

**Impact of Capillary and Bond Numbers on
Relative Permeability**

Final Report

Reporting Period Start Date: 4-1-1999

Reporting Period End Date: 9-31-2002

Kishore K. Mohanty

DOE Award Number: DE-AC26-99BC15206

University of Houston

4800 Calhoun Road

Houston, TX 77204-4004

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, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, 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.

Abstract

Recovery and recovery rate of oil, gas and condensates depend crucially on their relative permeability. Relative permeability in turn depends on the pore structure, wettability and flooding conditions, which can be represented by a set of dimensionless groups including capillary and bond numbers. The effect of flooding conditions on drainage relative permeabilities is not well understood and is the overall goal of this project. This project has three specific objectives: to improve the centrifuge relative permeability method, to measure capillary and bond number effects experimentally, and to develop a pore network model for multiphase flows. A centrifuge has been built that can accommodate high pressure core holders and x-ray saturation monitoring. The centrifuge core holders can operate at a pore pressure of 6.9 MPa (1000 psi) and an overburden pressure of 17 MPa (2500 psi). The effect of capillary number on residual saturation and relative permeability in drainage flow has been measured. A pore network model has been developed to study the effect of capillary numbers and viscosity ratio on drainage relative permeability. Capillary and Reynolds number dependence of gas-condensate flow has been studied during well testing. A method has been developed to estimate relative permeability parameters from gas-condensate well test data.

Table of Contents

Executive Summary	9
Introduction	10
Task 1: Experimental Determination of Relative Permeability	11
Centrifuge Method	11
Capillary Number Dependence Experiments	23
Task 2: Pore-Level Model of Relative Permeability	35
Skeletonization of Realistic Porous Structure	35
Dynamic Network Model for Oil-Water Flow	37
Network Model of Gas-Condensate Flow	42
Gas-Condensate Relative Permeability from Well Testing	55
Conclusions	71
Nomenclature	73
References	75

List of Graphical Materials

Fig. 1 - Discrete approximations to Corey relations for wetting and non-wetting phases	78
Fig. 2 – Wetting phase represented by discrete approximation to Corey relation and non-wetting phase represented by quadratic spline	78
Fig. 3 – Both wetting and non-wetting phase relative permeabilities represented by discrete representations	79
Fig. 4 - Wetting phase saturation as a function of time within core	79
Fig. 5 - Wetting phase production curve	80
Fig. 6– The fixed-rotor centrifuge with high pressure coreholders	80
Fig. 7 – The fixed-rotor centrifuge assembly	81
Fig. 8a – Relative Permeability Set #1, M=5: History match to local saturation and production measurements	82
Fig. 8b – Relative Permeability Set #1, M=5: History match to only production measurements	82
Fig. 9 – Relative Permeability Set #1, M=1000: History match to local saturation and production measurements	83
Fig. 10 – Relative Permeability Set #1, M=1000: History match to production measurements	83
Fig. 11 – Relative Permeability Set #2a, M=5: History match to local saturation and production measurements	84
Fig. 12 – Relative Permeability Set #2a, M=5: History match to production measurements	84
Fig. 13 – Relative Permeability Set #2b, M=5: History match to local saturation and production measurements	85
Fig. 14 – Relative Permeability Set #2b, M=5: History match to production measurements	85
Fig. 15 – Relative Permeability Set #3, M=5: History match to local saturation and production measurements	86
Fig. 16 – Relative Permeability Set #3, M=5: History match to production measurements	86
Fig. 17 – Relative Permeability Set #3, M=1000: History match to local saturation and production measurements	87

Fig. 18 – Relative Permeability Set #3, M=1000: History match to production measurements	87
Fig. 19 – Production curves for M=5 and 1000 for relative permeability set #3	88
Fig. 20 – Confidence intervals (90%) for measurement error of 0.01% (production data measurements)	88
Fig. 21 - Stability of viscous brine floods	89
Fig. 22 – Effect of viscosity ratio on remaining brine saturation	89
Fig. 23 – Brine Recovery trend for oilflood experiments	90
Fig. 24 - Pressure trend for oilflood experiments	91
Fig. 25 – Brine recovered in the bump step	92
Fig. 26 – Effect of Capillary number on S_w for $\mu_w/\mu_o \sim 1$	92
Fig. 27 - Effect of Capillary number on S_w for $\mu_w/\mu_o = 10$	93
Fig. 28 – Automatic History matching of pressure data for 4 ft/day (low IFT)	94
Fig. 29 – Automatic History matching of recovery data for 4 ft/day (low IFT)	94
Fig. 30 - Automatic History matching of pressure data for 10 ft/day (3.5 cp oil)	95
Fig. 31 – Automatic History matching of recovery data for 10 ft/day (3.5 cp oil)	95
Fig. 32 – Relative Permeability Dependence on Capillary number	96
Fig. 33 – Effect of viscosity ratio on Relative permeability	96
Fig. 34 – Obtaining the Network Statistics from 3D Pore Space	97
Fig. 35 – Effect of Correlation length on Pore Structure for same porosity (0.3)	97
Fig. 36 – Effect of correlation length for porosity = 0.3 on network statistics ($\lambda \propto 1/\sqrt{\text{Correlation length}}$)	98
Fig. 37– Water in pore i displacing oil in pore j	99
Fig. 38a – Film pressure computation	99
Fig. 38b – Film pressure computation in absence of bulk pressure	99
Fig. 39 – A schematic section of porous medium used to define relative permeability and dynamic capillary pressure as a function of saturation	100
Fig. 40a – Saturation front as a function of time for $N_{ca}=1E-2$ and unit viscosity ratio	100
Fig. 40b – Saturation front as a function of time for $N_{ca}=1E-6$ and unit viscosity ratio	101
Fig. 41a – Simulated dependence of relative permeability on N_{ca} for unit viscosity ratio	102

Fig. 41b – Experimental dependence of relative permeability on N_{ca} for unit viscosity ratio (from Lefebvre du Prey, 1973)	102
Fig. 42a – Simulated capillary desaturation curve for unit viscosity ratio drainage	103
Fig. 42b – Experimental capillary desaturation curves from Fulcher et al. (1985)	103
Fig. 43a - Topology of pore network	104
Fig. 43b – Longitudinal section through model pore bodies and throats	104
Fig. 44 – Condensate ganglion	105
Fig. 45a – Type-I droplet formation	105
Fig. 45b – Type-II droplet formation	105
Fig. 46a – Regimes of flow (IFT = 0.02 mN/m, S_{wi} = 5%)	106
Fig. 46b – Regimes of flow (S_l = 16.9%)	106
Fig. 47 – Effect of shape parameter (S_{wi} = 8%, low N_c).	107
Fig. 48 – Effect of throat and body radii (S_{wi} = 8%, low N_c)	107
Fig. 49 – Effect of spatial correlation (S_{wi} = 8%, low N_c)	108
Fig. 50a – Superficial gas velocity (IFT = 0.02 mN/m, S_{wi} = 5%)	108
Fig. 50b – Superficial condensate velocity (IFT = 0.02 mN/m, S_{wi} = 5%)	109
Fig. 51 – Condensate relative permeability (IFT = 0.02 mN/m, S_{wi} = 5%)	109
Fig. 52 – Gas relative permeability (IFT = 0.02 mN/m, S_{wi} = 5%)	110
Fig. 53 – Gas relative non-Darcy coefficient (IFT = 0.02 mN/m, S_{wi} = 5%)	110
Fig. 54. Synthetic well test	111
Fig. 55. Pressure distribution within reservoir	111
Fig. 56. Capillary number distribution	112
Fig. 57. Reynolds number distribution	113
Fig. 58. Condensate saturation vs. radial distance	113
Fig. 59. Gas interstitial velocity distribution within reservoir	114
Fig. 60. Effective gas relative permeability	114
Fig. 61. Condensate and effective gas relative permeabilities	115
Fig. 62. k_{rg}^*/k_{ro} profile in reservoir for each rate	116
Fig. 63. Pressure simulation; k_{rg}^* expressed as a function of k_{rg}^*/k_{rc} ratio	116
Fig. 64. Regressions using correlation IA	117
Fig. 65. Regressions using correlation IB	117

Fig. 66. Regressions performed using correlation II	118
Fig. 67. Forward simulation with 2 layer model, regression performed using 1 layer	118
Fig. 68. 99% confidence limit krg* estimation	119
Fig. 69. 99% confidence limit for krc estimation	119

Executive Summary

Recovery and recovery rate of oil, gas and condensates depend crucially on their relative permeability. Relative permeability in turn depends on the pore structure, wettability and flooding conditions, which can be represented by a set of dimensionless groups including capillary and bond numbers. The effect of flooding conditions on drainage relative permeabilities is not well understood and is the overall goal of this project. This project has three specific objectives: to improve the centrifuge relative permeability method, to measure capillary and bond number effects experimentally, and to develop a pore network model for multiphase flows. A centrifuge has been built that can accommodate high pressure core holders and x-ray saturation monitoring. The centrifuge core holders can operate at a pore pressure of 6.9 MPa (1000 psi) and an overburden pressure of 17 MPa (2500 psi). The effect of capillary number on residual saturation and relative permeability in drainage flow has been measured. A pore network model has been developed to study the effect of capillary numbers and viscosity ratio on drainage relative permeability. Capillary and Reynolds number dependence of gas-condensate flow has been studied during well testing. A method has been developed to estimate relative permeability parameters from gas-condensate well test data.

Introduction

Recovery and recovery rate of oil, gas and condensates depend crucially on their relative permeabilities. Relative permeabilities in turn depend on the pore structure, wettability and the flooding conditions. Relative permeabilities are measured in the laboratory often on reservoir cores. If the cores have been treated properly (overburden stress, wettability restoration, live fluids), then it is possible not to alter the pore structure and wettability. The flooding condition, however, is often different in the laboratory test than in the reservoir, by necessity. For example, flow rates used in the laboratory experiments are higher than the field rate to avoid capillary end effect. The movements of fronts in the field are very different from what is achieved in the steady state laboratory method. Gas and condensate may move in crossflow directions in a gas condensate reservoir, but not in laboratory tests of gas condensates. In fact, the laboratory data from different methods (steady state, unsteady state and centrifuge) and at different conditions (e.g. at different flooding rates) are often different. One often wonders which relative permeability data is the appropriate one to be used in field simulation. Thus it is imperative to understand the impact of flooding condition on relative permeabilities and scale the laboratory data to the field conditions before applying in field simulations.

That is the overall goal of this proposal. The flooding condition can be represented by a set of dimensionless groups including capillary number, bond number and heterogeneity index. Their effects on imbibition relative permeabilities (e.g. waterflood in strongly water-wet rock) are understood and well documented in the literature. That is not the case for drainage relative permeabilities. Many oil reservoirs are mixed-wet and their waterfloods are controlled by drainage-type process. Gravity drainage of oil by a gas, near-miscible and immiscible gasflooding processes are also drainage-type processes. Production of gas-condensate reservoirs involves both imbibition and drainage modes as well as crossflow of condensates and gases. This study is aimed at understanding the effect of flooding condition on relative permeability for the above cases by conducting a set of well-controlled experiments and developing a pore-scale mechanistic model. This study was initiated in April, 1999. This report summarizes all our results through September, 2002. The two tasks of this project are: experimental determination of relative permeability and pore-level modeling of relative permeability.

Task 1: Experimental Determination of Relative Permeability

1.1 Centrifuge Method

Relative permeability can be measured by three different methods: steady-state, unsteady state and centrifuge. The centrifuge method is very attractive because it is relatively fast and data for low wetting phase saturation can be attained. It is, however, limited to the determination of only the wetting phase relative permeability at the present state of development, especially at high mobility ratio.

A standard centrifuge experimental data set consists of wetting phase production measurements at single or multiple angular velocities. At a constant angular velocity, the wetting phase is produced until equilibrium is reached between the capillary pressure and centrifugal force. Wetting phase production ceases at equilibrium. Relative permeability information is derived from the non-equilibrium data, i.e. during production of the wetting phase. The capillary pressure curve is constructed from the equilibrium data acquired at multiple centrifuge speeds. Hassler and Brunner¹ documented the use of the centrifuge to measure capillary pressure. The capillary pressure curve was determined based on an average wetting phase saturation within the core at multiple centrifuge speeds.

Hagoort² introduced an analytic method to estimate the oil phase relative permeability in a gas-oil system from the centrifuge data. Oil production measurements were used to construct the oil relative permeability curve. Two key assumptions in this development were: (i) capillary pressure was neglected and (ii) mobility of the gas (non-wetting) phase was considered infinite compared to that of the oil (wetting) phase. A numerical model was also developed which considered capillary pressure in an approximate manner, i.e. through the Leverett function.

Numerical methods have been developed to estimate relative permeabilities from centrifuge experiments.³⁻⁸ O'Meara & Crump⁴ developed a semi-implicit method for estimating wetting phase relative permeability and capillary pressure simultaneously from a single experiment in a gas-oil system. Estimation of the oil (wetting phase) relative permeability and capillary pressure was achieved by history matching the production data. Nordtvedt, J.E. et al.⁷ used production data to estimate wetting and non-wetting phase relative permeabilities in addition to capillary pressure.

Firazoobadi & Aziz⁵ proved that history matching production data would not yield a unique set of relative permeabilities. They estimated non-wetting (gas) and wetting (oil) phase relative permeabilities by matching production data. They concluded that good matches of production data could be obtained with two different sets of relative permeability relationships. Capillary pressure was included in their model.

Chardaire-Riviere⁶ et al. attempted to use local saturation measurements to estimate both wetting and non-wetting phase relative permeabilities in addition to capillary pressure. The local saturation measurements were determined with ultrasonic transducers placed at three locations along the core. Thus gas was avoided in the system; oil and water were used and mobility ratios were close to unity. The mobility ratio, M , is defined as the ratio of the endpoint mobility of the invading (non-wetting) to the endpoint mobility of the displacing (wetting) phase, i.e.,

$$M = \frac{k_{rnw} \mu_w}{\mu_{nw} k_{rw}}. \quad (1)$$

Measurements were made during dynamic operation of the centrifuge. They claimed improved estimation of both capillary pressure and relative permeability by using local saturation as opposed to only production data.

Estimation of relative permeabilities through least squares regression has been addressed by several authors.⁵⁻¹² This is an inverse problem where the objective is to minimize the sum of the least square difference between measured data and simulated data from a mathematical model. For the case of relative permeability estimation, the minimization is accomplished by adjusting the parameters in the relative permeability models. A modified Levenberg-Marquardt algorithm is used for the regression. With the exception of Chardaire-Riviere et al. only production data has been considered in the regression procedure. The goal of this work is to determine under what conditions local saturation measurements improve the estimation of wetting and non-wetting phase relative permeabilities. This will be investigated at different mobility ratios.

Methodology

Estimation of relative permeability from production and/or local saturation history is an inverse problem in which system parameters or variables are determined based on an observed response. This requires a set of measurements and a mathematical model to represent the process of interest. A summary of the general procedure used in this study is described below. A more detailed discussion follows.

1. Observed or experimental data was generated by forward simulation. Simulations were performed for three sets of relative permeability curves at low and high mobility. The experimental data sets included:

- local wetting phase saturation measurements within the core as a function of time at 25%, 50% and 75% of the core length, and,
- wetting phase production as a function of time.

2. The relative permeability curves were then recovered, or history matched, based on the experimental data generated in the forward simulations. Two history matches were performed for each set of relative permeability and mobility ratio. One simulation used only production measurements in the regression while the second used local saturation and production measurements. By this means the benefit of local saturation measurements in estimating relative permeabilities could be assessed.

3. The history matching process involved adjusting the parameters in the selected relative permeability representations to match the experimental data. Additionally, initial guesses for the relative permeability curves were required. The results depended on the type of function used to represent the relative permeabilities. In this study either splines or Corey functions were used to represent the relative permeability functions for the wetting and non-wetting phases.

4. Confidence intervals were evaluated for the estimated relative permeabilities.

Generation of synthetic experimental data

Mathematical Model: The experimental data sets were generated based on a 1D model representing the macroscopic relations for flow of two incompressible, immiscible fluids through a homogeneous porous medium. The model is a finite difference, fully implicit formulation incorporating both centrifugal force as a function of radial distance in the core and capillary pressure. It is similar to the semi-implicit formulation developed by O'Meara and Crump.³

Relative Permeability Models: Three sets of relative permeability curves were used in this study. These are shown in Figs. 1-3. Relative permeability functions are represented by Corey relations¹⁴, B-splines¹⁰⁻¹² and piecewise linear (discrete) representations.

The curves in Set #1 (Fig. 1) are both concave upwards. They were constructed as piecewise linear approximations to Corey relations (discussed below). The exponents for the wetting and non-wetting phases were 4 and 2.5, respectively. In Set #2 (Fig. 2), the non-wetting relative permeability curve is “S-shaped”. Many consolidated media show this kind of non-wetting relative permeability shape. (Jerauld & Salter 1990) A quadratic spline was used to construct the ‘S’ shaped non-wetting relative permeability curve and the wetting phase relative permeability curve was developed from a Corey relation with an exponent of 4. In Set #3 (Fig. 3), the wetting relative permeability curve is “S-shaped”. This is unusual, but has been included to test the versatility of the history matching procedure. The non-wetting curve was designed to approximate a Corey relation with an exponent of 2.5. The wetting curve was constructed using cubic splines to have an “S” shape.

Capillary Pressure Model: Capillary pressure was calculated as a function of saturation using the Thomeer model.

$$P_{C^*} = \frac{P_c}{P_{ce}} = \exp \left[\frac{-d}{\ln(1 - S^*)} \right] \quad (2)$$

P_{ce} is the entry capillary pressure and the constant, d , is a fitting constant. Values for P_{ce} and d were 1 and 0.1, respectively. These values were held fixed for all simulations.

Synthetic Experimental Data: A data set was generated for each set of relative permeability curves at mobility ratios of 5 (a typical oil-water system) and 1000 (a typical oil-gas system). Six data sets were generated and are tabulated in Table 1. The core properties, fluid properties and centrifuge operating parameters used to generate the data are shown in Table 2. The variation in mobility ratio was achieved by modifying the viscosity of the wetting and non-wetting phases.

Table 1 – Experimental Data Sets Generated by Forward Simulation		
Data Set	Relative Permeability Set	Mobility Ratio
1-2	Relative Permeability Set #1	5 & 1000
3-4	Relative Permeability Set #2	5 & 1000
5-6	Relative Permeability Set #3	5 & 1000

Fig. 4 represents the local wetting phase saturation as a function of time for a typical centrifuge process. Apparent is the decrease in wetting phase saturation with time at the three locations of interest, 25%, 50% and 75% along the core. The associated production curve is shown in Fig. 5. The transient, or non-equilibrium, portion of the curve was used to history match the relative permeability relationships.

History Matching Procedure

The history matching procedure involved adjusting the parameters in the selected relative permeability representations to minimize an objective function, X . The objective function is a sum of squares of residuals, i.e., sum of squared differences between measured data and predicted data from a mathematical model. This can be written as:

$$X = \left[\begin{matrix} \vec{Y} - F(\vec{p}) \end{matrix} \right]^T W \left[\begin{matrix} \vec{Y} - F(\vec{p}) \end{matrix} \right] \quad (3)$$

In this equation, X is the objective function, Y is the measured data, F(p) corresponds to the computed values from the mathematical model, p corresponds to the adjustable parameters in the relative permeability representations and W is the weighting matrix. The weighting matrix is a diagonal matrix with entries often chosen to be equal to the inverse of the variance of the measured data. For this study, the weighting matrix is chosen to be the identity matrix as all measurements are assumed to be independent and identically distributed. A Levenberg-Marquardt algorithm with constraints was used to minimize the objective function. Constraints were required to restrict the predicted relative permeabilities to realistic values.

When local saturation and production measurements are used in the regression the above least squares relationship can be rewritten as:

$$X = \sum_{i=1}^N \{S_{oi}^* - S_{oc}^*\}_{25}^2 + \{S_{oi}^* - S_{oc}^*\}_{50}^2 + \{S_{oi}^* - S_{oc}^*\}_{75}^2 + \{pv_{oi} - pv_{oc}\}^2 \quad (4)$$

where

N= number of observed values

S_{oi}^* = measured saturation

S_{oc}^* = model calculated saturation

pv_{oi} = measured production

pv_{oc} = model calculated production

Analogously, if only production values are used in the regression the relationship becomes:

$$X = \sum_{i=1}^N \{pv_{oi} - pv_{oc}\}^2. \quad (5)$$

Table 2 - Core & Fluid Properties, Centrifuge Operating Conditions	
Absolute Permeability, k (md)	100

Porosity (%)	20
L (cm)	5.7
ρ_w (g/cc)	0.6
ρ_{nw} (g/cc)	0.003
r_b (cm)	10
ω (rev/min)	500
k_{rnw}°	0.45
k_{rw}°	0.80

Relative Permeability Function Parameters

The Corey relations used in this study for the wetting and non-wetting phases are given below. Both are one-parameter models, with the exponent being the adjustable parameter.

$$k_{rw}^* = \frac{k_{rw}}{k_{rw}^\circ} = (S^*)^{n1} \quad 0 \leq k_{rw}^* \leq 1 \quad (6)$$

$$k_{rnw}^* = \frac{k_{rnw}}{k_{rnw}^\circ} = (1-S^*)^{n2} \quad 0 \leq k_{rnw}^* \leq 1 \quad (7)$$

S^* represents the normalized wetting phase saturation and is defined as:

$$S^* = \frac{(S - S_{wr})}{(1 - S_{wr} - S_{wc})} \quad 0 \leq S^* \leq 1 \quad (8)$$

Relative permeabilities represented by quadratic splines (B-splines) are shown below. The coefficients a_j , b_j and c_j are adjusted during the history matching process.

$$k_{rw}^* = a_j S^{*2} + b_j S^* + c_j \quad (9)$$

$$k_{rnw}^* = a_j (1-S^*)^2 + b_j (1-S^*) + c_j \quad (10)$$

Subscript j denotes the partition segment. A detailed description of B-spline representation of relative permeabilities is available from Kerig & Watson.¹⁰⁻¹²

Initial Guesses: Initial guesses for the relative permeability functions are required for the history matching process. When quadratic splines were used to represent the relative permeabilities the

initial guesses were linear functions of the wetting phase saturation. The coefficients of the quadratic splines were adjusted to provide the following initial guesses:

$$krw^* = S^* \quad (11)$$

$$krnw^* = (1-S^*) \quad (12)$$

Initial guesses for the exponents in the Corey representations were 5 for the wetting phase and 3 for the non-wetting phase. (The exponents used in the forward simulations were 4 and 2.5 for the wetting and non-wetting phases, respectively.)

$$krw^* = \frac{krw}{krw_{\circ}} = (S^*)^5 \quad (13)$$

$$krnw^* = \frac{krnw}{krnw_{\circ}} = (1-S^*)^3 \quad (14)$$

Confidence Intervals: Confidence intervals for the estimated relative permeability curves were calculated based on linearized covariance analysis.¹⁰

Results and Discussions

A new centrifuge has been designed, built and installed in our laboratory. It is a fixed arm centrifuge capable of speeds up to 5000 rpm. The common centrifuges used in the industry are modified Beckman centrifuges with swinging arms. This centrifuge is capable of rotating four coreholders. A picture of the coreholders inside the centrifuge is shown in Fig. 6. The coreholders are made of aluminum (to transmit x-ray) and weigh 1200 grams. All wetted pieces, namely the core end pieces, are made of stainless steel to prevent corrosion. The receiver of the coreholder is made of quartz. The centrifuge has two windows. An optical CCD camera is mounted on one window to monitor fluid production. An X-ray system can be mounted on the second window to monitor in situ saturations. The whole centrifuge is shown in Fig. 7. The centrifuge and the coreholders are built by Harbert Engineering, Tulsa, OK.

For each synthetic data set, two history match simulations were performed: (1) with local saturation and production measurements, and (2) only production measurements. History matching results are summarized in Table 3. The results are based on whether the use of local saturation measurements resulted in improved relative permeability estimates. The effect of mobility ratio,

and the shape of true relative permeability curves are described in detail below.

Table 3 – Improvement in Relative Permeability Estimation Using Local Saturation & Production Measurements				
	M=5		M=1000	
	Wetting Phase	Non-Wetting Phase	Wetting Phase	Non-Wetting Phase
Relative Permeability Set #1	Yes (quadratic Spline)	Marginal (Corey)	Yes (quadratic spline)	No (quadratic spline)
Relative Permeability Set* #2	n/a	Yes (quadratic spline)	N/a	No (quadratic spline)
Relative Permeability Set #2	No (Corey)	Yes (quadratic spline)	No (Corey)	No (quadratic spline)
Relative Permeability Set #3	Yes (quadratic spline)	Yes (Corey)	No (quadratic spline)	No (Corey)

* history match to only non-wetting curve

1. Relative Permeability Set #1

$M=5$: Figs. 8 (a) & (b) represent history match results to the first set of relative permeability curves for a mobility ratio of 5. Three and two partition splines represent wetting and non-wetting relative permeabilities, respectively. The number of parameters in these relative permeability representations is eight for the wetting phase and five for the non-wetting phase.

Fig. 8a represents a history match regressing upon both local saturation and production measurements. Fig. 8b illustrates the history match based only on production measurements. Comparison of both figures shows a slightly improved match to both the wetting and non-wetting

relative permeability curves when local saturation and production measurements are used in the regression.

M=1000: The same history match simulations were run as for the *M=5* case except the mobility ratio was increased to 1000. At the higher mobility ratio the use of local saturation measurements in the regression procedure becomes more pronounced. This is clearly shown in Figs. 9 and 10. The wetting phase relative permeability can be estimated only when local saturation and production measurements are used in the regression procedure. Above a wetting phase saturation of 70% the curve is estimated nearly exactly. Below 70% the curve is overestimated. The wetting phase relative permeability curve could not be estimated by matching to only production measurements (Fig. 10).

The non-wetting relative permeability curve could not be matched, even with the local saturation data. In fact, the final predicted non-wetting phase relative permeability is the same as the initial relative permeability guess. This observation is not surprising given the large mobility ratio. The resistance due to the non-wetting phase is much less than that of the wetting phase.

2. Relative Permeability Set #2:

An ‘S’ shaped non-wetting phase relative permeability curve is considered in these cases. A Corey relation represents the wetting phase relative permeability with an exponent of four. Simulations performed in Case #2a history matched only the non-wetting phase relative permeability with the wetting phase curve held fixed. In Case #2b both the non-wetting and wetting phase relative permeability curves were history matched. For both sets the non-wetting curve was represented by a quadratic spline (2 partition, 5 parameters). A Corey relation represented the wetting phase curve in the Case #2b simulations.

Case #2a, M=5: Local saturation and production measurements were required to match the non-wetting phase relative permeability. This is shown in figs. 11 & 12. Without local saturation measurements the predicted curve was the same as the initial guess in the regression algorithm (Fig. 12).

Case #2a, $M=1000$: The non-wetting phase relative permeability curve could not be predicted at a mobility ratio of 1000. Local saturation and production measurements were used in this history match. Again, this is to be expected given the minimal resistance offered by the non-wetting phase as compared to the wetting phase at this high mobility ratio.

Case #2b, $M=5$: At low mobility both the wetting and non-wetting phase relative permeabilities could be estimated based on both local saturation and production measurements. This is shown in Fig. 13. Without the use of local saturation measurements, however, only the wetting phase relative permeability could be predicted (Fig. 14). The non-wetting phase curve could not be predicted even with an initial guess close to the actual curve. In fact, the final prediction was the same as the initial guess.

Case #2b, $M=1000$: Neither the wetting nor the non-wetting phase relative permeabilities could be predicted using local saturation and production measurements for this set of relative permeability curves.

3. Relative Permeability Set #3

This set of relative permeability curves represents an ‘S’ shaped wetting phase relative permeability and a Corey type non-wetting phase relative permeability. In the history matching process the wetting phase relative permeability was represented by a 4 partition quadratic spline (eleven parameters) and a Corey relation represented the non-wetting phase relative permeability.

Figs. 15-18 illustrate the history matches to this set of relative permeability curves at mobility ratios of 5 and 1000. The poorest match is observed at a mobility ratio of 5 using only production measurements in the regression. However, a match was obtained at a mobility ratio of 1000 using only production measurements (Fig. 18).

This apparent discrepancy can be explained by inspection of the production response at both mobility ratios. Fig. 19 shows a plot of the production curves (normalized) for mobility ratios of

5 and 1000 as a function of dimensionless time. The rate of production is initially higher at a mobility ratio of 1000 and reaches equilibrium faster than for a mobility ratio of 5. This is apparently enough information required to obtain a history match based on only production data. For a mobility ratio of 5 the production curve is more gradual. Based on the regression results (Figs. 15-16) additional information, i.e. saturation measurements are required to estimate the wetting phase relative permeability. It should be noted that the disparity between production curves at mobility ratios of 5 and 1000 for relative permeability sets #1 & 2 is much less.

Confidence Intervals: Linearized covariance analysis was used to estimate the 90% confidence intervals for both the wetting and non-wetting phase relative permeabilities.¹⁰ Confidence intervals determined for the predicted relative permeability curves resulted in estimates that fell outside the region of acceptable values (between 0 and 1). Previous investigators have documented that confidence intervals predicted by this method may result in estimates outside the region of acceptable values.¹³ Additional techniques are required involving Monte-Carlo simulation to confine the confidence intervals to acceptable values.¹³

Fig. 20 illustrates a history matched wetting phase relative permeability curve and associated confidence intervals. The history match regressed on production data. A quadratic spline with eight parameters represented the relative permeability curve. The measurement error used to estimate the confidence intervals in Fig. 20 was 0.01%. Further work in determining acceptable confidence intervals was outside the scope of this work.

1.2 Capillary Number Dependence Experiments

Methodology

We have conducted primary drainage relative permeability measurement on a fairly homogeneous core at several capillary numbers, $N_c = \mu_o v / \sigma_{ow}$. Unsteady state method is used in which water is displaced, from a water-wet completely brine-saturated Berea sandstone core, by oil (drainage). To study the dependence of capillary number on relative permeability, N_c is varied from 10^{-8} - 10^{-4} . To achieve this, different oil injection flow rates, oil-to-water viscosity ratios and oil-water interfacial tensions are used. To study the effect of viscosity ratio on the relative permeability, five different viscosity ratios are used for same capillary number, thus keeping capillary

end-effects the same in these experiments. A homogenous Berea sandstone water-wet core 9.5” long and 2” in diameter is used. Before the core materials are tested for relative permeability and residual saturations, they are characterized so that the experimental data can be interpreted correctly. Porosity and permeability were experimentally measured using N₂ gas before the start of these experiments.

The capillary end effect in these experiments can be represented by a dimensionless flow parameter, $N_{c,end}$, the end-effect number. $N_{c,end}$ is the ratio of a characteristic capillary pressure, P_{cc} , to the viscous pressure drop across the core, ΔP ; i.e.,

$$N_{c,end} = \frac{P_{cc}}{\Delta P} \approx \frac{\sigma_{ow}\sqrt{(\phi k)}}{\mu_o v_o L}.$$

ΔP can be the end-point pressure drop and P_{cc} is some characteristic capillary pressure and is approximated by $\sigma_{ow}\sqrt{\phi/k}$, where k is the absolute permeability and ϕ is the porosity. This dimensionless number is proportional to the inverse of capillary number, N_c because the length of the core is kept constant in the following experiments. When $N_{c,end} > 0.1$, end-effect is significant and hence it should affect both the relative permeabilities and residual saturations calculated by the JBN method.¹⁵

Many studies have been conducted on the onset of fingering in relatively homogenous, unconsolidated porous media. Peters and Flock (1981) prescribe the following conditions for instability in water-wet cores:

$$M > 1, \tag{15}$$

$$N_I = \frac{(M-1)(v-v_c)\mu_o d^2}{\sigma_{ow}k_{orw}} > 4152, \tag{16}$$

$$v_c = \frac{k_{orw}(\rho_w - \rho_o)g \cos \alpha}{\mu_o(M-1)} \tag{17}$$

where $M = \frac{\mu_w}{\mu_o}$, and N_I is the instability number, v is the superficial velocity and d is the core diameter.

S_{wm} is defined here as the brine saturation remaining in the core before the bump step and S_{wb} is the brine saturation after the bump, whereas S_{wr} is the brine residual saturation. The plot of S_{wr}

against N_c is called as the Capillary Desaturation Curve (CDC).

The fluids used were brine (1 wt % NaCl), Paraffin oil, Hexadecane, Soltrol 130 and Isopropyl Alcohol (IPA) and mixtures of some of these fluids. IPA is used for cleaning purposes. IPA is totally miscible with brine and partially miscible with all the types of oil used. Soltrol 130 and Paraffin oil were mixed in varying proportion to obtain oils of desired viscosity. Table 4 lists some important properties of these fluids. The preparation of each experiment started by completely saturating the core with brine.

Table 4. Properties of Fluids used in the Oilfloods

Fluid	Density (gm/cc)	Surface Tension (Dynes/cm)	Viscosity (cp) @ 25°C
IPA	0.78	21.7	2.5
Glycerol	1.26	63.4	1600
Hexadecane Oil	0.71	18	3.5
Soltrol 130 Oil	0.7	15	1.9
Paraffin Oil	0.85	35.4	140
Viscous Brine	1.02	70	19
Normal Brine (1% wt. NaCl)	1	72.75	1
Mineral Oil A	0.75	28	11
Mineral Oil B	0.77	30	24

Oil was injected from the top of the core at a constant flow rate. All the injections were carried out in a gravity-stable way, injecting lighter (oil) fluids from the top and heavier (IPA, brine) from the bottom of the core. Effluent samples were collected at the exit of the system. The sample volume corresponded to 0.05 core pore volume. Each sample corresponded to a time interval ranging from 1 minute to 2 hours depending on the flow rate imposed. The oil and water production at the outlet was monitored along with the pressure at the entrance of the core. Since the pressure at the exit of the system was always atmospheric, the pressure drop along the core was known at the end of each time interval. After injection of oil at a constant flow rate, a “bump”, injecting the same oil at a higher flow rate, was given in all the experiments to reduce capillary end-effect and some brine was recovered during the bump.

At the end of each experiment, isopropyl alcohol (IPA) was injected in the core to remove brine and oil from the core. At least 5 pore volumes of IPA were injected to ensure that no oil or brine is left behind in the core. IPA injection was followed by brinefloods to flush IPA and to make the core 100% saturated with brine for the next experiment. The pressure drops across the core were recorded for different flow rates to ensure that the same core state was reached before the start of

each experiment. If the brineflood pressure drops along the core were higher than those of the brineflood during the preparation of the previous experiment, the brineflood was interrupted and IPA injection was resumed to clean the core from any brine or oil left inside. The brineflood pressure drops across the core recorded just before the oilflood were used to calculate single phase (brine) permeability. This absolute permeability was further used in the oil and water relative permeabilities calculation.

Table 5. Oilflood Experiments

Expt. No.	Fluids (Displacing-displaced)	Flow-rate (ft/day)	μ_w/μ_o	IFT (dynes/cm)	Capillary No. $N_c = \mu_o u_o / \sigma_{ow}$
1	Hexadecane/Brine	0.1	1/3.5	30	3.86E-08
2	Hexadecane/Brine	1	1/3.5	30	3.86E-07
3	Hexadecane/Brine	4	1/3.5	30	1.54E-06
4	Hexadecane/Brine	10	1/3.5	30	3.86E-06
5	Soltrol/ Viscous brine	0.5	19/1.9	20	1.68E-07
6	Soltrol/ Viscous brine	4	19/1.9	20	1.34E-06
7	Soltrol/ Viscous brine	10	19/1.9	20	3.35E-06
8	Soltrol/ Viscous brine	46	19/1.9	20	1.61E-05
9	Soltrol/Brine (Surfactant)	0.5	1.1/1.7	0.25	1.20E-05
10	Soltrol/Brine (Surfactant)	1	1.1/1.7	0.25	2.40E-05
11	Soltrol/Brine (Surfactant)	4	1.1/1.7	0.25	9.60E-05
12	Soltrol/Brine (Surfactant)	10	1.1/1.7	0.25	2.40E-04
13	Paraffin Oil/Brine	4	1/140	30	6.08E-05
14	Paraffin Oil/Brine	0.24	1/140	30	3.65E-06
15	Mineral Oil/brine	1.5	1/24	30	3.91E-06
16	Mineral Oil/brine	4	1/11	30	4.30E-06

Automatic History Matching

A core-level simulator is used to history match the production and in situ saturation to infer the in situ relative permeability.^{12,13} This simulator has the options of matching the experimental data using Corey⁴ type relative permeability curves or quadratic spline relative permeability functions or Chierici type relative permeability curves. An automatic history matching simulator is developed to do this history matching efficiently. This simulator takes into account the capillary forces and hence is useful in interpreting the results for low capillary number correctly where capillary end effects are significant. The recovery, pressure drop and relative permeabilities are matched with that obtained from the experimental data analysis. Automatic history matching is thus a mathematical minimization problem. Oilflood history matching involves a large number of unknown parameters of relative permeability function. The problem is defined as

$$\min \frac{1}{2} \sum_{i=1}^m ((\Delta p_e(i) - \Delta p_s(i))^2 + (Q_{we}(i) - Q_{ws}(i))^2) \quad (18)$$

where Δp is the normalized pressure drop across the core, Q_w is the normalized wetting phase cumulative production at i -th experimental data point, m is the total number of experimental data points and subscripts e and s refers to the experimental and simulation data points respectively. This least square problem subject to bounds on the variables was solved using modified Levenberg-Marquardt algorithm and a finite difference jacobian. An IMSL subroutine DBCLSF was used for solving this problem.

Results

Our experiments are grouped into four sets: normal brine oilfloods, viscous brine oilfloods, low IFT oilfloods and constant capillary number oilfloods. All the experiments are assigned a number as stated in Table 5, which will be used to refer to any particular experiment. The detail and results of each set are discussed below:

Normal brine Oilfloods: Four oilfloods (experiments # 1 to 4) were done in this set changing the velocity of oil injection. These were the lowest Capillary Number experiments ranging from 10^8 - 10^6 . The corresponding flow-rates used were 0.1, 1, 4 and 10 ft/day. Hexadecane was the oil

used, which has a viscosity of 3.5 cp and the IFT between oil and water was measured using spinning drop tensiometer to be 30 dynes/cm. The duration of experiments ranged from 2 hours for 10 ft/day to 8 days for 0.1 ft/day experiment.

A bump was given for all the experiments at a flow-rate of 20 ml/min (~ 45 ft/day) to reduce the capillary end-effect. Some brine was recovered during the bump, which gave an estimate of the degree of capillary end-effect.

Table 6. Brine recovery in the bump

Flow-rate (ft/day)	Capillary Number N_c	Brine Recovery before the bump (PV)	Brine Recovery after the bump (PV)
10	3.86E-06	0.58	0.62
4	1.54E-06	0.58	0.61
1	3.86E-07	0.57	0.65
0.1	3.86E-08	0.22	0.60

The trends are same in all the four experiments. Table 6 gives the amount of brine recovered in all the experiments of this set before the bump and after the bump. The lower the flow rate, the higher was the recovery in the bump, which signify that there was a lot of end-effect in low flow-rate experiments (especially 0.1 ft/day).

Low IFT Oilfloods: Various surfactants and oil-brine system were used to study the phase behavior of aqueous and oil phase. Three-phase region in the phase diagrams was avoided.

Table 7. Surfactant Preparation

Surfactant	Volume % Surfactant	Volume % Soltrol Oil	Volume % Brine	IFT (Dynes/cm)
Aerosol MA 80-1	20	40	40	2.2
Glucopon 225CS	15	55	40	6.1
Petronate EOR-2095	5	27.5	67.5	0.25
BASF Pluronic F85	10	40	50	5.5

Different NaCl wt. % (ranging from 0.5-2 %) were tried, similarly different oils were tested and IPA was also added in some cases to aid as a co-surfactant. Table 7 above lists the sets, which yielded lowest IFT for a particular Oil-Water-Surfactant system.

Surfactant Petronate EOR-2095 was used to obtain the interfacial tension between oil and water of 0.25 dynes/cm. Spinning drop tensiometry was used to measure these low IFT's of 0.25 Dynes/cm. Brine and oil were mixed with surfactant and left to equilibrate for a couple of days so that no mass-transfer takes place between the two phases during the experiment. Then this aqueous phase was used to saturate the core before starting oil-surfactant phase flooding. Oilfloods were conducted at 0.5, 1, 4 and 10 ft/day with Capillary Number ranging from 10^{-5} - 10^{-4} , these were the highest capillary number floods (experiments # 9 through 12).

Table 8. Brine recovery in the bump for surfactant experiments

Flow-rate (ft/day)	Capillary Number N_c	Brine Recovery before the bump (PV)	Brine Recovery after the bump (PV)
10	2.40E-04	0.79	0.80
4	9.60E-05	0.786	0.794
1	2.40E-05	0.678	0.70
0.5	1.20E-05	0.635	0.70

Bumps were given in all the low IFT oilfloods at 20 ml/min (~ 45 ft/day) to reduce capillary end-effect. The brine recovery after the bumps are significantly different for 10 and 4 ft/day experiments as compared to 1 and 0.5 ft/day experiments. This signifies that even when the final capillary number is same the recoveries are different, thus history matters.

In these low IFT experiments, capillary end-effects are almost absent in the high flow-rate experiments (4 and 10 ft/day, # 11 and 12) and brine residual is close to 20% as compared to approximately 35% with hexadecane oil and brine. However, for 0.5 and 1 ft/day experiments (# 8

and 9) there is some end-effect as some brine is recovered during the bump. Thus reducing the IFT, increases the capillary number and lowers the capillary end-effect. Breakthrough is also late in all these experiments.

Viscous Brine Oilfloods: Viscous brine was obtained by mixing Glycerol of viscosity 1600 cp with 1% wt NaCl brine. Four experiments were done in this set with adverse viscosity ratio, a less viscous fluid (Soltrol oil, 2 cp) displacing a more viscous fluid (Brine+Glycerol, 20 cp) with flow-rates 0.5, 4, 10 and 46 ft/day (experiments # 5 through 8). Capillary Number was in the range of 10^{-7} - 10^{-6} . Bump was given in all these experiments also at a flow-rate of 20 ml/min (46 ft/day) to reduce capillary end-effect. In these experiments after IPA injection, core was saturated 100% first with normal brine and then with viscous brine. An unstable displacement leads to premature breakthrough and a longer period of two-phase flow at the outlet.

Table 9. Brine recovery in the bump

Flow-rate (ft/day)	Capillary Number N_c	Brine Recovery before the bump (PV)	Brine Recovery after the bump (PV)
46	1.61E-05	0.316	0.362
10	1.34E-06	0.351	0.383
4	3.35E-06	0.316	0.362
0.5	1.68E-07	0.382	0.426

Table 9 gives the amount of brine recovered in all the experiments of this set before the bump and after the bump. From this table, it is evident that a lot of brine has been bypassed in these experiments (fingering was there). S_{wb} was about 60% in all these experiments and lowest flow-rate (# 5, 0.5 ft/day) was more stable as the brine recovery was slightly higher compared to the highest flow-rate experiment. Fig. 21 shows that these experiments were almost unstable, according to equation (3).

Constant Capillary Number Oilfloods: A total of five experiments were conducted for Capillary number of 10^{-6} , four with favorable viscosity ratios using oils of viscosities 3.5, 11, 24, 140 cp and one with unfavorable viscosity ratio using brine of 20 cp. Two experiments (# 7 and 14) were performed at this capillary number. Capillary number was kept constant for three experiments (# 4, 15 and 16) by adjusting the flow velocity for different viscosity oil assuming same IFT, thus having same order of pressure drop across the core and hence same degree of capillary end-effect. Paraffin oil and Soltrol 130 oil were mixed in different proportions to obtain oils of viscosities 24 and 11 cp. Bump was given at a flow-rate such that the pressure drops in the bump was almost same, thus keeping capillary end effect same in these experiments.

Fig. 22 shows the effect of water-to-oil viscosity ratio on the water saturation for $N_c \sim 10^{-6}$. The plot shows that for oil viscosity greater than equal to 24 cp (brine viscosity is always 1 cp) the floods are stable and residual is not a function of viscosity ratio. The oilflood (experiment # 7) with viscous brine (20 cp brine and 2 cp oil) is highly unstable and has the highest brine saturation. The plot also shows that the increase in remaining brine saturation is gradual with the increase in water to oil viscosity ratio after a critical viscosity ratio. This critical viscosity ratio is found to be around 24 in our case.

Comparison of Oilflood Experimental Data: Fig. 23 shows the trend in brine recovery for different experiments. The total amount of brine recovered is a strong function of the flow-rates and flow properties like viscosity, IFT etc. The nomenclature used in the legend of this figure is that the first number corresponds to the flow-rate in ft/day and then the 'o' and 'b' refers to oil and brine, respectively, followed by their viscosities in cp. For example, 10 o3.5 b1 refers to the experiment at 10 ft/day with 3.5 cp oil and 1 cp brine. Early breakthrough (< 0.25 PV injected) was observed in experiments like 0.1 ft/day (3.5 cp oil and 1 cp brine), 10 ft/day (viscous brine) and there was also a long period of two-phase flow in these experiments. In experiments like 4 ft/day (140 cp oil and 1 cp brine) and 4 ft/day (surfactant) there was a delayed breakthrough (around 0.6-0.7 PV injected) and there was more overall brine recovery also. But even in these two experiments with high recovery, the 140 cp experiment has less recovery (as indicated by the flat recovery curve) after breakthrough indicating a better sweep than the 4 ft/day surfactant experiment. Fig. 8 shows the trend in the observed pressure drops across the core in some oilfloods ex-

periments. Since the absolute values of pressure drops are different for each experiment, for comparison they have been normalized in two ways. In Fig. 24(a), pressure is normalized w.r.t. pressure corresponding to brine's absolute permeability pressure at the experimental flow-rate, whereas, in Fig. 24 (b), pressure is normalized w.r.t. pressure corresponding to end-point pressure in the particular experiment. All the plots start from a value of one in Fig. 12(a) and end at a value of one in Fig. 24(b).

The pressure drop after the breakthrough for the 4 ft/day (# 11) low IFT surfactant experiment drops faster to the end-point pressure as compared to the 10ft/day (oil 3.5 cp and brine 1 cp, # 4) experiment (Fig. 24(a)). This suggests that the two-phase region is less prolonged in the surfactant experiment. For 4 ft/day (140 cp experiment, # 13), as shown in Fig. 8(b), the end-pt pressure is almost same as the breakthrough pressure, indicating that there is a very short period of two-phase flow in this experiment. Same trend was observed in the brine recovery also for 140 cp experiment as discussed in this section before (Fig. 23), thus confirming a good sweep efficiency. The displacement is almost piston-like in the 140 cp experiment. For the viscous brine experiment, however, the pressures decrease all throughout the experiment as a less viscous fluid is replacing a high viscous fluid, resulting in reduced pressure drops (see Fig. 24(a)).

Capillary end-effect: Fig. 25 is the plot of brine recovered in the bump step against the capillary end-effect number based on the oil injection velocity before the bump is given. It shows that the brine recovery increases with increasing $N_{c,end}$. This signifies increasing end-effect with increasing $N_{c,end}$ or decreasing N_c .

Effect of Capillary number on Brine Residual Saturation: Figures 26 and 27 show the plot of the brine saturation before and after the bump in the core against the capillary number. Fig. 11 is the curve for experiments with water to oil viscosity ratio of 1. For N_c in the range of 10^{-8} - 10^{-6} , S_{wb} 's are high in the range of 35-40% but for higher N_c around 10^{-6} , they start to decline and become fairly low (~20%) at N_c around 10^{-4} (low IFT experiments). Thus brine residuals are clearly a function of capillary number in the range of 10^{-6} - 10^{-4} .

This effect is reversed for the case with brine more viscous than the oil (see Fig. 27). The lower the capillary number, the more stable the flood and less bypassing, resulting in lower residuals. This result should be obvious because capillarity tends to stabilize viscous instability. If the pressure drops are so large that capillary pressure effects are negligible compared with viscous effects, then the stabilizing force is negligible and hence the flow is unstable. The effects of fingering and capillarity cannot be suppressed simultaneously. At low rates, fingering is small, but the capillary end effect is high. At high rates, fingering is large, but the capillary end effect is low. Brine recovery decreases with increasing capillary number. This implies less capillary end-effect in experiments with higher capillary number.

Automatic History Matching: Automatic history matching of experiment #11 is shown in Figures 28 and 29. The initial guesses for this experiment were the relative permeabilities obtained from the JBN method analysis, since JBN method should yield good result for this experiment as $N_{c,end} \ll 0.1$. For oil, Corey type relative permeability was used, whereas, for water one section was fitted with a linear curve and the other section with Corey type relative permeability function. These initial guess functions for relative permeabilities were not very different from those obtained by automatic history matching. This is also evident from the good matching of the pressure drop and recovery for the 4 ft/day experiment (# 11) as shown in Figures 28 and 29, respectively. This is a conclusive evidence of the validity of JBN analysis for negligible end-effects.

For the 10 ft/day oilfloods (# 4) with 3.5 cp oil and 2 cp brine, the match was not very satisfactory (see Figures 30 and 31). JBN method was used to obtain the initial guess for relative permeability parameters. A quadratic function was used for oil relative permeability, whereas, water relative permeability was fitted with three different functions in three sections: a linear function, a quadratic function and a Corey type relative permeability function. Automatic history matching simulation was then used to obtain the best set of parameters. For the experiment (# 13) with 140 cp oil and 1 cp brine at 4 ft/day, pressure drops were high compared to capillary pressure drop ($N_{c,end} \ll 0.1$), hence JBN method relative permeability is accurate and automatic history matching was not used to obtain relative permeability.

Automatic history matching was performed to obtain relative permeability functions for all the

oilfloods, except for viscous brine set. The agreement between the experimental data and forward simulation result was not found to be satisfactory for viscous brine oilfloods. This can be attributed to the one-dimensional nature of our forward simulation model. The effect of capillary number and viscosity ratio on relative permeabilities is discussed next.

Dependence of Relative Permeability on Capillary Number: The brine and oil relative permeability showed a dependence on N_c . Increasing N_c increases relative permeability for water phase. For oil, the effect of N_c was opposite on relative permeability (see Fig. 32). Increasing N_c from 10^{-5} to 10^{-4} showed a marked decrease in oil-phase relative permeability. The oil relative permeability was higher for $N_c = 10^{-6}$ and 10^{-7} experiments also. Some inconsistency in this trend could be attributed to unsatisfactory agreement of experimental data with the automatic history matching simulation results for low capillary number experiments. The legend used in Figures 32 has the value of capillary number for each curve.

Effect of Viscosity ratio on Relative Permeability: The effect of viscosity ratio on relative permeability was studied for experiments with N_c of $\sim 10^{-6}$. This capillary number was chosen because this was relatively free of capillary end-effects and the automatic history matching showed a good agreement with the experimental data. The relative permeability for oil shows an increase with the increase in water-to-oil viscosity, whereas for water the relative permeabilities decrease with increasing water-to-oil viscosity ratio (see Fig. 33).

Task 2: Pore-Level Model of Relative Permeability

2.1 Skeletonization of Realistic Porous Structure

The prediction of macroscopic transport properties of porous media from the microstructure is of great practical importance in the areas of hydrology, chemical engineering, petroleum engineering and materials science. Macroscopic transport coefficients like permeability, formation factor, effective thermal or electrical conductivity and effective diffusivity of porous materials cannot be obtained theoretically without consideration of the microgeometry and connectivity of the pore spaces through which transport takes place. This requires 3D reconstruction of pore space from data obtained experimentally by serial sectioning of pore casts or X-ray and magnetic resonance microtomography. This 3D reconstructed porous media can be used to get the network of pore bodies and pore throats to simulate fluid flow.

Model pore networks have been constructed in the past by assigning pore and throat sizes from respective distribution to the lattice sites and bonds, respectively. These models use simplistic geometry and topology. Obtaining the network of the pore space from the reconstructed porous media eliminates the simplifying assumptions regarding the shape, size, connectivity and spatial arrangement of flow channels. The skeleton is obtained from the reconstructed porous media using 3DMA software and then this pore body and throat network is used to calculate absolute permeability. The reconstructed porous media is assumed to be a two-phase (solid and pore) system and the skeleton can be obtained for either of these phases through a series of algorithms.

The various steps involved in obtaining a network of pore bodies and throat from a 3D pore space are as follows:

- Image segmentation;
- Skeleton generation;
- Skeleton modification;
- Throat/body network creation.

Skeleton modification involves boundary voxel trimming, path-pruning, cluster merging and surface remnant reduction. This throat/body network is then converted into an equivalent resistor network with throats representing the resistances. Throat radius is taken at a point along the

throat length where the area is minimum and hence the resistance to the flow is maximum. This resistor network is then used to calculate absolute permeability and capillary pressure curves.

The effective hydraulic conductance of each throat is calculated by taking the harmonic average of the conductance of segments of thickness 1 voxel. The effective hydraulic conductance g_{ij} of the link connecting pore bodies i and j is estimated as follows:

$$\frac{1}{g_{ij}} = \sum_k \frac{8}{\pi r_t(k)^4} \quad (19)$$

where $r_t(k)$ is the radius of the voxel along the path of throat connecting bodies i and j . The problem of fluid flow in porous media is reduced to a resistor-type network problem. The rate of flow between two nodes i and j can be written as:

$$Q_{ij} = g_{ij} (P_i - P_j) \quad (20)$$

where P_i and P_j are the pressures at nodes i and j , respectively. Since the fluid is incompressible, the mass balance at node i requires that:

$$\sum_j Q_{ij} = 0 \quad (21)$$

where j runs over all the links connected to node i . Combination of equation [2] and [3] and application to all nodes results in a linear algebraic system for the unknown nodal pressures. This linear sparse system is solved for pressures at nodes by imposing constant pressure and no-flow boundary conditions for nodes in contact with flow and non-flow direction boundaries, respectively. By imposing a pressure drop ΔP across the pore network and computing the average flow rate Q , the absolute permeability is calculated from Darcy's law. Thus this resistor-type network model is used to predict the absolute permeability values.

Realistic Porous Media Modeling Results

The throat/body network gives the pore throat size distribution $\{r_t\}$, pore body size distribution $\{r_b\}$, throat length distribution $\{l_t\}$ and coordination number distribution $\{z\}$, as shown in Fig. 34. The effect of correlation length, which is defined as the distance after which the porous media becomes uncorrelated, on these distributions is studied using simulated porous structures (Fig. 35). The effect of correlation length is studied for structures with identical porosity ($\phi=0.3$). The effect of decrease in correlation length for same porosity structure is shown in Fig. 36, there is an increase in total number of throats and bodies, average size of bodies as well as throats decreases and the average throat length decreases.

2.2 Dynamic Network Model for Oil-Water Flow

Network Description

The porous medium is represented as a collection of cubic pore bodies connected by throats that are square in cross-section. A generic network model with Cartesian topology is generated such that the throat and body sizes obey a Weibull distribution. The pore body-pore body and pore body-pore throat sizes are spatially correlated.

Pressure Solution

Analogous to the Kirchhoff's law for random resistor networks we formulate a mass conservation problem for our network model. The flow resistance between two nodes in the network model is determined from the radius of the connecting throat and pore bodies. The pressure difference (potential difference) between two nodes determines the mass flux (electric current) between those two nodes. For single-phase flow through the network, the above problem reduces to a linear matrix problem that can be solved to estimate the unknown pressures at each node.

In the presence of two phases the problem becomes nonlinear. The pressure difference across a throat should overcome the throat entry capillary pressure for flow to take place through that throat (otherwise that throat is “capillary blocked” or “frozen”). So whether or not flow takes place across the throat is a function of the pressure difference across it. Using pressure field from the previous time step, each throat is assigned a step conductance depending upon the pressure field around it (this is similar to the IMPES scheme used in reservoir simulation). Water imbibes

into pore J (see Fig. 37) if the capillary pressure corresponding to pore body J is overcome. Oil drains into pore I if the throat capillary pressure is overcome. These conditions are expressed mathematically in Eq. (22)

$$Q_{ij} = \begin{cases} G_{ij}(P_{wi} - P_{nwj} + P_{cbj}), & P_{wi} - P_{nwj} + P_{cbj} \geq 0 & \text{Imbibition from pore i to j} \\ G_{ij}(P_{wi} - P_{nwj} + P_{ctij}), & P_{wi} - P_{nwj} + P_{ctij} \leq 0 & \text{Drainage from pore j to i} \\ 0 & & \text{Otherwise} \end{cases} \quad (22)$$

Similar step conductance equations are formulated for other interface configurations and incorporated into the model. The linear matrix problem is solved to estimate the pressure field by ITPACK 2C which is an iterative solver for sparse linear systems.

Film Pressure Computation

The wetting phase maintains hydraulic connectivity through wetting films and this fact is used to compute the film pressures by spatial extrapolation of wetting phase pressures. We identify a pore body totally filled with wetting phase in either direction (upstream and downstream) of the point where film pressure is to be estimated (Fig. 38a). The material balance for flow through films can be written as

$$G_{w1}(P_{w1} - P_{f1}) = (G_{w2} + G_{w3})(P_{f1} - P_{w2}) \quad (23)$$

which gives

$$P_{f1} = \frac{G_{w1}P_{w1} + (G_{w2} + G_{w3})P_{w2}}{(G_{w1} + G_{w2} + G_{w3})} \quad (24)$$

Fig. 38b shows the case where no upstream pore body can be found. In such cases the wetting pressures in the downstream pore body will determine the film pressure. In other words,

$$P_{f1} = P_{f2} = P_{w2} \quad (25)$$

Saturation Updating

As in the IMPES scheme, saturation at the interfaces is updated after pressure computation by identifying a characteristic time (hereafter called $T_{\min}$). At each interface, the product of pressure

difference and interface conductance approximates the flow rate at that interface. The ratio of volume that needs to be invaded to the flow rate at each interface location gives the time for that interface to move and fill up the next pore body (called T_{event}). T_{min} is defined as the minimum of all T_{event} . All the interfaces are advanced during T_{min} as given by Eq. (26).

$$S_{nw}^{\text{new}} = S_{nw}^{\text{old}} + \frac{Q_i T_{\text{min}}}{V_{\text{invade}}} \quad (26)$$

Film Flow Mechanism

The wetting phase in a porous medium maintains connectivity through wetting films that form on the porous medium surface and in the crevices. The flow of wetting phase through these films plays an important part in the overall removal of wetting components from the porous medium. An explicit and “more correct” way of incorporating film flow is to solve two linear flow problems, one for bulk flow and the other for film flow. The solutions of the two problems would give the pressure fields in the bulk and in the film. The two pressure solutions are related through capillary pressure that will define the new radius of curvature of the interface. Then the conductances need to be recomputed with the new radius of curvature and the procedure needs to be iterated until a converged radius of interface curvature is reached. Once the film pressure profile is solved for – the flow through film can be imposed in parallel to the flow in bulk. As is fairly obvious, this procedure would require expensive and time-consuming computations at each time step. In addition, the convergence properties of this type of iterative procedure have been found to be very poor.

We have developed a heuristic scheme to implement film flow in the network model. The procedure involves computation of potential at each interface location. The potential is defined as the capillary pressure drop across the interface. Then an amount of wetting phase in proportion to the interface potential at that location is removed from the interface. In other words, an interface with higher potential would have more wetting fluid removed through this procedure as compared to an interface with lower potential. The total amount of wetting fluid that is removed is specified a priori. The film flow rate is specified as either a fraction (0.01) of the bulk flow rate or as a constant.

Capillary Desaturation Curves

For a water-wet media, the wetting phase maintains connectivity for all saturation values through wetting films. The wetting films disjoin or rupture when the film thickness reaches molecular dimensions – this happens at extremely low wetting saturation. If drainage is carried out for a long enough time then the wetting phase will slowly flow out through these films and reduce the wetting saturation. Thus, for all practical purposes, the residual wetting saturation (henceforth called “true wetting residual”) would be zero.

Seldom is a drainage displacement (in field or lab) carried out for a long enough time. The displacement is stopped once the outlet fractional flow of nonwetting phase approaches unity or when several pore volumes have been injected. Under these circumstances, wetting phase saturation is never reduced to the extremely low values corresponding to true wetting residual. We define “apparent wetting residual” as the wetting residual observed in these cases. The ratio of viscous to capillary force ($N_{Ca} = \frac{\mu V}{\sigma}$) is a measure of competition between driving force for removal of wetting phase and the retention force for the wetting phase in the porous medium. A plot of apparent wetting residual versus N_{Ca} (called Capillary Desaturation Curve) shows this dependence.

Drainage Relative Permeability

Two-phase displacements are characterized and scaled up by using relative permeability and capillary pressure curves. If two flowing phases are present then each competes with the other for occupying the flow area. The sum of the two relative permeabilities is less than one showing that two-phase flow always retards the overall flow. This happens because some interfaces are “frozen” or “capillary blocked” and that imparts nonlinear saturation dependence to relative permeability. In other words, if all interfaces move then relative permeability will be a linear function of saturation.

In this work, relative permeability (k_{rw} and k_{rnw}) is obtained by applying two-phase Darcy's law (Eq. 27a&b) to thin slices of the porous media. Fig. 3 shows a schematic section used to estimate

two-phase relative permeability. The in situ saturation, flow rates and pressure field is explicitly known during the simulation,

$$Q_w = \frac{k_{rw} K}{\mu_w} \frac{\Delta P_w}{L} \quad (27a)$$

$$Q_{nw} = \frac{k_{rnw} K}{\mu_{nw}} \frac{\Delta P_{nw}}{L} \quad (27b)$$

Low N_{ca} Modeling

At low capillary numbers ($<10^{-6}$) the viscous pressure drop in each phase is negligible and capillary forces govern interface motion. In the limit of zero N_{ca} , percolation models describe fluid motion through network models of porous medium. The dynamic model that is described above effectively captures high N_{ca} flows when several interfaces move in a single time step. In the percolation or low N_{ca} regime only one interface moves at a time by recruiting fluids from nearby pores. The dynamic model gave numerical difficulties when only one interface moves due to nonlinear dependence of throat conductance on pressure. Thus, we use what we like to call as “pseudo-percolation model” to simulate low N_{ca} flows. All interfaces are assigned a potential that equals the pressure drop across the interface (defined as in Film Flow Mechanism). At each time step, the throat with the highest potential is “opened” or assigned a nonzero conductance. Physically, this corresponds to opening a throat for the invading phase to drain into. Then the pressure solution and saturation updating are carried out as usual. In the limit of zero N_{ca} , the “opened” throat would be the one with the biggest throat radius. The pseudo-percolation model allows us to capture the near-zero pressure gradient in the invading and defending phases. In this respect, the present model better captures low but non-zero N_{ca} flows as compared to percolation models.

Stopping Criteria

The drainage simulations are not carried out for sufficient time for true wetting residuals to be reached. In fact the true wetting residuals would trivially be zero as explained earlier. Steady state is assumed if either of the following conditions are met:

1. $T_{min}=0.0$ i.e. all the interfaces are “capillary blocked”.
2. The number of interfacial locations is unchanged for 1000 iterations

3. The outlet fractional flow reaches 0.99 for drainage.
4. T_{min} is larger than the total time spent till that point or if T_{min} is larger than a pre-specified number (=1000 seconds).

Drainage Relative Permeability Results

Fig. 40a & b show the progress of saturation-fronts as a function of time for two different flow rates (or N_c). Note that the saturation fronts have almost time independent velocity that are saturation dependent. Thus relative permeability can be derived for such displacements. Fig. 41a shows two-phase relative permeability for different N_c . Fig. 41b shows a similar (N_c is defined here as inverse of our definition) plot from the work of Lefebvre du Prey (1973).¹⁷ The two results show excellent qualitative agreement. As expected at higher N_c , the relative permeability curves approach a linear dependence upon saturation. Fig. 42a shows the variation of “apparent wetting residual” as a function capillary number (N_{ca}). Fig. 42b shows some of the experimental capillary desaturation curves^{18, 19} obtained from literature.

2.3 Network Model of Gas-Condensate Flow

Pore-space is approximated by a cubic model in this study. The shapes of all pore bodies are assumed to be cubes in this model. The throats are assumed to be bipyramidal with a square cross-section. The network is assumed to be a simple cubic lattice, i.e., six throats are connected to each pore body.²⁰

Fig. 43 shows the network topology and a longitudinal section of the model through two adjacent pores. The throat cross-section (e.g. AA in Fig. 43b) is square. r_b and r_t are pore body and throat radii, respectively. L_{tt} is the path length from one body center to another and it is assumed to be a constant for all pores. A shape parameter X is used to change the end sizes of the throats where throats connect bodies. The end size of the throat, r_{tb} , is:

$$r_{tb} = r_t + (r_b - r_t) X \quad (28)$$

When X equals to zero, the throats are straight. When X equals to 1, r_{tb} equals r_b . The pore and throat size distributions for the inscribed radius are assigned by using a Weibull distribution that has been used in the past to model Berea sandstones.²¹ The pore-throat and pore-body radii dis-

tributions are given by

$$\begin{aligned} g(x) &= \frac{x}{x_2} \exp\left(-\frac{x^2}{x_2}\right) & \text{for } x \leq x_3, \\ &= 0 & \text{for } x > x_3, \end{aligned} \quad (29)$$

where $x = r - r_{\min}$, $x_2 = \bar{r} - r_{\min}$, and $x_3 = r_{\max} - r_{\min}$. r represents the pore throat or body radius, $r_{\min}$ and $r_{\max}$ define the minimum and maximum sizes, respectively, and $\bar{r}$ is the average size. Thus, three parameters ($r_{\min}$, $r_{\max}$ and $\bar{r}$) for each pore throat and pore body, are required to define the pore size distribution in the network. This model is not geometrically consistent, but it serves as a simple model for studying condensation and flow. Pore body radius, r_b , is defined as the radius of the largest sphere that can fit into a pore body. Pore throat radius, r_t , is defined as the minimum radius that a collapsible sphere needs to take to pass through a throat. The pore body radii are first distributed according to the assumed body size distribution with no assumed spatial correlation. Then the pore throats connecting the two pore bodies are assigned randomly or according to a throat-body correlation. In the case of throat-body correlation, the pore bodies are assigned randomly, but larger throats are connected to larger bodies. Throat radii are assigned according to the average radius of the two bodies adjacent to any throat. Periodic boundary conditions are used in the directions perpendicular to the inlet and outlet directions and help minimize finite-size effects in the results.

This structural model was used in the past²² to estimate realistic critical condensate saturations. It features corners within throats and bodies, explicitly. The corners are regions of highly positive curvature in the pore space. They are often separated by ridges (regions of highly negative curvature). The wetting fluid accumulates in corners but not on ridges. When the saturation of the wetting fluid builds up in a pore, the ridges can be covered by the wetting fluid. The condensate in one corner can be connected to the condensate in an adjacent corner if the saturation builds up enough to cover these ridges.

Pore-Scale Gas-Condensate Flow Mechanisms

During condensation or liquid dropout process in the absence of flow, the pressure and the tem-

perature of the fluid sets the radius of curvature, r_p , of the liquid/gas interface.²³ The pore structure can affect this curvature in submicron pores²⁴ but is not included here. In the cubic model, the condensate fills the small corners of each throat with an appropriate meniscus as long as the radius of the throat is greater than the threshold radius, r_p . If the radius of a throat, r_t , is equal to or smaller than the threshold radius, r_p , the condensate fills the middle part of the throat. We call condensate accumulations filling the throat cross-section a *slug*. Once the condensate slug forms in the throat, the condensate in corners surrounding the throat are connected. The connection between the body corner and the throat corner can be established when the condensate in the corner of the body reaches the corner of the throat, i.e., $(r_b - r_{tb})$ is smaller than r_p . Obviously, the connection between body and throat corners is easier for a larger shape parameter, X . The condensate in adjacent throats and bodies is also connected if the whole pore body is filled with the condensate. The connectivity of the condensate accumulated in the throats and bodies contributes to the conductance of the condensate.

In order to exist, a condensate slug has to satisfy the hydrodynamic force balance and the stability criterion,²⁵ in addition to meeting the curvature requirements dictated by thermodynamics. The gravitational and viscous pressure difference between the two menisci of a slug needs to be balanced by the capillary pressure difference due to the difference between the two curvatures. The gravitational head across a slug of height h is given by $\Delta\rho gh$. The analysis of detailed viscous forces is outside the scope of this paper, but the overall viscous pressure drop can be treated in a manner similar to the gravitational head. The capillary pressure difference is given by $2\sigma(r_1^{-1} - r_2^{-1})$, where σ is the interfacial tension (IFT) and r_1 and r_2 are the radii of curvature of the two menisci. At typical values of the interfacial tension, $\sigma > 0.01$ dynes/cm, the difference in curvature is slight and can be easily accommodated in a throat because it is converging-diverging, unlike cylindrical throats. The contact angle hysteresis affects the volume of the fluid accumulated, but it is not essential to the presence of a liquid slug in a throat, as in the cylindrical throat model.²⁴ If the difference in curvature is large for the liquid slug, it cannot be accommodated in a single throat and would flow down. The largest value the capillary pressure difference can take is $2\sigma(r_t^{-1})$, assuming the bottom menisci is flat. A slug cannot be accommodated in a pore throat

if $\sigma < \Delta\rho g h r_t / 2$. For a scenario of $\Delta\rho \sim 0.1$ g/cc, $h \sim 50$ μm , $r_t \sim 10\mu\text{m}$, the critical interfacial tension is $\sim 2.5 \times 10^{-4}$ dynes/cm. The corresponding Bond number, $N_B = \Delta\rho g K / \sigma$ is $\sim 4 \times 10^{-3}$. At tensions above this value (which is often the case in gas-condensate systems), slugs can be accommodated in single pore throats. A slug has two concave menisci in the diverging sections of a throat and thus it is also hydrodynamically stable.²⁵ At lower tensions, or equivalently at higher Bond or capillary numbers, the single throat slug may form and move, as shown in the micro-model experiments of Gray and Dawe.²⁶

As the fluid pressure falls, the radius of curvature at gas/condensate menisci increases. The number of throats having radius below the threshold radius r_p , increases. Condensates form liquid slugs in these throats and the condensate saturation increases. The liquid slugs in the throats connect with some adjacent throats through the corners.

A set of condensate slugs which are connected to each other through the condensates in the corners can be called a *condensate ganglion*. A condensate ganglion (shown in Fig. 44) is different from a nonwetting fluid ganglion or blob in two respects. The latter has convex menisci and the connections are not through the corners.²⁵ In order to exist, a condensate ganglion has to satisfy the hydrodynamic force balance and the stability criterion.²⁵ These conditions for a ganglion are similar to those for a slug except that the length of the ganglion (in the direction of gravity or viscous flow) can be larger. The maximum length of a ganglion,

$$h_{\max} = 2\sigma / \Delta\rho g r_t = 2K / N_B r_t. \quad (30)$$

For a scenario of $\Delta\rho \sim 0.1$ gm/cc, $r_t \sim 10\mu\text{m}$, $K \sim 1$ Darcy, this length is ~ 2000 μm or about 20 pore lengths at an interfacial tension of 0.01 dynes/cm or $N_B \sim 10^{-4}$. For a scenario of $\Delta\rho \sim 0.1$ gm/cc, $r_t \sim 1$ μm , $K \sim 0.01$ Darcy, this length is ~ 2 cm or about 200 pore lengths at an interfacial tension of 0.01 dynes/cm or $N_B \sim 10^{-6}$. Given the interfacial tension (or the Bond number), one can calculate the distance $h_{\max}$ over which menisci have to be connected to flow. The condensate saturation at which the condensate ganglia of this critical length ($h_{\max}$) or longer exist is called the critical condensate saturation, S_{cc} . The meniscus radius at this condition is termed the critical radius, r_{pc} . The networks employed in this study are finite, typically 20x20x20 pores. At low

Bond number, the maximum height exceeds the sample size. In these cases, the critical condensate saturation is defined as the lowest saturation at which a sample-spanning cluster forms.

In the above discussion, water was assumed to be absent. Water is the most wetting fluid in gas-condensate reservoirs because polar hydrocarbon molecules are seldom present in gas-condensate hydrocarbons. Connate water is usually present in such reservoirs. Most condensates spread on water with respect to the gas.²⁷ The contact angle between condensate/gas on water and the contact angle hysteresis are expected to be small. Water occupies the tight pores and highly curved regions like corners, being the most wetting fluid. The condensate accumulates on the top of the water starting with highly curved surfaces and small pore throats.²⁵ For a given radius of curvature r_p for the gas-condensate interface, the condensate saturation in the presence of water is equal to the liquid saturation minus the water saturation. This effect can potentially decrease the critical condensate saturation in the presence of water. The presence of water as slugs in some pore throats implies the absence of connections in the condensate phase across those throats. This reduction in connectivity can potentially increase the critical condensate saturation.

Low N_c Flow Regime. In this flow regime, capillary forces dominate over viscous forces. Only sample-spanning condensate or gas can flow under its own pressure gradient. Non-sample-spanning condensate ganglia cannot move. Thus condensate flows only above its critical condensate saturation. In our numerical model, a radius of curvature, r_w , is first assigned to the water-hydrocarbon interface. All pore throats and bodies smaller than this radius are filled with water. All corners (in unfilled throats and bodies) are also filled with water with menisci of this radius of curvature. The connate water saturation is calculated on the basis of this water distribution. If there is no connate water, then this step is skipped. Then a radius of curvature, r_p ($>r_w$), is assigned to the gas-condensate interface. All corners, throats, and bodies are filled up to this radius of curvature. Gas occupies the remaining pore space. The conductivity of each gas-occupied throat is computed.²⁸ A small pressure drop is applied in the gas phase across the sample. The continuity equation is solved for each gas-occupied pore body. The solution to this set of equations gives the pressure field in our lattice and the total gas flow rate. The effective permeability to the gas phase is calculated from pressure drop and flow rate, using Darcy's law. The

ratio of the effective permeability to the single-phase permeability gives the relative permeability of gas. The presence of condensate is ignored during the gas permeability calculation.

If the condensate saturation is above its critical value, then the condensate relative permeability is calculated in the following manner. First, the sample-spanning condensate ganglia are identified. The conductivity of each condensate-occupied throat and corner is computed.²⁸ A small pressure drop is applied in the condensate phase across the sample. The continuity equation is solved for each condensate-occupied pore body in the sample-spanning condensate ganglia. The solution to this set of equations gives the pressure field in our lattice and the total condensate flow rate. The effective permeability to the condensate phase is calculated from pressure drop and flow rate, using Darcy's law. The ratio of the effective permeability to the single phase permeability gives the relative permeability of condensate. The presence of gas is ignored during the condensate permeability calculation.

Low S_c -High ∇P Flow Regime. In this regime, inertial terms can be important to gas flow and droplets of condensate can form (Fig. 45). Condensate ganglia can move in this regime but are presumed not to be present because of low condensate saturation. This is an approximation that needs to be corrected in a future study. The initial liquid distribution is assumed to be determined by the imposed r_p , as in the last case. For the gas flow, large pressure drops are applied across the sample. Inertial flows in converging, diverging and bending flow sections are computed, as shown by Cooper et al.²⁹ The pressure distribution within the sample is calculated. Some of the condensate slugs cannot be accommodated under this pressure distribution. These slugs are removed and the liquid distribution is modified. The pressure distribution is computed again at the applied pressure drop. This leads to an effective flow rate or superficial velocity for the gas. A small pressure gradient is then applied to this modified fluid distribution and the Darcy flow superficial gas velocity is computed. The gas effective permeability (k_g) is computed from the Darcy flow superficial gas velocity. The effective non-Darcy coefficient (β_g) is computed from the Forcheimer equation using the actual superficial velocity and the calculated effective permeability. Relative permeability ($k_{rg} = k_g/k$) and relative non-Darcy coefficient ($\beta_{rg} = \beta/\beta_g$) are computed after comparison with the corresponding single-phase values.

Results from Pore Network Models of Gas-Condensate Flow

The base case input parameters of the model are shown in Table 10. The base case includes the throat-body spatial correlation, discussed earlier. The boundaries between different flow regimes are discussed in the next section in terms of pressure gradients. The relative permeabilities in the low N_c regime are described in the following section. The results from the low S_c -high ∇P flow regime are presented in the last section. In order to study the sensitivity of the model to the network size, we varied the network size from 12x20x20 to 50x20x20. The simulation results showed little effect of the network size on relative permeabilities of gas and condensate beyond 20x20x20 networks.²² All results reported in this paper are based on simulations on 20x20x20 pore networks.

Table 10-Parameters for the base case	
Parameter	<u>Value</u>
$\bar{r}_t$	12
$r_t(\text{min})$	0 μm
$r_t(\text{max})$	22 μm
$\bar{r}_b$	25 μm
$r_b(\text{min})$	10 μm
$r_b(\text{max})$	35 μm
L_{tt}	100 μm
X	0.1
size of the system	20 x 20 x 20

Regimes of Flow. Fig. 46 shows various flow regimes in terms of pressure gradient, saturation and interfacial tension. The results are for the base case parameters chosen for the medium. The dashed line shown in Fig. 46a corresponds to $N_c = 10^{-5}$ at a constant interfacial tension. Below this pressure gradient, non-sample spanning condensate ganglia would not move, i.e. the flow belongs to the low N_c regime. The condensate flows due to pressure gradient within its own phase if the saturation is high enough to have sample-spanning clusters. The gas flows in effective pores occupied by gas. Above this pressure gradient, high N_c flow can occur. At this pressure gradient, both gas and condensate flows are creeping, i.e. Darcy regime.

The solid line in Fig. 46a shows the critical pressure gradient at which the non-Darcy term becomes important, i.e. contributes 10% to the total pressure gradient. The value reported in Fig. 46a is for single-phase gas flow and would depend on condensate saturation (not shown).

As the pressure gradient increases, the type-II droplet formation occurs, i.e. some of the liquid slugs in throats break into droplets and reform. As the condensate saturation increases, there are more condensate slugs in throats and also in larger throats. Thus, the pressure gradient needed

for the type-II droplet formation decreases. As the pressure gradient increases further, the type-I droplet formation sets in, i.e. condensate droplets are formed from condensate in corners and layers by the viscous drag of the gas. This critical pressure gradient also decreases with condensate build up because the interstitial gas velocity increases.

The dependence of these critical pressure gradients on interfacial tension (at a constant condensate saturation) is illustrated in Fig. 46b. Pressure gradient for high capillary number flow is directly proportional to the interfacial tension, as shown by the dashed line. The pressure gradient for non-Darcy flow is again shown at the single-phase limit. The critical pressure gradients for both types of droplet formation increase with the increase in interfacial tension, but at different rates. At low interfacial tension, type II occurs at a lower pressure than the pressure gradient for type I. At high interfacial tension, it is the reverse. In the next section, flow in the low N_c regime is considered, that is the pressure gradient is below that shown by the dashed line in Fig. 46a or 46b.

Low N_c Flow Regime. In this flow regime, a fluid phase moves only in its sample-spanning pores under its own pressure gradient with no interaction between the two phases. This regime is valid away from the wells where pressure gradients and flow rates are low. Pore structure and saturation are the two key variables that control the fluid distribution and hence the relative permeabilities. The effect of throat shape parameter (X), pore size distribution and spatial correlation on the relative permeabilities of gas and liquid phases is studied here. In this section, the average throat radius ($R_{t,ava}$) is taken as $9\text{ }\mu\text{m}$, the water saturation is 0.08, and the other parameters are the same as the base case.

Effect of Shape Parameter. The shape parameter, X , changes the converging-diverging character of throats, and thus the height of ridges ($r_b - r_{tb}$) connecting throats to adjacent pore bodies. In the low N_c flow regime, the condensate cannot move until the condensate in the inlet connects that in the outlet. The condensate connection between a body and an adjacent throat is established by the condensate connection at the ridges. When the parameter X is zero, the throat is straight, and therefore, the volume contribution of the throats to the total pore space is the lowest. Also, $(r_b - r_{tb})$ is at its maximum, and thus, it is the hardest for the condensate in a throat to

connect with the condensate in an adjacent body corner. S_{cc} is 0.25 for $X=0$. As X increases to 0.4, S_{cc} decreases to 0.015. As X increases, r_{tb} increases and (r_b-r_{tb}) decreases. The condensate connection between bodies and throats are easier when (r_b-r_{tb}) decreases, which increases the condensate relative permeability. The results are shown in Fig. 47 for the base case with a water saturation of 0.08. The condensate relative permeability increases with the shape parameter at any condensate (or liquid) saturation. Since the gas flows in the middle (not the corners) of throats and bodies, the gas relative permeability is mainly determined by the size distribution of the narrowest part of the gas-occupied throats (r_t), and the connectivity of the gas phase. Changing the shape parameter affects the saturation slightly, but not these parameters. Thus, it doesn't affect the gas relative permeability significantly, as shown in Fig. 47.

Effect of Throat Size. The sensitivity of the relative permeability to the throat size distribution in this model is shown in Fig. 48. The parameters for each curve include the values of r_{tmin} , $\bar{r}_t$, r_{tmax} , r_{bmin} , $\bar{r}_b$, and r_{bmax} , respectively, in μm . When the average throat radius is changed from 9 to 12 μm , (and other parameter are kept the same), the relative permeabilities of both gas and condensate increase. As the throat radii increase, (r_b-r_{tb}) values decrease and this makes it easier for condensates in throats to connect with those in bodies. That causes the critical condensate saturation to decrease and the condensate relative permeability to increase. The increase in the pore throat size leads to a larger contribution of the throat volume to the overall pore volume. Thus, at a given condensate (or liquid) saturation, less number of throats are occupied by the condensate and thus more throats open for gas flow. This increases the gas relative permeability. There is little experimental data in the literature on the effect of pore structure on gas-condensate relative permeability. The increase in gas and condensate relative permeabilities with throat sizes is consistent with the experimental data of Morgan and Gordon³⁰ on oil-water flow at low capillary number.

Effect of Body Size. Increasing the maximum pore body radius from 35 to 50 μm (and keeping other parameters unchanged) results in a small decrease in the condensate relative permeability and a large decrease in the gas relative permeability, as shown in Fig. 48. The increase in the

pore body size leads to a larger pore volume and the larger pore bodies contribute a larger amount to the overall pore volume. At the same gas saturation, fewer bodies and throats are occupied by gas because the gas phase occupies the larger pores preferentially. Gas occupation of fewer throats leads to lower gas relative permeability. As pore body size increases, $(r_b - r_{tb})$ also increases, which makes it difficult for condensates in throats to connect with those in bodies. That causes the condensate relative permeability to decrease.

Effect of Correlation. In the base case, spatial correlations are used in assigning pore throat radii. Fig. 49 shows the effect of this spatial correlation on the relative permeabilities of gas and condensate. Gas relative permeability is higher in the correlated model than in the uncorrelated model. Condensate relative permeability is lower in the correlated model than in the uncorrelated model. In the correlated model, smaller throats clump together and so do larger throats. Thus, the critical radii of curvature required to establish a sample-spanning network is larger. That decreases the condensate relative permeability and increases the gas relative permeability.

Low S_c -High ∇P Flow Regime. In this flow regime, droplets of condensate can form and inertial terms can be important to gas flow. We restrict this model to low condensate saturation because high capillary number movement of condensate ganglia is not included in the model. This regime is valid near the wells where pressure gradients and flow rates are high. The base case values, listed in Table 10, are assumed for the structural parameters in this case. The interfacial tension is chosen as 0.02mN/m. The water saturation is fixed at 0.05. Superficial velocities are computed in each phase given the pressure gradients. The relative permeabilities and non-Darcy coefficients are extracted from the superficial velocities.

Superficial Velocities. The dependence of gas superficial velocities on pressure gradient is shown in Fig. 50(a). When the pressure gradient is less than 5.1E3 Pa/m, the non-Darcy term divided by the overall pressure gradient is less than 0.1. Below this pressure gradient, the non-Darcy effect is not significant and the relationship between the pressure gradient and the flow rate is linear. When the pressure gradient increases, the non-Darcy effect caused by converging-diverging and bending flow cannot be neglected. The velocity is not proportional to the pressure gradient any more, as shown in Fig. 50(a). The Forchheimer equation is applicable which leads

to the calculations of relative permeability and relative non-Darcy coefficient for the gas phase. At a constant pressure gradient, the gas superficial velocity decreases with increasing condensate saturation, because increasing number of pore throats are occupied by the condensate. This decrease is, however, smaller than that at low pressure gradients where condensate slugs are immobile.

Fig. 50(b) shows the relationship between the pressure gradient and the condensate superficial velocity as a function of liquid saturation. It is not linear. This nonlinear phenomena is not caused by the flow rate of the condensate, since the condensate flow rate is pretty low, but due to the droplet entrainment caused by the high gas flow rate, as mentioned earlier. Entrainment droplets flow with the gas phase until they hit a pore wall. At higher condensate saturation, more throats have condensate slugs which can be entrained by the type-II mechanism. Thus, at the same pressure gradient, the condensate superficial velocity is higher at the higher condensate saturation.

Condensate Relative Permeability. The condensate relative permeability is calculated here from the superficial velocity by using the Darcy's law (not Forcheimer equation). In this model, the condensate relative permeability originates from only the droplet entrainment due to the gas drag force. It should be added to the low N_c relative permeability (contribution from condensate flow through sample-spanning condensate ganglia) to give the total relative permeability, especially above (say) $S_l > 0.2$. Condensate relative permeability due to only droplet entrainment is reported in Fig. 51.

At a constant condensate saturation and a fixed IFT, increasing the pressure gradient increases the gas drag force to the condensate, which enhances droplet formation. That causes the condensate relative permeability to increase. The increase in condensate relative permeability is higher at a low liquid saturation than at higher liquid saturation. Type I droplet formation dominates at low condensate saturations and increases with pressure gradient. Type II droplet formations dominate at high condensate saturations. As condensate saturation increases there is more type II droplet entrainment leading to higher condensate relative permeability. The results reported here for high saturations are not accurate because flow in sample-spanning condensate ganglia and flow of small condensate ganglia (due to high N_c flow) are not included here.

Gas Relative Permeability. Fig. 52 shows the variation of the gas relative permeability (K_{rg}) with the total liquid saturation, as a function of the pressure gradient. The gas relative permeability decreases with the liquid saturation, because the liquid partially blocks the gas flow paths. The gas relative permeability increases only slightly as the pressure gradient increase in our simulation range. This is due to the fact that at a higher pressure gradient, type-II droplet entrapment occurs more frequently and the condensate blocking is removed from some of the throats. This effect is small at low liquid saturation because the throats that open up are small and contribute little to gas permeability. At higher liquid saturation, the throats that open up are relatively large and contribute significantly to the gas permeability.

Gas Relative Non-Darcy Coefficient. The variation of gas relative non-Darcy coefficient (β_{rg}) with liquid saturation is shown in Fig. 53 at different pressure gradients. The relative non-Darcy coefficients are less than unity implying that the non-Darcy coefficient is higher in the presence of a liquid than otherwise. As the liquid saturation increases (at the same pressure gradient), the relative non-Darcy coefficient decreases, i.e. the non-Darcy coefficient increases. As the liquid saturation increases, the number of flow channels for gas decreases and the interstitial velocity increases for the same superficial velocity and the tortuosity of the path increases. Thus, the non-Darcy coefficient increases. There is little experimental data on non-Darcy coefficient for condensates. The trend observed here matches qualitatively the experimental trend observed on air/water systems.^{29,31}

As the pressure gradient increases the non-Darcy coefficient increases at low condensate saturations, but decreases at high condensate saturations. This is due to two different factors. At low condensate saturation (e.g. 0.08), the gas (or liquid) occupancy does not change significantly with the pressure gradient. Only a few type-II droplet formations occur. As the pressure gradient increases, velocity of gas increases and thus β_{rg} increases. At higher saturations, however, more condensate slugs are blown out due to the increasing gas velocity (type-II droplet formations), which decreases the tortuosity of the gas flow path. This factor causes β_{rg} to decrease with pressure gradient at high liquid saturations, e.g. 33%. β_{rg} does not change much with the liquid saturation at the highest pressure gradient due to these two competing factors. Non-Darcy gas-condensate flow experiments need to be conducted in the future to verify the predictions of this

model.

2.4 Gas-Condensate Relative Permeability from Well Testing

Synthetic or “experimental” well test

- A. The synthetic data was generated by forward simulation. Simulations were performed using a compositional simulator representing a rich gas-condensate system. A three-rate test followed by a buildup was modeled. Flowing bottom-hole pressures were below dew point for all three rates. This was designed to simulate a two-phase region within the near well-bore region. Both the gas and condensate relative permeabilities were considered capillary number dependent. Inertial, or Reynolds number, effects were included for the gas phase through the multiphase Forchheimer equation.
- B. Effective relative permeability functional relationships (with only a few parameters) were developed for both gas and condensate relative permeabilities based on the forward modeling results.
- C. The effective gas and condensate relative permeabilities were recovered by history matching the flowing bottom-hole pressures through non-linear regression. The history matching process involved adjusting the parameters in the simplified relative permeability correlations to match the observed flowing bottom-hole pressures.

Table 11
Fluid Composition

Component	Mole Fraction
CO ₂	0.0324
C ₁ N ₂	0.6377
C ₂	0.0968
C3-4	0.0897
C5-6	0.0328
C7-10	0.0562
C11-14	0.0219
C15-20	0.0184
C21-29	0.0103
C30+	0.0038

Generation of Simulated Well Test

Mathematical Model: A finite difference compositional simulator was used to generate the experimental data set. The rich gas-condensate system was represented by a 10 component modified Peng-Robinson equation of state. The composition of the system is listed in Table 11. This represents a rich gas-condensate system with a condensate to gas ratio of 250 bbls/mmcf. The dew point of the system is 5050 psia at 230 °F.

Table 12
Reservoir Properties

k(md)	22
Porosity (%)	8
S _{wc} (%)	10
Radius (ft)	4000
Net thickness (ft)	50
Mechanical Skin	0
Pi (psia)	5100
β _o (cm ⁻¹)	5.0E7

Simulated reservoir properties selected for this study are shown in Table 12. The mechanical skin is zero. The well test data was simulated with a one-dimensional radial model with a no flow boundary at the outer radius. The model was partitioned into 20 cells sized in logarithmic progression from the wellbore. This incorporated fine gridding within the near wellbore region to capture the near wellbore effects. Table 13 lists the outer radius of the cells. The model was sized to insure no pressure depletion during the test.

The experimental data was generated with capillary number dependent Corey type relative permeabilities. Inertial effects were included in the gas phase. A brief description of these models is described below.

The following Corey type relative permeability relation was used for both phases:

$$k_{r\alpha}(N_c, S_\alpha) = k_{r\alpha}^o \left[\frac{S_\alpha - S_{r\alpha}(N_c)}{1 - S_{wc} - \sum_{\alpha=1}^p S_{r\alpha}(N_c)} \right]^{E_\alpha(N_c)} \quad (31)$$

Table 13 Radial Grid Dimensions

Grid #	Radial Distance (ft)
Rw	0.55
1	0.84
2	1.28
3	1.96
4	2.99
5	4.57
6	6.98
7	10.66
8	16.27
9	24.85
10	37.95
11	57.96
12	88.52
13	135.19
14	206.46
15	315.30
16	481.51
17	735.36
18	1123.02
19	1715.06
20	2619.21
21	4000.00

Relative permeabilities were considered capillary number dependent for capillary numbers between $1\text{E-}2$ and $1\text{E-}5$. The values for the parameters used in the forward relative permeability model are listed in Table 14.

Table 14 Relative Permeability Models: Forward Model & Simplified Forms

Forward Model: Relative Permeability Input Parameters								
	S_{rimm}	S_{rth}	k_{imm}	k_{th}	E_{imm}	E_{th}	Desaturation Curve Slope (DCS)	Threshold N_{cth}
Gas	0.18	0	1	1	2	1	-0.35	1E-2
Condensate	0.20	0	1	1	3	1	-0.35	1E-2

Determination of phase residual saturation and Corey Exponent for $N_c < N_{cth}$ given by:

$$S_{ra}(N_c) = S_{rth} + DCS[S_{rimm} - S_{rth}] [\log N_c - \log N_{cth}] \quad 0 < S_{ra} < S_{rimm}$$

$$E_\alpha(N_c) = 1 + (E_{imm} - E_{th}) \frac{[S_{ra}(N_c) - S_{rth}]}{[S_{rimm} - S_{rth}]}$$

Simplified Functional Forms

I.	$K_{rg}^*(N_c, S_c, Re)$	$K_{rc}(N_c, S_c)$
	$\frac{\left[\frac{1 - S_c - S_{wc}}{1 - S_{wc}} \right]^{E_g(N_c)}}{(1 + Re)}$	$\left[\frac{S_c}{1 - S_{wc}} \right]^{E_c(N_c)}$
IA.	$E_g(N_c) = G * \log \left[\frac{GC}{Nc} \right] + 1.0$	$E_c(N_c) = C * \log \left[\frac{GC}{Nc} \right] + 1.0$
IB.	$E_g(N_c) = G * \log \left[\frac{1E-2}{Nc} \right] + 1.0$	$E_c(N_c) = C * \log \left[\frac{1E-2}{Nc} \right] + 1.0$
	$N_c > 1E-2, \quad E_\alpha(N_c) = 1$	
II.	$K_{rg}^*(N_c, S_c, Re)$	$K_{rc}(N_c, S_c)$
	$\frac{\left[\frac{1 - S_c - S_{wc}}{1 - S_{wc}} \right]^{E_g(N_c)}}{(1 + Re)}$	$\left[\frac{S_c - S_{rc}(N_c)}{1 - S_{wc} - S_{rc}(N_c)} \right]^{E_c(N_c)}$
	$E_g(N_c) = G * \log \left[\frac{1E-2}{Nc} \right] + 1.0$	$E_c(N_c) = C * \log \left[\frac{1E-2}{Nc} \right] + 1.0$
		$S_{rc}(N_c) = CR * \log \left[\frac{1E-2}{Nc} \right]$
	$N_c > 1E-2, \quad E_\alpha(N_c) = 1$	$S_{rc} = 0$

Inertial effects were included in the gas phase through the Forchheimer equation and a multiphase inertial coefficient. Inertial effects were not considered for the condensate phase. A dimensionless multiphase inertial coefficient for gas flowing in the presence of either a mobile or immobile liquid can be expressed as³²:

$$\beta_{rg} = \frac{\beta_g(S_l \neq 0)}{\beta_o(S_l = 0)} = k_{rg}^{-2}(N_c, S_c) \quad . \quad (32)$$

β_g is the multiphase inertial coefficient for gas and β_o is the single-phase inertial coefficient for gas. A value for β_o of $5.0E7 \text{ cm}^{-1}$ was selected for this study. This was based on a formation permeability of 22 md.

Through rearrangement of the multiphase Forchheimer equation an effective gas relative permeability dependent upon capillary number, saturation and Reynolds number can be expressed as:

$$k_{rg}^*(N_c, S_c, \text{Re}) = k_{rg}(N_c, S_c) / \{1 + \text{Re}\} \quad (33)$$

The capillary number definition used in this study is:

$$N_c = \frac{k \|\nabla P\|}{\sigma} \quad (34)$$

Experimental Data Output: Forward simulations using a single layer model generated phase saturations, pressure, capillary number and condensate relative permeability ($k_{rc}(N_c, S_c)$) for each cell. Simulations were performed with and without the inertial term included in the gas phase. With inertial effects neglected ($\beta_o=0$) only a capillary number and saturation dependent gas relative permeability was generated, $k_{rg}(N_c, S_c)$. With inertial effects included ($\beta_o \neq 0$) a gas

relative permeability dependent upon capillary number, saturation and Reynolds number was generated, $k_{rg}^*(N_c, S_c, Re)$. Additionally, with $\beta_o \neq 0$ a Reynolds number was also generated for the gas phase within each cell.

For regression purposes only, flowing bottom-hole pressure data was generated using a two-layer model. The net thickness of each layer was 25 ft. with layer permeabilities of 22 and 10 md, respectively.

Simplified Correlations for K_{rg}^ and K_{rc} ; Adjustable Parameters*

Simplified correlations for k_{rg}^* and k_{rc} were developed for history matching relative permeabilities through non-linear regression. Table 14 contains the two simplified correlations investigated in this study. The effective gas relative permeability, k_{rg}^* , is dependent upon saturation, capillary number and Reynolds number. The condensate relative permeability is considered saturation and capillary number dependent. Both correlations resemble a Corey relation.

The gas relative permeability was not expressed in terms of the k_{rg}/k_{rc} ratio and the capillary number as suggested by previous investigators³³. This formulation is based on steady state multiphase flow of gas and condensate and well deliverability estimates are generally based on a single k_{rg}/k_{rc} ratio representative of the near wellbore region. These estimates are made at various stages of reservoir depletion. As a reservoir depletes, the k_{rg}/k_{rc} ratio increases in response to the gas mixture becoming leaner. The time duration for this process is on the order of years as opposed to hours or days for a typical well test. As will be discussed later, a single k_{rg}/k_{rc} value cannot be used to simulate the pressure response in a well test. A simulation will also be presented in which the synthetic well test flowing bottom-hole pressures are matched based on a correlation for k_{rg}^* as a function of the k_{rg}^*/k_{rc} ratio.

The principal difference between correlations I & II is that a residual condensate saturation is considered in correlation II while residual saturations for both phases are assumed zero in correlation I. The only capillary number dependent parameter in correlation I is the Corey exponent,

E(Nc). In correlation II, both the Corey exponent and the condensate residual saturation are considered capillary number dependent.

Adjustable parameters: Correlation IA requires three adjustable parameters. Parameter GC represents the threshold capillary number while parameters G and C represent the slope of the desaturation curve within the capillary number dependent region for each phase. Correlation IB is identical to correlation IA except that the threshold capillary number is held fixed at 1E-2. Hence, only two adjustable parameters are required for this correlation.

Correlation II contains three adjustable parameters. Parameters G and C have the same significance as in correlation I while parameter CR is required to estimate a capillary number dependent residual condensate saturation.

Parameter Estimation: Krg and Krc Correlations (History Matching)*

The estimation process involved adjusting the parameters in the gas and condensate relative permeability correlations to match the experimental flowing bottom-hole pressures. A compositional simulator was used in the regression analysis.

Mathematically the regression procedure involved adjusting the parameters in the selected relative permeability correlations to minimize an objective function, X. The objective function is a sum of squares of residuals, i.e., sum of squared differences between measured data and predicted data from a mathematical model. This can be written as:

$$X = \sum_{i=1}^n \{FBHP_o - FBHP_m\}_i^2 \quad (35)$$

In this equation, X is the objective function, i is the ith observation, n is the number of observations, FBHP_o represents the observed flowing bottom-hole pressures (generated from the forward simulations) and FBHP_m represents the flowing bottom-hole pressures calculated from the mathematical model. The model calculated flowing bottom-hole pressures are based on updated

estimates for the gas and condensate relative permeabilities. The relative permeability expressions are updated by adjusting the parameters in the relative permeability correlations. A Levenberg-Marquardt algorithm with constraints was used to minimize the objective function. Constraints were required to restrict the predicted relative permeabilities to realistic values.

In the regression procedure the Reynolds number was calculated according to Equation 6. This differs from form used in the forward modeling in that it is independent of the gas relative permeability and assumes a value for the characteristic length, r_t . Both forms, however, are dimensionless and represent a Reynolds number for flow through porous media.

$$Re = \frac{\rho_g V_g r_t}{\phi S_g \mu_g} \quad (36)$$

where V_g is the Darcy or superficial velocity and r_t is an average pore throat radius. A pore throat radius of 8E-4 cm was used to represent a 22 md system.

Table 15
Experimental Data Sets from Forward Simulation

Rate #	Qg (mscf/d)	Qc (bc/d)	Min FBHP (psia)	Nc	Re	Sc	Pore Velocity (m/d)	GOR
1	5062	968	4784	9.92E-4	0.51	0.40	279	5226
2	8483	1530	4488	4.81E-4	0.90	0.44	503	5543
3	11927	2050	4130	2.52E-4	1.45	0.46	760	5819

Review of Simulated Well Test Data

Fig. 54 represents a flowing bottom-hole pressure plot for the simulated well test. The test consists of three increasing rates followed by a pressure buildup. The duration of each rate is six hours with the buildup lasting six hours. Table 15 lists specific information for each rate of the test. The data shown in Table 15 represents conditions at the end of each flow period. The capillary number, Reynolds number and condensate saturation are maximum values from the two-phase region within the reservoir. The gas interstitial velocity is determined at a radial distance of approximately two feet from the wellbore. Figures 55-59 represent profiles within the two-phase region of the reservoir at the end of each rate period. These are discussed in detail below.

Pressure Distribution: The pressure distribution within the reservoir at the end of each rate period is shown in Fig. 55. Pressure profiles with and without inertial effects are plotted for each rate; the solid lines represent forward simulations with inertial effects and the dashed lines represent simulations without inertial effects included in the gas phase. Reservoir pressure varies semilog linearly with respect to the reservoir radius. As the rates increase the pressures decrease in response to the higher withdrawal rates. Inertial effects create additional pressure drop resulting in lower pressures for identical rates. Note the nonlinear semilog relationship between pressure and radial distance due to inertial effects.

Capillary Number Profile: The capillary number behavior is shown in Fig. 56. Capillary number profiles with and without inertial effects are plotted for each rate; the solid lines represent forward simulations with inertial effects and the dashed lines represent simulations without inertial effects included in the gas phase. At the onset of the two-phase region the capillary numbers decrease. This is due to the increase in interfacial tension between the gas and condensate caused by the reduction in reservoir pressure. The capillary numbers then start increasing due to the increase in phase velocities as the flow converges towards the wellbore. Fig. 56 clearly shows that capillary numbers are inversely proportional to rate; lower capillary numbers are observed for higher rates. This is based on lower reservoir pressures required for higher rates that causes an increase in the interfacial tension between the gas and condensate. Apparently, the increase in interfacial tension overrides the increase in the phase velocities at the higher rates.

Inertial effects, which increase the pressure drop for a given rate, increase the capillary number for a given rate and radial location. This effect is more pronounced within the near wellbore region where phase velocities and pressure drop are higher.

Reynolds Number Profile: The Reynolds numbers profiles are illustrated in Fig. 57. The Reynolds numbers become significant (exceed 0.1) at radial distances of less than 20 feet. Due to the radial flow geometry the Reynolds numbers increase as flow converges upon the wellbore. Previous investigators have reported that inertial effects for flow in porous media become important for Reynolds numbers above 0.1.³⁴

Condensate Saturation Profile: Condensate saturation as function of radial distance is shown in Fig. 58. The solid lines represent simulations performed with inertial effects included in the gas phase and the dashed lines represent simulations without inertial effects considered. A two-phase region extends nearly 1000 ft. into the reservoir by the end of the third rate. Condensate saturations increase as the flow converges towards the wellbore. This is due to condensate drop-out from the gas phase in response to the decrease in reservoir pressure. For a given radial position, the condensate saturations increase with rate. This is also due to increased retrograde condensation due to lower reservoir pressures at increased rates. The impact of inertial effects is to reduce the condensate saturation within the near wellbore region. This is the velocity stripping effect which has been documented by previous investigators.³⁵ This is the result of a coupled effect between effective gas relative permeability and condensate relative permeability. Inertial effects more severely impact effective gas relative permeability than condensate relative permeability, which translates into a larger reduction in gas mobility than condensate mobility. Interestingly, the velocity stripping effect was not observed when inertial effects were not considered in the gas phase.

Interstitial Gas Velocity Profile: Interstitial gas velocities as a function of radial distance are shown in Fig. 59. Only values with inertial effects included in the gas phase are presented. Interstitial velocities increase as the flow converges towards the wellbore. Gas velocities reach nearly 1800 m/d at the maximum rate of 11.9 mmscf/d. Also shown in Fig. 59 is the product rV_r plotted as a function of radial distance. For radial distances less than 100 ft. this product reaches

a constant value for each rate. This signifies a tenfold change in the interstitial velocity for each log cycle i.e. V_g is ten times larger at a radius of 1 ft. than at a radius of 10 ft.

Effective gas relative permeability: Effective gas relative permeability vs. radial distance is illustrated in Fig. 60. The solid lines represent simulations performed with inertial effects included in the gas phase and the dashed lines represent simulations without inertial effects considered. For a given rate, effective gas relative permeability increases with radial distance in response to increasing gas saturations. With respect to rates, effective gas relative permeability decreases with increasing rates. This is in response to reduced gas saturations caused by increased condensate dropout at the lower reservoir pressures. Inertial effects begin to impact the effective gas relative permeability at distance of between 10-20 ft. from the wellbore.

Condensate relative permeability: Condensate relative permeability as a function of radial distance is shown in Fig. 61. Effective gas relative permeability, with inertial effects included, is also shown for comparison purposes. The solid lines represent simulations performed with inertial effects included in the gas phase and the dashed lines represent simulations without inertial effects considered. Condensate relative permeabilities increase closer to the wellbore. This is in response to increasing condensate saturations caused by reduced reservoir pressures as flow converges towards the wellbore. In contrast to the effective gas relative permeability, there is minimal rate sensitivity to the condensate relative permeability. Inertial effects have less of an impact on the condensate relative permeability as compared to the effective gas relative permeability. For the maximum rate, the condensate relative permeability is reduced due to inertial effects at a radial distance of less than 10 ft.

k_{rg^}/k_{rc} ratio:* Fig. 62 represents a graph of k_{rg^*}/k_{rc} vs radial distance for each of the three rates. Clearly the k_{rg^*}/k_{rc} ratio is not constant as a function of either radial distance or rate. Therefore, a single value for the k_{rg^*}/k_{rc} ratio will not simulate the observed pressures during a well test. The k_{rg^*}/k_{rc} ratio increases with radial distance in response to reduced condensate dropout. With respect to rate, the k_{rg^*}/k_{rc} ratio decreases due to increased retrograde condensation at the higher rates, which reduces the effective gas relative permeability and increases the condensate relative permeability. A simulation of the flowing pressures based on a correlation

between k_{rg}^* and the k_{rg}^*/k_{rc} ratio is shown in Fig. 63. The large disparity between the simulated and observed pressures is not acceptable from a well test perspective.

k_{rg}^ and k_{rc} Estimation (History Match Results)*

The effective gas and condensate relative permeabilities were estimated by matching the observed flowing bottom-hole pressures. This was accomplished by adjusting the parameters in the effective gas and condensate correlations within the regression. All other parameters such as fluid properties, absolute permeability, β_o , mechanical skin and flow rates were assumed known. (Mechanical skin and permeability can be determined from a single rate test followed by a buildup with flowing bottom-hole pressures maintained above dew point. This requires a reservoir with sufficient productivity and separation between dew point and initial reservoir pressure.)

The regression results are summarized in Table 16. Several key regressions will be discussed in detail below. For each regression the initial and final parameter values are tabulated. The pressures selected for history matching were the last five points at the end of each flow period. These are highlighted in Fig. 64. All regressions were performed using a single layer model. Success of each regression can be measured by comparing the initial and final residual values. The residual represents the sum of the absolute value differences between the predicted and observed flowing bottom-hole pressures. It is similar to the objective function defined in Equation 5.

History match results using correlation IA, $\beta \neq 0$, single layer are graphically presented in Fig. 64. The solid lines represent the flowing bottom-hole pressures generated by the initial estimate for the effective gas and condensate relative permeabilities. Different initial estimates were achieved by adjusting the parameters in the relative permeability correlations. All four regressions were successful based on the low final residual values. Convergence was achieved with initial estimates both above and below the observed pressures. Regression or history match results, denoted as HM, are shown for cases 1C and 1G. These results are not evident on the graph as they essentially overlay the observed pressures. The most influential parameter in the regression is GC, which represents the threshold capillary number. The parameters G and C vary little compared to the movement of parameter GC.

Table 16: Regression Summary					
HM #	G	C	GC	CR	Initial/Final Residual
Correlation IA, $\beta \neq 0$, Single Layer					
1A	0.14/0.141	0.39/0.393	9.00E-3/6.32E-3		419/104
1B	0.18/0.184	0.42/0.42	6.00E-3/3.71E-3		643/35
1C	0.18/0.178	0.42/0.422	9.00E-3/3.88E-3		1254/42
1D	0.08/0.090	0.39/0.392	6.25E-3/3.84E-3		581/173
1E	0.09/0.081	0.39/0.395	3.00E-3/9.70E-3		1242/394
1F	0.09/0.094	0.39/0.387	4.00E-3/1.03E-2		1022/231
1G	0.18/0.179	0.42/0.419	1.00E-3/3.84E-3		1641/41
Correlation IB, $\beta \neq 0$, Single Layer					
2A	0.180/0.101	0.420/0.434	1E-2 (fixed)		1420/144
2B	0.030/0.061	0.420/0.420	1E-2 (fixed)		987/564
2C	0.080/0.100	0.420/0.433	1E-2 (fixed)		320/148
2D	0.055/0.090	0.420/0.417	1E-2 (fixed)		647/216
2E	0.080/0.140	0.300/0.290	1E-2 (fixed)		748/141
2F	0.040/0.077	0.300/0.311	1E-2 (fixed)		1253/746
2G	0.060/0.087	0.300/0.331	1E-2 (fixed)		1006/521
2H	0.030/0.116	0.200/0.224	1E-2 (fixed)		1737/622
Correlation II, $\beta \neq 0$, Single Layer					
3A	0.130/0.134	0.217/0.216		0.013/0.016	282/202
3B	0.217/0.216	0.217/0.217		0.013/0.012	1110/1086
3C	0.087/0.101	0.086/0.092		0.013/0.028	1502/1063
Correlation IA, $\beta \neq 0$, Two Layer, System, History Matched with Single Layer					
4A	0.18/0.176	0.42/0.424	9.00E-3/2.96E-3		2626/29
4B	0.08/0.099	0.42/0.379	2.00E-3/1.14E-2		2139/237
Correlation IA, $\beta = 0$, Single Layer					
5A	0.14/0.132	0.42/0.403	6.00E-3/2.61E-3		888/76
5B	0.18/0.186	0.42/0.422	9.00E-3/1.67E-3		2188/146

History match results using correlation IB, $\beta \neq 0$, single layer are shown in Fig. 65. Inspection of the final residual values indicates that these regressions were not as successful as those performed with correlation IA. Cases 2A and 2B converged, while case 2G did not converge. For

convergence, starting above the observed pressures required a closer initial estimate than starting from below the observed pressures.

Regression results from correlation II, which incorporates a capillary number dependent residual condensate saturation, are shown in Fig. 66. These regressions were not successful using the selected optimization scheme based on both the final residual values and plot of the final flowing bottom-hole pressures. Minor movement towards the observed pressures was observed for the two regressions with initial estimates above the observed pressures, 3A and 3C. No movement was observed for the regression which started from below the observed pressures, 3B.

A homogeneous, single layer system has been considered thus far. All reservoirs have some degree of heterogeneity. Heterogeneity was introduced by generating flowing bottom-hole pressure data with a two-layer model with different horizontal permeability. The observed data was then history matched with a single layer model. A single layer model was selected to history match the observed data due to difficulties often encountered in properly characterizing a heterogeneous reservoir. Fig. 67 illustrates the regression results for initial estimates above and below the observed pressures using correlation IA. The history matches were successful in both cases. The history matched pressure responses essentially overlay the forward generated data.

History matches to forward modeling without inertial effects ($\beta=0$) are summarized in Table 16 to illustrate the versatility of both the regression technique and the simplified relative permeability correlations. Both history match cases, 5A and 5B, were successful based on the final residual values. Correlation IA was used in these regressions. Correlation IA was found to be the most successful in most cases and was used in subsequent tests.

Confidence intervals (99%) were established for the estimated effective gas and condensate relative permeabilities for $\beta \neq 0$. History match case 1B was selected for this analysis as this case resulted in the lowest final residual. The confidence intervals were determined from linearized covariance analysis.¹⁰ Figures 68 & 69 represent the estimated relative permeabilities and confidence intervals. The dashed lines represent the confidence intervals that nearly overlay the estimated relative permeabilities. This represents a low degree of uncertainty for the estimated

relative permeabilities.

Well Test Design for Relative Permeability Estimation

The following procedure is recommended for relative permeability estimation from a well test.

Forward Simulation: Perform forward simulations using a compositional simulator to estimate rates and flow duration to develop two phases within the near wellbore region. Relative permeability estimation requires that pressures fall below the dew point within the near wellbore region. Information required for the forward modeling is an EOS representing the fluid system, an estimate of reservoir permeability and mechanical skin, capillary number dependent relative permeability expressions and a relationship relating the multiphase inertial coefficient to gas relative permeability. The single-phase inertial coefficient can be obtained from correlations. The pressure drop between the design rates should be sufficient to evaluate inertial effects. Develop initial parameter estimates for the simplified relative permeability correlations.

Test Design:

1. Perform a single rate test followed by a buildup to estimate permeability and mechanical skin. A low yet stable rate is recommended to minimize inertial effects and possibly maintain flowing bottom-hole pressures above dew point. This may not be achievable for low permeability systems if the reservoir is only slightly undersaturated. If flowing bottom-hole pressures fall below dew point the calculated skin may be higher than the true mechanical skin. With a low flow rate this difference will be minimized. The permeability should be accurate as the wellbore buildup pressures should be above dew point.
2. Modify the rate schedule determined from the forward simulations based on the permeability and mechanical skin information obtained from the low rate test.
3. Perform relative permeability estimation by matching the observed flowing bottom-hole pressures through non-linear regression.

Conclusions

Task 1:

- A centrifuge has been built that can accommodate high pressure core holders, an optical production monitoring system and an x-ray in situ saturation monitoring system. Local

saturation measurements had a greater impact on the estimation of the wetting phase relative permeability than to the non-wetting phase relative permeability. History matching Corey type relative permeabilities with quadratic splines required local saturation measurement to estimate the wetting phase relative permeability at high mobility ratio. Conversely, local saturation measurements had a negligible impact on predicting the non-wetting phase relative permeability either low or high mobility. Local saturation measurements and knowledge of the wetting phase relative permeability are essential for predicting an 'S' shaped non-wetting phase relative permeability curve at low mobility. At high mobility the 'S' shaped non-wetting phase relative permeability curve cannot be predicted even with local saturation measurements and knowledge of the wetting phase relative permeability.

- Core floods have been conducted to determine the effect of capillary number on drainage relative permeability. The nonwetting relative permeability was found to be a function of capillary number in the experiments analyzed. For N_c in the range of 10^{-8} - 10^{-6} , the residuals are not a strong function of capillary number but for higher capillary numbers, residuals start to decrease. Residuals decrease from $\sim 35\%$ for $10^{-8} N_c$ to $\sim 20\%$ for $10^{-4} N_c$. This is valid for the case when $\mu_w/\mu_o < 1$. For $\mu_w/\mu_o = 10$ case, residuals increase with increase in capillary number in the range of 10^{-7} to 5×10^{-6} and decrease beyond that. Oil relative permeability in most cases decreases with increasing capillary number, whereas water relative permeability increases with an increase in capillary number. Water relative permeability decreases with increasing water-to-oil viscosity ratio, whereas oil relative permeability increases with an increase in water-to-oil viscosity ratio.

Task 2:

- A pore-scale network model has been developed for multiphase drainage. Skeletonization of complex 3D porous media has been accomplished. As the correlation length increases, the pore throat lengths and radii and pore body radii decrease in general. Permeability of such random networks can be calculated. Relative permeability in simple cubic networks has been calculated in the dynamic mode. As capillary number increases, the relative permeability of both phases generally increases. As the mobility ratio increase, the injected phase relative permeability tends to increase and the other phase relative perme-

ability tends to decrease.

- A pore-scale network model is developed for gas condensate flow that includes flow in sample-spanning paths, droplet-entrainment, and non-Darcy gas flow. This model has been used to identify several flow regimes. At low pressure gradient and liquid saturation, low capillary number flow is observed. As the pressure gradient increases, non-Darcy flow sets in. Effect of Reynolds number and capillary number on relative permeability has been determined at low liquid saturation.
- Inertial effects significantly reduce the effective gas relative permeability within the near wellbore region in gas condensate reservoirs. As rates increase the reduction in effective gas relative permeability becomes more pronounced. The impact on condensate relative permeabilities is less pronounced. Effective gas and condensate relative permeabilities can be estimated from a properly designed multi-rate well test. The estimated relative permeabilities treat the inertial and capillary number effects in a coupled manner and not independently. For a low permeability, rich gas-condensate system studied, the velocity stripping effect within the near wellbore region is dependent upon gas phase inertial effects.

Nomenclature

β_{rg} = multiphase inertial coefficient, dimensionless
 β_g = multiphase inertial coefficient, cm^{-1}
 β_o = single phase inertial coefficient, cm^{-1}
 D = pore throat radius, cm
 $E(N_c)$ = Corey exponent, capillary number dependent
 k = absolute permeability, md
 $k_{rc}(S_c, N_c)$ = condensate relative permeability
 $k_{rg}(N_c, S_c)$ = gas relative permeability
 $k_{rg}^*(N_c, S_c, Re)$ = gas relative permeability
 L = core length, cm
 N_c = capillary number
 Q_{gi} = measured gas production rate, cc/sec
 Q_{ci} = measured condensate production rate, cc/sec
 Re = Reynolds number
 S_α = saturation of phase α
 $S_{r\alpha}$ = residual saturation of phase α
 S_{wc} = connate water saturation
 V_g = gas superficial velocity, cm/sec
 X = objective function
 μ = viscosity, cp
 ρ = density, g/cc
 σ = interfacial tension, dyne/cm

Superscripts

o = endpoint relative permeability

Subscripts

i = measured quantity

c = condensate

g = gas

m = calculated quantity from model

α = phase index

References

1. Hassler, G.L. and Brunner, E.: "Measurement of Capillary Pressures in Small Core Samples," *Trans.*, AIME (1945) **160**, 114.
2. Hagoort, J.: "Oil Recovery by Gravity Drainage," *SPEJ* (June 1980) 139.
3. O'Meara, D.J. Jr. and Lease, W.D.: "Multiphase Relative Permeability Measurements Using an Automated Centrifuge," paper SPE 12128 presented at the 1983 SPE Annual Technical Conference and Exhibition, San Francisco, Oct. 5-8.
4. O'Meara, D.J. Jr. and Crump, J.G.: "Measuring Capillary Pressure and Relative Permeability in a Single Centrifuge Experiment," paper SPE 14419 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, Sept. 22-25.
5. Firazoobadi, A. and Aziz, K.: "Relative Permeability from Centrifuge Data," paper SPE 15059 presented at the 1986 SPE California Regional Meeting, Oakland, April 2-4.
6. Chardaire-Riviere, C. *et al.*: "Improving the Centrifuge Technique by Measuring Local Saturations," paper SPE 24882 presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, DC, Oct. 4-7.
7. Nordtvedt, J.E., *et al.*: "Estimation of Capillary Pressure and Relative Permeability Functions From Centrifuge Experiments," *SPERE* (Nov. 1993) 292-298
8. Hirasaki, G.J., Rohan, J.A., and Dudley, J.W. II: "Interpretation of Oil/Water Relative Permeabilities from Centrifuge Displacement," paper SPE 24879 presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, DC, Oct. 4-7
9. Sigmund, P.M. and McCaffery, F.G.: "An Improved Unsteady-State Procedure for Determining the Relative-Permeability Characteristics of Heterogeneous Porous Media," *SPEJ* (Feb.1979) 15-28.
10. Kerig, P.D. and Watson, A.T.: "Relative-Permeability Estimation From Displacement Experiments: An Error Analysis," *SPERE* (March 1986) 175-82.
11. Kerig, P.D. and Watson, A.T.: "A New Algorithm for Estimating Relative Permeabilities From Displacement Experiments," *SPERE* (Feb. 1987) 103; *Trans.*, AIME **283**.
12. Watson, A.T. *et al.*: "A Regression-Based Method for Estimating Relative Permeabilities From Displacement Experiments," *SPERE* (March 1988) 953.
13. Mejia, G. M. V.: "A Method For Estimating Three-Phase Flow Functions," PhD disserta-

tion, Texas A&M U. (May 1992)

14. Corey, A.T.: "The Interrelation Between Gas and Oil Relative Permeabilities," *Prod. Monthly* (Nov. 1954) 38-44.
15. Johnson, E.F., Bossler, D.P., and Naumann, V.O.: "Calculation of Relative Permeability from Displacement Experiments," *Trans., AIME* (1959) **216**, 370-72.
16. Corey, A.T.: "The Interrelation Between Gas and Oil Relative Permeabilities," *Prod. Monthly* (Nov. 1954) 38-44.
17. Lefebvre du Prey, E. J.: "Factors Affecting Liquid-Liquid Relative Permeability of Consolidated Porous Media," *SPE J.* (Feb. 1973) 39-47.
18. Fulcher, R.A., Ertekin, T. and Stahl, C. D.: "Effect of Capillary Number and Its Constituents on Two-Phase Relative Permeability Curves," *SPE J.* (Feb. 1985) 249-260.
19. Mohanty, K. K. & Miller, A. E.: "Factors Influencing Unsteady Relative Permeability of a Mixed-Wet Reservoir Rock," *SPE Formation Evaluation*, **6**, 349-358 (1991).
20. Dullien, F. A. L.: *Porous Media – Fluid Transport and Pore Structure*, Academic Press, 1992.
21. Mani, V. and Mohanty, K. K., *J. Coll. & Interf. Sci.*, **187**, 45 (1997).
22. Wang, X. & Mohanty, K. K.: "Critical Condensate Saturation in Porous Media, " *J. Coll. & Interf. Sci.*, **214**, 416-426 (1999).
23. Fang, F., Firoozabadi, A., Abbaszadeh, M. and Radke, C., in "Proceedings, 71st Annual Technical Conference and Exhibition of the SPE, " Denver, CO, Oct. 6-9, 1996." SPE 36716.
24. Everett, D. H. and Haynes, J. M., *J. Coll. & Interf. Sci.*, **38**, 125 (1972).
25. Mohanty, K. K., Davis, H. T., and Scriven, L. E., *SPE Reservoir Engineering*, **1**, 113 (1987).
26. Gray, J. D. and Dawe, R. A., in "Proceedings, 64th Annual Technical Conference and Exhibition of the SPE, " San Antonio, TX, Oct. 8-11, 1989." SPE 19696.
27. Kalaydjian, F. J-M., Bourbiaux, B.J., Lombard, J.M., in "Proceedings, 71st Annual Technical Conference and Exhibition of the SPE, " Denver, CO, Oct. 6-9, 1996." SPE 36715.
28. Mani, V. and Mohanty, K. K.: "Pore-Level Network Modeling of Three-Phase Capillary Pressure and Relative Permeability Curves," *SPE J.*, 238-248 (September 1998).
29. Cooper, J. W., Wang, X. and Mohanty, K. K.: "Non-Darcy Flow Experiments in Anisotropic Porous Media," SPE 49224, submitted to *SPE Reservoir Engineering*, (1998).
30. Morgan, J. T. and Gordon, D. T.: "Influence of Pore Geometry on Water-Oil Relative Per-

meability," *J. Pet. Tech.*, 1199-1208, (Oct. 1970).

31. Liu, X., Civan, F., and Evans, R. D.: "Correlation of the Non-Darcy Flow Coefficient," *J. Can. Pet. Tech.*, **43**, 50-54 (1995).
32. X. Wang: "Pore-Level Modeling of Gas-Condensate Flow in Porous Media," PhD Thesis, University of Houston, Houston (April 2000).
33. Whitson, C. H., Fevang, O., Saevareid, A.: "Gas Condensate Relative Permeability for Well Calculations", SPE 56476, SPE Annual Technical Conference and Exhibition, Houston, Texas (1999).
34. Thauvin, F., Mohanty, K. .K.: "Network Modeling of Non-Darcy Flow Through Porous Media," *Transport in Porous Media*, 31, 19-37 (1998).
35. Henderson, G.D., Danesh, A., Tehrani, D.H., Al-Kharusi, B.: " The Relative Significance of Positive Coupling and Inertial Effects on Gas Condensate Relative Permeabilities at High Velocity," SPE 62933, SPE Annual Technical Conference and Exhibition, Dallas, Texas (2000).

Relative Permeability Set #1

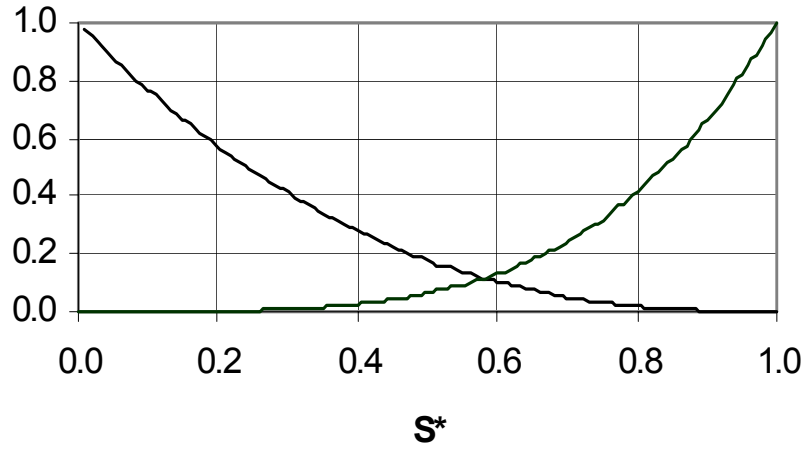


Fig. 1- Discrete approximations to Corey relations for wetting and non-wetting phases.

Relative Permeability Set #2

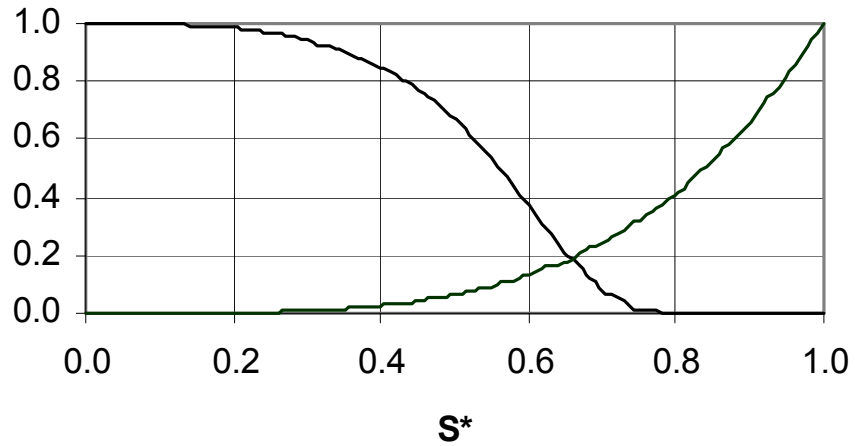


Fig. 2 - Wetting phase represented by discrete approximation to Corey relation and non-wetting phase represented by quadratic spline.

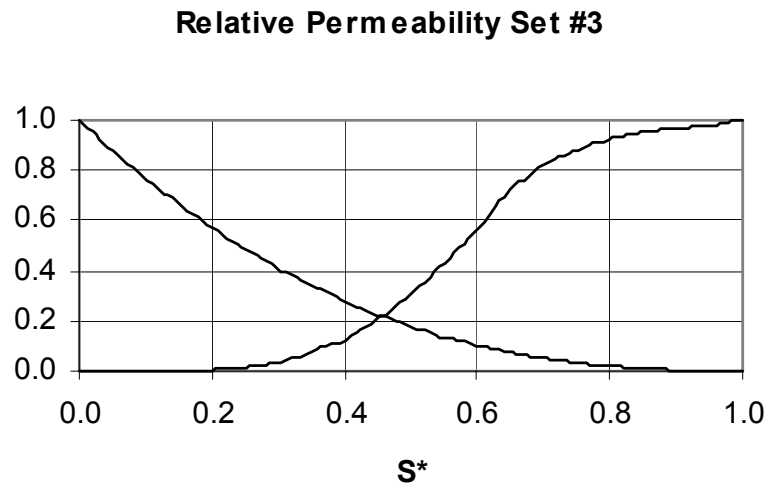


Fig. 3 – Both wetting and non-wetting phase relative permeabilities represented by discrete representations.

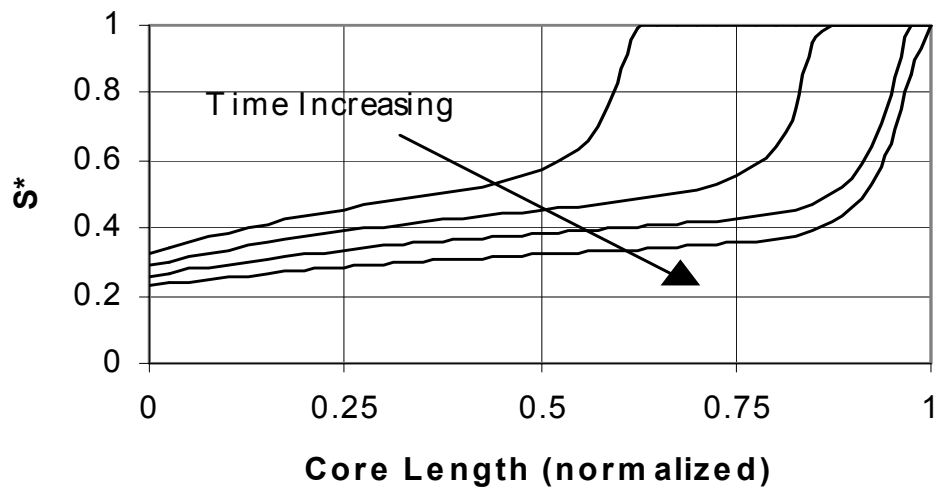


Fig. 4 – Wetting phase saturation as a function of time within core.

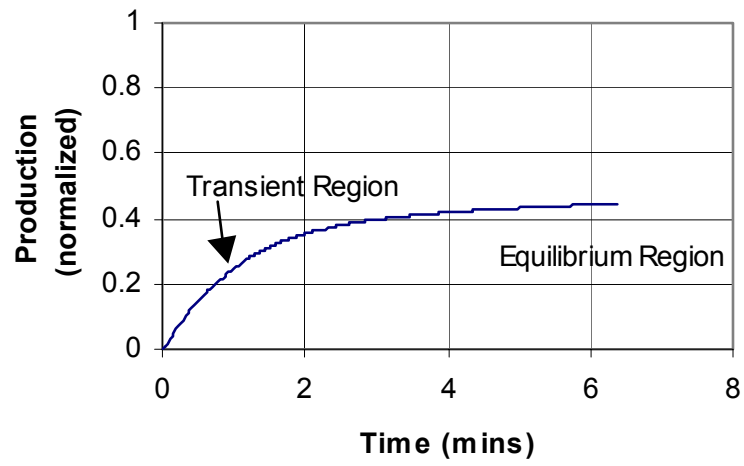


Fig. 5 – Wetting phase production curve

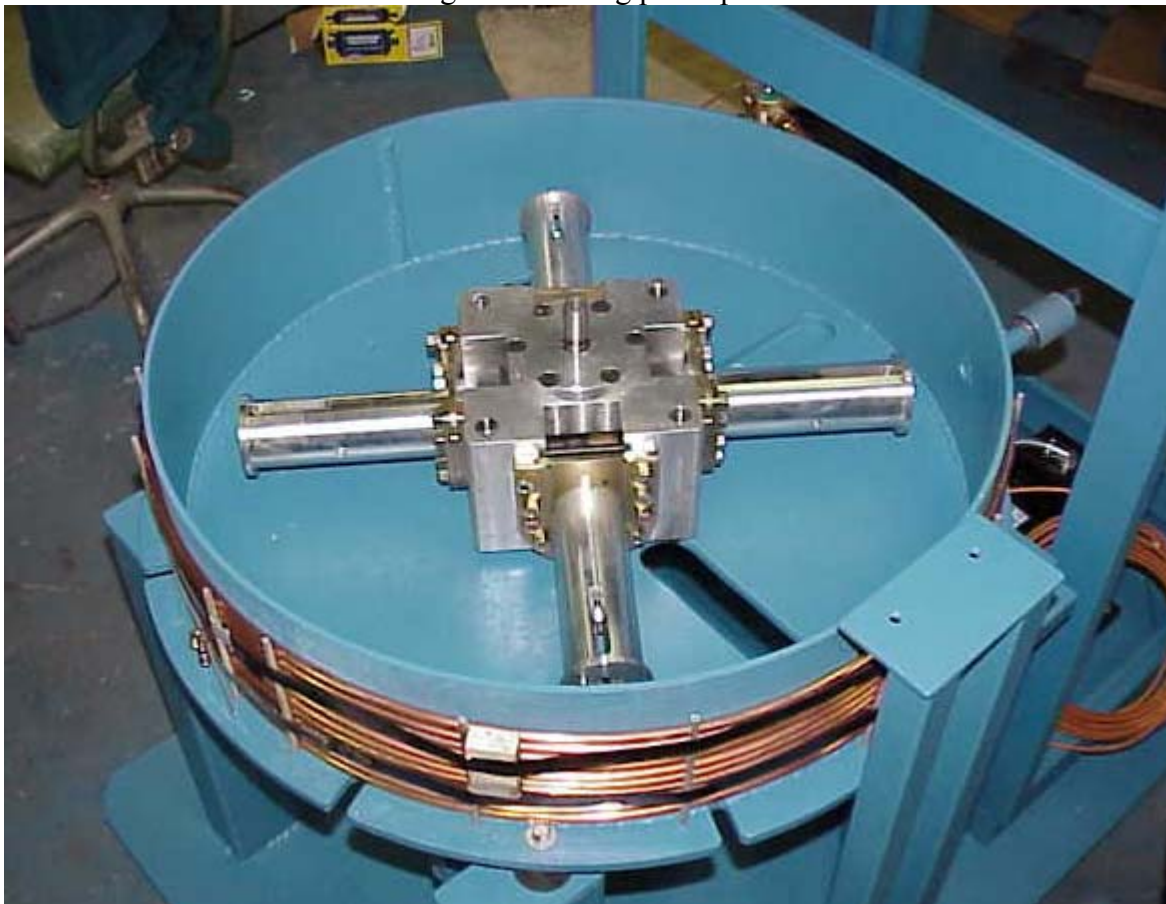


Fig. 6 – The fixed-rotor centrifuge with high pressure coreholders.



Fig. 7 – The fixed-rotor centrifuge assembly.

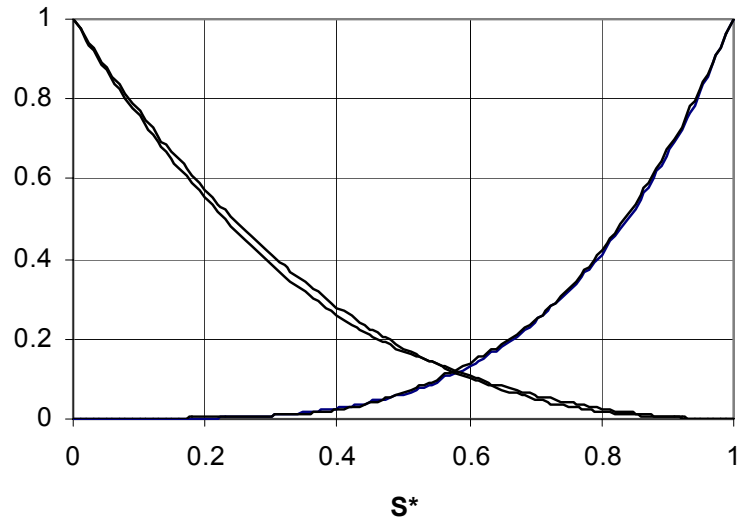


Fig. 8a – Relative Permeability Set #1, M=5: History match to local saturation and production measurements.

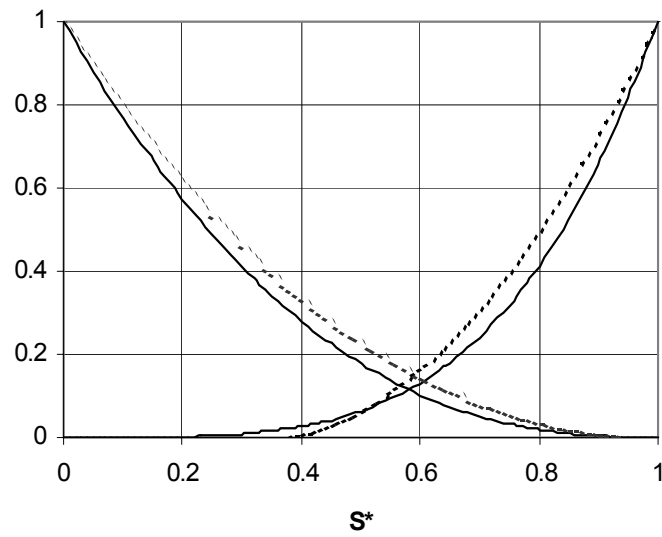


Fig. 8b – Relative Permeability Set #1, M=5: History match to only production measurements.

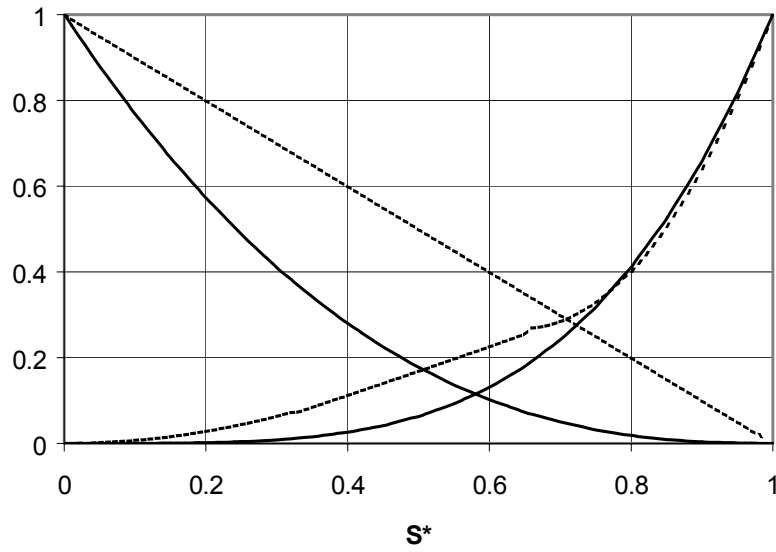


Fig. 9 – Relative Permeability Set #1, M=1000: History match to local saturation and production measurements.

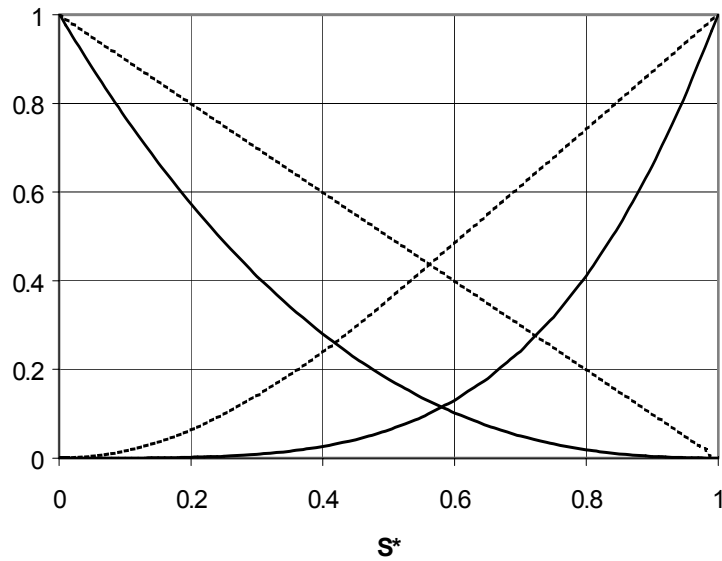


Fig. 10 – Relative Permeability Set #1, M=1000: History match to production measurements.

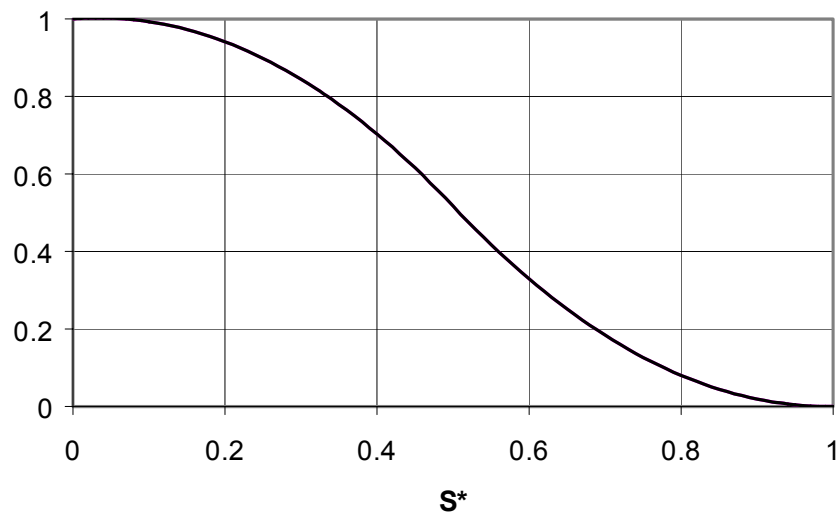


Fig. 11 – Relative Permeability Set #2a, $M=5$: History match to local saturation and production measurements.

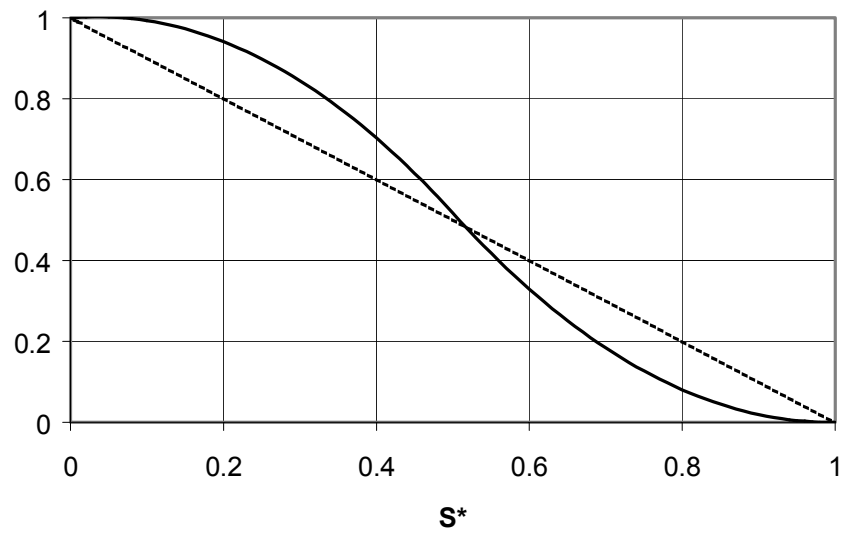


Fig. 12 – Relative Permeability Set #2a, $M=5$: History match to only production measurements.

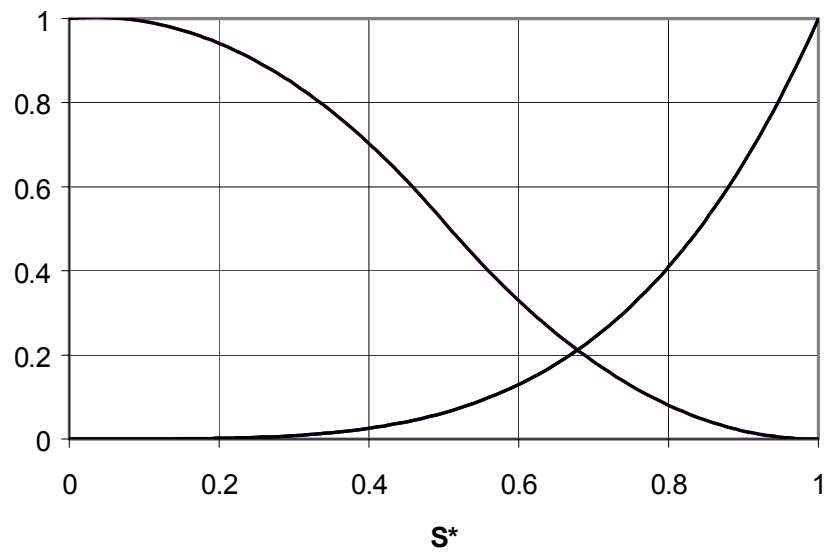


Fig. 13 – Relative Permeability Set #2b, $M=5$: History match to local saturation and production measurements.

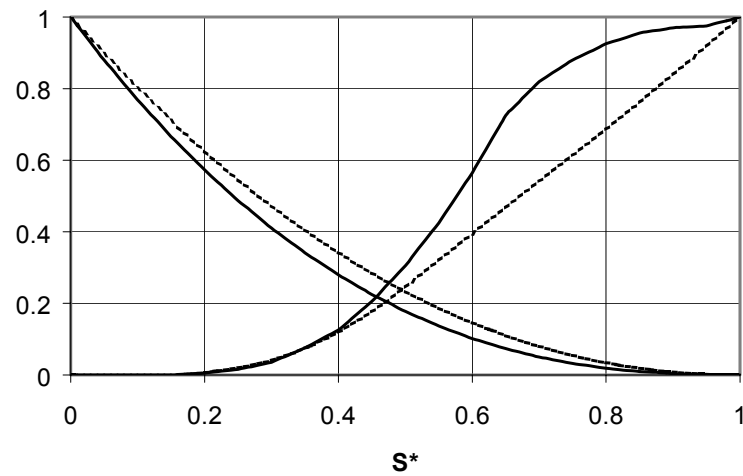


Fig. 14 – Relative Permeability Set #2b, $M=5$: History match to production measurements

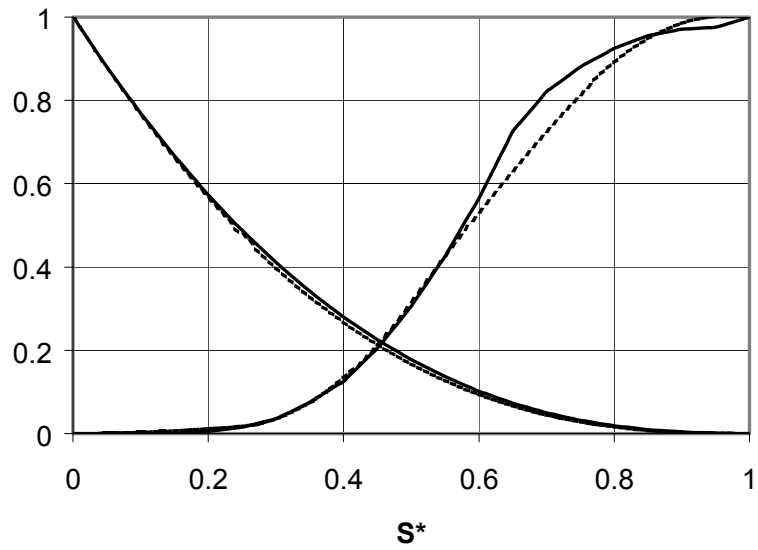


Fig. 15 – Relative Permeability Set #3, M=5: History match to local saturation and production measurements.

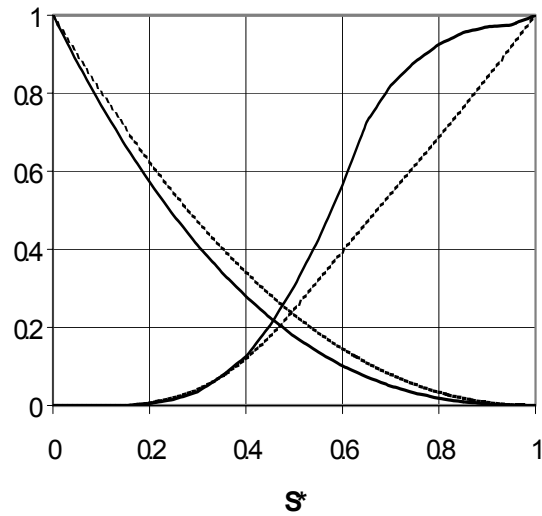


Fig. 16 – Relative Permeability Set #3, M=5: History match to only production measurements.

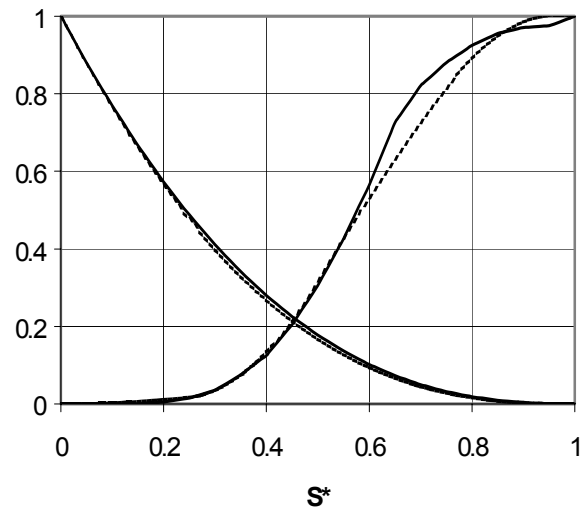


Fig. 17 – Relative Permeability Set #3, M=1000: History match to local saturation and production measurements

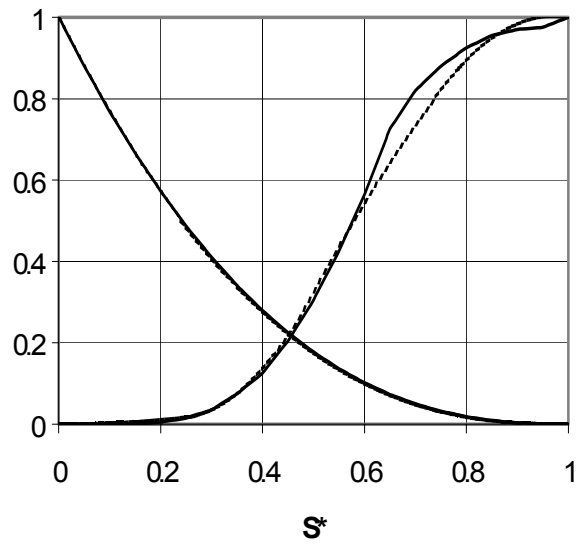


Fig. 18 – Relative Permeability Set #3, M=1000: History match to only production measurements.

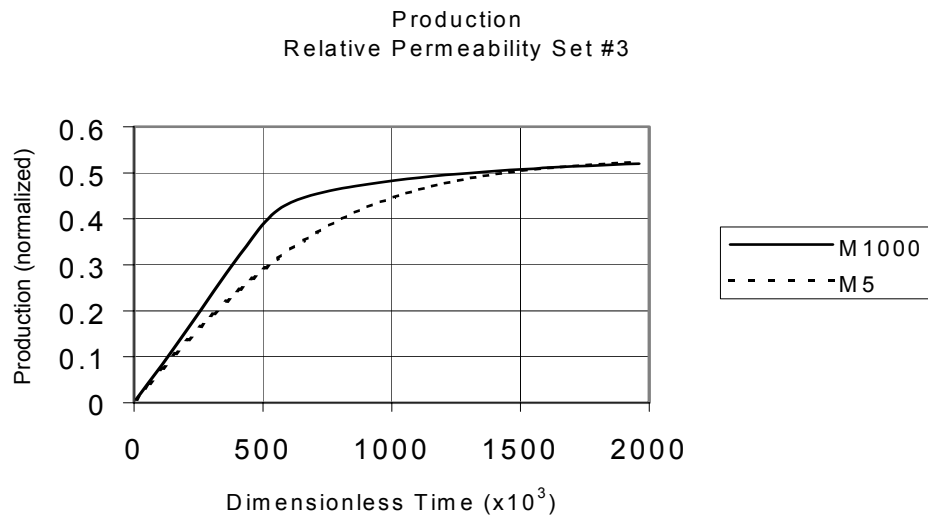


Fig. 19 – Production curves for M=5 and 1000 for relative permeability set #3

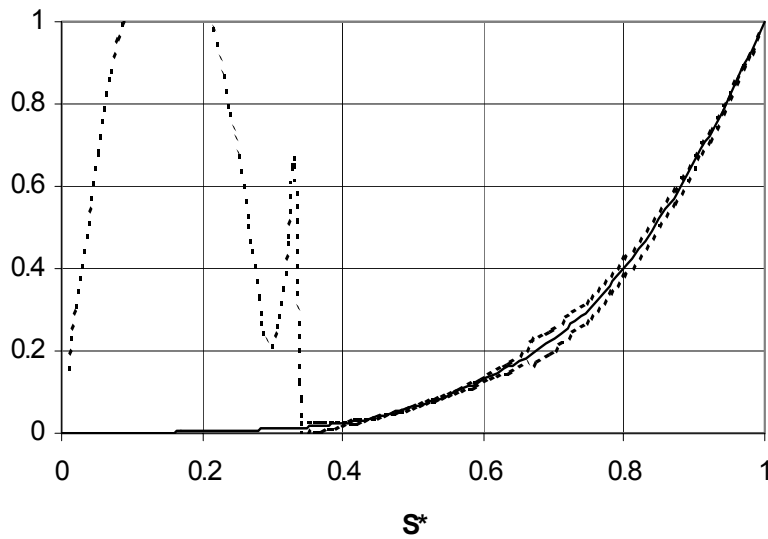


Fig. 20 - Confidence intervals (90%) for measurement error of 0.01% in production data
measurements

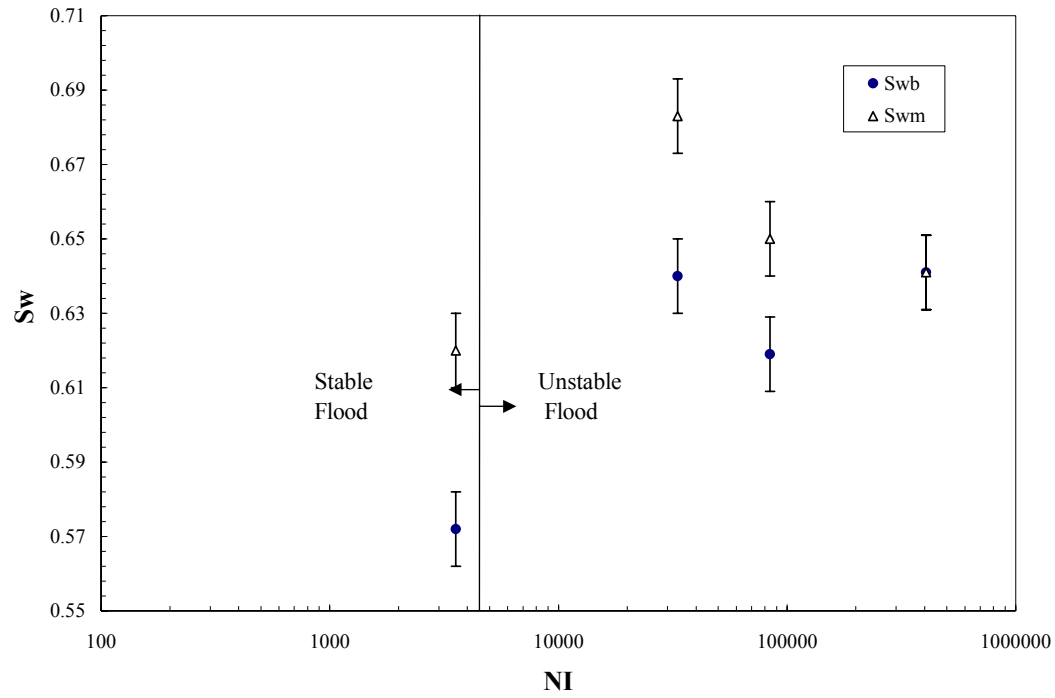


Fig. 21 Stability of viscous brine floods

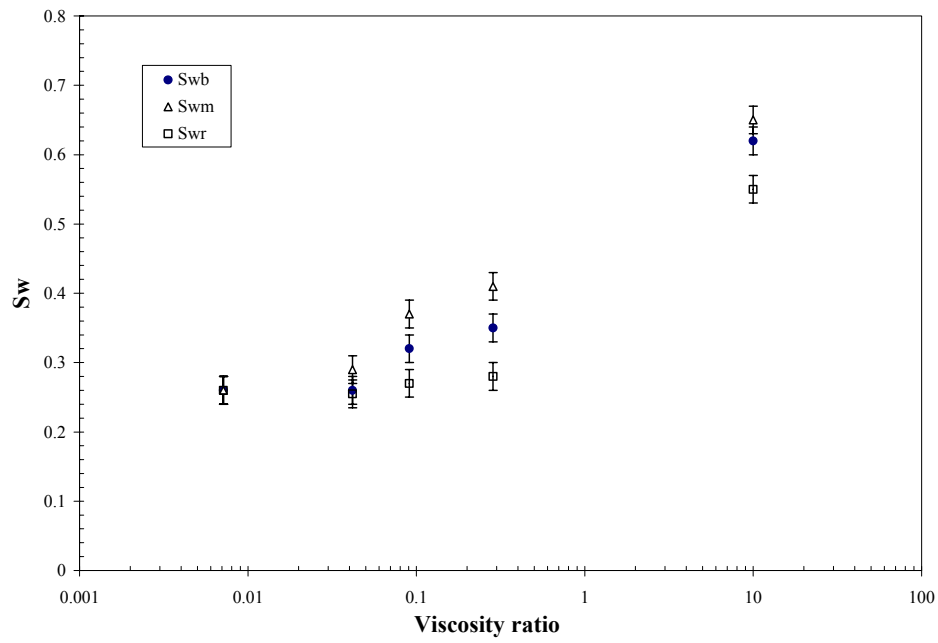


Fig. 22 Effect of viscosity ratio on remaining brine saturation

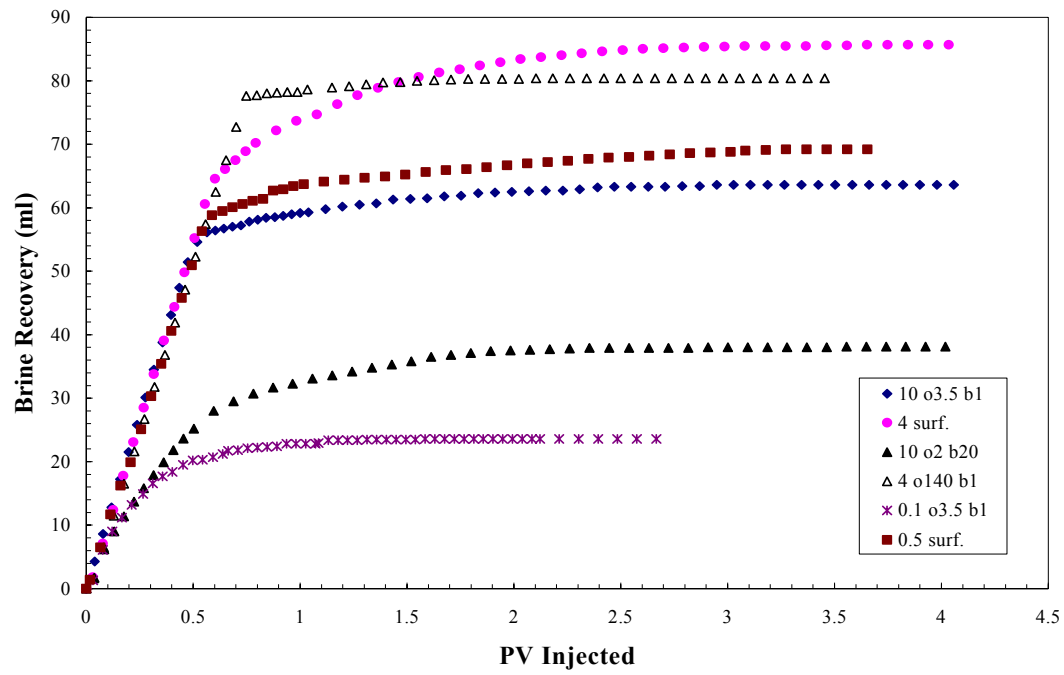


Fig. 23 Brine Recovery trend for oilflood experiments

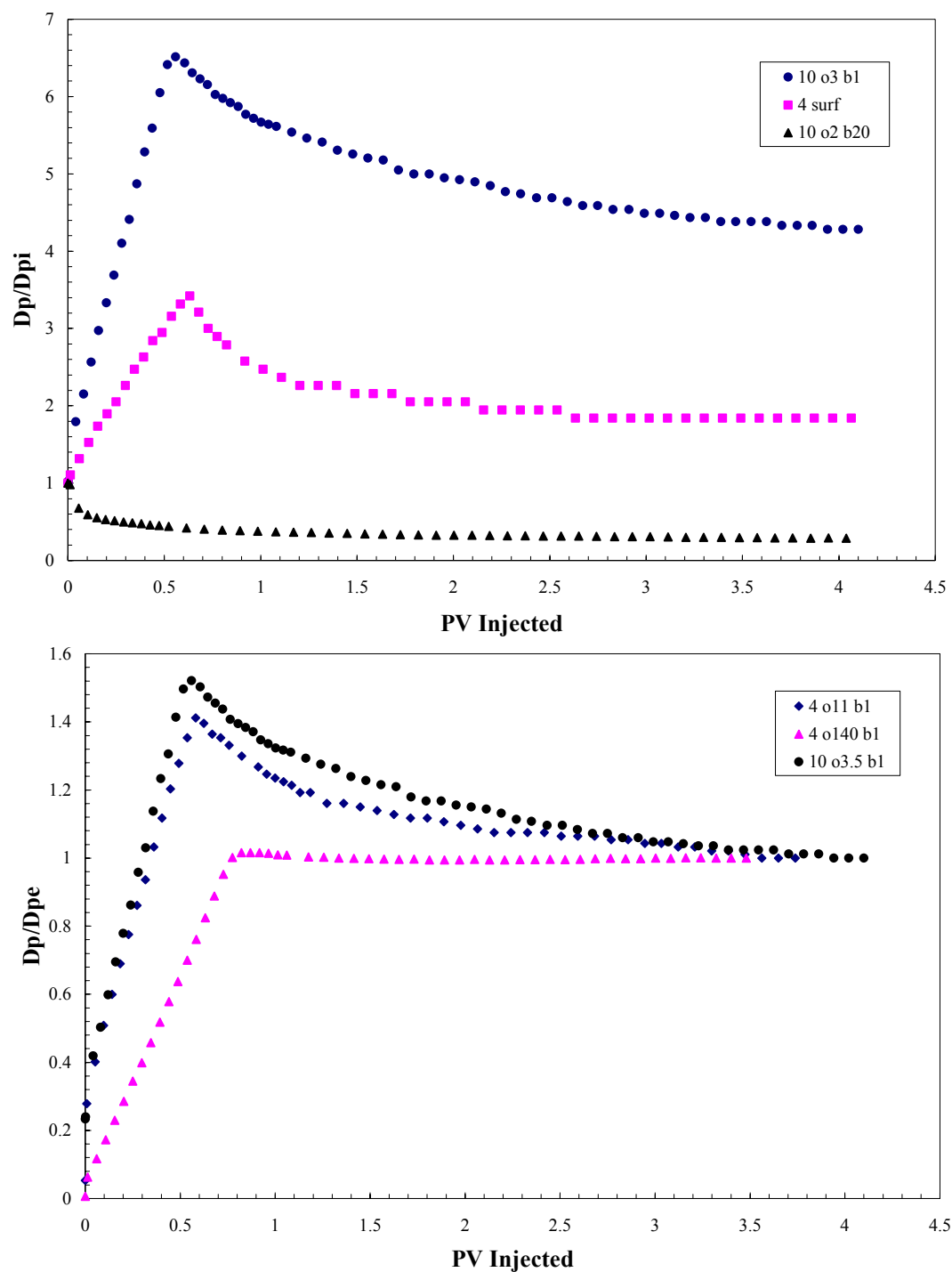


Fig. 24 Pressure trend for oilflood experiments (a) Normalized with initial brine pressure, and (b) Normalized with end-point oil pressure

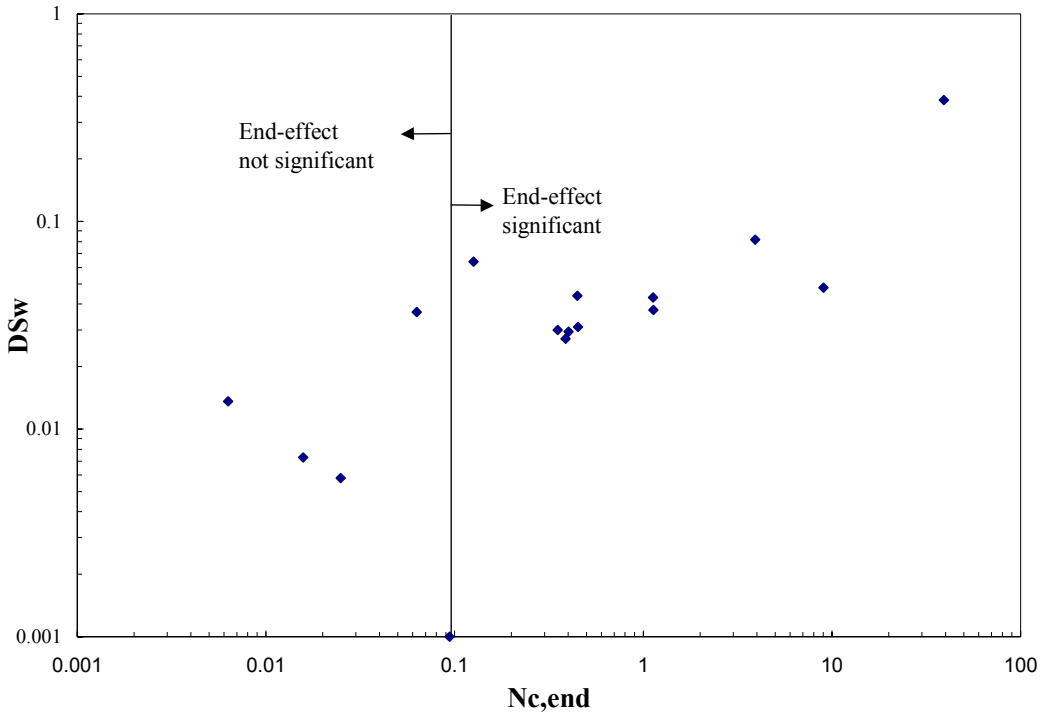


Fig. 25 Brine recovered in the bump step

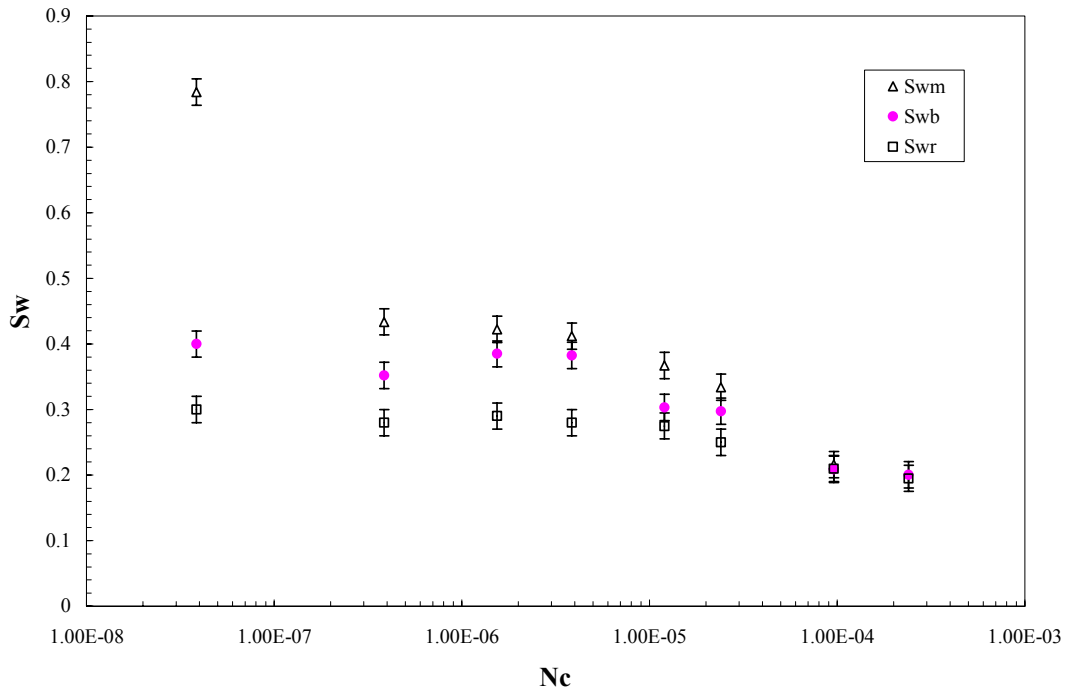


Fig. 26 Effect of Capillary number on S_w for $\mu_w/\mu_o \sim 1$

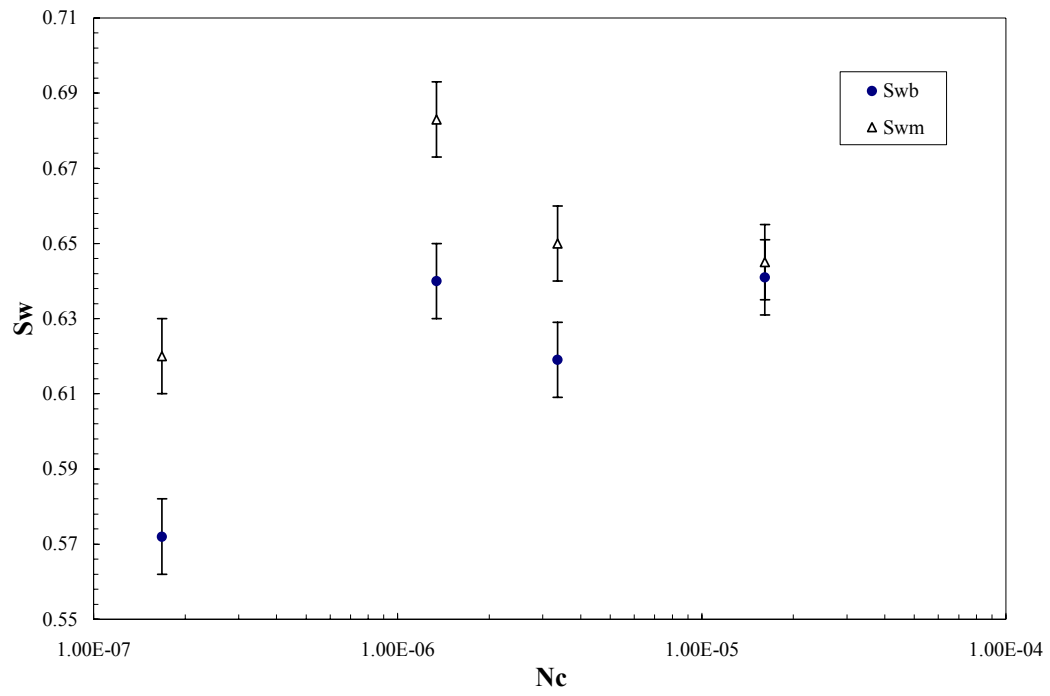


Fig. 27 Effect of Capillary number on S_w for $\mu_w/\mu_o = 10$

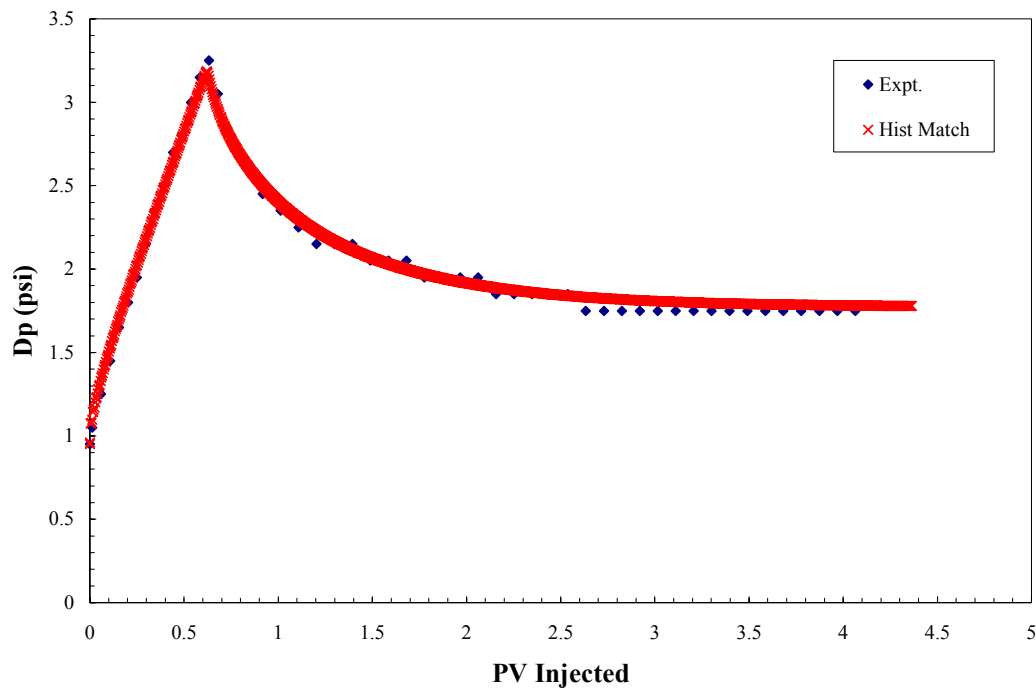


Fig. 28 Automatic History matching of pressure data for 4 ft/day (low IFT)

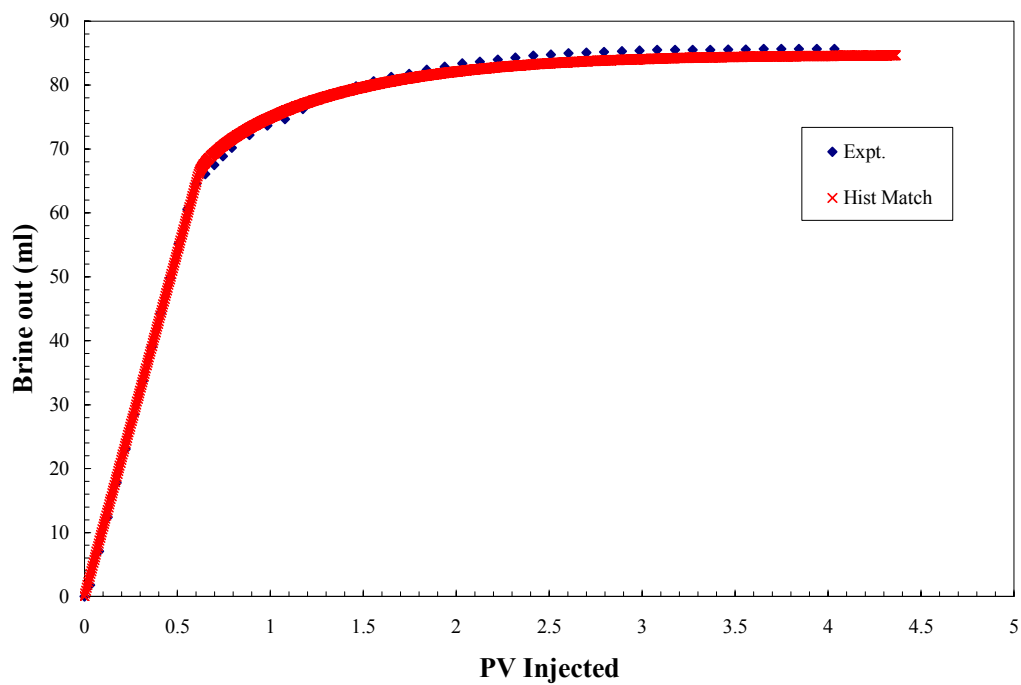


Fig. 29 Automatic History matching of recovery data for 4 ft/day (low IFT)

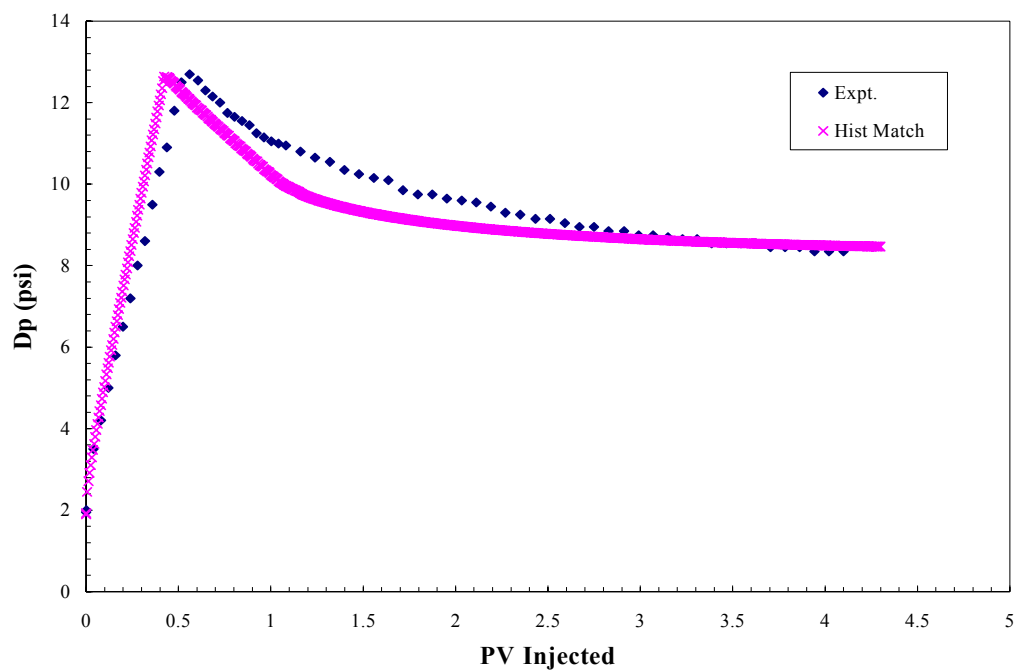


Fig. 30 Automatic History matching of pressure data for 10 ft/day (3.5 cp oil)

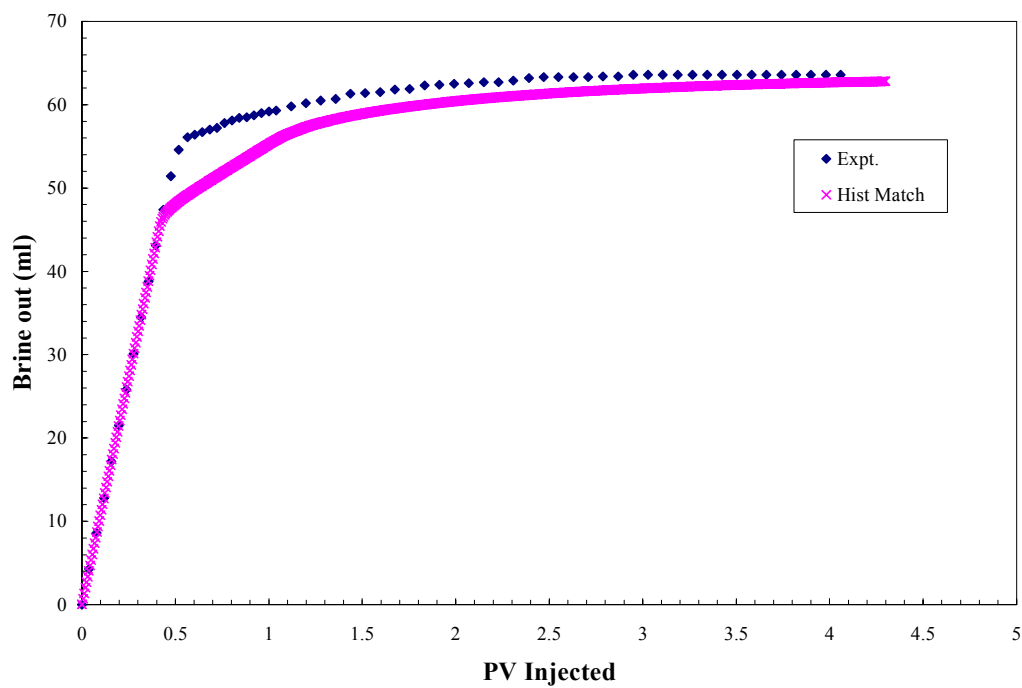


Fig. 31 Automatic History matching of recovery data for 10 ft/day (3.5 cp oil)

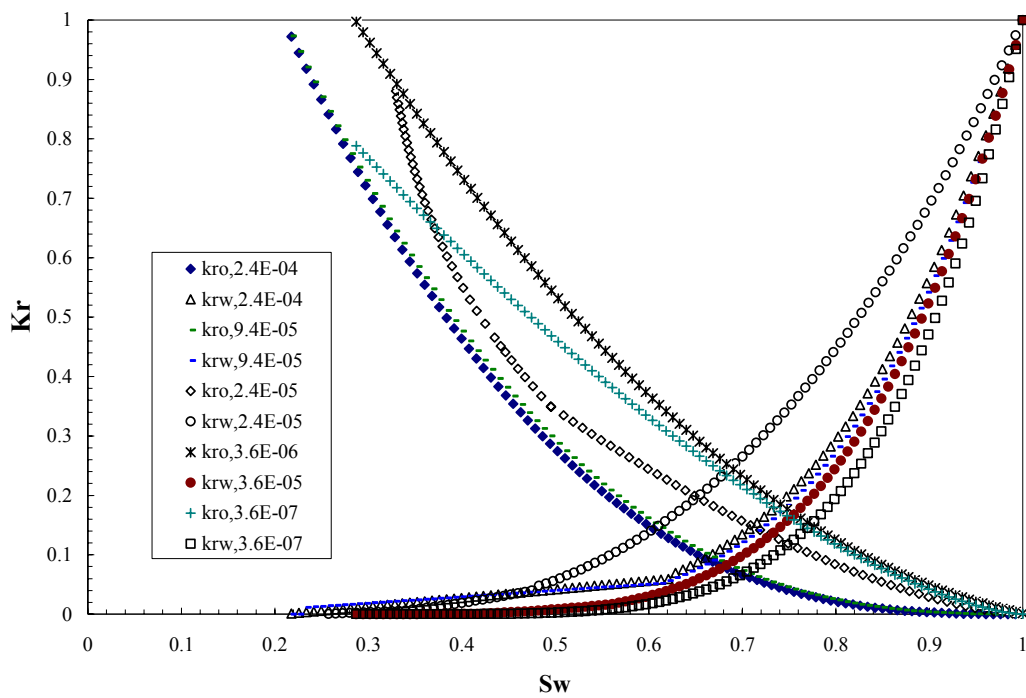


Fig. 32 Relative Permeability Dependence on Capillary number

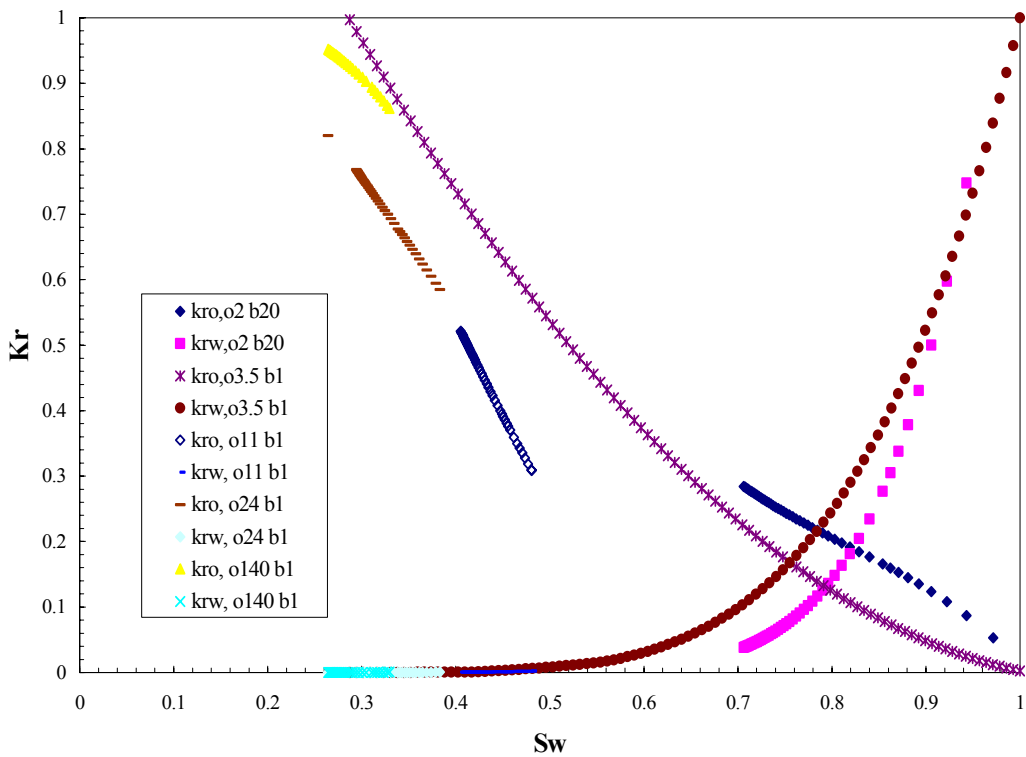


Fig. 33 Effect of viscosity ratio on Relative permeability

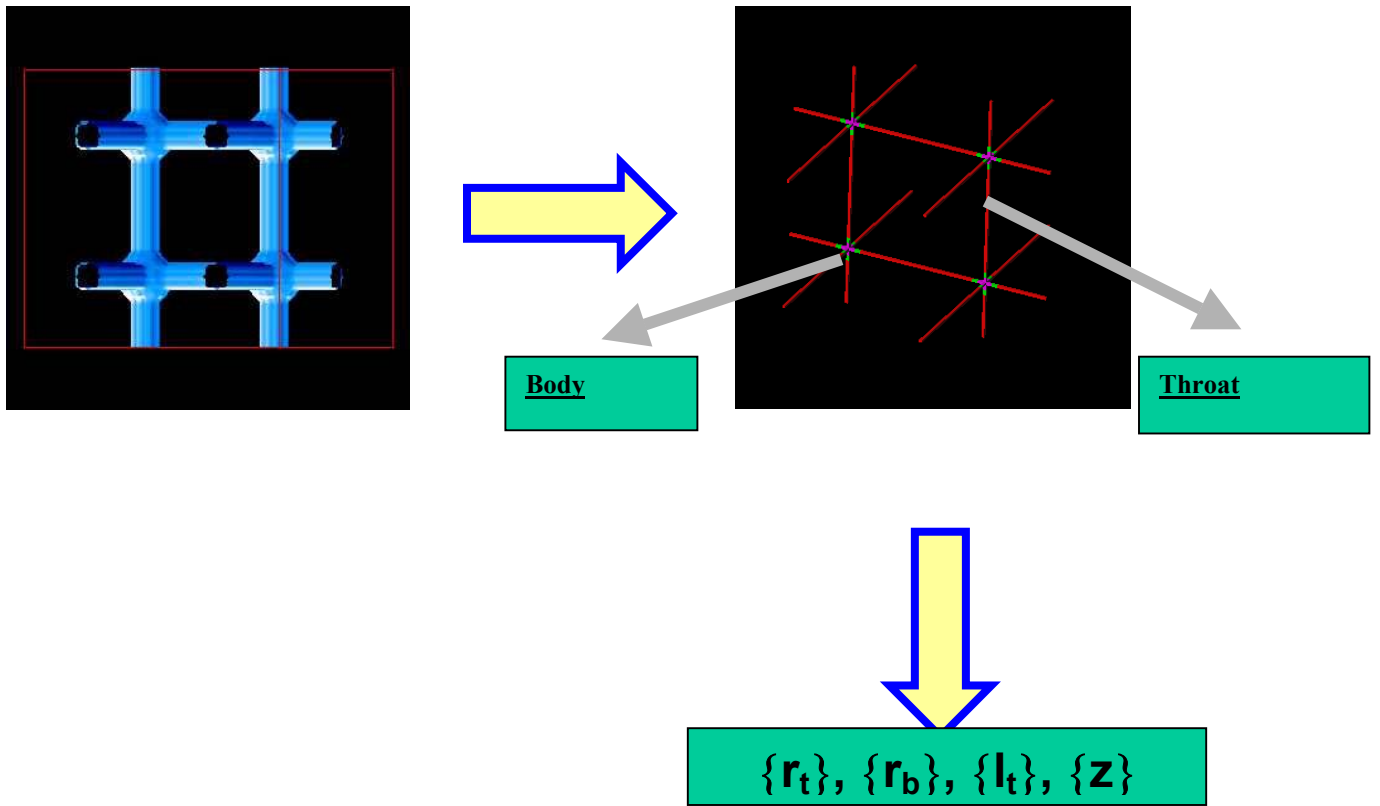


Fig. 34 Obtaining the Network Statistics from 3D Pore Space



(a) High Correlation length

(b) Low Correlation length

Fig. 35 Effect of Correlation length on Pore Structure for same porosity (0.3)

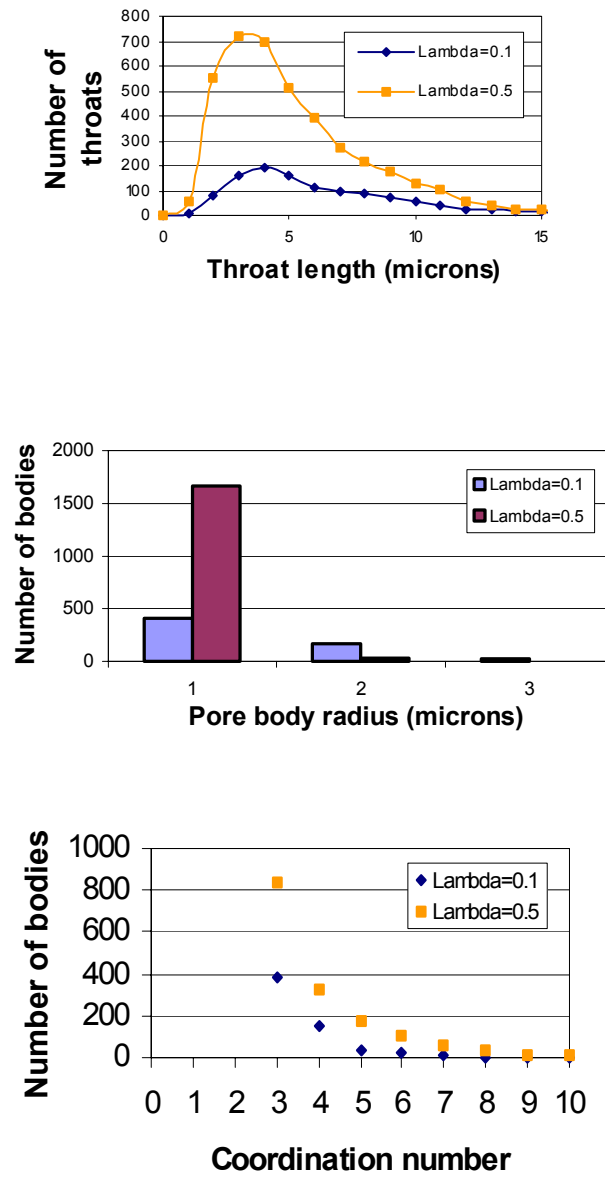


Fig. 36 Effect of correlation length for porosity = 0.3 on network statistics
($\lambda \propto 1/\sqrt{\text{Correlation length}}$)

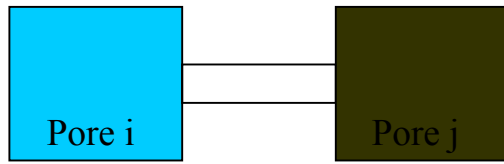


Fig. 37 Water in pore i displacing oil in pore j

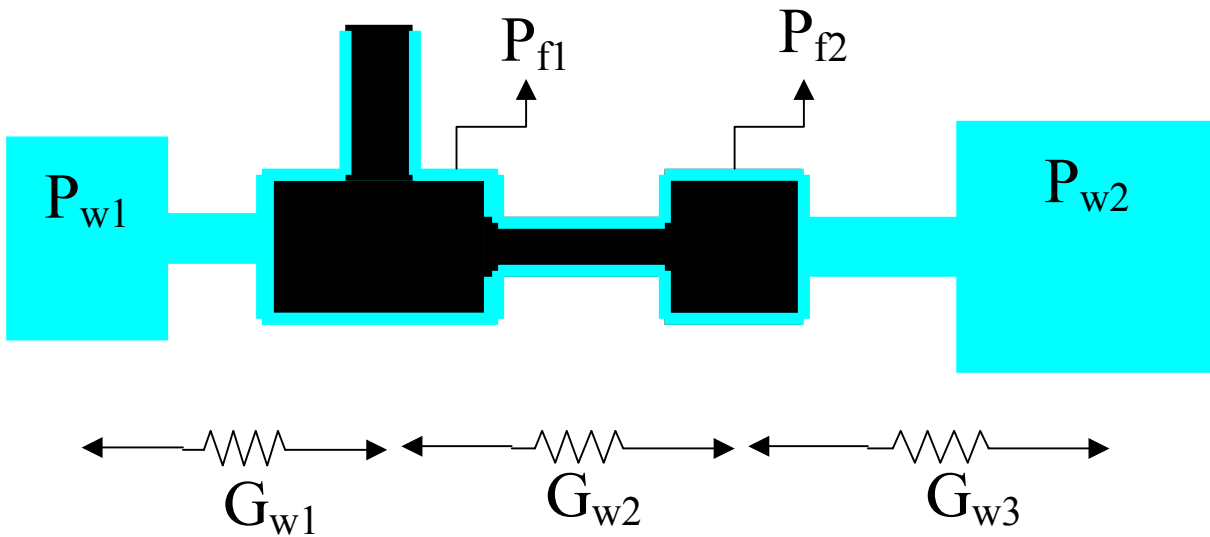


Fig. 38a Film pressure computation

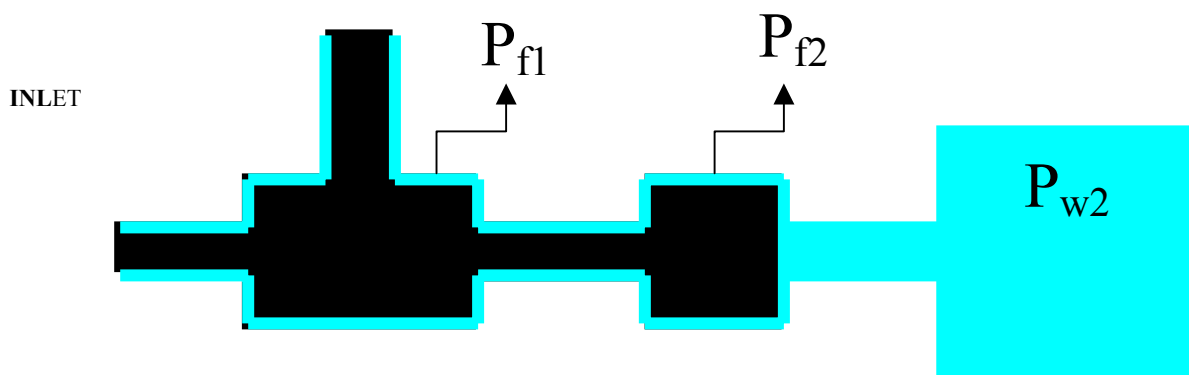


Fig. 38b Film pressure computation in absence of bulk pressure

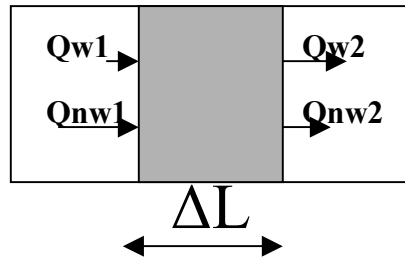


Fig. 39 A schematic section of porous medium used to define relative permeability and dynamic capillary pressure as a function of saturation.

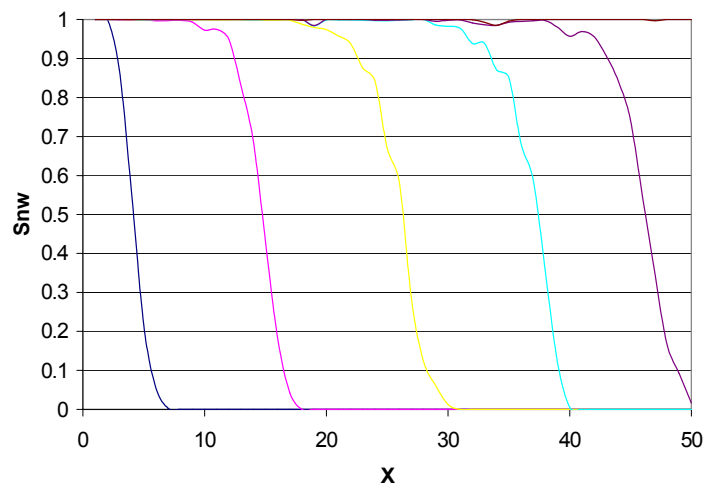


Fig. 40a Saturation front as a function of time for $N_{ca}=1E-2$ and unit viscosity ratio.

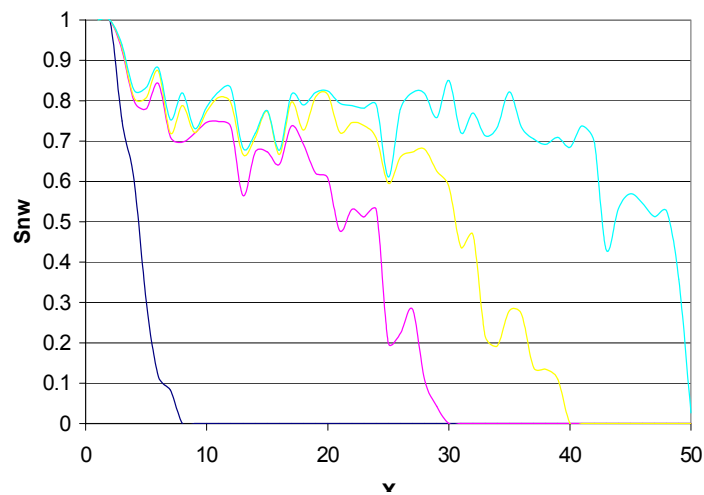


Fig. 40b Saturation front as a function of time for $N_{ca}=1E-6$ and unit viscosity ratio.

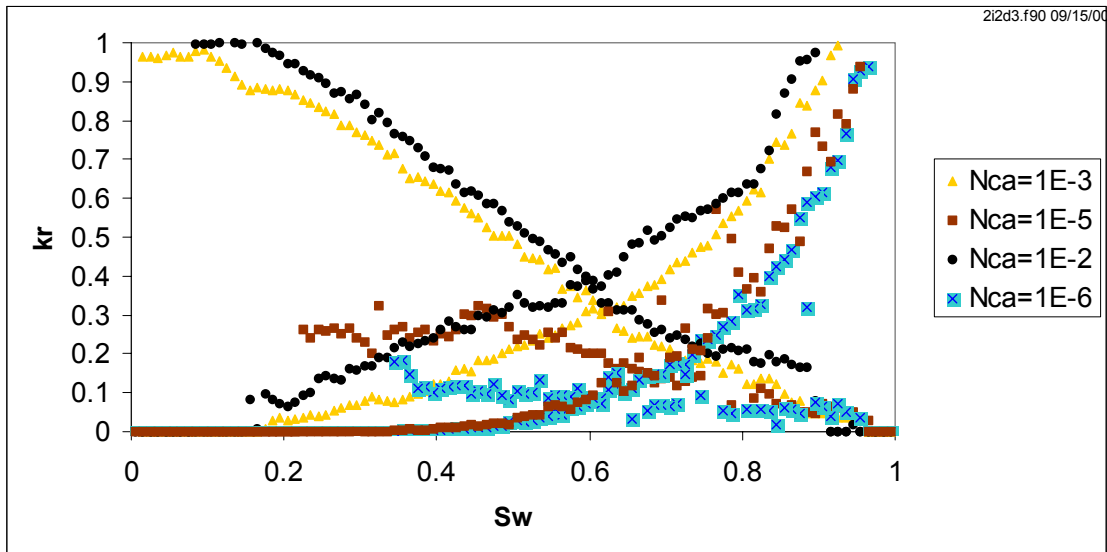


Fig. 41a Simulated dependence of relative permeability on N_{ca} for unit viscosity ratio.

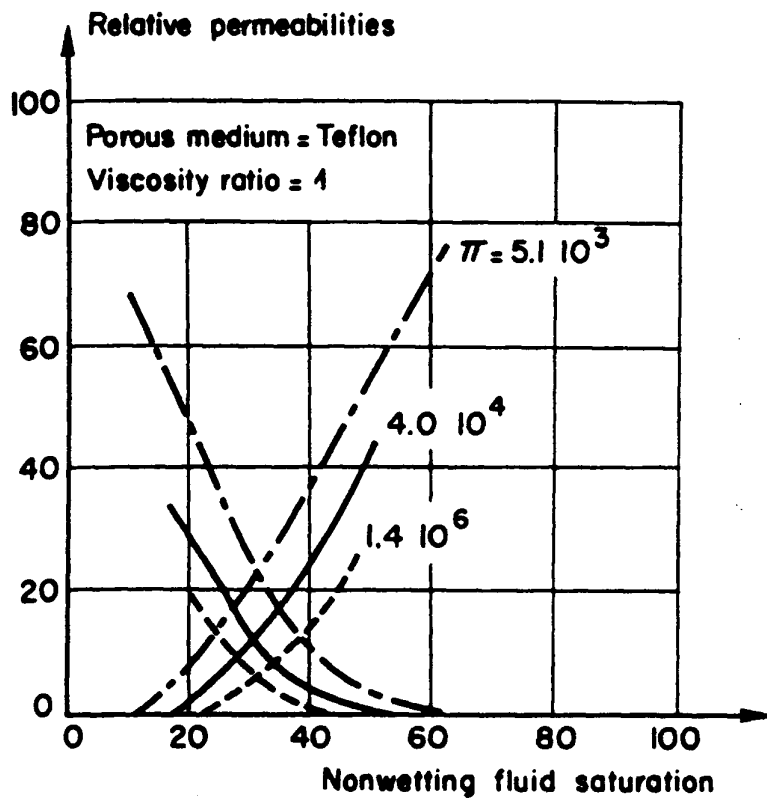


Fig. 41b Experimental dependence of relative permeability on N_{ca} for unit viscosity ratio (from Lefebvre du Prey,¹⁷ 1973).

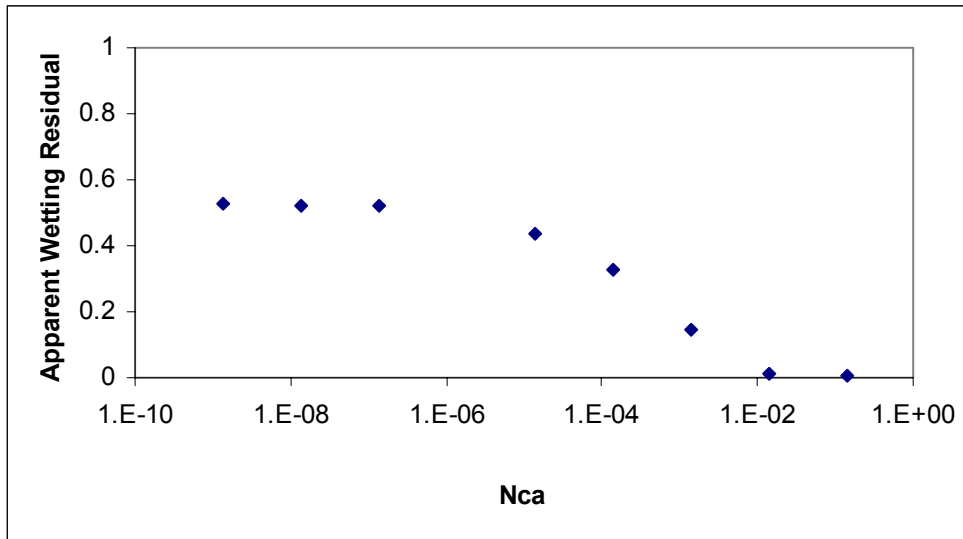


Fig. 42a Simulated capillary desaturation curve for unit viscosity ratio drainage.

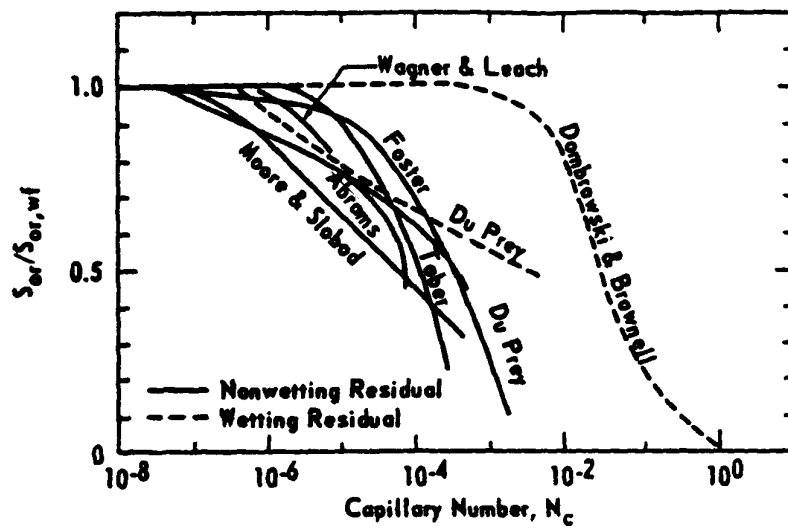


Fig. 42b Experimental capillary desaturation curves from Fulcher et al.¹⁸ (1985)

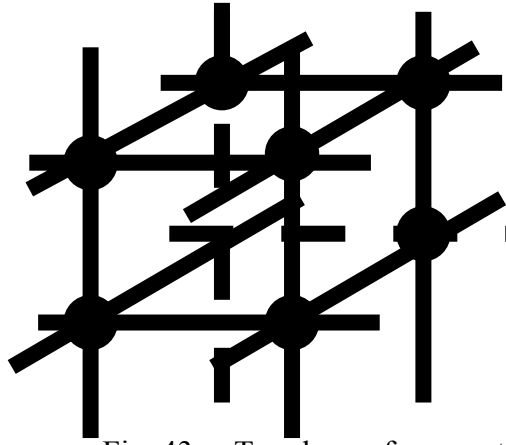


Fig. 43a - Topology of pore network

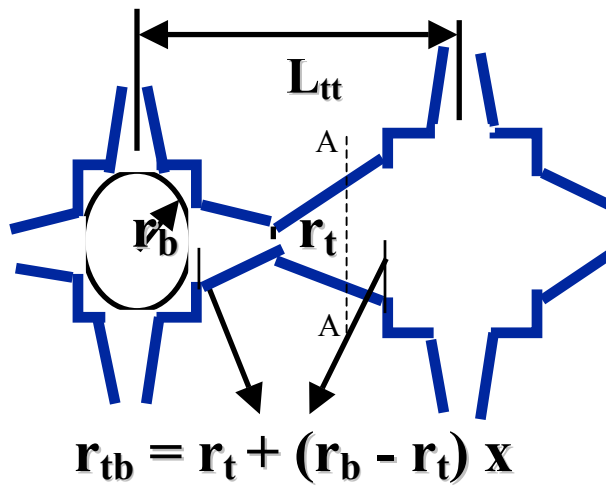


Fig. 43b – Longitudinal section through model pore bodies and throats

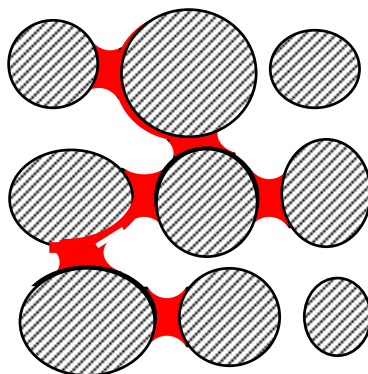


Fig. 44 – Condensate ganglion.

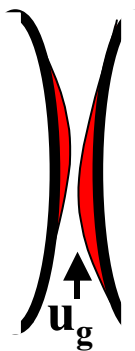


Fig. 45a – Type-I droplet formation.

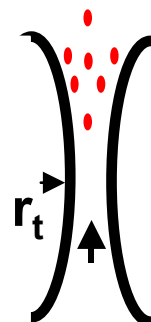
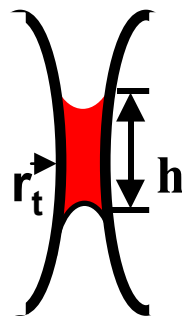
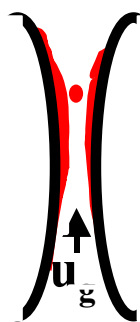


Fig. 45b – Type-II droplet formation.

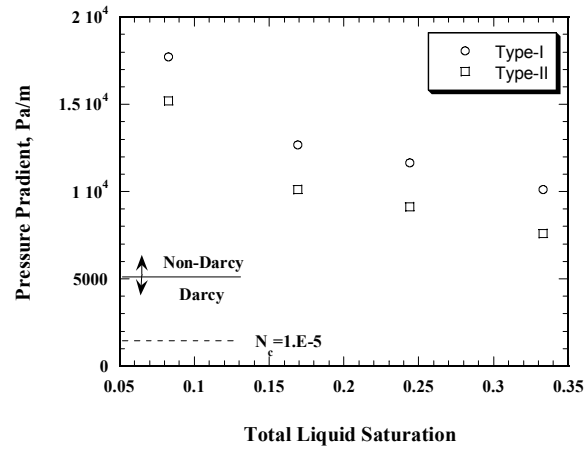


Fig. 46a – Regimes of flow (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

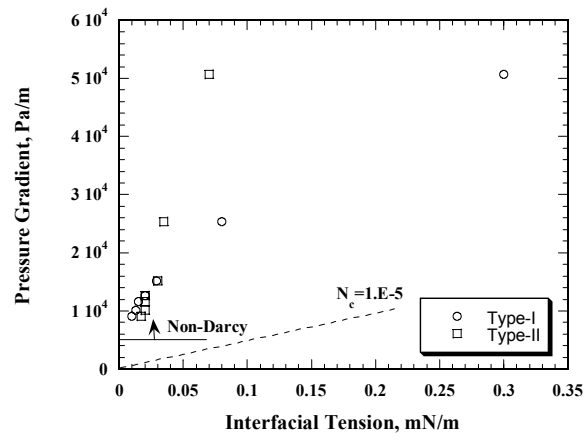


Fig. 46b – Regimes of flow ($S_l = 16.9\%$).

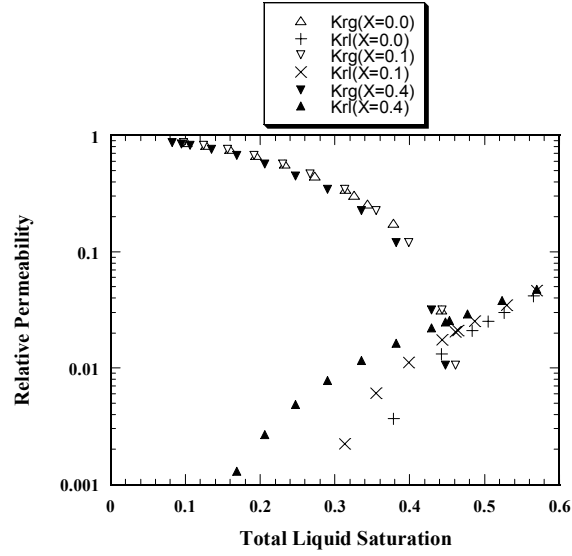


Fig. 47 – Effect of shape parameter ($S_{wi} = 8\%$, low N_c)

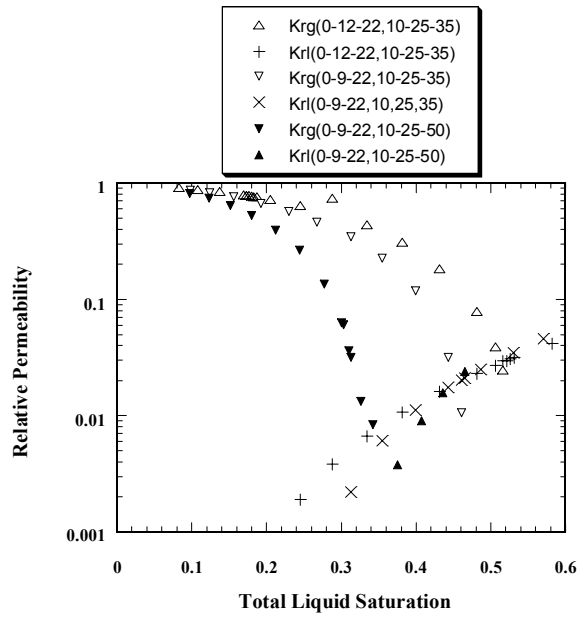


Fig. 48– Effect of throat and body radii ($S_{wi} = 8\%$, low N_c)

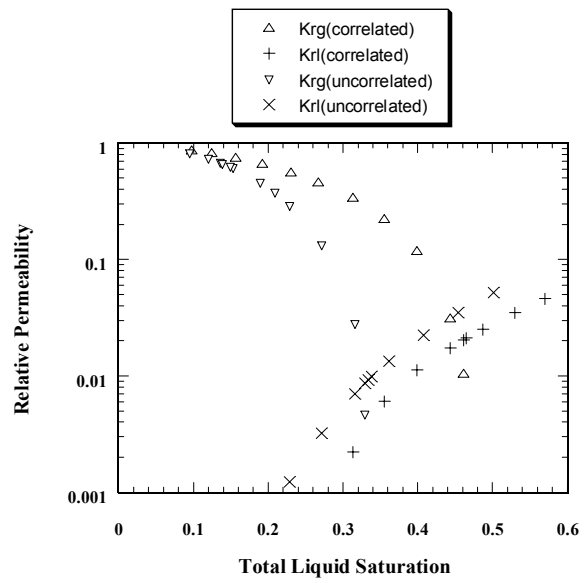


Fig. 49 – Effect of spatial correlation ($S_{wi} = 8\%$, low N_c)

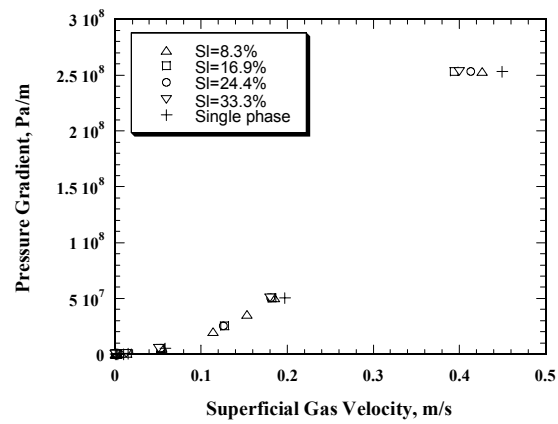


Fig. 50a – Superficial gas velocity (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

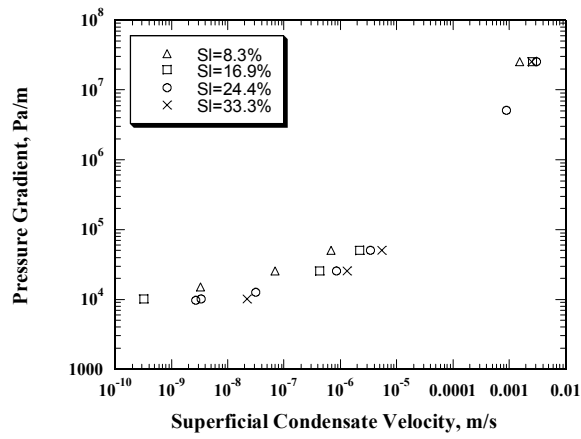


Fig. 50b – Superficial condensate velocity (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

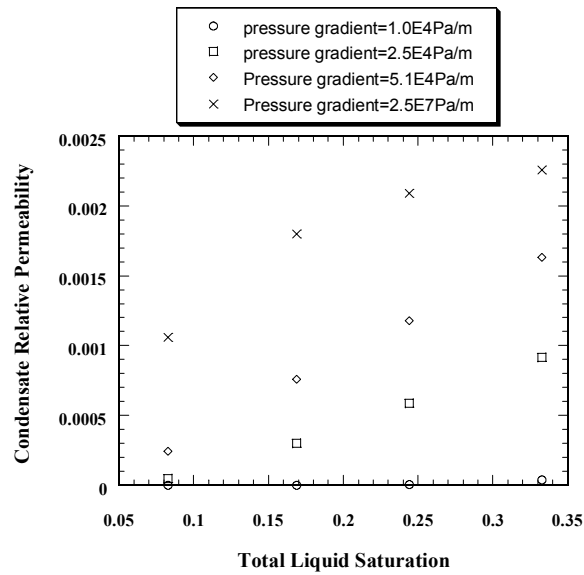


Fig. 51 – Condensate relative permeability (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

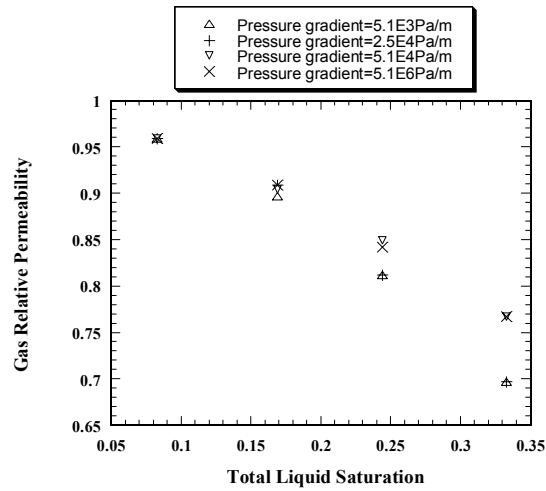


Fig. 52 – Gas relative permeability (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

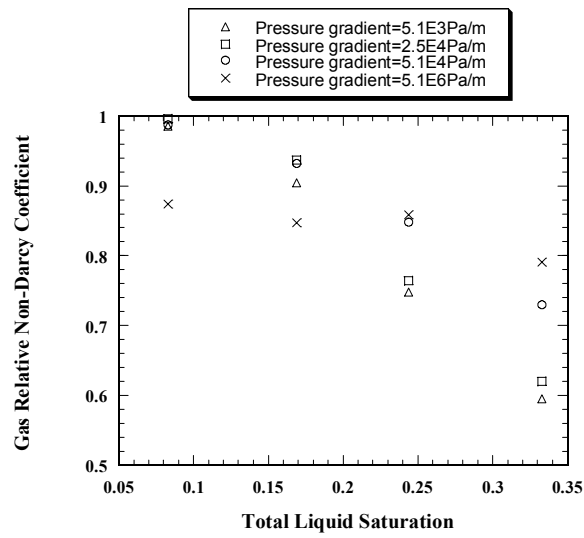


Fig. 53 – Gas relative non-Darcy coefficient (IFT = 0.02 mN/m, $S_{wi} = 5\%$)

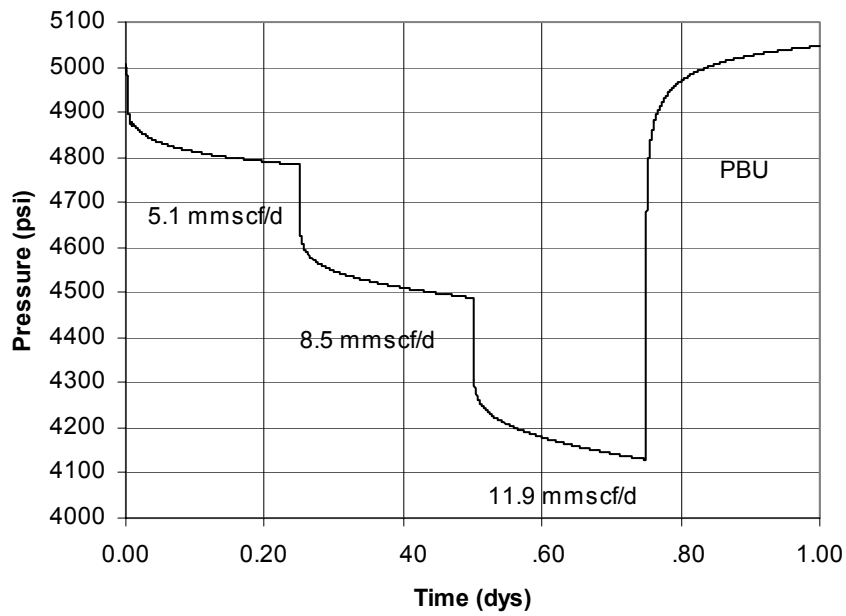


Fig. 54 – Well pressure during a test

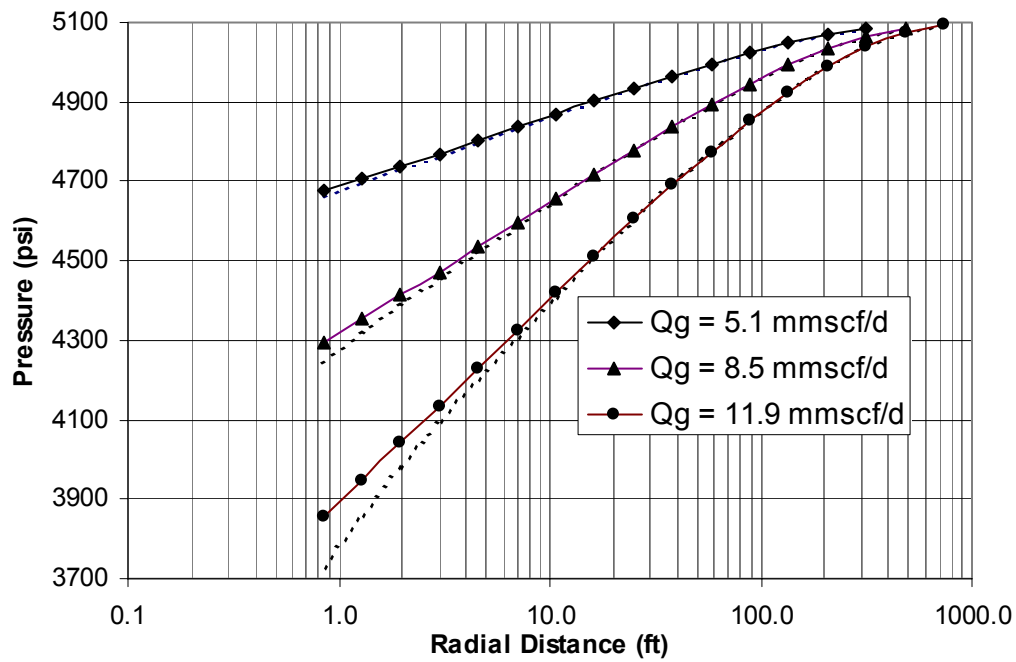


Fig. 55 - Pressure distribution within reservoir

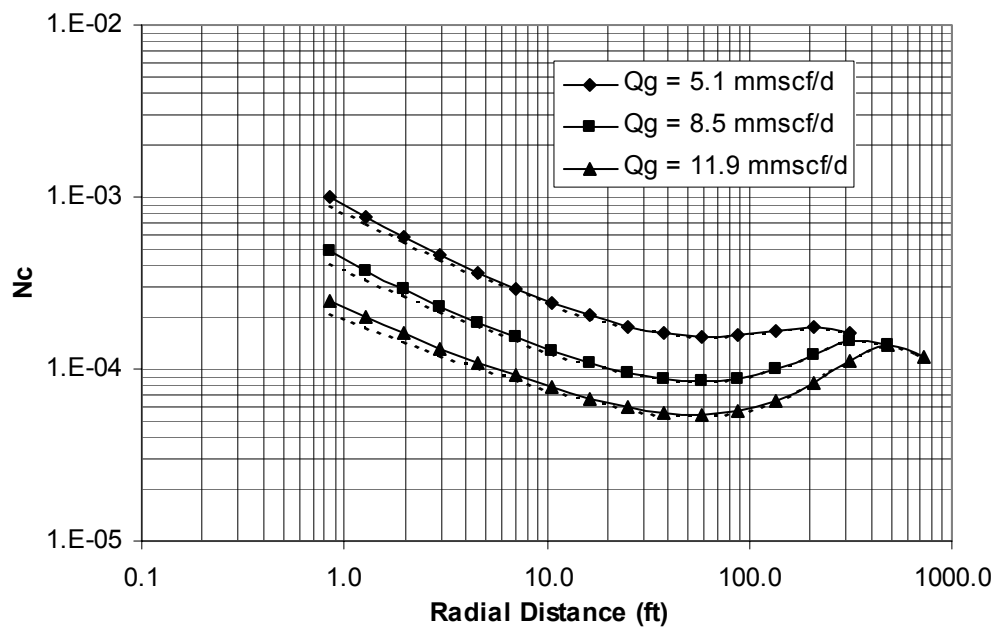


Fig. 56 - Capillary number distribution

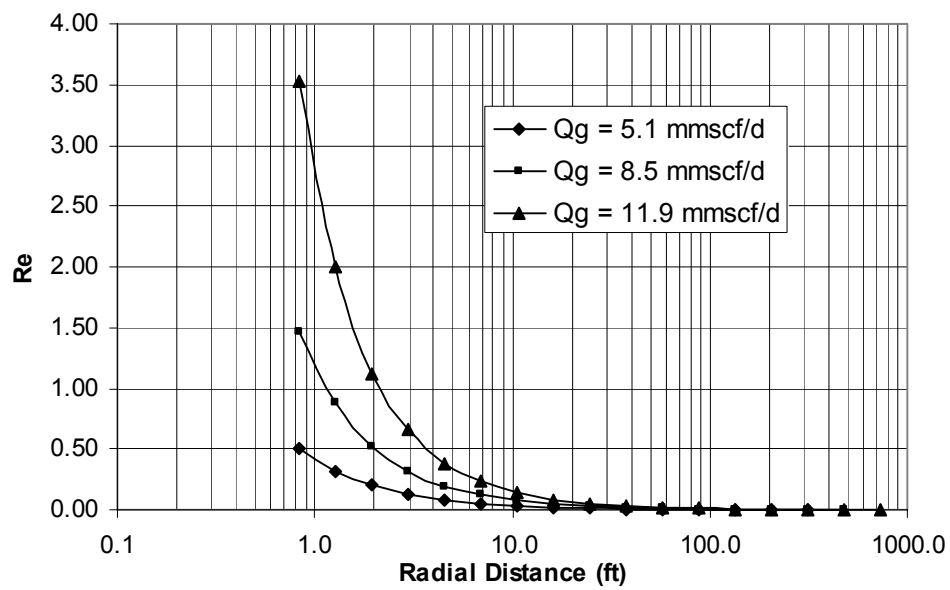


Fig. 57 - Reynolds number distribution

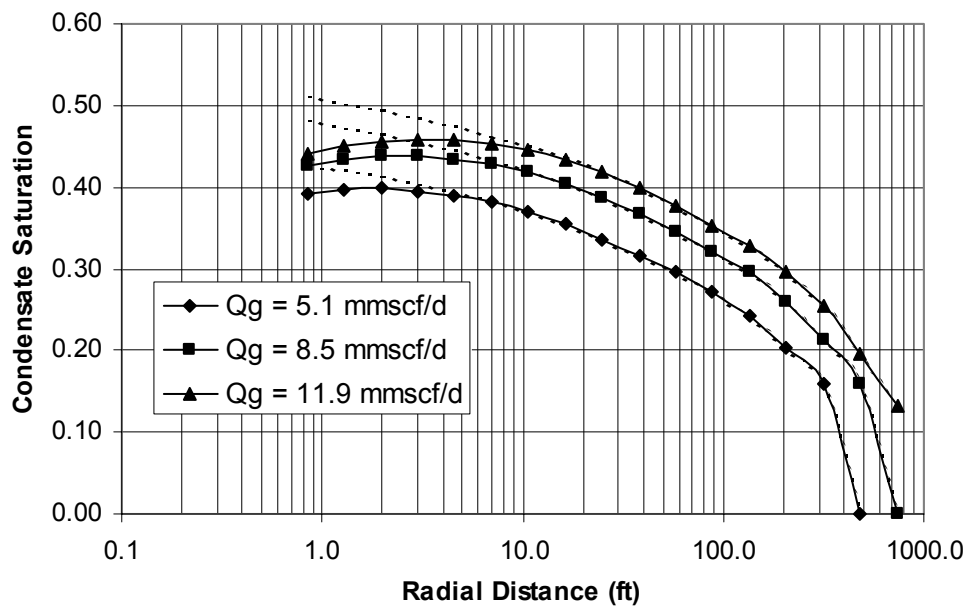


Fig. 58 - Condensate saturation vs. radial distance

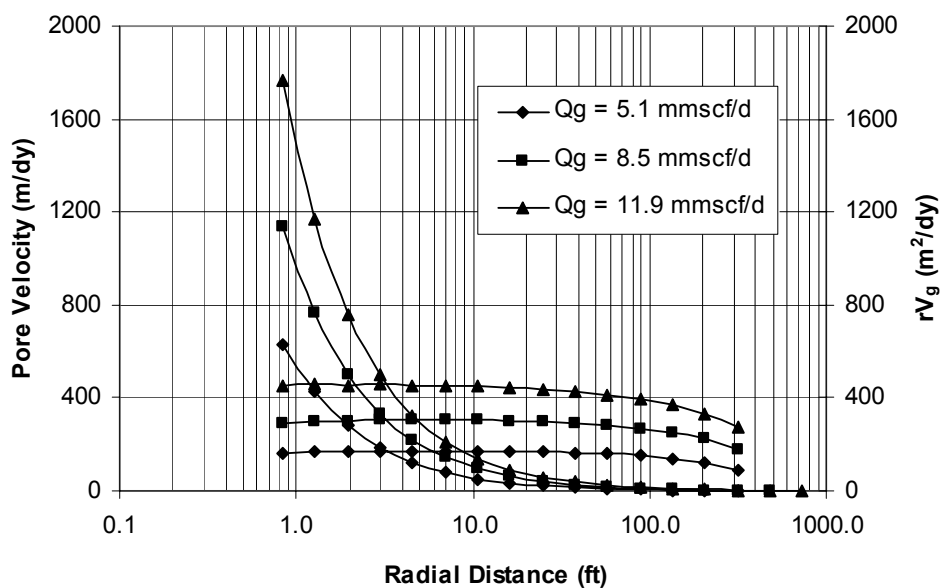


Fig. 59 - Gas interstitial velocity distribution within reservoir

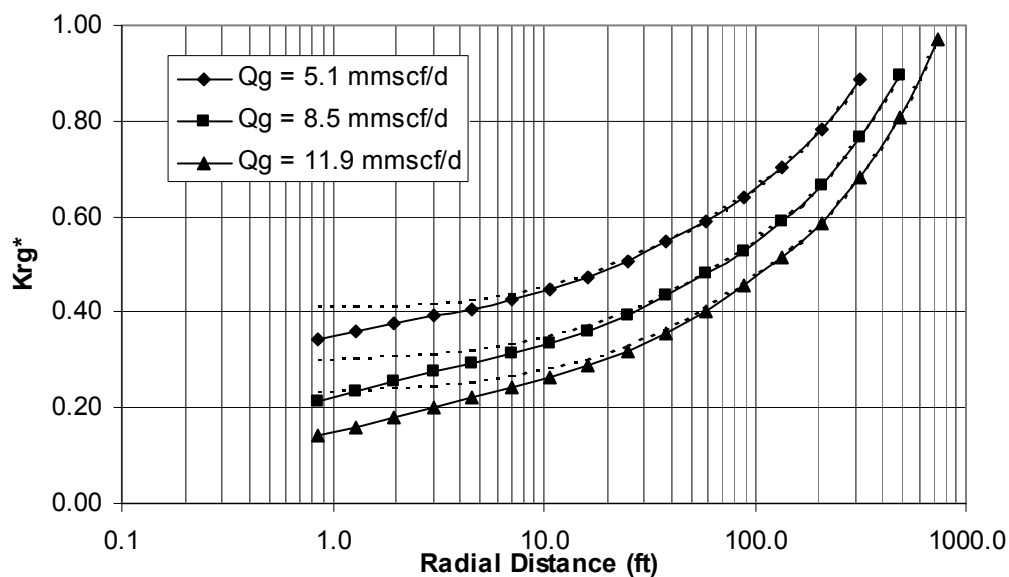


Fig. 60 - Effective gas relative permeability

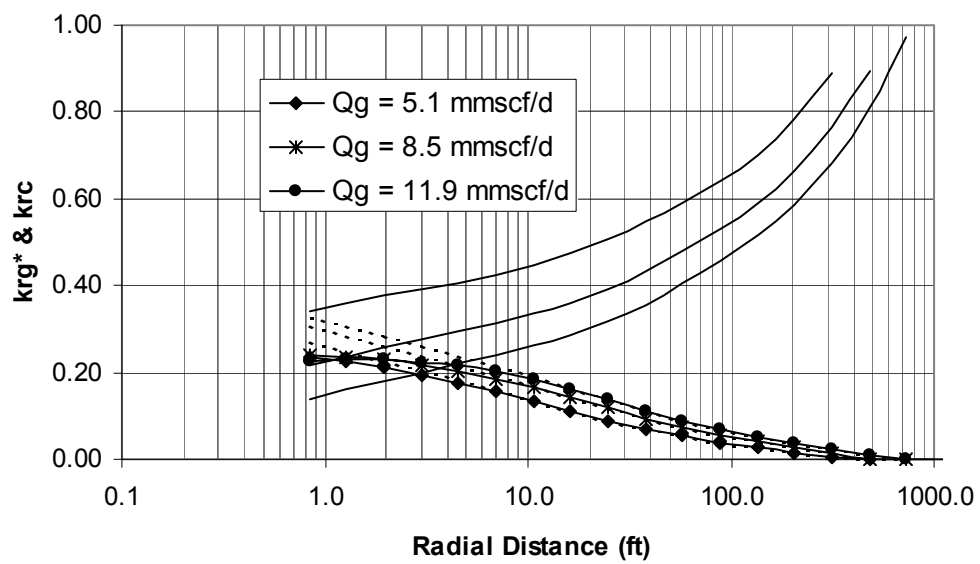


Fig. 61 - Condensate and effective gas relative permeabilities

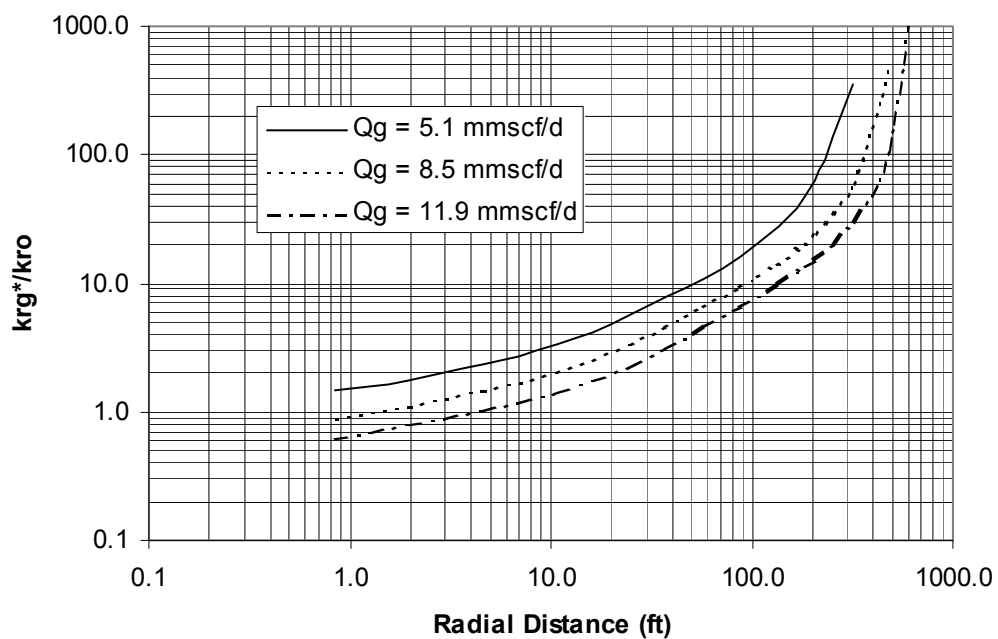


Fig. 62 – k_{rg^*}/k_{ro} profile in reservoir for each rate

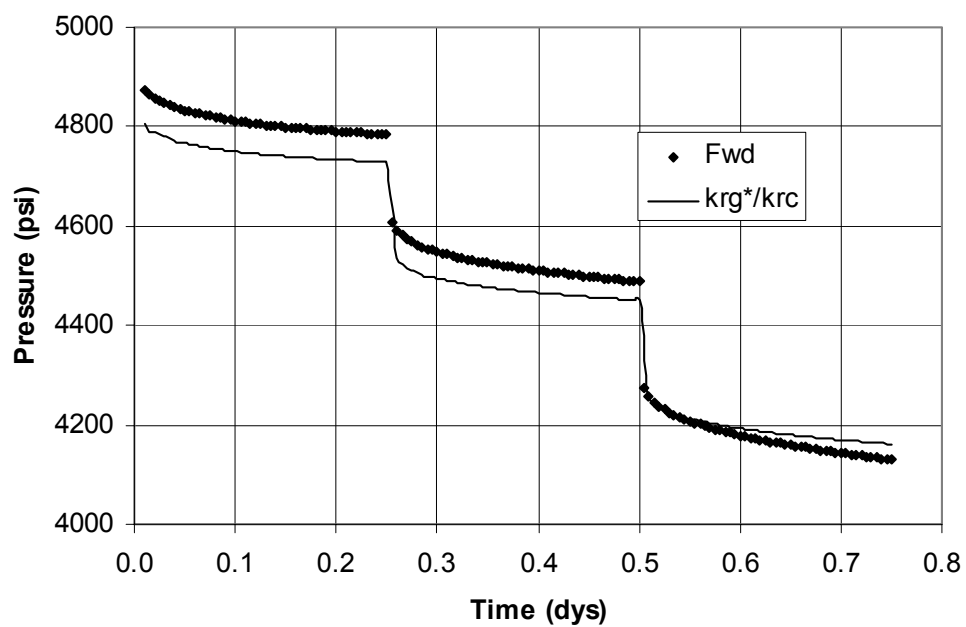


Fig. 63 – Pressure simulation; k_{rg^*} expressed as a function of k_{rg^*}/k_{rc} ratio.

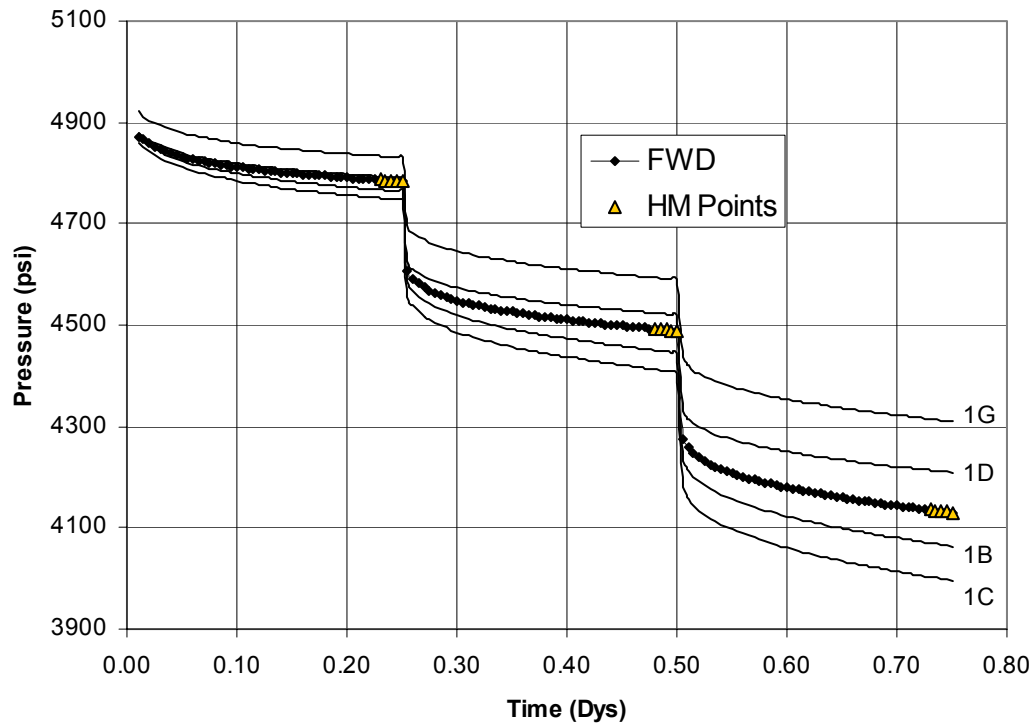


Fig. 64 - Regressions using correlation IA

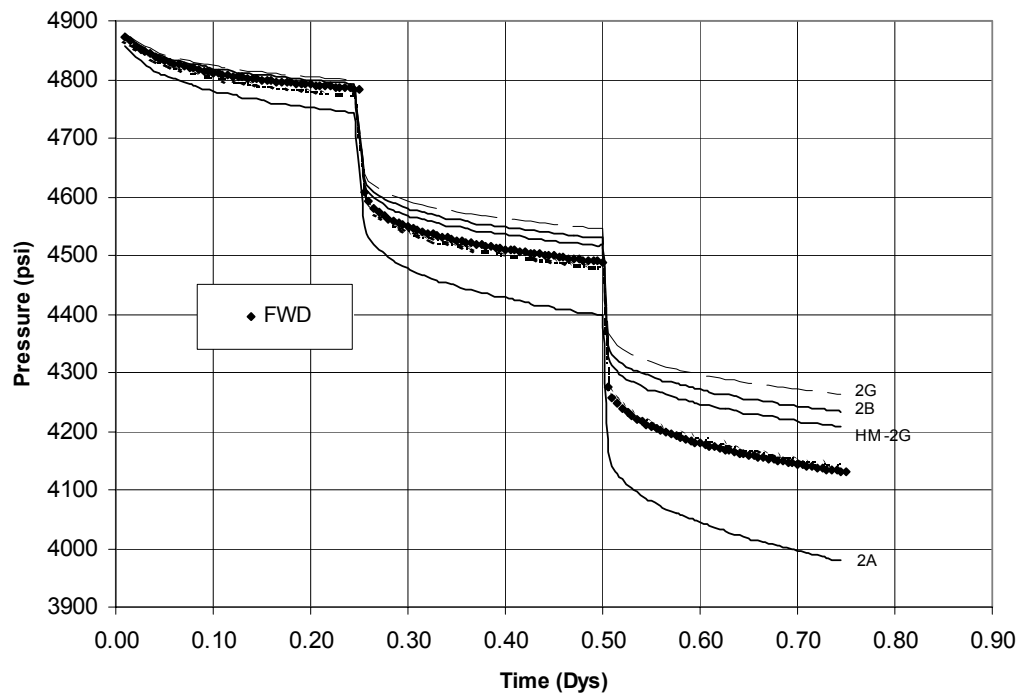


Fig. 65 - Regressions using correlation IB

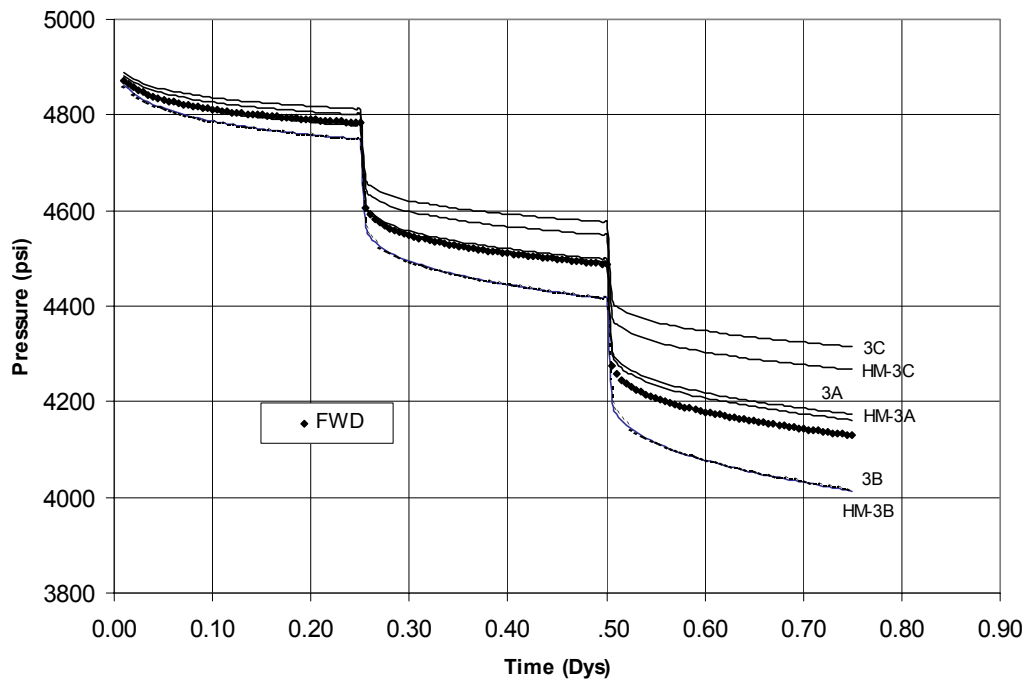


Fig. 66 - Regressions performed using correlation II

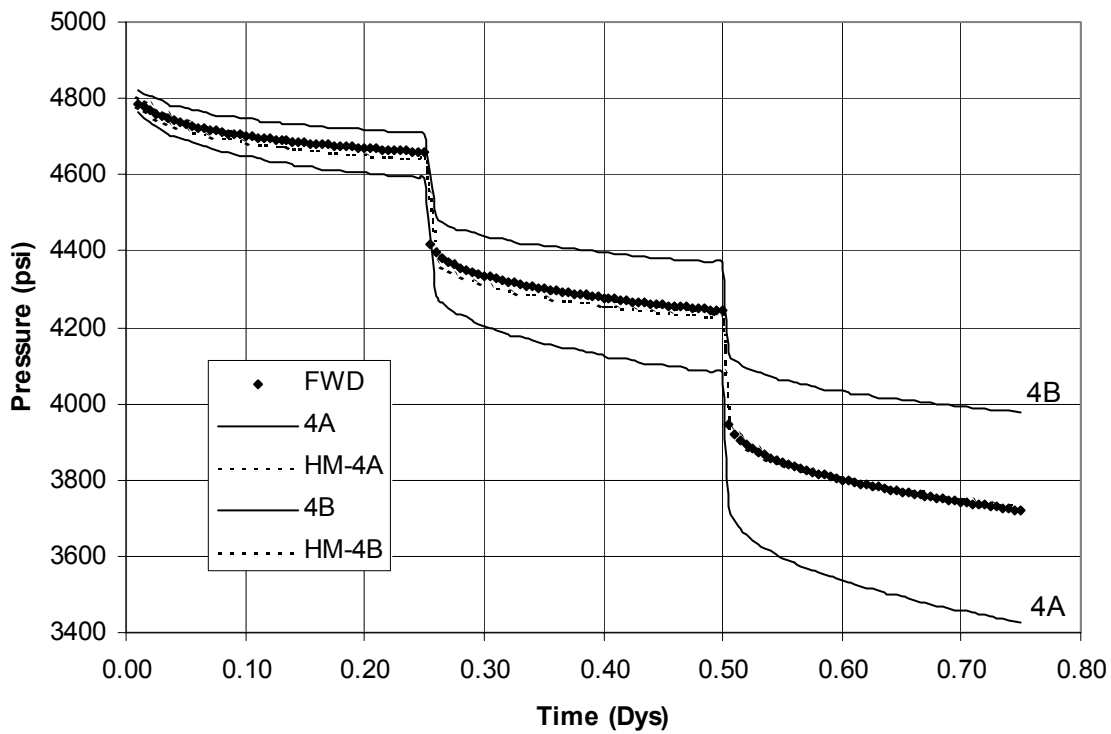


Fig. 67 - Forward simulation with 2 layer model, regression performed using 1 layer.

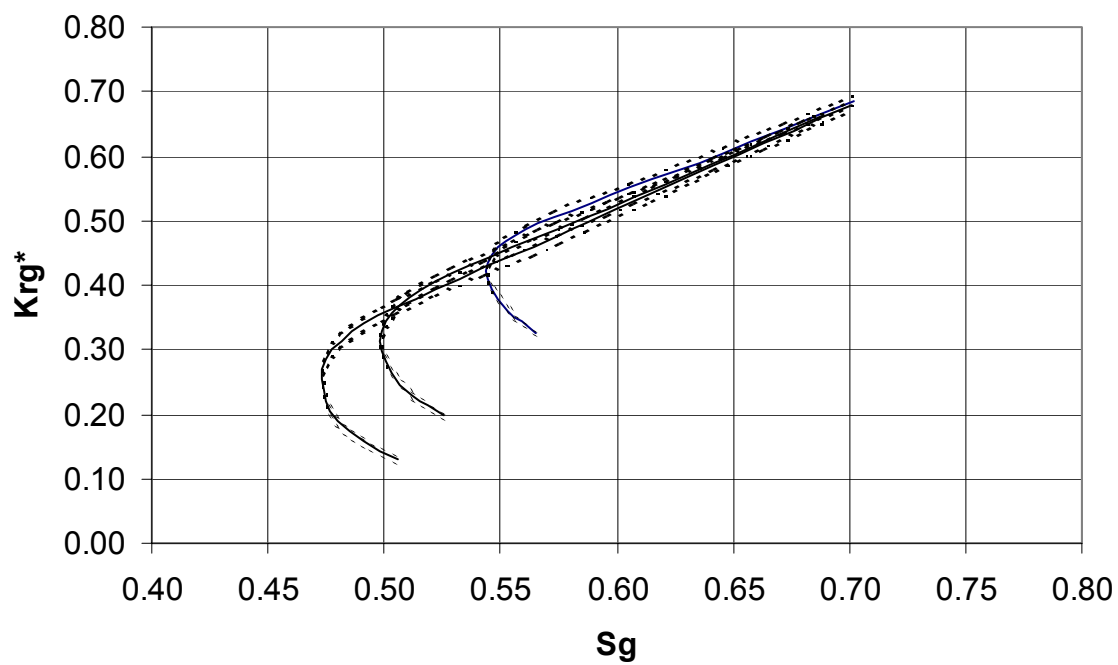


Fig. 68 – 99% confidence limit k_{rg}^* estimation

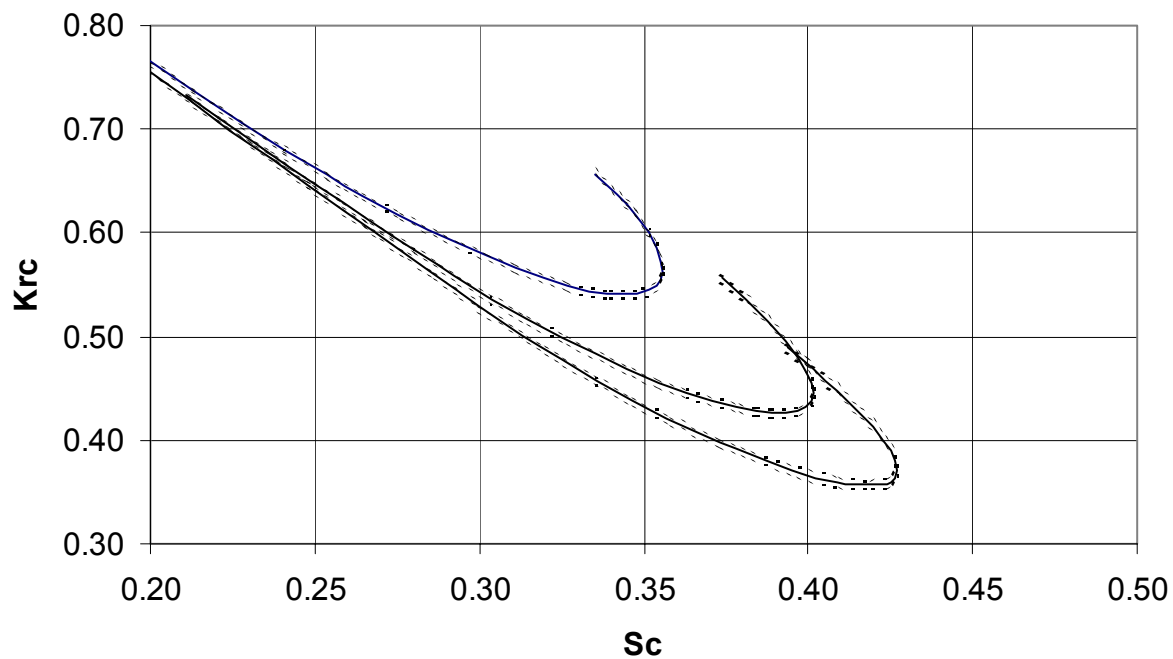


Fig. 69 – 99% confidence limit for k_{rc} estimation