

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

G.D. Henderson, A. Danesh SPE, D.H. Tehrani SPE, S. Al-Shaidi SPE, & J.M. Peden SPE.

Heriot-Watt University, Department of Petroleum Engineering, Riccarton, Edinburgh, EH14 4AS.

e-mail: graeme_henderson@pet.hw.ac.uk

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Abstract

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 ratio's (CGR), with the velocity and interfacial tension (IFT) being varied between tests in order 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 was also 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, with the relative permeability of the gas phase reducing more than the condensate phase. The influence of end effects was shown to be negligible at the IFT conditions used in the tests, with the Reynolds number indicating that flow was well within the so called laminar regime at all test conditions. The observed rate effect was contrary to that of the conventional non-Darcy flow where the effective permeability should decrease with increasing flow rate. A generalised correlation between relative permeability, velocity and IFT has been proposed, which should be more appropriate for condensing fluids than the conventional correlation.

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. This study will be particularly applicable to the vicinity of producing wells, where the rate effect on gas relative permeability can significantly affect well productivity. The findings provide previously unreported data on relative permeability and recovery of gas condensate fluids at realistic conditions.

Introduction

During the production of gas condensate reservoirs, the reservoir pressure will be gradually reduced to below the dew-point, 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 relative permeability of gas, due to the shrinkage of pore space available to gas flow. It is the perceived effect of this local condensate accumulation on the near wellbore gas and condensate mobility that is one of the main areas of interest for reservoir engineers. The availability of accurate relative permeability data applicable to flow in the wellbore region would therefore greatly enhance the management of gas condensate reservoirs.

When generating relative permeability data in the laboratory to be applied to 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 [1,2,3] however; there are 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 that fundamental differences exist between the flow behaviour of condensing and conventional gas-oil fluids [4]. It was reported that during the course of a series of unsteady-state drainage displacements, a relative permeability sensitivity to flow rate was observed when using condensing fluids. No such relationship was observed when using conventional gas-oil fluids. These preliminary findings are considered to be significant, as they clearly demonstrate that the flow of condensing fluids cannot be accurately represented in laboratory core tests using conventional procedures.

It was the objective of this study to further investigate the effect of surface (capillary) and shear (viscous) forces on the relative permeability of condensing fluids, in this case using the steady-state method to generate relative permeability data. The effect of increasing velocity and IFT on relative permeability was investigated by gradually increasing the CGR (condensate to gas ratio, see nomenclature) to measure the imbibition curve at different velocities, before reducing the CGR to measure the drainage curve, with the extent of hysteresis being investigated. The flow rates used in the study were selected to approach the flow rates expected in the wellbore vicinity of gas condensate reservoirs.

In addition to investigating the effect of velocity and IFT on gas condensate relative permeability, it was also the objective of the study to establish sound experimental procedures for the measurement of gas condensate relative permeability. As the generation of accurate data was a priority, part of the study involved an investigation into the repeatability of the procedures used. This approach was required in order to verify the accuracy of the experimental methods, whilst also providing guidelines for the future generation of accurate and realistic relative permeability data for condensing fluids.

The number of relative permeability curves that could be generated when measuring steady-state relative permeability at different velocities and different values of IFT will be large as relative permeability is known to change with IFT [1,2,3], and has been reported to vary with velocity when using condensing fluids [4]. This will potentially 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. There is clearly therefore a need to develop a generalised correlation for relative permeability, with work 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 measured at all flow rates and values of IFT.

The reported findings highlight the need for the accurate measurement of relative permeability for condensing fluids using the appropriate experimental procedures, with

consideration given to important factors such as velocity and IFT, whilst 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, as shown in Figure 1. 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.

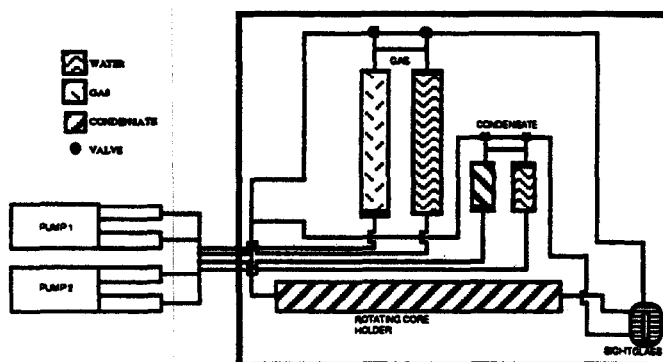


Figure 1 . Core Facility

The pumps used to circulate the fluid have a resolution of 0.01cc, with the volumes of fluid displaced into the core being checked independently using linear transducers with a resolution of 0.01cc. The gas / condensate fluid interface in the large sightglass at the core outlet can be measured to within a resolution of 0.05 cc, equivalent to 0.03% of the HCPV. The differential pressure was measured using two Quartzdyne quartz crystal high accuracy transducers located at the inlet and outlet of the core. The transducers provided 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.

Table 1 Core Properties					
Core	(cm) Length	(cm) Diameter	(%) Porosity	(%) Swi	(md) K at Swi
Berea	61	5.0	19.8	26.4	92

The core was mounted horizontally and continually rotated through 360 degrees for the duration of the tests, in order to minimise the influence of gravitational forces on the fluid distribution [5]. Tracer analysis of the core prior to the tests had indicated that the core was homogeneous. The core was known to be water-wet, and contained a connate water saturation of 26.4%. The connate water saturation is believed to have remained constant between tests, as the base relative permeability remained unchanged. The test fluids were kept in equilibrium with water throughout the course of the tests.

The reported gas and condensate saturations for each Test were normalised and 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 dew point of 12.9 MPa at a temperature of 37°C. The liquid drop-out curve of the fluid can be seen in Figure 2, and was measured in a PVT cell.

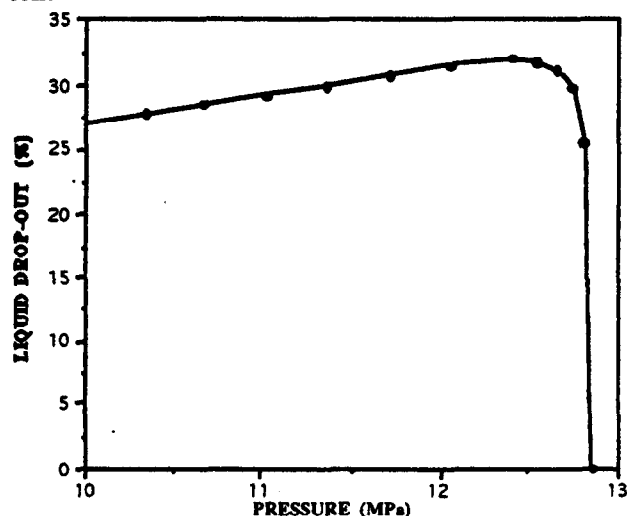


Figure 2. Liquid drop-out of binary by CCE

This fluid was selected as 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 prior to the injection of condensate. This was considered to be an important aspect of the tests, as previous studies had shown that when measuring gas condensate relative permeability 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 fixed temperature below the dew-point, regardless of the total fluid composition.

The test pressures selected for the tests were 12.32 MPa corresponding to an IFT of 0.14 mN/m, and 10.79 MPa corresponding to an IFT of 0.90 mN/m. The IFT values quoted were obtained from the literature available for the test fluid at the test conditions [7]. Although the tests were conducted in the region of re-vapourisation, the rate of re-vapourisation at 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 initially saturated with gas condensate fluid at a pressure well above its dew-point of 12.9 MPa, prior to each suite of tests being conducted at both IFT values. The pressure was then reduced to below the dew-point to the selected test pressure,

allowing an initial condensate saturation of 30.2% to be established by condensation at an IFT of 0.14 mN/m, and 28.5% at an IFT of 0.90 mN/m. It has been calculated that the value of the initial condensate saturation in the core is accurate to within $\pm 0.24\%$ of the pore volume of the core.

In order to establish steady-state flow, gas and condensate were injected at a selected CGR, with the fluids being continually displaced from the injection cells through the core to a 100cc sightglass at the core outlet, and on to gas and condensate receiving cells (see Figure 1). this was continued until steady-state conditions were established, i.e. 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 isolated from the flow system. The new condensate saturation in the core was then calculated from the change in the total volume of condensate (volume of condensate in the sightglass + storage cells) in the flow system at the start of each test, relative to the new condensate volume. The accuracy of measuring the condensate saturation relative to the volume by depletion after each steady-state point was in the region of $\pm 0.22\%$ 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 $\pm 0.32\%$.

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 8.8 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 cc/hour and pore velocity (m/day).

(cc/hr) Gas Flow rate	(cc/hr) Condensate Flow rate	(m/day) Pore Velocity	(Nc) Gas Capillary number
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

After the test sequence shown in Table 2 was conducted at the lowest CGR of 0.05, the CGR was stepwise increased, mostly in steps of 0.05, and the sequence of seven tests were

repeated in order to generate the imbibition steady-state curves at each flow rate. When the maximum CGR was reached, the CGR was reduced in steps back towards the initial value of 0.05 to generate 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, and Figure 13. The capillary number was calculated using;

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

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

$$v_g = \frac{q}{A[\phi(1 - S_{wi})]} \quad \dots\dots\dots(2)$$

The highest flow rate of 74 m/day used in the tests corresponds to a distance of within 3 metres 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 flow was within the laminar flow regime, where Re is calculated as;

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

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

A modified Reynolds number for flow through porous media, based on equations developed by Ergun [8,9], has also been used in this study. This modified Reynolds number takes account of the tortuosity of porous media, and is given by equation 4;

$$Re = \left(\frac{D_p \rho v}{\mu} \right) \left(\frac{1}{1 - \phi} \right) \quad \dots\dots\dots(4)$$

where, D_p is a characteristic length scale typical of the internal structure of the porous medium, ρ is the density of the flowing fluid, μ is the viscosity of the flowing fluid, v is the superficial fluid velocity, and ϕ is the porosity of the medium.

In order to calculate the D_p values necessary for calculating the Modified Reynolds number (Re), the flow in porous media was treated similar to flow in packed columns where spheres are conveniently chosen to be the packing material [8,9]. Fluid flows in tubes of irregular cross sections in the space available for flow between the packing material, where D_p is the diameter of the spheres. For this model, flow is completely described as follows:

$$\Delta P = \left(\frac{150 \mu L v}{D_p^2} \right) \frac{(1 - \phi)^2}{\phi^3} + \left(\frac{1.75 \rho L v^2}{D_p} \right) \frac{(1 - \phi)}{\phi^3} \quad \dots(5)$$

The procedure for calculating the Modified Reynolds' Number involves the use of equation 5 to calculate D_p ; this value of D_p is then used to calculate the Modified Reynolds' number, as given by equation 4. The Modified Reynolds' number values calculated for the flow rates used in the tests reported in this study were found to range from 0.0083 to 0.0817. These values are significantly less than 1.0, which is the lower limit of the transition zone between laminar and turbulent flow, according to this modified Reynolds' Number classification.

A net porosity (ϕ_n) value was used for the absolute porosity term (ϕ) in the equations, to compensate for the presence of the other phase; (ϕ_n) defines the amount of pore volume available for the flow of a specific phase (e.g. gas-phase) by subtracting the pore volume occupied by the other co-existing phases (water-phase and condensate-phase). The possibility of turbulent flow occurring is more likely at high condensate saturations, where less pore space is available for gas flow. Hence, the net porosity associated with the flow of the gas phase for a core with a 18.2% absolute porosity, an initial water saturation of 26.4%, and a maximum condensate saturation of 50.2%, is 4.3%.

Results

Data repeatability : As 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 resultant data should be shown to be accurate and repeatable, allowing all data reported to be used with confidence.

Imbibition steady-state relative permeability data points generated at an IFT value of 0.14 mN/m were initially measured at four velocities, ranging from 8.8 to 70.4 m/day. To determine the quality of the data, the same test sequence was then repeated by re-saturating the core with the single phase gas condensate fluid above the dew-point, and

subsequently depleting the core to the same test pressure below the dew-point before repeating the initial test sequence. Figure 3 is a plot of the steady-state relative permeability data points measured at the lowest velocity of 8.8 m/day, with the CGR ranging from 0.05 to 0.30, for both tests. The match obtained between the two independent sets of data show good repeatability.

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.

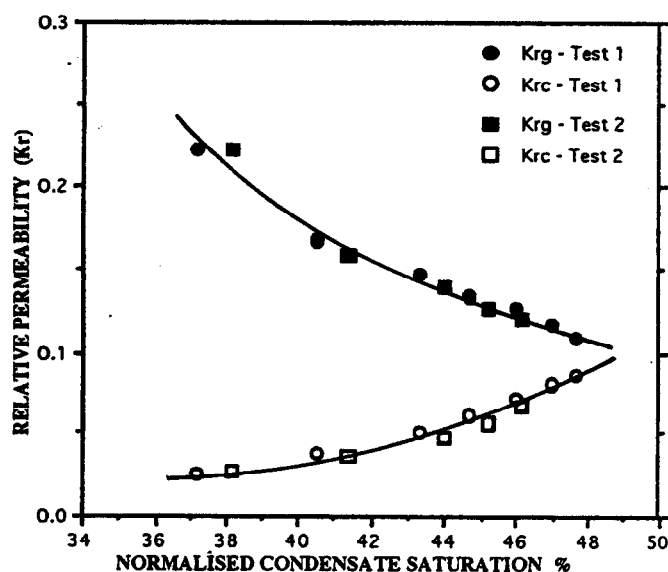


Figure 3. Repeatability of measured Relative Permeabilities by the Steady-State Method, Velocity 8.8 m/day.

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 involved a series of steady-state imbibition relative permeability curves being generated at increasing velocities, following the tests sequence shown in Table 2.

Relative Permeability Sensitivity to Velocity : IFT 0.14 mN/m : Figure 4 is a plot of all steady-state points measured at each of the four velocities and all the CGR 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 clearly visible. Generally, the increase in the condensate relative permeability between the lowest and highest velocity used was two fold, with the associated gas relative permeability increase being slightly greater.

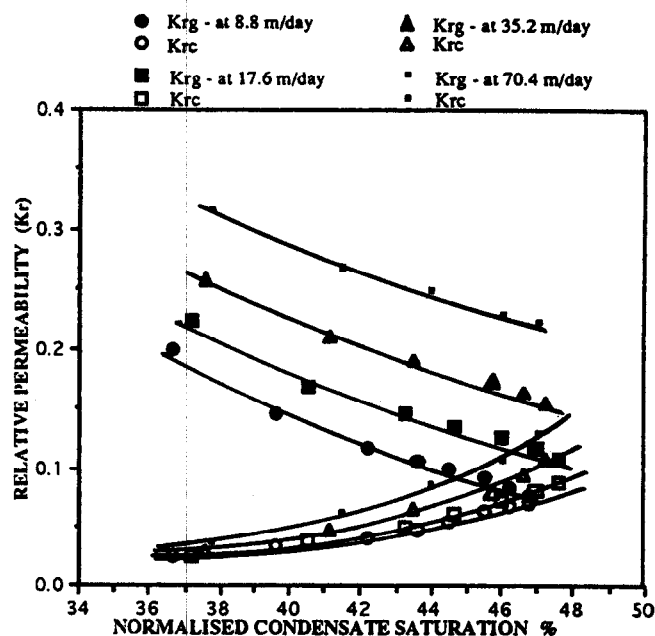


Figure 4 Steady-State Relative Permeability Curves, IFT = 0.14 mN/m.

As the velocity was increased from the minimum to the maximum at each CGR, the condensate saturation in the core was found to increase by 1 to 2%, as shown in Figure 4.

Relative Permeability Sensitivity to Velocity : IFT 0.90 mN/m : 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 Figure 5.

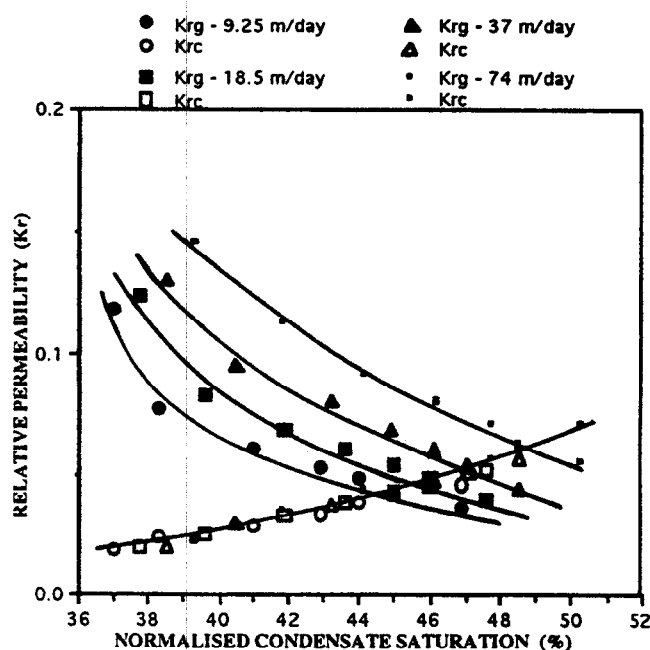


Figure 5 Steady-State Relative Permeability Curves, IFT = 0.9 mN/m.

The gas relative permeability curves clearly show that a rate effect still exists at this higher IFT value, with the gas relative permeability increasing by approximately 30% between the lowest and highest rates at each CGR. The effect of velocity on condensate relative permeability appears 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.

Compared to the tests conducted at low IFT, the increase in the condensate saturation in the core associated with increasing velocity at each CGR was a greater, at 3 to 4%.

Condensate Relative Permeability Sensitivity to Pore Velocity with Increasing IFT: Figure 6 is a plot of condensate relative permeability versus pore velocity and CGR, for both values of IFT.

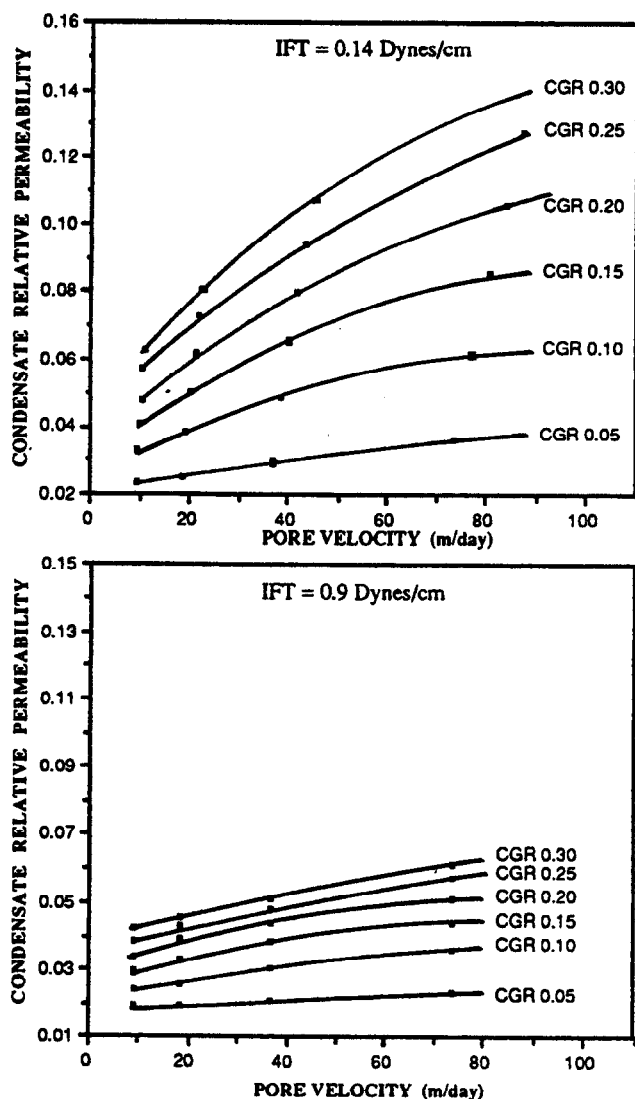


Figure 6 Variations of Condensate Relative Permeability with Flow Velocity, IFT 0.14 and 0.90 mN/m.

The plots highlight more subtle variations in the sensitivity of condensate relative permeability to velocity and IFT than the conventional graphs shown in Figures 4 and 5. Although the increase in IFT to 0.90 mN/m can be seen to have significantly reduced the condensate relative permeability sensitivity to velocity compared to the tests conducted at 0.14 mN/m, the sensitivity of relative permeability to velocity at the higher IFT is still detectable.

Figure 6 highlights that with increasing CGR, the increase in condensate relative permeability associated with increasing velocity became more pronounced. At an IFT of 0.14 mN/m and a CGR of 0.05, the increase in condensate relative permeability associated with increasing velocity from 10 to 80 m/day was approximately 50%. The corresponding increase in relative permeability with increasing velocity at a CGR of 0.30 was over 100%. A similar trend can be also seen for the data generated at an IFT of 0.90 mN/m.

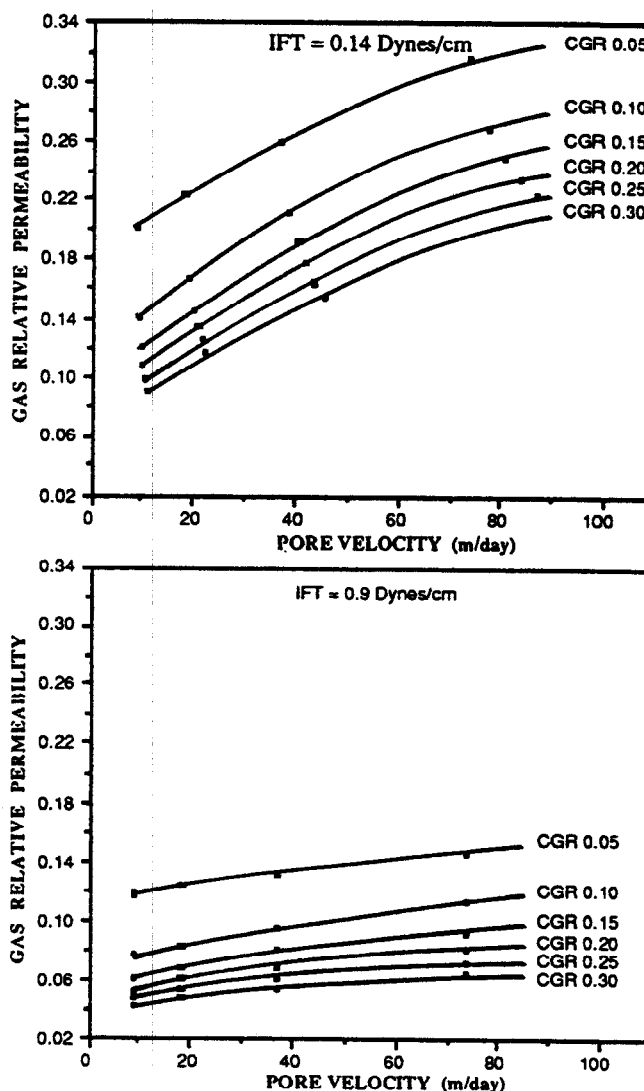


Figure 7 Variations of Gas Relative Permeability with Flow Velocity, IFT 0.14 and 0.90 mN/m.

Increasing the IFT reduced the overall condensate relative permeability as would be expected. For a given pore velocity of 10 m/day, the condensate relative permeability reduced by an average 40% with increasing IFT, while at the higher pore velocity of 80 m/day the corresponding reduction was in the region of 50%.

Gas Relative Permeability Sensitivity to Pore Velocity with Increasing IFT : Figure 7 is a plot of gas relative permeability versus pore velocity and CGR. The increase in gas relative permeability associated with increasing velocity is clearly greater at lower IFT. The curves of relative permeability versus pore velocity at both values of IFT are roughly parallel for all CGR's reported, with no significant change in relative permeability associated with increasing CGR observed. This is a significant variation from the corresponding plots of condensate relative permeability versus velocity shown in Figure 6.

The reduction in gas permeability associated with increasing IFT ranged from 50% at a pore velocity of 10 m/day, to 60% at the higher pore velocity of 80 m/day.

Hysteresis : The extent of hysteresis in the steady-state relative permeability points due to 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 due to the increase and subsequent decrease in velocity at each CGR was investigated.

Figure 8 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 velocity reducing was the saturation, as the differential pressure and hence 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 due to 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 Figure 9. There is a greater degree of hysteresis at the higher IFT, as the relative permeability data points measured as the velocity was reduced show a consistently higher gas relative permeability and lower condensate relative permeability at a higher condensate saturation. This trend was observed at all CGR.

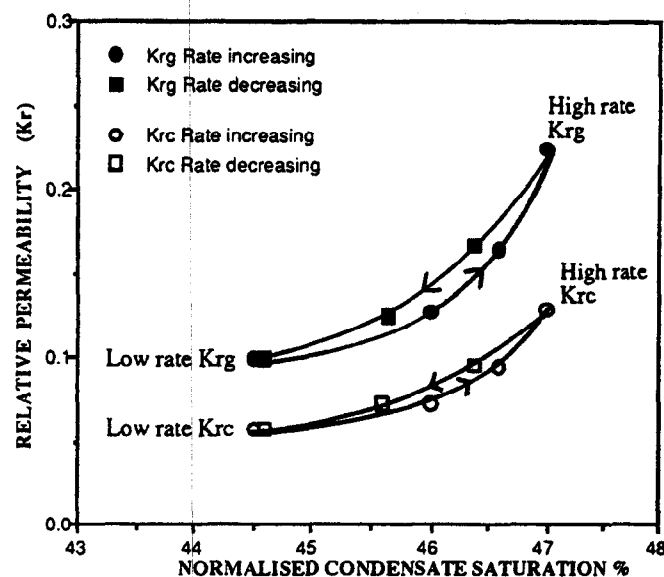


Figure 8 Rate Hysteresis at CGR = 0.25, IFT = 0.14 mN/m.

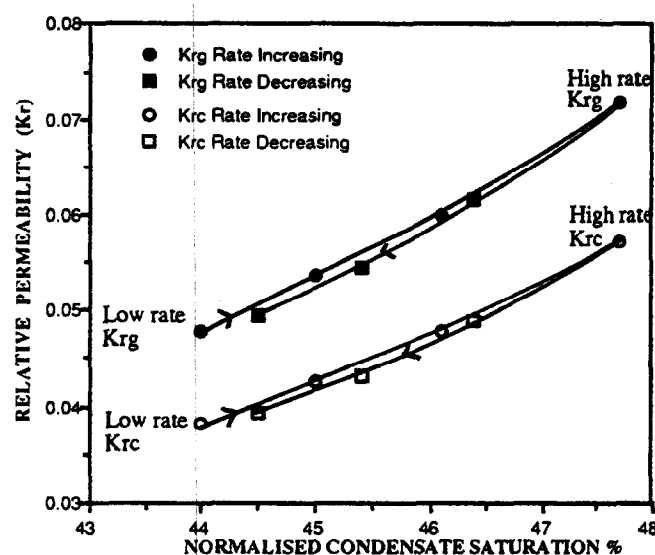


Figure 9 Rate Hysteresis at CGR = 0.25, IFT = 0.90 mN/m.

Imbibition and Drainage Hysteresis : The minimal rate hysteresis observed in the tests conducted at an IFT of 0.14 mN/m was repeated when the hysteresis between the imbibition and drainage relative permeability curves was investigated at the same value of IFT. Figure 10 shows that at a velocity of 35.2 m/day, with the CGR being initially increased from 0.05 to 0.20 (imbibition) before being reduced to 0.05 (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. At the lower velocity of 9.25 m/day hysteresis was greatest, as shown in Figure 11, with the gas relative permeability being higher during drainage, and the condensate relative permeability being lower. The degree of hysteresis generally reduced as the velocity increased.

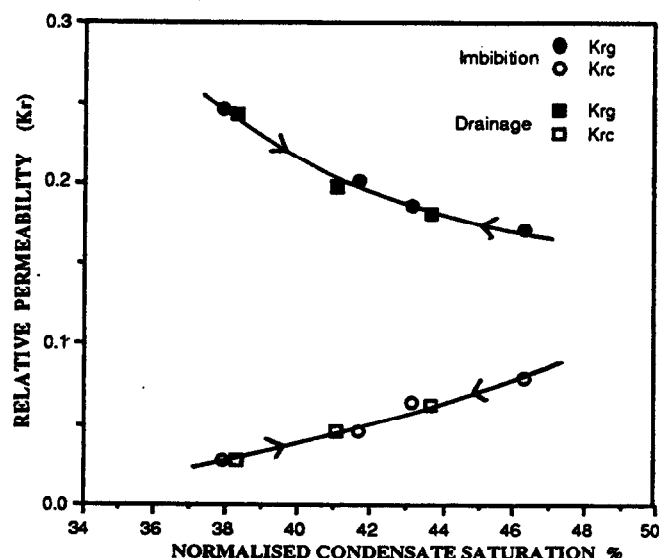


Figure 10 Hysteresis between Imbibition and Drainage

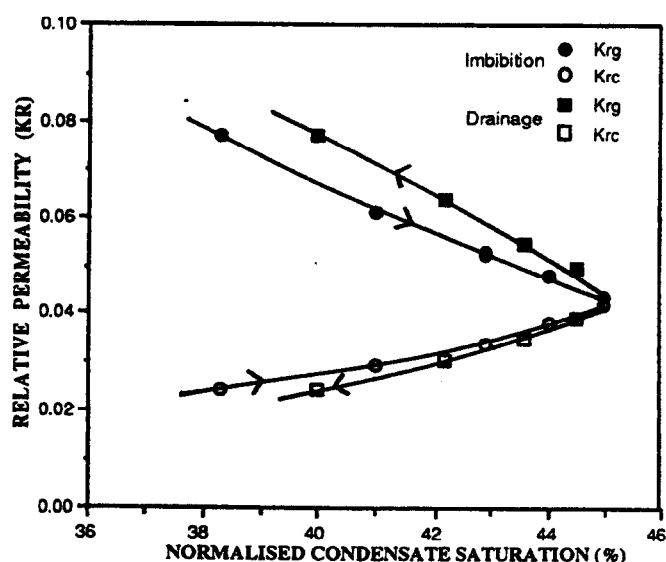


Figure 11 Hysteresis between Imbibition and Drainage

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 in order to explain the significant variation of relative permeability to velocity at similar saturations.

The straightening of the relative permeability curves with increasing velocity, especially at lower values of IFT, is more associated with relative permeability curves measured at a fixed velocity with the IFT being reduced^[1,3]. The sensitivity of gas condensate relative permeability to velocity has only been reported previously by the present authors, during a sequence of unsteady-state displacements conducted using gas condensate fluids^[4].

Rate sensitivity during conventional gas-oil unsteady-state drainage displacements has also been investigated by the present authors. The same core as used in the present study was saturated with equilibrium butane and displaced with equilibrium methane, with unsteady-state relative permeability curves being generated at three different flow rates^[4]. The results of the conventional displacements are shown in Figure 12, and clearly show that no rate effect was evident when using this procedure. 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, shown in Figure 4.

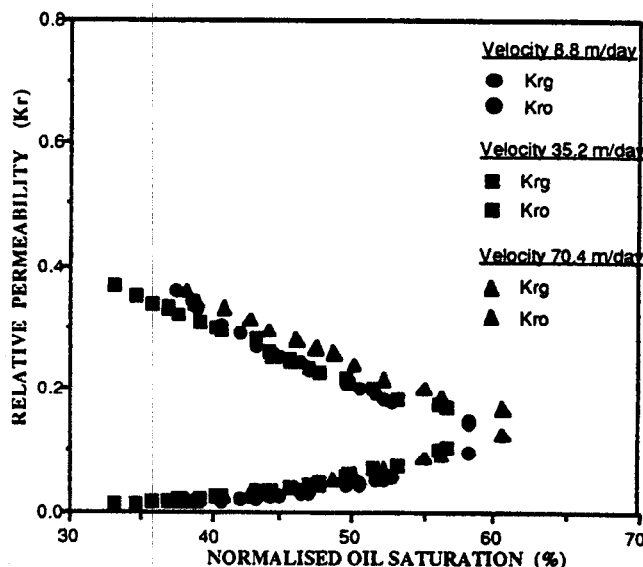


Figure 12 Conventional Gas-Oil Relative Permeability (IFT = 0.14 dynes/cm)

The present study therefore supports the previous findings of a relative permeability rate sensitivity for gas condensate fluids, now observed using steady-state as well as unsteady-state procedures. The factors governing the reported relative permeability behaviour for gas condensate fluids will now be discussed.

Influence of End-Effects : Variations in relative permeability with flow rate have been previously reported and attributed to capillary end effects [10]. However, calculations based on a work conducted by Hassler [11], as well as calculations based on mercury injection data generated from samples of the core 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 compare to the differential pressure measured across the core which were 2 to 3 orders of magnitude greater than the calculated capillary end effects.

It should be noted that changes in connate water saturation along the length of the core may be present, with the water saturation increasing at the core outlet due to capillary end effects. The water in the core is believed to have remained immobile as no water was ever recovered from the core during the duration of the tests. To support this, the base gas permeability was found to remain constant between tests.

When the base gas permeability was measured between tests at different flow rates, no sensitivity to velocity was observed. This suggests that the distribution of connate water in the core did not cause the reported rate sensitivity to condensing fluids.

Variations Between the Mechanisms Governing the Flow of Conventional and Gas Condensate Fluids : It has been shown that conventional gas-oil displacements, where the core is initially saturated with oil prior to gas injection, will show no relative permeability rate sensitivity [1,4]. Such tests have previously been used to generate data to be applied to gas condensate flow, with the assumption being that the low IFT values used in the tests will make the flow mechanisms representative of those in gas condensate systems.

During conventional unsteady-state gas-oil displacements, gas and oil will largely flow in their own pore space. Gas will invade the largest accessible pores, displacing the oil, but leaving oil films present 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 in pore space where oil is largely immobile, with oil flowing in pore space not invaded by gas. This type of flow is described as channel flow, and is normally applied to the Darcy type flow of conventional fluids.

The flow of gas condensate fluids however does not resemble the distributions of conventional fluids. It has been shown from micromodel studies that when the process of condensation occurs at and below the dew-point, the condensate phase will wet all surfaces, acting as an intermediate phase in a water-wet three phase system;

wetting with respect to gas, non-wetting with respect to water [12]. Flow through the condensate wetting film can be very efficient [6,12], with it being reported that gas and condensate flow together in all pore space, with both phases flowing as if a single phase [13]. This is a significant variation from the flow behaviour and fluid distribution of conventional fluids where oil flow in gas invaded pores behind the gas front will be minimal.

The process of condensation, which generates oil films throughout the porous medium, as well as the flow of gas and condensate efficiently in 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%, injection of oil with gas may result in fluid distributions being present which are similar to the fluid distributions of gas condensates. If the oil has a positive spreading co-efficient and IFT is low (reducing capillary forces), 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 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 for the condensate phase when the CGR was at its highest, i.e. when the fractional flow of injected condensate was increased. If it was only the process of condensation that 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 from the studies that the relative permeability of gas condensate fluids will vary when;

- a) The velocity changes at a fixed IFT, &
- b) The velocity is fixed and the IFT is changed.

This 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. In order to develop a generalised correlation for relative permeability the capillary number (N_c), which incorporates both 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 both values of IFT. The definition of the capillary number used is shown in equation 1.

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

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 Figure 13 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 (8.8 m/day) conducted at an IFT of 0.14 dynes/cm, plotting onto the capillary number of the highest rate tests (74 m/day) conducted at the higher IFT of 0.9 dynes/cm. The value of the capillary number for both tests was in the region of 0.14×10^{-4} . The contours of capillary number for all steady-state points follow a similar slope from top left to bottom right of the graph, with both sets of data from the two IFT values showing continuity.

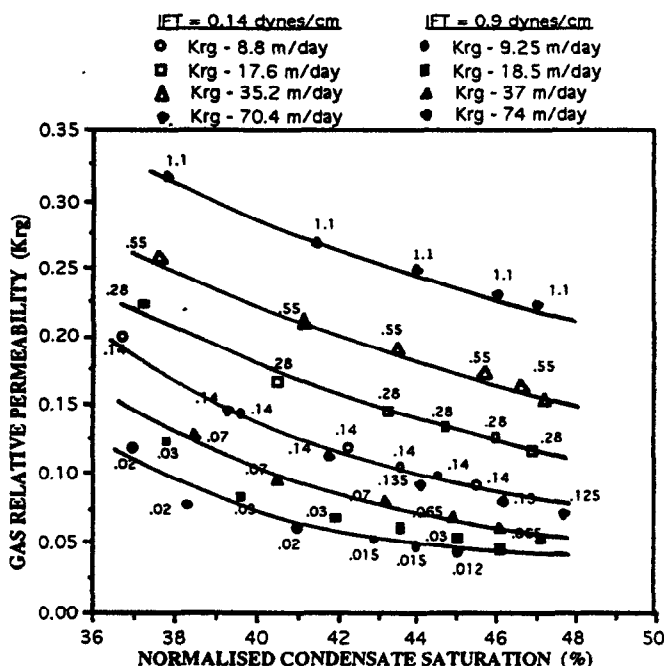


Figure 13 Correlation between Gas Relative Permeability and Capillary Number.

The attempted correlation does show that for the tests reported, there would appear to be a correlation between gas relative permeability and capillary number. Future tests will be required which cover a range of capillary number out with the scope of the test reported in order to further validate the data. This will hopefully be extended in future to cover 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.
2. At higher CGR's the sensitivity of the condensate relative permeability to velocity increased. The gas relative permeability exhibited no overall variation with changing CGR.
3. At higher values of IFT, the gas and condensate relative permeabilities reduced, however the rate effect was still evident, particularly for the gas phase.
4. The rate effect was shown to be independent of core end effects.
5. Hysteresis became more pronounced with increasing IFT.
6. The accuracy of the experimental procedures was validated by measuring a repeat series of relative permeability curves.
7. 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 redistribution of fluids as the flow rate increases, with minimal change in saturation.
8. In order to accurately measure the relative permeability of gas condensate fluids, experimental procedures are required which will be representative of the fluid distributions in gas condensate reservoirs.
9. A generalised correlation between relative permeability and capillary number has been identified.

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Nomenclature

- A = Area.
- CGR = Volume of condensate per unit volume of gas, both at test pressure and temperature.
- D_p = characteristic length scale typical of the internal structure of the porous medium.
- HCPV = Hydrocarbon pore volume.
- IFT = Interfacial tension.
- k = Permeability.
- N_c = Capillary number.
- q = Flow rate.
- Re = Reynolds number.
- Re(mod) = Modified Reynolds number.
- Swi = Connate water saturation.
- v_{sg} = Superficial pore velocity.
- μ_g = Gas viscosity.
- ρ_g = Gas density.
- σ = Interfacial tension.
- ϕ = Porosity.
- ϕ_n = Net porosity.

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Author Biographies

Graeme Douglas Henderson is a Senior Research Associate in the Department of Petroleum Engineering at Heriot-Watt University. He holds a BA in Geology and PhD in petroleum engineering. His research interests mainly involve the study of fluid flow and relative permeability in both high pressure micromodels and cores. He has worked on the study of gas condensate flow in the department for the past 10 years.

Ali Danesh is a professor in the Department of Petroleum Engineering at Heriot-Watt University. He holds a BS degree in petroleum engineering from Abadan Inst. of Technology and a PhD degree in chemical engineering from Manchester U. His research interests include reservoir fluids and flow in porous media, and he teaches courses in PVT based behaviour and multiphase flow in pipes.

Dabir Tehrani is currently an Honorary Professor at Heriot-Watt University. His education is in Mathematics (Tehran U) and Petroleum Engineering (Birmingham U). He has had 39 years of experience in the oil industry, including the positions of Petroleum Engineering Manager (OSCO), Reservoir Engineering Manager (Britoil) and Reservoir Studies Manager (BP Exploration Europe) and teaching reservoir simulation at HWU. His main interests are research in reservoir engineering subjects.

Salman Al-Shaidi works for Petroleum Development Oman, Muscat. Currently assigned on PhD Scholarship at Heriot-Watt University, Edinburgh. Before, PDO he worked for Penn. DOT, Pennsylvania and Parsons Brinckerhoff, New Jersey. Salman holds BSCE from Drexel University and MSE from the University of Texas at Austin. Member of SPE, ASCE, NSPE.

James McKenzie Peden (professor) is head of the horizontal well technology unit, at Heriot-Watt University. He holds a BS degree in chemical engineering and ME and PhD degrees in petroleum engineering from Heriot-Watt University.