Measurement and Correlation of Gas Condensate Relative Permeability by the Steady-State Method

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Summary

High-pressure core flood experiments using gas condensate fluids in long sandstone cores have been conducted. Steady-state relative permeability points were measured over a wide range of condensate-to-gas ratios (CGR; volume of condensate per unit volume of gas, both at test pressure and temperature), and the velocity and interfacial tension (IFT) were varied between tests to observe the effect on relative permeability. The experimental procedures ensured that the fluid distribution in the cores was representative of gas condensate reservoirs. Hysteresis between drainage and imbibition during the steady-state measurements also was investigated, as was the repeatability of the data.

A relative permeability rate effect for both gas and condensate phases was observed, with the relative permeability of both phases increasing with an increase in flow rate. The relative-permeability-rate effect was still evident as the IFT increased by an order of magnitude. The influence of end effects was shown to be negligible under the IFT conditions used in the tests, with the Reynolds number indicating that flow was well within the so-called laminar regime under all test conditions. The observed rate effect was contrary to that of conventional non-Darcy flow, where the effective permeability should decrease with increasing flow rate. A generalized correlation between relative permeability, velocity, and IFT has been proposed.

The results highlight the need for appropriate experimental methods and relative permeability relations where the distribution of the phases are representative of those in gas condensate reservoirs.

Introduction

During the production of gas condensate reservoirs, the reservoir pressure will be reduced gradually to below the dewpoint, giving rise to retrograde condensation. In the vicinity of producing wells, where the rate of pressure reduction is greatest, the increase in the condensate saturation from zero is accompanied by a reduction in gas relative permeability. The perceived effect of this local condensate accumulation on the near wellbore gas and condensate mobility is one of the main areas of interest for reservoir engineers.

When generating relative permeability data in the laboratory to be applied to the flow in gas condensate reservoirs, it is, therefore, important that the experimental procedures are representative of the condensing processes that occur in such reservoirs. Previous studies have used conventional gas/oil drainage relative permeability procedures at low IFT to generate data to be applied to gas condensate reservoirs.[1-3] There are, however, major differences in the fluid distribution between the fluid systems, as the oil saturation reduces from 100% for conventional unsteady-state displacements, as opposed to increasing from zero for condensing fluids. Recent observations made during laboratory measurements of relative permeability in long cores have highlighted fundamental differences that exist between the flow behaviors of condensing and conventional gas/oil fluids.[4] These preliminary findings are considered to be significant, because they demonstrate clearly that the flow of condensing fluids cannot be accurately represented in laboratory core tests using conventional procedures.

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It was the objective of this study to investigate further the effect of surface (capillary) and shear (viscous) forces on the relative permeability of condensing fluids, using the steady-state method to generate relative permeability data. The effect of an increase in velocity and IFT on relative permeability was investigated. The flow rates used in the study were selected to approach the flow rates expected in the wellbore vicinity of gas condensate reservoirs.

It was also the objective of the study to establish sound experimental procedures for the measurement of gas condensate relative permeability. Because the generation of accurate data was a priority, part of the study involved an investigation into the repeatability of the procedures used.

The number of relative permeability curves that can be generated when measuring steady-state relative permeability at different velocities and values of IFT will be large, inasmuch as relative permeability is known to change with IFT[1–3] and has been reported to vary with velocity when using condensing fluids.[4] These facts potentially will result in the need for the requirement for numerous relative permeability curves to cover the range of flow rates and IFT values within different reservoir flow regimes. There is, therefore, a clear need to develop a generalized correlation for relative permeability. Work is currently in progress to develop a fundamental and rigorous formulation between relative permeability, fluid velocity, and fluid properties (IFT, density, etc.). In the meantime, to expedite the development of such a correlation, an attempt has been made to relate the relative permeability to the capillary number (N_c), which incorporates both variables of IFT and velocity. The capillary number was calculated for all steady-state relative permeability points.

The findings highlight the need for the accurate measurement of relative permeability for condensing fluids using the appropriate experimental procedures. Consideration also should be given to important factors such as velocity and IFT, while also providing guidelines for future reservoir management.

Experimental Procedure

High-Pressure Core Facility. A high-pressure core facility was developed to allow steady-state relative permeability tests to be conducted. Within the core facility, a fixed volume of gas and condensate can be circulated in a closed loop around the flow system, which increased the accuracy of the calculated fluid saturations in the core.

The pumps used to circulate the fluid have a resolution of 0.01 cm^3, with the volumes of fluid displaced into the core being checked independently using linear transducers with a resolution of 0.01 cm^3. Fluid production from the core can be measured in a large sightglass situated at the core outlet to within 0.05 cm^3 accuracy, which is equivalent to 0.03% of the hydrocarbon pore volume. The differential pressure was measured using two Quartzdyne (Edinburgh, Scotland) quartz crystal high-accuracy transducers located at the inlet and outlet of the core. The transducers provide stable differential pressure data with a resolution of 0.01 psi during the course of the tests.

Core Properties. The core used in all tests was a Berea core, the characteristics of which are shown in **Table 1**. The core was mounted horizontally and was rotated continually through 360° for the duration of the tests to minimize the influence of gravitational forces on the fluid distribution.[5] Tracer analysis of the core before the tests had indicated that the core was homogeneous. The core

TABLE 1—CORE PROPERTIES					
Core	Length (cm)	Diameter (cm)	Porosity (%)	S_{wi} (%)	k at S_{wi} (md)
Berea	61	5.0	19.8	26.4	92

was known to be water-wet, and it contained a connate water saturation of 26.4%. The connate water saturation is believed to have remained constant between tests, because the base-relative permeability remained unchanged. All fluids were kept in equilibrium with water throughout the course of the tests. The reported gas and condensate saturations for each test were normalized and were reported as a percentage of the hydrocarbon pore volume.

Test Fluid. The gas condensate fluid was a mixture of methane and normal butane, with a dewpoint of 12.9 MPa at a temperature of 37°C. The liquid drop-out curve of the fluid can be seen in **Fig. 1** and was measured in a pressure/volume/temperature (PVT) cell.

This fluid was selected because there was an initial high rate of liquid drop out, which would allow a condensate saturation of up to 31% to be established in the core before the injection of the condensate. This was considered to be an important aspect of the tests, inasmuch as previous studies had shown that it was important that the condensate saturation should be established by condensation as opposed to injection.[4,6] An added attraction of the use of a binary fluid is that the physical properties of the gas and condensate phases would be constant at a given pressure and a fixed temperature below the dewpoint, regardless of the total fluid composition.

The test pressures selected for the tests were 12.32 MPa, which corresponds to an IFT of 0.14 mN/m, and 10.79 MPa, which corresponds to an IFT of 0.90 mN/m. The IFT values quoted were obtained from the literature available for the test fluid used under the test conditions.[7] Although the tests were conducted in the region of revaporization, the rate of revaporization under the test conditions was relatively low. A pressure change of approximately 20 psi, which was the maximum differential pressure at the highest rate during the course of the tests, would result in a variation of only 0.3% in the liquid drop out.

Experimental Procedure. The core was saturated initially with gas condensate fluid at a pressure well above its dewpoint (12.9 MPa) before each suite of tests was conducted at both IFT values. The pressure then was reduced to below the dewpoint to the selected test pressure, allowing initial condensate saturations of 30.2% and 28.5% to be established by condensation at IFT's of 0.14 and 0.90 mN/m, respectively. It has been calculated that the value of the initial condensate saturation in the core is accurate to within ±0.24% of the pore volume of the core.

To establish steady-state flow, the gas and condensate were injected at a selected CGR, with the fluids continually displaced through the core until steady-state conditions were established, i.e., until the CGR at the outlet was the same as that of the inlet.

After steady-state conditions were established, the test was halted and the core was isolated from the flow system. The new condensate saturation in the core then was calculated from the change in the total volume of condensate in the flow system (final condensate volume relative to initial condensate volume). The accuracy of the measurement of the condensate saturation relative to the volume by depletion after each steady-state point was in the region of ±0.22% of the pore volume. The total error in the measurement of the condensate saturation in the core for each steady-state relative permeability point is, therefore, estimated at ±0.32%.

Measurement of Steady-State Points. Steady-state relative permeability curves were measured at selected CGR's, with the fractional flow ranging from the lowest CGR used in the tests of 0.05, up to a maximum of 0.40. Four velocities were used at each CGR, ranging from 9.25 m/day to 74 m/day.

At each CGR the flow rate was increased in four stages from a minimum to a maximum, before the rate was reduced in steps back to the initial value, giving a total of seven steady-state points. The test sequence can be seen in **Table 2**, where the flow rate is shown in terms of cm^3/h and pore velocity (m/day). After this test sequence was conducted at the lowest CGR of 0.05, the CGR was increased stepwise, mostly in steps of 0.05, to generate imbibition steady-state curves for each flow rate. When the maximum CGR of 0.4 was reached, the CGR was reduced in steps back toward the initial value of 0.05, which generated the drainage steady-state relative permeability curves at each flow rate. This test sequence was repeated for both values of IFT.

In conventional gas/oil displacement experiments, the term "imbibition" is used for the case where the wetting fluid is "imbibed" into the core from outside. However, in the case of condensing fluid, the wetting-phase saturation increases from within the core by the process of condensation during pressure reduction, without being imbibed from outside. In this study, we refer to any process by which the wetting-phase saturation in the core increases with time (by condensation or injection) as the imbibition process.

Flow Regimes. The flow regime during injection is defined in terms of the capillary number for the gas phase, the values of which are given in Table 2. The capillary number was calculated using

$$N_c = \frac{\mu_g v_{sg}}{\sigma_{gc}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

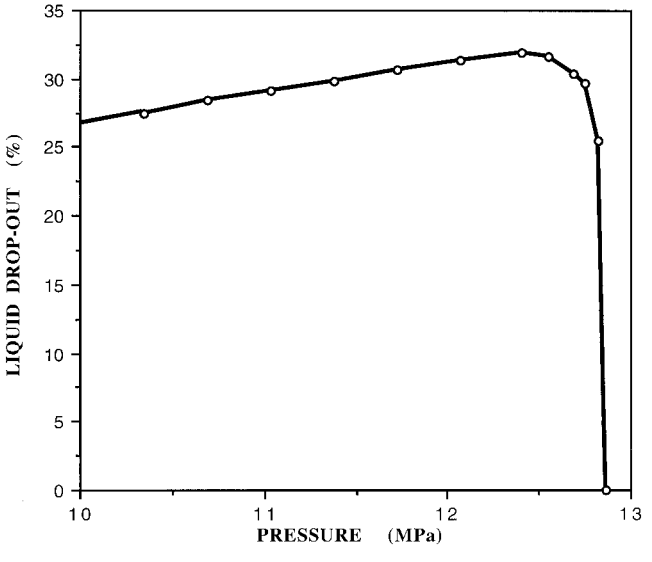

Fig. 1—Liquid drop out of binary fluid by constant composition expansion.

TABLE 2—TEST SEQUENCE, CGR = 0.05			
Gas Flow Rate (cm^3/h)	Condensate Flow Rate (cm^3/h)	Pore Velocity (m/day)	Gas Capillary Number (Nc)
100	5	9.25	0.18 E − 5
200	10	18.5	0.36 E − 5
400	20	37	0.72 E − 5
800	40	74	0.14 E − 4
400	20	37	0.72 E − 5
200	10	18.5	0.36 E − 5
100	5	9.25	0.18 E − 5

where μ is the gas viscosity, σ_{gc} is the IFT between the gas and condensate, and v_{sg} is the superficial pore velocity of gas defined as

$$v_{sg} = \frac{q}{A[\phi(1 - S_{wi})]}. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (2)$$

The highest flow rate (74 m/day) that was used in the tests corresponds to a distance of within 3 m from the wellbore of a typical North Sea gas condensate reservoir.

The calculated Reynolds number (Re) ranged from 0.31 E−3 to 0.20 E−2, indicating that the flow was within the laminar flow regime, where Re is calculated as

$$Re = \frac{\rho_g v_{sg} \sqrt{k}}{\mu_g}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3)$$

where ρ_g is the gas density, v_{sg} is the superficial pore velocity of gas, k is the permeability, and μ_g is the gas viscosity.

Results

Data Repeatability. Because one of the objectives of the research was to provide high-quality relative permeability data applicable to flow in the vicinity of the wellbore region of gas condensate reservoirs, it was important that the test procedure and the resultant data should be shown to be accurate and repeatable, allowing all data to be used with confidence.

Imbibition steady-state relative permeability data points generated at an IFT value of 0.14 mN/m initially were measured at four velocities, ranging from 9.25 to 74 m/day. To determine the quality of the data, the same test sequence then was repeated by resaturating the core with the single-phase gas condensate fluid above the dewpoint, and subsequently depleting the core to the same test pressure below the dewpoint before repeating the initial test sequence. **Fig. 2** is a plot of the steady-state relative permeability data points measured at the lowest velocity of 9.25 m/day. A good match was obtained between the two independent data sets.

A similar match was achieved for the other three velocities used, which clearly demonstrated that the relative permeability curves generated were reproducible, and that the experimental procedure was accurate.

Velocity Effect. The principal objective of this study was to investigate the effect of velocity and IFT on the relative permeability of condensing fluids. This investigation involved the generation of a series of steady-state imbibition relative permeability curves at increasing velocities, following the tests sequence shown in Table 2.

Relative Permeability Sensitivity to Velocity. **Fig. 3** is a plot of all steady-state points measured at each of the four velocities and of all the CGR's used in the tests conducted at an IFT of 0.14 mN/m. The relative permeability curves clearly show that a rate effect exists, with the relative permeability for both gas and condensate phases increasing at higher velocities. Four distinct curves, corresponding to the four velocities, can be seen for the gas relative permeability, with the associated condensate relative permeability curves also visible.

Relative Permeability Sensitivity to Velocity. A plot of all steady-state points measured at each of the four pore velocities used in the tests conducted at an IFT of 0.90 mN/m can be seen in **Fig. 4**. The gas relative permeability curves clearly show that a rate effect still exists at this higher IFT value. The effect of velocity on condensate relative permeability seems to be minimal at this increased value of IFT, compared to the curves generated at an IFT of 0.14 mN/m, with all condensate steady-state points plotting more or less on a single curve.

Hysteresis. The extent of hysteresis in the steady-state relative permeability points as a result of variations in flow rate at a fixed CGR, as well as the degree of hysteresis between imbibition and drainage relative permeability curves, was investigated at both values of IFT.

Rate Hysteresis. The test sequence, as shown in Table 2, was conducted at each CGR and at both values of IFT. During the course of this test sequence the extent of relative permeability hysteresis as a result of the increase and subsequent decrease in velocity at each CGR was investigated.

Fig. 5 is a plot of the gas and condensate steady-state relative permeability points generated at a CGR of 0.25 and an IFT of 0.14 mN/m, where the flow rate was increased then decreased by an order of magnitude. The major difference between the points measured with the velocity increasing compared to the points measured with the velocity reducing was the saturation, because the differential pressure, and hence the relative permeability values, were similar. The greatest change in saturation observed in all tests conducted was 0.3%, which is within the reported saturation error band. The results were repeated at all CGR's, which suggests that any hysteresis resulting from variation in velocity was minimal during the course of the tests conducted at the low IFT of 0.14 mN/m.

The extent of rate hysteresis at an increased IFT of 0.90 mN/m and a similar CGR of 0.25 can be seen in **Fig. 6**. There is a greater degree of hysteresis at the higher IFT, because the relative permeability data points that were measured as the velocity was reduced

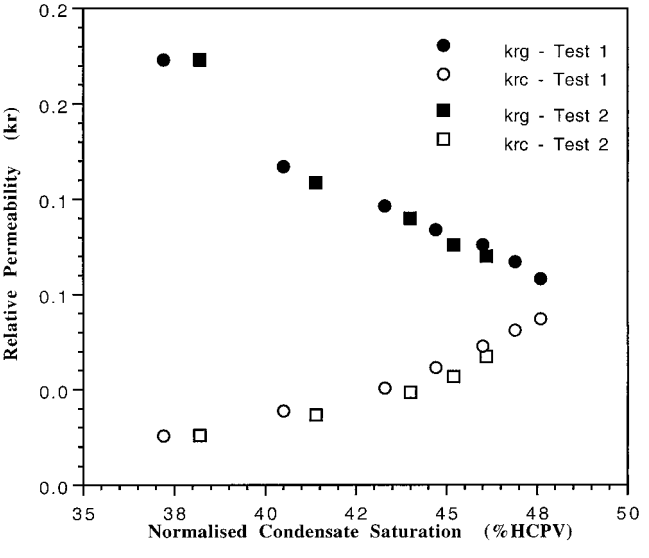

Fig. 2—Repeatability of measured relative permeabilities.

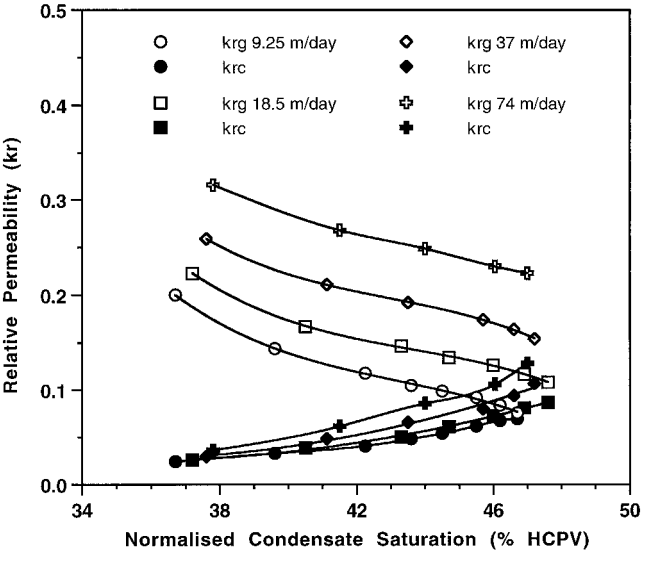

Fig. 3—Steady-state relative permeability curves: IFT = 0.14 mN/m.

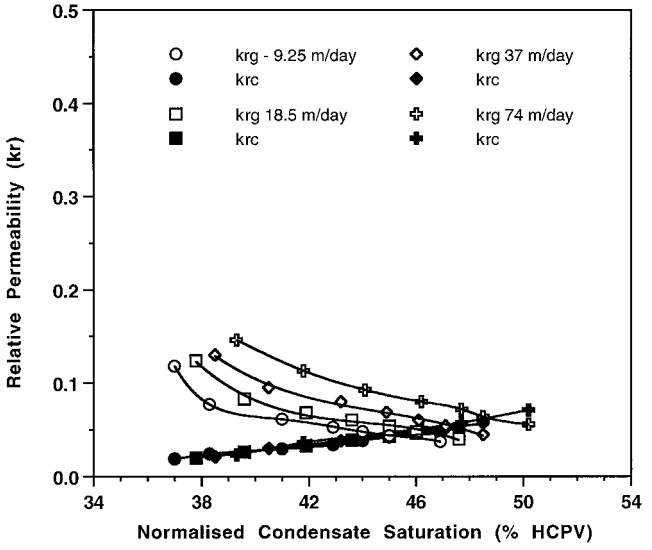

Fig. 4—Steady-state relative permeability curves: IFT = 0.9 mN/m.

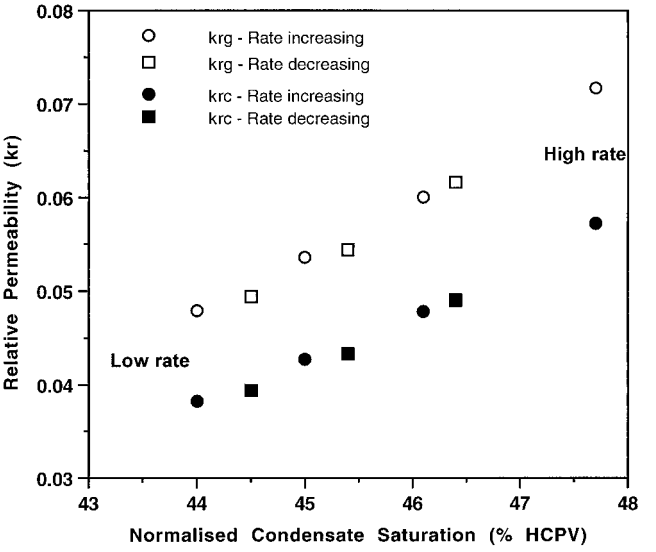

Fig. 6—Rate hysteresis at CGR = 0.25 and IFT = 0.90 mN/m.

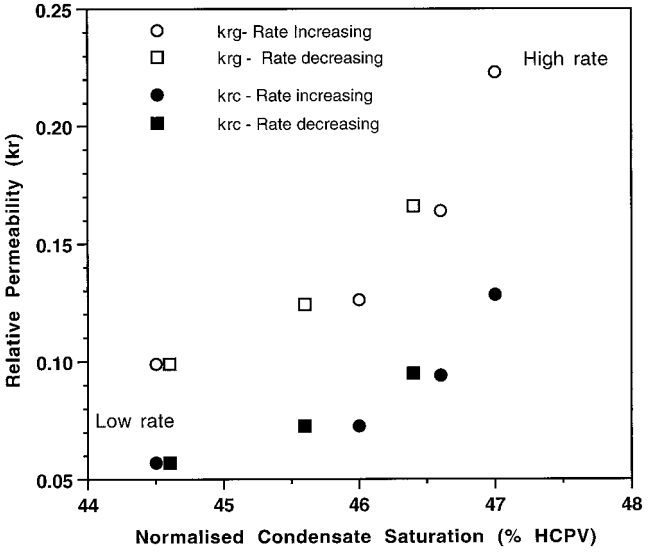

Fig. 5—Rate hysteresis at CGR = 0.25 and IFT = 0.14 mN/m.

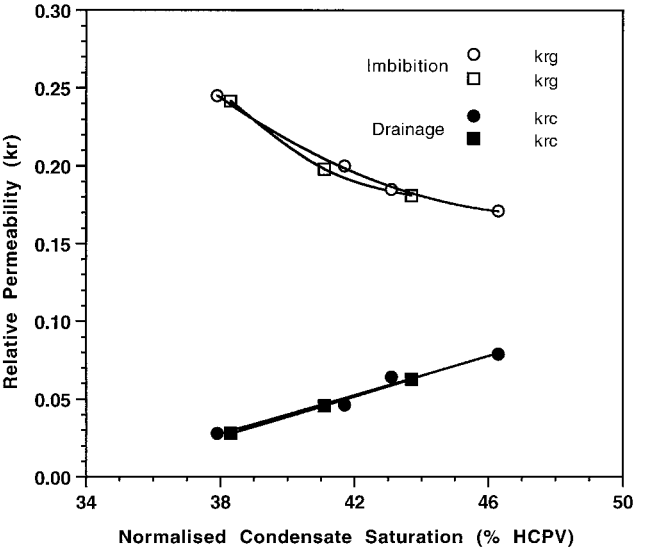

Fig. 7—Hysteresis between imbibition and drainage relative permeabilities: IFT = 0.14 mN/m.

show a consistently higher relative permeability at a higher condensate saturation. This trend was observed at all CGR values.

Imbibition and Drainage Hysteresis. Minimal rate hysteresis was observed in the tests conducted at an IFT of 0.14 mN/m between the imbibition and drainage relative permeability curves. **Fig. 7** shows that at a velocity of 37 m/day, with the CGR initially increased (imbibition) then reduced (drainage), the extent of hysteresis is minimal.

Hysteresis between the initial imbibition and subsequent drainage curves was, however, more pronounced at the higher IFT of 0.90 mN/m. The gas relative permeability was observed to be higher during drainage, with the condensate relative permeability being lower. The degree of hysteresis generally was reduced as the velocity increased.

Discussion

Relative Permeability Rate Effect. The sensitivity of relative permeability, measured by the steady-state method, to velocity for both the gas and condensate phases is the most significant finding of this study. At each CGR, the increase in relative permeability for both phases with increasing velocity was accompanied by a relatively low increase in the condensate saturation. This indicates that redistribution of fluids in the core would be required to explain the significant variation of relative permeability with changes in velocity at similar saturations. The sensitivity of gas condensate relative permeability to velocity has been reported previously only by the present authors during a sequence of unsteady-state displacements conducted using gas condensate fluids.[4]

We also have investigated rate sensitivity during conventional gas/oil unsteady-state drainage displacements. The same core used in the present study was saturated with equilibrium butane and was displaced with equilibrium methane, and unsteady-state relative permeability curves were generated at three different velocities.[4] The results of the conventional displacements are shown in **Fig. 8**, and they show clearly that the rate effect was minimal when using this procedure compared with tests conducted using condensing fluids. The IFT at which the conventional tests were conducted was 0.14 mN/m, the same value as the low IFT gas condensate relative permeability tests reported in this study (Fig. 3). The factors governing the reported relative permeability behavior for gas condensate fluids will now be discussed.

Influence of End Effects. Variations in relative permeability with variations in flow rate have been reported previously and have been attributed to capillary end effects.[8] However, calculations based on a work conducted by Hassler *et al.*,[9] as well as calculations based on mercury injection data generated from samples of the core

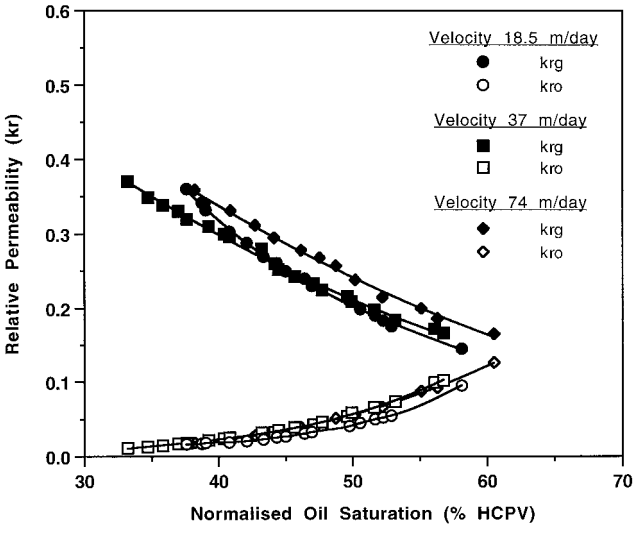

Fig. 8—Conventional gas/oil relative permeability: IFT = 0.14 dyne/cm (after Henderson *et al.*[11]).

used in this study, indicate that the reported gas condensate rate effect is independent of capillary pressure at the end faces of the core. The calculated capillary pressures ranged from an average value of 0.10 kPa, at an IFT of 0.14 mN/m, to an average value of 0.48 kPa, at an IFT of 0.90 mN/m. These values were comparable to the differential pressures measured across the core, which were two to three orders of magnitude greater than the calculated capillary end effects.

Variations Between the Mechanisms Governing the Flow of Conventional and Gas Condensate Fluids. Different flow regimes will exist in gas condensate reservoirs, where different combinations of forces govern the flow. In the heart of the reservoir, the main forces governing condensate mobility will be gravitational and capillary. As the vicinity of the wellbore is approached, the flow will become dominated increasingly by viscous and capillary forces. It is within this high-velocity flow regime in the vicinity of production wells that the reported increase in relative permeability with increasing velocity for gas condensate fluids will be at its greatest. This runs contrary to conventional non-Darcy flow theory, where the permeability reduces with increasing velocity when the flow becomes turbulent. The gas condensate core tests reported were modeled on the near-wellbore flow regime, where viscous and capillary forces were dominant and gravitational forces were minimized by continually rotating the core.

It has been shown that conventional gas/oil displacements, where the core is initially saturated with oil before gas injection, will show no relative permeability rate sensitivity.[1,4] Such tests have been used previously to generate data to be applied to gas condensate flow, which contains the assumption that the low IFT values used in the tests will make the flow mechanisms representative of those in gas condensate systems. However, during conventional unsteady-state gas/oil displacements, gas and oil will flow in their own pore space. Gas will invade the largest accessible pores, displacing the oil, but will leave oil films on the pore walls surrounding the gas channels. The overall recovery from the remaining oil films will be minimal as long as there are continuous oil networks in the smaller pore space. Gas will, therefore, flow into the pore space where oil is mostly immobile, with oil flowing into the pore space not invaded by gas. This type of flow is described as channel flow, and normally it is applied to the Darcy-type flow of conventional fluids.

The flow of gas condensate fluids, however, does not resemble the distribution of conventional fluids. It has been shown from micromodel studies that when the process of condensation occurs at and below the dewpoint, the condensate phase will wet all surfaces, acting as an intermediate phase in a water-wet, three-phase system: wetting with respect to gas, nonwetting with respect to water.[10] Flow through the condensate wetting film can be very efficient.[6,10] It has been reported that gas and condensate flow together in all pore spaces, with both phases flowing as if they were a single phase.[11] This is a significant variation from the flow behaviors and fluid distributions of conventional fluids, where oil flow into gas-invaded pores behind the gas front will be minimal.

The fluid distributions that arise from the process of condensation, which generate oil films throughout the porous medium that result in the efficient flow of gas and condensate into the same pore space, are, therefore, believed to be responsible for the reported relative permeability rate effect.

However, during conventional steady-state relative permeability tests, when the gas saturation in the core is initially 100%, the injection of oil with gas eventually may result in fluid distributions similar to those of condensing fluids. If the oil has a positive spreading coefficient and if IFT is low, the injected oil may redistribute throughout the core with time to form oil films on all surfaces. The simultaneous injection of oil with gas during the steady-state tests will continually supply oil to the oil films on the walls of the pores (unlike unsteady-state displacements where no further oil is supplied to the oil films in the pores after gas invasion), giving flow conditions that are similar to the fluid distributions in gas condensate systems. A relative permeability sensitivity to velocity for tests conducted using conventional steady-state gas/oil procedures may, therefore, be detectable.

This view is supported by the results of the steady-state tests reported using gas condensate fluids in this study. It was observed that the rate effect was most evident when the CGR was at its highest, i.e., when the fractional flow of injected condensate was increased. If the process of condensation solely governed the relative permeability rate sensitivity, the injection of additional condensate would be expected to reduce the rate sensitivity.

Correlating Relative Permeability to Capillary Number

It has been shown that the relative permeability of gas condensate fluids will vary when the velocity changes at a fixed IFT, and when the velocity is fixed and the IFT is changed. These conditions will result in the need for numerous relative permeability curves being required to cover the range of flow rates and IFT values within different reservoir flow regimes. To develop a generalized correlation for relative permeability, the capillary number (N_c), which incorporates both the variables of IFT and velocity, was selected as the correlating parameter. The capillary number was calculated for all steady-state relative permeability points measured at all flow rates and for both values of IFT. The definition of the capillary number used is shown in Eq. 1. The capillary number in this form required the superficial gas velocity to be used in association with gas viscosity at the test conditions. The correlation was, therefore, considered to be more applicable to the gas relative permeability.

It can be seen from **Fig. 9** that a correlation between gas relative permeability and capillary number was identified for the tests conducted. This is shown by the capillary number of the lowest rate tests (9.25 m/day) conducted at an IFT of 0.14 mN/m corresponding to the capillary number of the highest rate tests (74 m/day) conducted at the higher IFT of 0.9 mN/m. The value of the capillary number for both tests was in the region of 0.14 E-4. The contours of the capillary numbers for all steady-state points follow similar slopes from top left to bottom right of the graph, with both sets of data from the two IFT values showing continuity.

The attempted correlation shows that for the tests reported there seems to be a correlation between gas relative permeability and capillary number. Future tests will be required to cover a wider range of capillary numbers, and they will entail using different core types and fluids.

Conclusions

1. Steady-state relative permeability tests conducted using gas condensate fluids have shown that relative permeability was rate sensitive. The relative permeabilities of both phases were found to increase as the velocity increased.

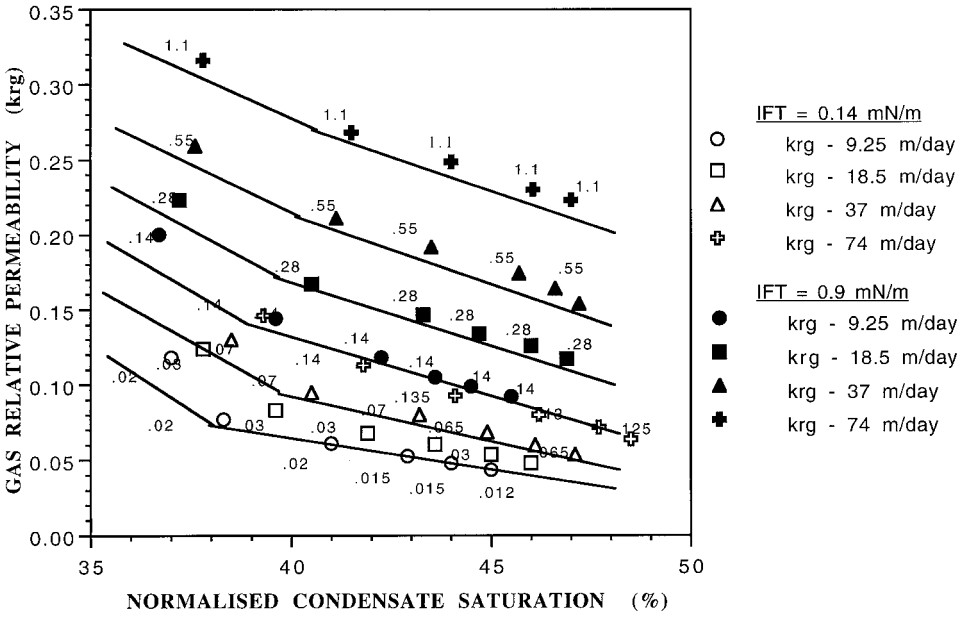

Fig. 9—Correlation between gas relative permeability and capillary number.

2. At higher IFT values the gas and condensate relative permeabilities were reduced; however, the rate effect was still evident, particularly for the gas phase.

3. The rate effect was shown to be independent of core end effects.

4. Hysteresis became more pronounced with increasing IFT.

5. The accuracy of the experimental procedures was validated by measuring a repeat series of relative permeability curves.

6. The relative permeability rate effect is attributed to the process of condensation in conjunction with the flow characteristics of gas condensate fluids. This leads to a redistribution of fluids as the flow rate increases, with a minimal change in saturation.

7. To accurately measure the relative permeability of gas condensate fluids, experimental procedures are required that will be representative of the fluid distributions in gas condensate reservoirs.

8. A generalized correlation between relative permeability and capillary number has been identified.

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Nomenclature

A = area
k = permeability
N_c = capillary number
q = flow rate
Re = Reynolds number
S_{wi} = connate water saturation
v_s = superficial pore velocity
μ_g = gas viscosity
ρ_g = gas density
σ = interfacial tension
ϕ = porosity

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SI Metric Conversions Factors

atm × 1.013 250*	E+05	= Pa
dyne × 1.0*	E−02	= mN
°F (°F − 32)/1.8		= °C
ft × 3.048*	E−01	= m
in.^{3} × 1.638 706	E+01	= m^3
psi × 6.894 757	E+00	= kPa

*Conversion factors are exact.

SPEREE

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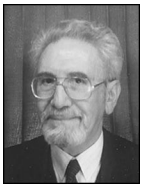
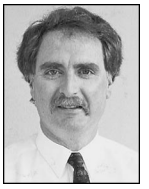
Henderson

Danesh



Tehrani



Peden