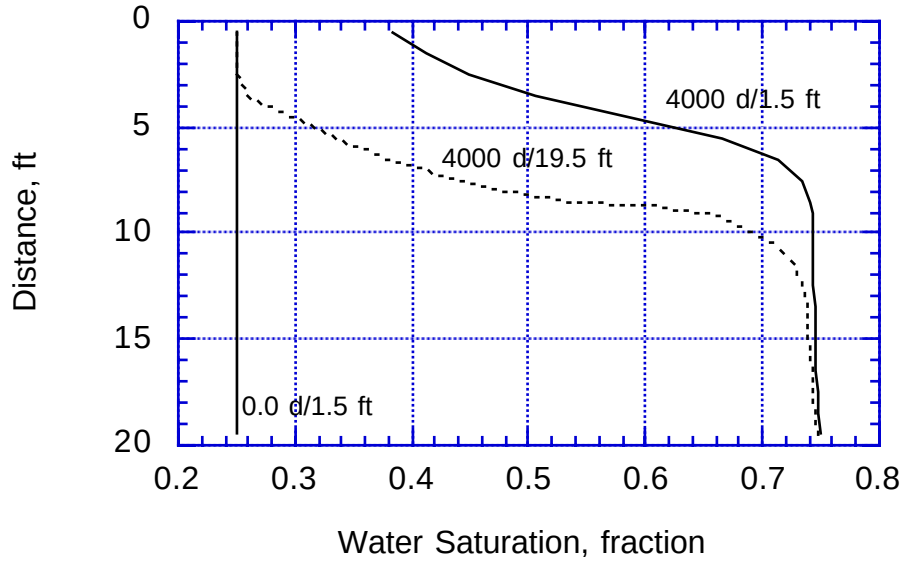


**Figure 9** **Vertical water saturation profiles at different times for columns at distances of 1.5 ft and 19.5 ft from the fracture for the homogeneous matrix**

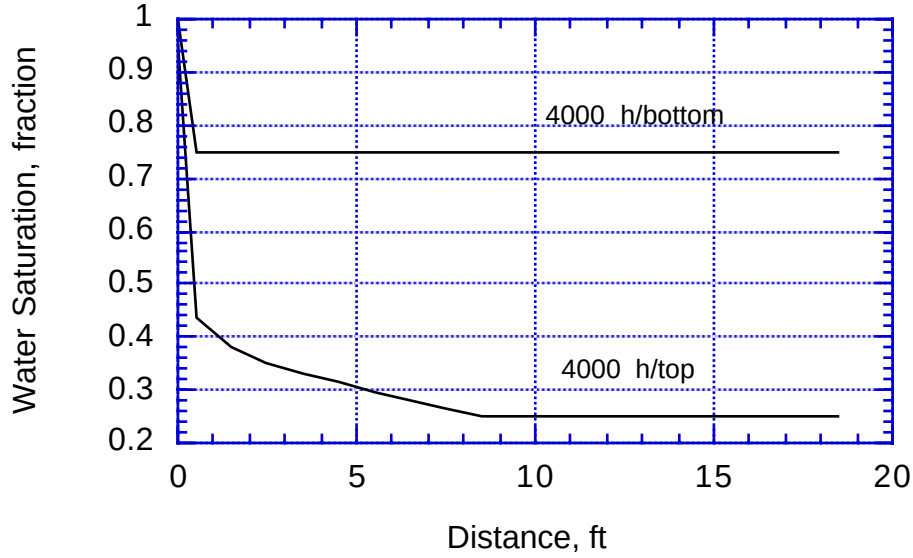


**Figure 10** **Horizontal water saturation profiles at 4000 hrs. for the top and bottom layer of the homogeneous matrix**

Water saturations in the lower portion of the block increased from residual values to the end-point value related to the residual oil saturation. Gravitational forces caused the water saturations to increase beyond the critical value of 45% associated with capillary forces only. For the upper portion of the block, water saturations at the matrix-end (at a distance of 19.5 ft from the fracture-end) were lower than those at a distance of 1.5 ft from the fracture-end. Figures 11 and 12 show vertical and horizontal pressure (oleic phase) profiles at different times.

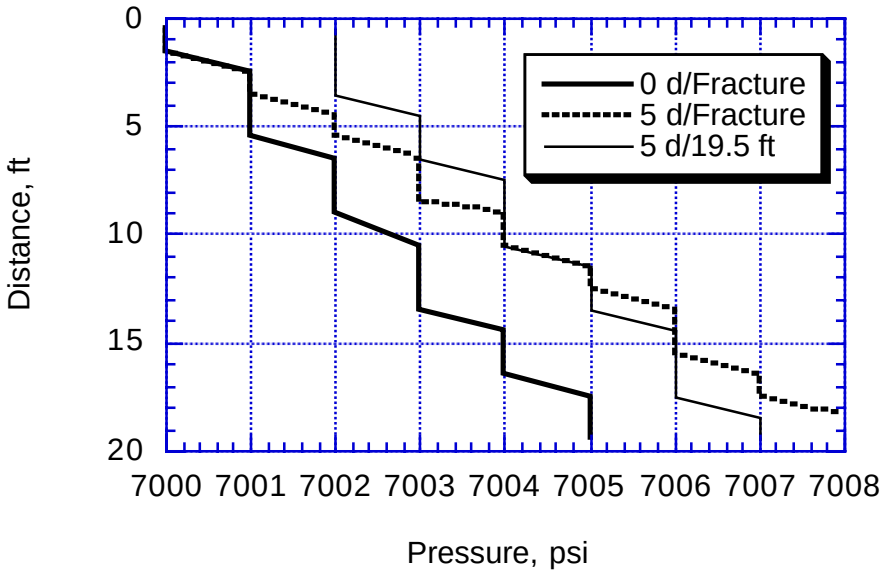


**Figure 11** **Vertical pressure (oleic phase) profiles at different times for fracture column and column at a distance of 19.5 ft from the fracture for the homogeneous matrix**

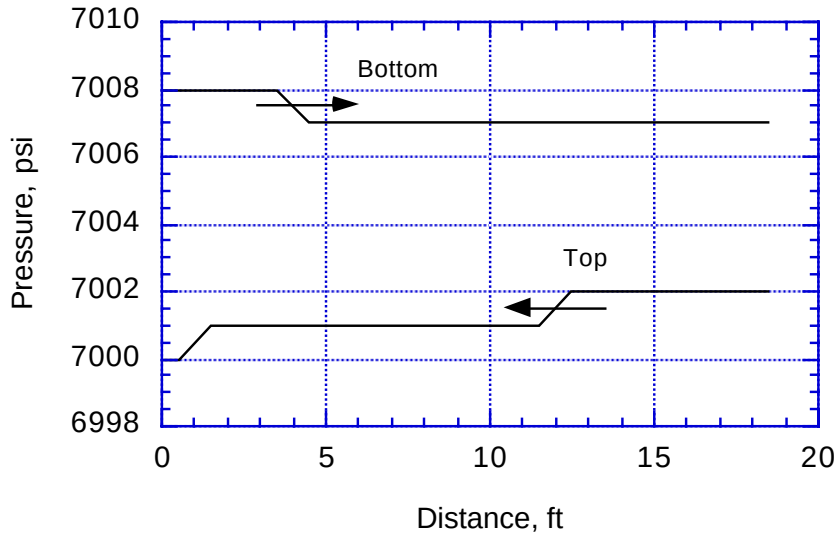


**Figure 12** **Horizontal pressure (oleic phase) profiles at 5 days for the top and bottom layers of the homogeneous matrix**

The vertical pressure profiles show that pressures varied from 7,000 psi in the top to 7,005 psi in the bottom for both matrix and fracture (both filled with oil). After five days of imbibition, pressures in the fracture varied from 7,000 psi to 7,008 psi because the oil in the fracture was displaced by water. However, pressures in the matrix-end varied from 7,002 psi to 7,007 psi because the oil in the matrix was not displaced. This created a forced imbibition. In the bottom portion of the block, water was pushed into the matrix. In the upper part, oil was forced out of the matrix. At the end of imbibition, pressure profiles in the fracture and matrix were similar. Additional pressure gradients created by gravitational forces were the reason for matrix water saturations to reach beyond that allowed by capillary forces only.

Figure 13 compares initial and final vertical water saturation profiles at the matrix end for the homogeneous and heterogeneous matrix blocks. For the heterogeneous case, the initial water saturations were different because of differences in permeabilities. Final water saturations were similar because the residual oil saturations were assumed to be the same.

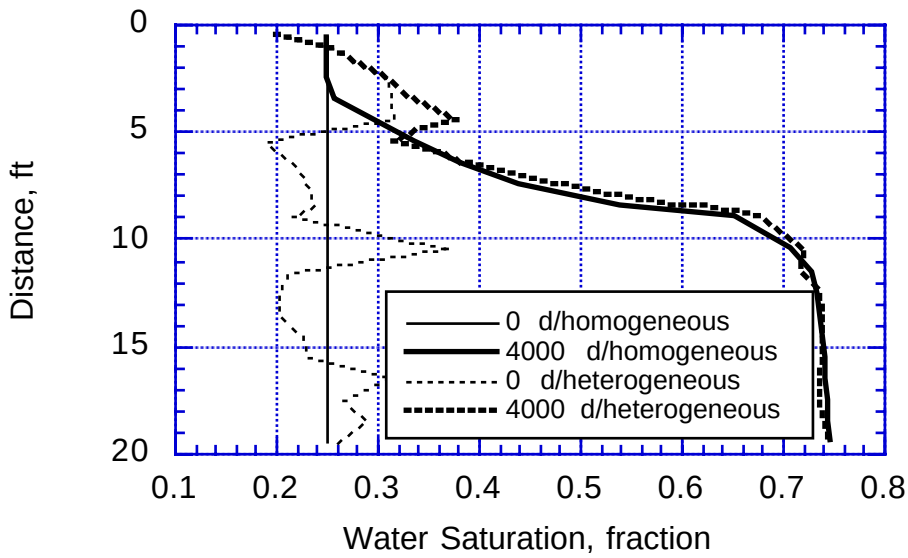


**Figure 13** **Vertical water saturation profiles at different times for the column at a distance of 19.5 ft from the fracture for the homogeneous and heterogeneous matrix blocks**

To improve the quality of predictions, suitable correlations for residual oil saturations as functions of porosities and permeabilities are required. Also, the IMEX simulator needs modifications to estimate capillary pressures for individual grid blocks.

*Experimental Data.* Doughty and Tomutsa (1995) conducted spontaneous imbibition tests using a heterogeneous Bartlesville sand plug. CT scans were used to collect data on changes in water saturation distributions. An attempt to history-match the experimental results is in progress.

Data collection for oil-water relative permeabilities, capillary pressures, and appropriate correlations for residual oil saturations is in progress. As mentioned in the Synthetic Data section, the IMEX simulator needs modifications.

## 4.0 CONCLUSIONS

1. Imbibition in a low-permeability, low-porosity limestone core is slower than that in the high-permeability, high-porosity Berea sandstone core.

2. Lower flow rates in a thin fracture increase residual water saturations and reduce endpoint relative permeabilities. The fracture relative permeabilities are sensitive to fluid densities and fluid-flow rates and directions.

3. Gravity forces enhance recovery during imbibition in field-size matrix blocks.

4. For the rock descriptions studied, a homogeneous matrix block with permeability and porosity obtained from geometric and arithmetic averaging, respectively, reproduced the results for the heterogeneous matrix block.

## 5.0 TECHNOLOGY TRANSFER

A paper entitled *2D X-ray Scanner and Its Uses in Laboratory Reservoir Characterization Measurements* was presented in the poster session at the Fourth International Reservoir Characterization Technical Conference, Houston, March 2–4.

Another paper entitled *Multiphase Flow in Fractures* was presented at the 1997 International Symposium of the Society of Core Analysts, Calgary, Alberta, Canada, September 7–10.

Technologies developed under this project were described to core analysts and engineers during presentations to others at oil companies and at BDM Petroleum Technologies facilities.

## 6.0 PLANNED ACTIVITIES

The following activities will continue during the next year:

- Conduct reservoir-condition imbibition at pressures above and below the bubble-point pressure.
- History-match experimental results.
- Perform microporous membrane capillary pressure and fracture relative permeability tests.

- Modify the IMEX simulator so that capillary pressures can be estimated for each grid block.
- Generate more realizations of reservoir data and evaluate their characteristics.
- Conduct literature search for correlations on residual oil saturations as functions of porosities and permeabilities.
- Conduct field-scale flow simulations of the imbibition processes.

## 7.0 REFERENCES


Amyx, J. W., D. M. Bass, and R. L. Whiting. 1960. *Petroleum Reservoir Engineering-Physical Properties*. New York: McGraw Hill.

Bulnes, A. C., and R. U. Fitting. 1945. An Introductory Discussion of the Reservoir Performance of Limestone Formations. *Transactions of AIME* 160: p. 179.

Doughty, D. and L. Tomutsa. 1995. *Magnetic Resonance Imaging Techniques Applied to the Study of Fluids in Porous Media: Magnetic Resonance Microscopy.* NIPER/BDM-0176.

Killough, J. E. 1976. Reservoir Simulation with History-Dependent Saturation Functions. *SPE Journal* February: p. 37.

Maloney, D, K. Doggett, and A. K. Sarkar. 1996. *Laboratory Characterization of Oil Production Mechanisms in Fractured Rock.* NIPER/BDM-0274.

Mattax, C. C. and J. R. Kyte. 1962. Imbibition Oil Recovery from Fractured Water-Drive Reservoirs. *Transactions of AIME* 225: p. 177–184.

da Silva, F. V. 1989. Primary and Enhanced Recovery of Ekofisk Field: A Single- and Double Porosity Numerical Simulation Study. Paper SPE 1984 presented at the Annual Technical Conference and Exhibition, October 8–11, San Antonio, Texas.

Sulak, R. M., and J. Danielsen. 1989. Reservoir Aspects of Ekofisk Subsidence. *Journal of Petroleum Technology* July: p. 709.

Thomas, L. K., T. N. Dixon, C. E. Evans, and M. E. Vienot. 1987. Ekofisk Waterflood Pilot. *Journal of Petroleum Technology* February: p. 221.