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# Measurements and Simulation of Inertial and High Capillary Number Flow Phenomena in Gas-Condensate Relative Permeability

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## Abstract

The productivity of most gas condensate wells is reduced significantly by condensate banking when the bottom hole pressure falls below the dew point. The most important parameter for determining condensate well productivity is the effective gas permeability in the near well region, where very high velocities can occur. An understanding of the characteristics of high-velocity gas-condensate flow is necessary for accurate forecasts of well productivity.

A number of laboratory experiments have demonstrated that gas condensate relative permeabilities increase at high velocity, reducing the negative impact of condensate banking on well productivity. On the other hand, inertial (non-Darcy) flow effects can reduce the effective gas permeability and lead to lower productivity.

This paper presents results of relative permeability measurements on a low permeability sandstone core, using a 5-component gas-condensate fluid. The experiments used a pseudo-steady-state technique at high pressure and high velocity, measuring relative permeability under conditions similar to the near-well region of a gas-condensate reservoir.

By carrying out measurements at a range of interfacial tensions and velocities, the results can be used to distinguish between high capillary number and inertial flow effects, and to quantify the impact of these two conflicting phenomena. The experiments suggest that the inertial flow coefficient in a 3-phase gas-condensate-water system is about 50% higher then in the equivalent 2-phase gas-water system.

The results of these experiments have been modelled through a correlation of relative permeability versus capillary number, together with an inertial flow correction to the gas permeability. The paper discusses these models and demonstrates how they can be used to calculate gas-condensate well performance in full-field reservoir simulation.

## Introduction

Well productivity is an important issue in the development of many gas-condensate reservoirs. Accurate predictions of well productivity are needed to select the best development plan, to optimise the number of wells and to set gas sales contracts.

When the well bottom hole flowing pressure falls below the dew point, a condensate bank forms near the well, impairing the flow of gas and reducing productivity. Condensate saturations as high as 50 or 60 per cent can be attained in the near-well region, reducing gas productivity by up to an order of magnitude. The most important parameter for determining the impact of condensate blockage is the effective gas permeability in the near-well region.

Most of the pressure drop from condensate blockage occurs within a few feet of the well bore, where the gas phase will be flowing at a high velocity. An understanding of the characteristics of high-velocity gas-condensate flow is necessary for accurate forecasts of well productivity.

In the flow of gas-condensate fluids through porous media at high velocities, there appear to be two competing phenomena which may cause the effective gas permeability to be rate-dependent.

- An increase in relative permeability with velocity, which has been demonstrated in numerous laboratory core flood experiments [1,2,3,4,5,6,7,8]. This effect is sometimes termed 'velocity stripping' or 'positive coupling'.
- Inertial (non-Darcy) flow effects, which reduce the effective gas permeability at high velocity.

These two high-velocity phenomena act in opposite directions. Velocity-dependent relative permeability has the effect of improving well productivity, while inertial flow reduces the effective gas permeability and leads to lower productivity. At the flow rates in typical gas-condensate wells, it appears that the change in relative permeability has a much larger impact, so that the overall effect of these high-velocity phenomena is an improvement in productivity.

The increased productivity due to high-velocity effects is consistent with results from several gas-condensate fields where simulation with conventional relative permeability models underestimates well productivity. In the Arun field [9], the measured relative permeability needed to be increased empirically to obtain a good match between simulation results and well test data. In the Cupiagua reservoir [10], simulation results could only be reconciled with field data when the high-velocity effects were modelled explicitly.

## Data Needed to Estimate Condensate Blockage

In a well where condensate blockage is important, most of the pressure drawdown occurs in a region close to the well, where both oil (condensate) and gas phases are mobile. Fevang and Whitson [11] have shown that the most important parameter in determining condensate blockage is the relationship between $k_{rg}$ and $k_{rg}/k_{ro}$. (The ratio $k_{rg}/k_{ro}$ can be thought of as a measure of the fractional flow of the gas and oil phases in the near-well region.)

The relevant values of $k_{rg}/k_{ro}$ depend on the PVT properties of the reservoir fluids, but typical values might be 10 to 100 for lean condensates, 1 to 10 for rich condensates, and 0.1 to 10 for near-critical fluids.

It is also essential to understand how relative permeability changes at high velocity. This is usually modelled through correlations in terms of the capillary number, a dimensionless number which measures the relative importance of viscous and capillary forces.

There are various ways of defining the capillary number, but in this paper we use the definition

$$N_c = \frac{v_g \mu_g}{\sigma} \tag{1}$$

so that the capillary number is proportional to gas velocity and inversely proportional to interfacial tension (IFT).

The range of capillary numbers which affect well productivity calculations will depend on the flow rate, fluid type and well bottom hole pressure, but as a general rule, values between $10^{-6}$ and $10^{-3}$ are most important.

Inertial flow effects can be modelled through the inertial (non-Darcy) flow coefficient $\beta$. It is straightforward to measure $\beta$ for single-phase gas flow, but in multi-phase flow it can be difficult to distinguish the effects of inertial flow from changes due to high capillary number.

## Core Flood Experiments

**Core.** The experiments described in this paper were carried out on a core taken from the Obernkirchner sandstone outcrop in Germany. This core has low permeability (absolute gas permeability of about 12 md) and high porosity (about 21%). Details of the core properties are given in Table 1.

**Objectives.** The objectives of these experiments were to examine the variation of relative permeability with capillary number for a low permeability core, and to distinguish between the conflicting effects of inertial flow and high capillary number flow.

**Synthetic Condensate Fluid.** A 5-component synthetic gas-condensate was used for the high-velocity experiments. The composition of the fluid is given in Table 2. The experiments were carried out at a core temperature of 60°C. At this temperature the fluid behaves as a rich gas-condensate with a dew point pressure of about 212 bar, and a maximum liquid saturation of about 25% in a constant volume depletion test.

**Experimental Procedures**. Experiments were carried out above the dew point pressure to measure the inertial (non-Darcy) flow coefficient, and below the dew point pressure to measure the gas and oil relative permeability. We refer to these experiments as single-phase and two-phase respectively, according to the number of **hydrocarbon** phases which were present. A water saturation of about 5% was present in the core during these experiments.

The two-phase experiments were carried out using the pseudo-steady-state technique [8], which is designed to measure relative permeabilities under conditions which are similar to the near-well region of a gas-condensate reservoir. Gas-condensate from an inlet vessel flows into the core through a pressure reducing valve. The inlet vessel represents conditions in the reservoir away from the well, while the core represents the region close to the well.

This technique determines $k_{rg}$ as a function of the 'fractional flow' ratio $k_{rg}/k_{ro}$ and capillary number, without the need to measure saturations directly. With this technique it is possible to measure all of the relative permeability data needed to predict well productivity, including the increase in mobility at high capillary number.

## Experimental results

**Single-Phase Measurements.** Two sets of measurements were carried out with the core inlet pressure at 230 and 250 bar, where pressures throughout the core were maintained above the dew point of 212 bar. The results were used to estimate the permeability and the inertial flow coefficient, using the analysis of Evans *et al* [12]. This analysis is shown in Figure 1, and involves fitting a straight line through the data points; the intercept on the *y* axis is (1/permeability) and the slope is the inertial flow coefficient.

Figure 2 plots the difference between the squares of the inlet and outlet pressures ($P_{in}^2$-$P_{out}^2$) against the flow rate. (We use $\Delta(P^2)$ rather than $\Delta P$ to allow for gas compressibility). The departure from a straight line is a measure of the effect of inertial flow. The permeability and inertial flow coefficient $\beta$ can also be estimated by fitting a quadratic curve through the data points.

Due to the low permeability and high flow rates, some of the experiments involved a pressure drop across the core of about 30 bar. The analysis methods were modified to allow for the variation in gas viscosity and Z-factor along the core.

The analyses gave absolute permeabilities between 8.4 and 8.7 md, and inertial flow coefficients between $0.30 \times 10^{-10}$ and $0.34 \times 10^{-10}$ m$^{-1}$.

There is significant inertial flow effect at the higher rates in these experiments; the straight line on Figure 2 shows the results which would be expected if there were no inertial flow effects.

**Two-Phase Measurements.** Five series of two-phase measurements were carried out. In each series of experiments, the core inlet pressure and flowing fluid composition were fixed while the core outlet pressure was changed to vary the flow rate. The measurements are summarised in Table 3.

In these experiments, the core conditions are representative of the near-well region and the flowing fluid represents the gas phase flowing into the near-well region from the main part of the reservoir. The flowing fluid composition is defined in terms of its dew point pressure.

The pressure drop across the core was measured, together with the volumetric flow rates of the oil and gas phases **at the core outlet pressure**.

When the pressure drop across the core is large, the volumetric flow rates will vary along the core, especially for the oil phase. However, if steady state conditions have been reached in the core, the phase flow rates will be proportional to the phase volumes in a Constant Composition Expansion (CCE) on the flowing fluid composition. If the oil flow rate $Q_o$ at the outlet pressure $P_{out}$ is known, it is possible to estimate the oil phase flow rate at any pressure from

$$\frac{Q_o(P)}{Q_o(P_{out})} = \frac{V_o(P)}{V_o(P_{out})} \qquad (2)$$

where $V_o$ is the oil phase volume in a CCE, which can be calculated from an Equation of State (EoS) model of the synthetic condensate. A similar expression can be used to estimate the gas flow rate. PVT properties such as viscosity and IFT will also vary along the core, but they can be again predicted from the EoS model.

These methods were used to convert the flow rates measured at the core outlet pressure to flow rates at the mean core pressure. The effective permeabilities were then calculated using flow rates and viscosities at the mean core pressure. Capillary number was also calculated at the mean core pressure.

**Check of the $k_{rg}/k_{ro}$ ratio.** Due to the steady state conditions in the core, it is possible to predict the ratio of $k_{rg}/k_{ro}$ from the fluid PVT properties [11]. Figure 3 compares the measured data with the predicted values calculated using the EoS model. The pressure on the *x*-axis is the mean core pressure (defined as the average of the inlet and outlet pressures), and the measured data were calculated from the flow rates at the mean core pressures.

There is reasonable agreement between the measured and predicted data, except for a few points. The most obvious discrepancies are at the right hand end of the set for each experiment. These points correspond to the lowest flow rates, where the data are subject to greater experimental error due to the small pressure drop.

**Relative Permeability Measurements.** Figures 4 and 5 show the measured gas and oil (condensate) relative permeabilities, plotted as a function of capillary number, for each of the five sets of experiments. The data show a clear trend of increasing gas relative permeability with capillary number, and there is also some evidence for the oil relative permeability increasing with capillary number, especially when the capillary number is above about $10^{-4}$. The higher oil relative permeabilities for experiment hr_200 are due to the richer flowing gas condensate giving higher oil saturations in the core. Figure 3 shows that this experiment gives a much lower value of $k_{rg}/k_{ro}$, both in theory and in practice.

Three of the experiments were carried out at similar values of the $k_{rg}/k_{ro}$ ratio, but at different core pressures, and hence different IFT's. These experiments are hr_190, hr_170, and hr_150, which all have a $k_{rg}/k_{ro}$ ratio of about 10. The conditions for these three experiments are summarised in Table 4. As capillary number is proportional to (velocity/IFT), the velocity to achieve a given capillary number is proportional to the IFT. Thus the velocities at a given capillary number are highest in experiment hr_150, next highest in hr_170, and lowest in hr_190.

The gas relative permeability data for these three experiments are shown in Figure 6, which is the same as Figure 4, but with all other data removed for clarity. The results in Figure 6 can be summarised as follows.

- At a fixed IFT, gas relative permeability increases with velocity.
- At a fixed capillary number, gas relative permeability decreases with velocity.

The second point is especially important, as most models for high-velocity gas-condensate relative permeability have been based on the assumption that relative permeability can be correlated as a function of capillary number and saturation [13]. These results do not fit into such a model. The decrease in gas relative permeability with velocity at a fixed capillary number suggests that the gas permeabilities may be subject to inertial (non-Darcy) flow effects. The higher velocities for hr_150 would lead to a larger inertial effect, so reducing the effective gas permeability.

## Interpretation of Experimental Results

**How to define Gas Relative Permeability?** The interpretation of these experiments to study high-velocity gas-condensate flow depends on the definition of relative permeability.

The simplest definition of gas relative permeability $k_{rg}$ is from the equation

$$k_{rg} = \frac{k_{g,eff}}{k} \qquad (3)$$

where $k_{g,eff}$ is the effective gas permeability and $k$ is the absolute permeability. In this case, the gas relative permeability incorporates both the high capillary number and inertial flow effects.

On the other hand, most numerical simulators model high capillary number and inertial flow phenomena separately. Inertial flow effects are modelled through a multiplication factor $F_{ND}$, given by

$$F_{ND} = \frac{1}{1 + \dfrac{\beta k \rho u}{\mu}} \tag{4}$$

The effective gas permeability is then calculated from

$$k_{g,eff} = k.F_{ND}.k_{rg}\left(S_g, N_c\right) \tag{5}$$

so that $F_{ND}$ models inertial flow effects (as a function of the Darcy velocity $u$) and $k_{rg}$ models multi-phase effects (as a function of the phase saturation and the capillary number).

The two definitions of $k_{rg}$ are illustrated in Figure 7. The thickest curve is the 'base' gas relative permeability at low velocity and low capillary number. The dotted curve shows $k_{rg}$ at high velocity and high capillary number defined using Equation 3, so that $k_{rg}$ includes both inertial and capillary number effects. At low condensate saturations, the inertial effects dominate, and the net effect is to reduce $k_{rg}$. At high saturations, the capillary number effects become more important so that the net effect is to increase $k_{rg}$. The other curve shows $k_{rg}$ at high velocity and high capillary number, defined using Equation 5. In this case $k_{rg}$ only includes capillary number effects, and is always higher than the 'base' $k_{rg}$.

Henderson *et al* [5] have reported results of gas-condensate relative permeability measurements which appear to show both velocity-dependent relative permeability and inertial flow, in which $k_{rg}$ was defined using Equation 3. For a fixed IFT, these results show $k_{rg}$ decreasing with velocity at low condensate saturations (where inertial effects dominate), and increasing with velocity at high condensate saturations (where capillary number effects dominate), with a 'cross-over' saturation where the relative permeability is almost independent of velocity.

When $k_{rg}$ is defined using Equation 3, it will include both capillary number and inertial effects, so we would expect $k_{rg}$ to be a function of both capillary number and velocity (or any two variables from capillary number, velocity and IFT).

We prefer to model high-velocity effects using the definition of $k_{rg}$ in Equation 5. First, this allows the two competing high-velocity phenomena to be handled independently. Second, it is consistent with the models in numerical simulators, where the data will be used. Finally, the separation of inertial flow effects may allow $k_{rg}$ to be modelled in terms of a correlation against capillary number.

A number of correlations have been developed for $k_{rg}$ against capillary number [13], mainly based on experiments at lower velocities where inertial effects may be less important. If the inertial effects can be modelled by the $F_{ND}$ parameter, it may still be possible to use these correlations at higher velocities where inertial flow is significant.

**Adjusted Relative Permeability Results.** The gas relative permeabilities in Figures 4 and 6 were calculated from

$$k_{rg} = \frac{k_{g,eff}}{k_{g,ref}} \tag{6}$$

where $k_{g,ref}$ is the gas permeability measured at low velocity and single phase conditions. (In this context, 'single phase' means a single hydrocarbon phase, so that the core contains gas and a small immobile water saturation). This is essentially the same definition as in Equation 3, so that inertial flow effects are included in $k_{rg}$.

To convert the gas relative permeability to the definition in Equation 5, we need to divide the values in Figures 4 and 6 by $F_{ND}$. (As $F_{ND}$ is less than 1, this will increase the relative permeabilities.) The permeability and beta coefficient were measured for this core in 'single-phase' experiments as 8.6 md and 3.1 x $10^9$ $m^{-1}$ respectively, and these values were used to calculate $F_{ND}$ using Equation 4.

Figure 8 shows the results for the experiments hr_190, hr_170, and hr_150, after dividing gas relative permeability by $F_{ND}$. $k_{rg}$ is now defined by Equation 5, with inertial flow effects excluded. These results give a much more consistent trend for $k_{rg}$ as a function of capillary number, but the fit can be improved further by using a larger value of β of about 4.6 x $10^9$ $m^{-1}$, as shown in Figure 9. The difference between Figures 8 and 9 is not that great, so it is difficult to draw any firm conclusions about the change in β between single-phase and two-phase conditions. However, the data suggest that β is higher in multi-phase flow than in single-phase flow, which is consistent with other results which have been reported.

These results suggest that that if the gas relative permeability $k_{rg}$ is defined by Equation 5, it may still be possible to model the effects of IFT and rate through a correlation in terms of capillary number. In this case inertial flow effects are modelled separately and do not affect the relative permeability.

The velocities for the liquid (condensate) phase in these experiments were between 10 and 300 times smaller than for the gas phase. The effect of inertial flow in the liquid phase is not significant (a change in the effective permeability of 2% at the most), and has been ignored in this analysis.

## Fitting Data To Empirical Correlations

A number of correlations have been proposed for modelling the change in condensate relative permeability at high velocity. All of these correlations share two common features. First, relative permeabilities are calculated by interpolating between two extremes - 'base' relative permeabilities for capillary dominated flow, and 'miscible' or 'straight line' relative permeabilities for viscous dominated flow. Second, the capillary number is used as an interpolation parameter.

The correlations can be divided into two types.

- $k_{rg}$ is expressed as a function of $k_{rg}/k_{ro}$ and capillary number.
- $k_{rg}$ and $k_{ro}$ are expressed as a function of saturation and capillary number.

The first type of correlation can be used in pseudopressure calculations [11], either in a reservoir simulator or in engineering spreadsheet calculations [14], while the second is needed for use in a fine grid reservoir simulation model.

Results from the pseudo-steady-state technique, where phase saturations do not need to be measured, are much more suitable for modelling with the first type of correlation, for $k_{rg}$ versus $k_{rg}/k_{ro}$ and capillary number. However, it is also possible to fit the data to correlations versus saturation.

We have fitted the Obernkirchner core data with both types of correlation. The analyses are based on $k_{rg}$ defined by Equation 5, with the inertial effects removed.

**Correlation for $k_{rg}$ versus $k_{rg}/k_{ro}$.** The correlation of Whitson and Fevang [15] models the change in $k_{rg}$ with capillary number, **at a fixed value of the ratio $k_{rg}/k_{ro}$**. The gas relative permeability is given by

$$k_{rg} = fk_{rgb} + (1-f)k_{rgm} \tag{7}$$

where $k_{rgb}$ is the 'base' gas relative permeability at the same value of $k_{rg}/k_{ro}$, $k_{rgm}$ is the 'miscible' gas relative permeability at the same value of $k_{rg}/k_{ro}$, $f$ is an interpolation function given by

$$f = 1 - \frac{1}{(\alpha N_c)^n + 1} \tag{8}$$

and α and $n$ are empirical parameters. The value of $f$ varies between 1 (at low capillary number) and 0 (at high capillary number).

We have obtained a reasonable match to the experimental data on the Obernkirchner core using $n = -0.6$ and $\alpha = 3000$. The 'miscible' values $k_{rgm}$ were calculated from straight line functions with zero end points, and the 'base' values $k_{rgb}$ were estimated by extrapolation from the low velocity data. As the base relative permeabilities are very small, they do not have a great effect on the predictions at moderate capillary numbers. The results of the correlation are compared with the experimental data in Figure 10.

The empirical parameters used to fit to the Obernkirchner data are quite similar to those reported by Saeverid *et al* [6], who carried out gas-condensate relative permeability measurements on Berea sandstone, and fitted their data with values of $n = -0.64$ and $\alpha = 2000$.

The results in Figure 10 show that $k_{rg}$ is relatively insensitive to the value of $k_{rg}/k_{ro}$. Changing $k_{rg}/k_{ro}$ by an order of magnitude only changes $k_{rg}$ by about 20 to 30%, while an order of magnitude change in capillary number can cause $k_{rg}$ to double. The value of $k_{rg}/k_{ro}$ will only vary by about one order of magnitude during the entire life of a well. It is more important for near-well gas-condensate relative permeability measurements to concentrate on covering a range of velocities and capillary numbers rather than a wide range of $k_{rg}/k_{ro}$ values.

**Correlation for $k_{rg}$ versus saturation.** For a correlation versus saturation, the gas relative permeability is given by

$$k_{rg} = fk_{rgb} + (1-f)k_{rgm} \tag{9}$$

where $k_{rgb}$ is the 'base' gas relative permeability at the same value of saturation, $k_{rgm}$ is the 'miscible' gas relative permeability at the same value of saturation, and $f$ is an interpolation function. The oil relative permeability is calculated from a similar equation, but with different parameters in the interpolation function $f$.

The relative permeability and saturation data were fitted using this type of correlation, with the interpolation function given by Equation 8. The 'base' curves were modelled through Corey functions, and the 'miscible' curves were straight lines. The end points of the straight lines were scaled to avoid discontinuities in the critical saturation; for example, the straight line relative permeability for gas had an end point saturation of $f\,S_{gc}$, where $S_{gc}$ is the critical gas saturation on the 'base' curve. The same function $f$ was used for scaling the end point saturation and for interpolating between the 'base' and straight line relative permeabilities.

The values obtained for the parameters in the interpolation function were

| | | |
|---|---|---|
| gas phase | $n = -0.87$, | $\alpha = 11000$ |
| oil phase | $n = -4.59$, | $\alpha = 1000$. |

With these parameters, the model gave a reasonable match to the measured relative permeability data, with an average error of 6%.

## Impact on Well Productivity Calculations

To demonstrate the importance of the high-velocity effects, we show the results from some simplified well productivity calculations using the measured relative permeability data for the Obernkirchner core. Well production rates were calculated using an Excel spreadsheet which combines a material balance model for reservoir depletion, with a pseudopressure calculation for well inflow [14]. The well inflow calculation can include the effects of both high capillary number and inertial flow.

The calculations were for a well in a homogeneous 10 md reservoir, with a drainage radius of 3000 feet and a net thickness of 100 feet. The fluid was a rich gas-condensate with a dew point pressure of about 6750 psi. The initial reservoir pressure was 8000 psi, the limiting well bottom hole pressure was 2000 psi, and the plateau gas production rate was 15 MMscf/d.

Figure 11 shows the gas production profiles for three cases; a base case where no high-velocity effects were modelled, a second case which included the variation of relative permeability with capillary number, and a third case which modelled both the variation of relative permeability with capillary number and inertial flow effects.

These results show a dramatic improvement in productivity due to the increase of relative permeability at high capillary number, while inertial flow has only a small effect. This result emphasises the importance of high-velocity phenomena in predictions of well productivity.

## Conclusions

1. High-velocity gas-condensate relative permeabilities have been measured for a low permeability sandstone outcrop core.
2. These experiments show two conflicting effects; an increase in relative permeability due to high capillary number flow, and a reduction in effective gas permeability due to inertial flow.
3. The capillary number effect is much more significant, so that the combined effect is to increase mobility for the flow rates in these experiments.
4. Modelling of these experimental results depends on the definition of gas relative permeability. The most promising approach was to model inertial flow effects separately through the non-Darcy flow factor $F_{ND}$, in which case the relative permeability could be modelled as a function of capillary number. The relative permeability data could be fitted either through a correlation of $k_{rg}$ as a function of capillary number and the ratio $k_{rg}/k_{ro}$, or by a correlation of $k_{rg}$ and $k_{ro}$ as functions of saturation and capillary number.
5. The changes in relative permeability at high capillary number can lead to a significant increase in calculated well productivity.

## Nomenclature

$f$ = interpolation function for relative permeability
$F_{ND}$ = inertial (non-Darcy) flow factor
$k$ = absolute permeability
$k_r$ = relative permeability
$k_{g,eff}$ = effective gas permeability
$n$ = parameter in correlation for high-velocity relative permeability
$N_c$ = capillary number
$P$ = pressure
$Q$ = volumetric flow rate
$S$ = phase saturation
$u$ = Darcy velocity
$V$ = phase volume in CCE test
$v$ = superficial velocity
$\alpha$ = parameter in correlation for high-velocity relative permeability
$\beta$ = non-Darcy flow coefficient
$\mu$ = viscosity
$\rho$ = density
$\sigma$ = gas-oil interfacial tension

## Subscripts

$b$ = base (capillary dominated flow)
$g$ = gas phase
$in$ = core inlet conditions
$m$ = miscible (viscous dominated flow)
$o$ = oil phase
$out$ = core outlet conditions

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**TABLE 1 – RESERVOIR CORE PROPERTIES**

| | |
|---|---|
| Length (cm) | 28.6 |
| Diameter (cm) | 3.79 |
| Cross sectional area ($cm^2$) | 11.3 |
| Bulk volume ($cm^3$) | 322.3 |
| Pore volume (mL) | 67.0 |
| Porosity (%) | 20.8 |
| Absolute gas permeability (md) | 12.0 |

**TABLE 2 - SYNTHETIC CONDENSATE COMPOSITION**

| Component | mol % |
|---|---|
| Methane | 80.0 |
| n-Butane | 14.0 |
| n-Heptane | 4.0 |
| n-Decane | 1.4 |
| n-Tetradecane | 0.6 |

**TABLE 3. CONDITIONS FOR TWO-PHASE EXPERIMENTS**

| Exper-iment | Dew point pressure of flowing fluid (bar g) | Pressure drop across reducing valve (bar) | Core inlet pressure (bar g) | Core outlet pressure (bar g) |
|---|---|---|---|---|
| hr_190 | 190 | 10 | 180 | 168 - 179 |
| hr_170 | 170 | 10 | 160 | 140 - 159 |
| hr_140 | 140 | 10 | 130 | 96 - 130 |
| hr_200 | 200 | 20 | 180 | 161 - 179 |
| hr_150 | 150 | 20 | 130 | 95 - 129 |

**TABLE 4. CONDITIONS FOR HR_190, HR_170, AND HR_150 EXPERIMENTS**

| Experiment | Mean core pressure (bar a) | IFT at $P_{mean}$ (mN/m) | Superficial velocities (m/day) |
|---|---|---|---|
| **hr_190** | 175 - 181 | 0.2 – 0.25 | 16 - 300 |
| **hr_170** | 151 - 161 | 0.4 – 0.6 | 18 - 500 |
| **hr_150** | 114 - 131 | 1.2 – 1.9 | 23 - 850 |

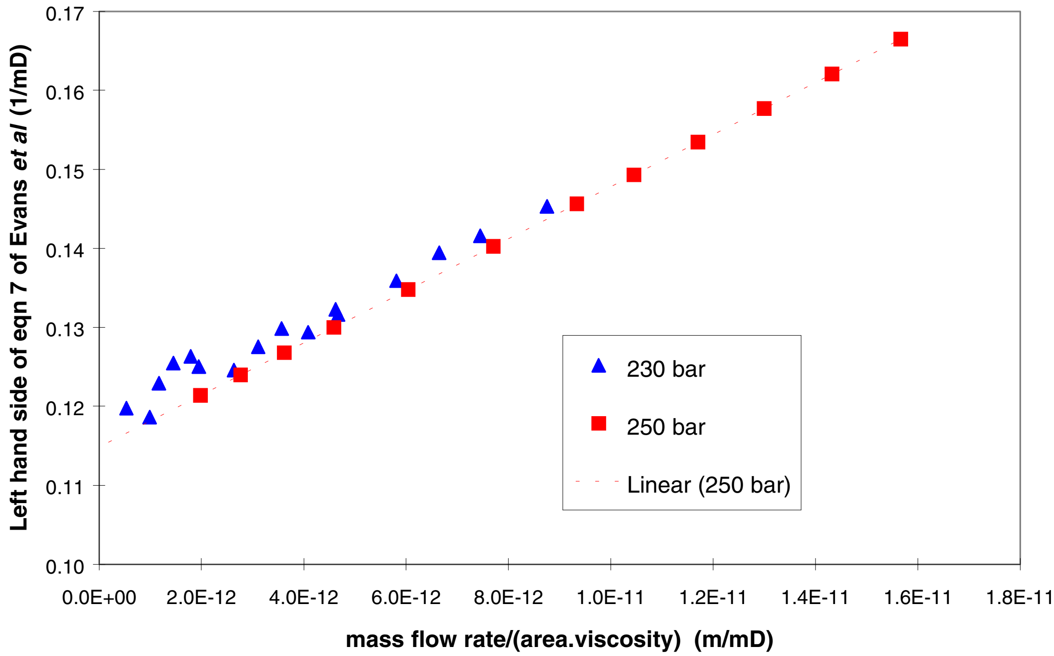


**Figure 1. Evans *et al* analysis of single-phase experiments to determine permeability and inertial flow coefficient.**

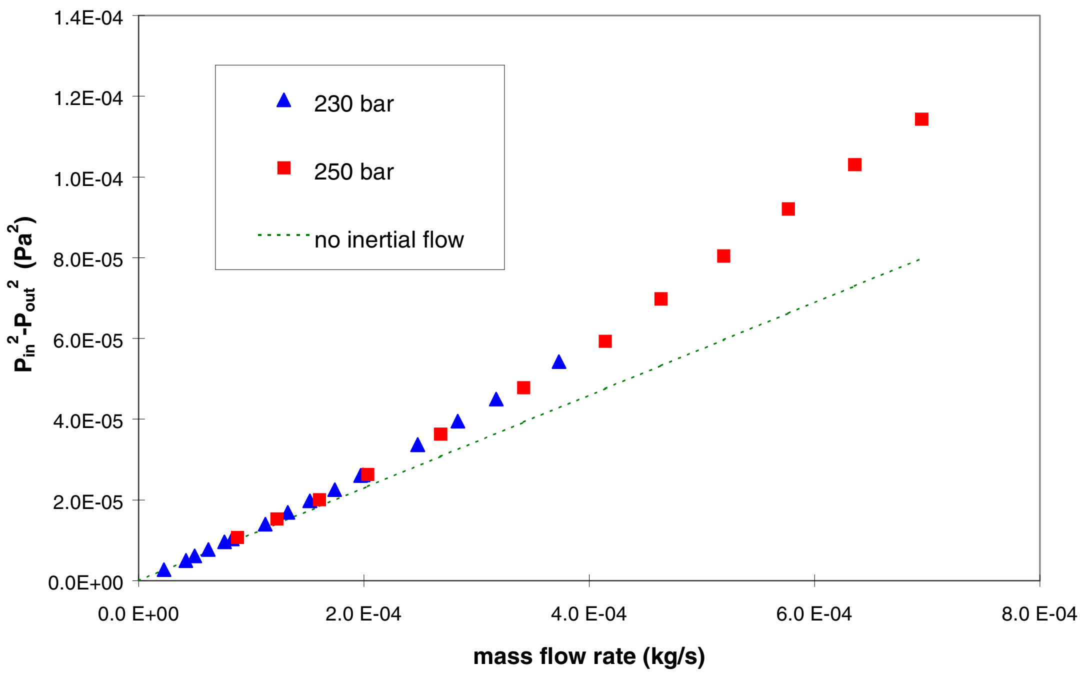


**Figure 2. Plot of $\Delta P^2$ versus flow rate in single phase experiments.**

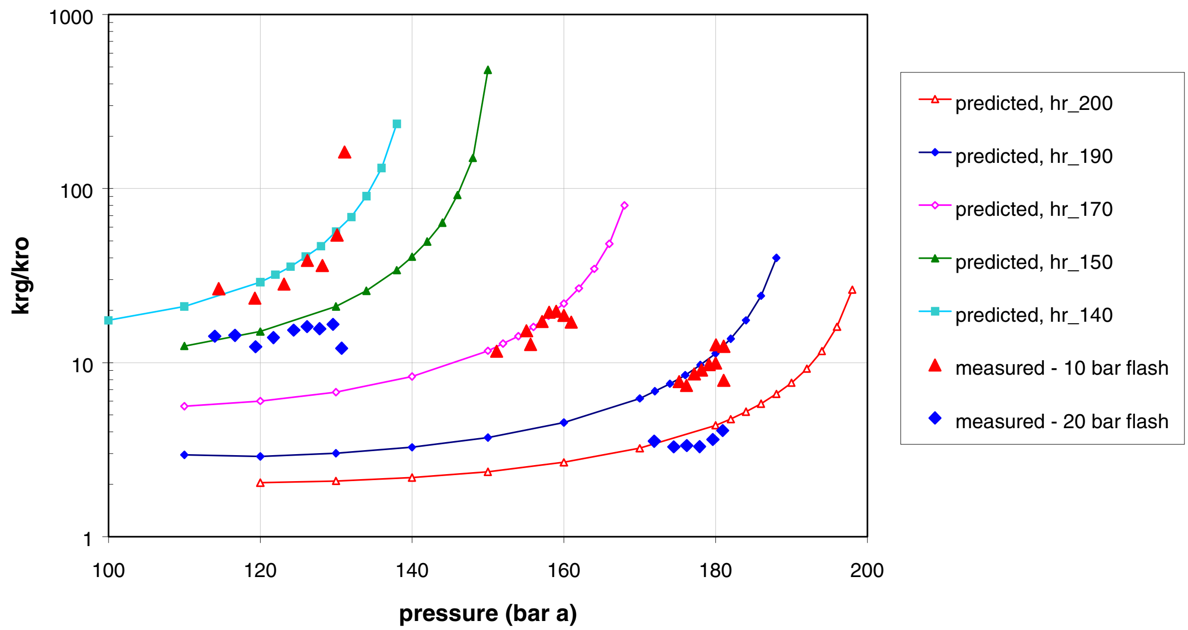


**Figure 3. Predicted and measured $k_{rg}/k_{ro}$ values.**

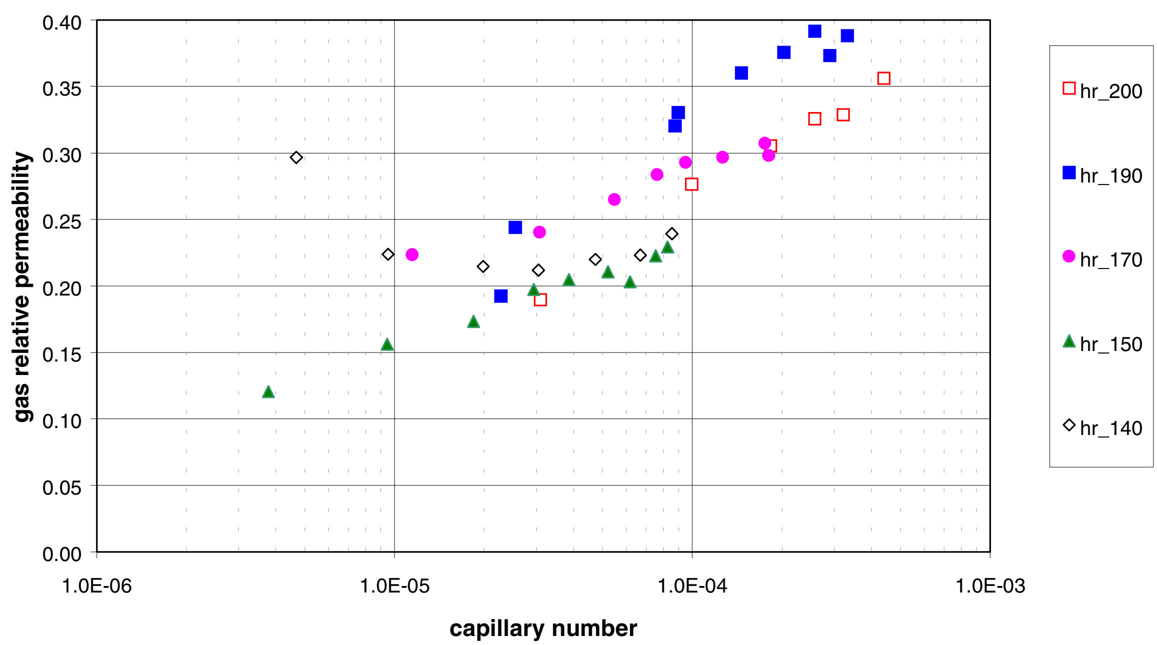


**Figure 4. Gas relative permeability versus capillary number ($k_{rg}$ defined from Equation 3).**

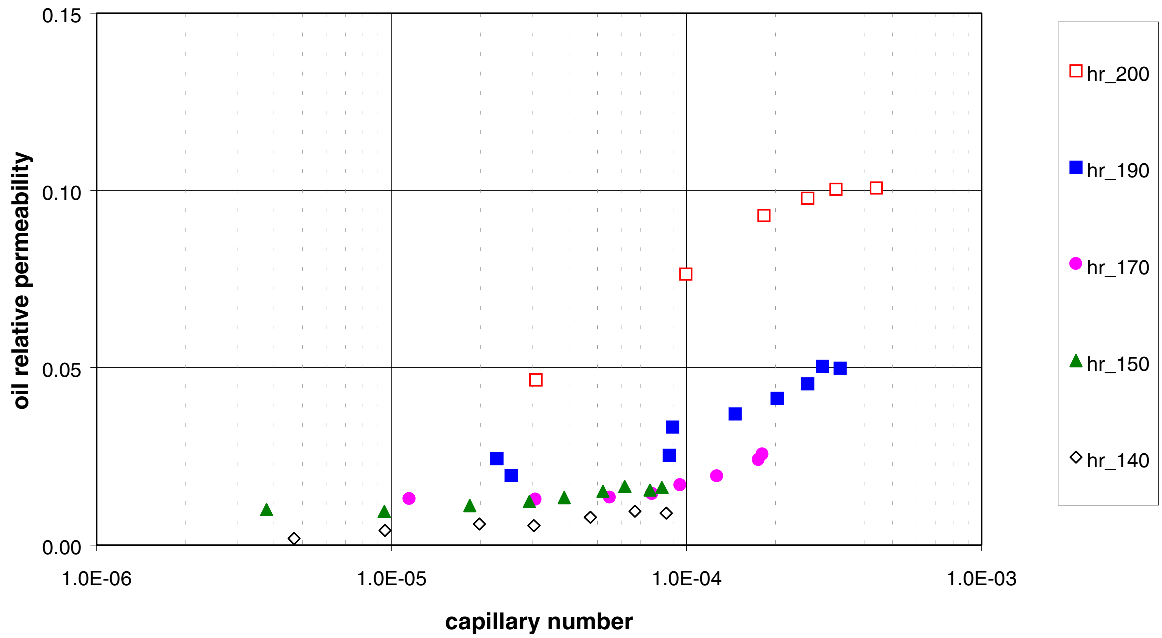


**Figure 5. Oil relative permeability versus capillary number.**

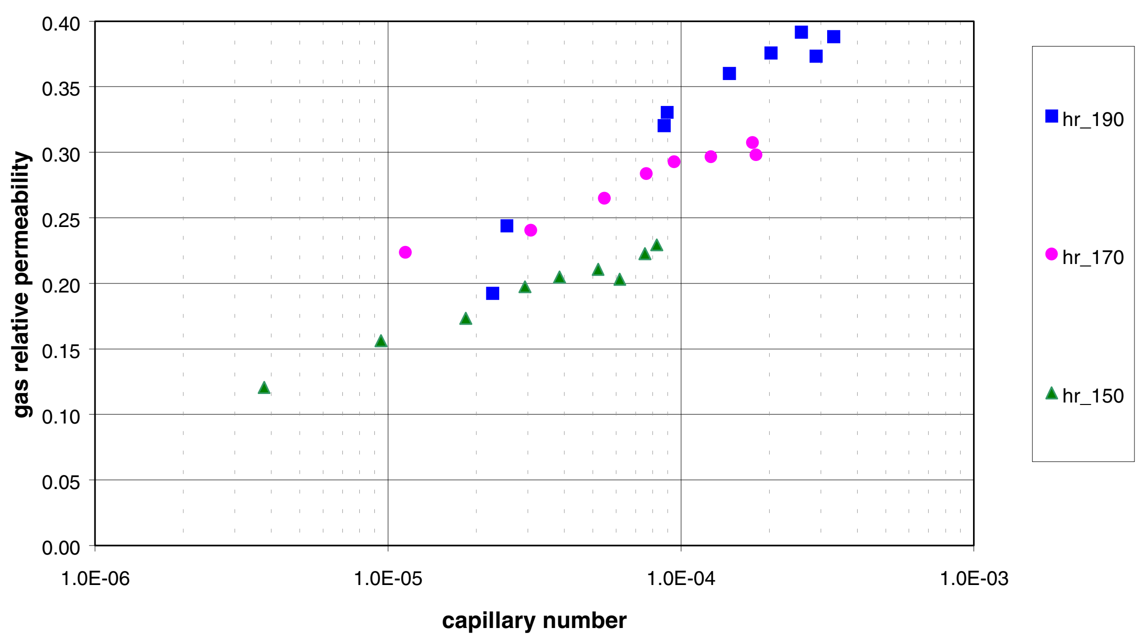


**Figure 6. Gas relative permeability versus capillary number for experiments where $k_{rg}/k_{ro}$ ~10. ($k_{rg}$ defined from Equation 3).**

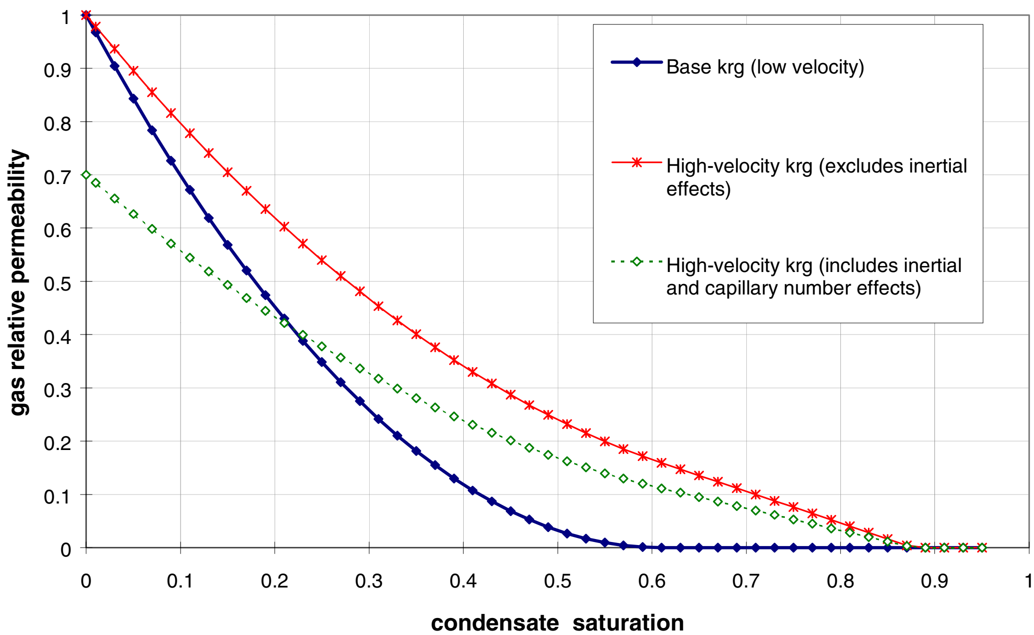


**Figure 7. Different definitions of gas relative permeability for high-velocity flow.**

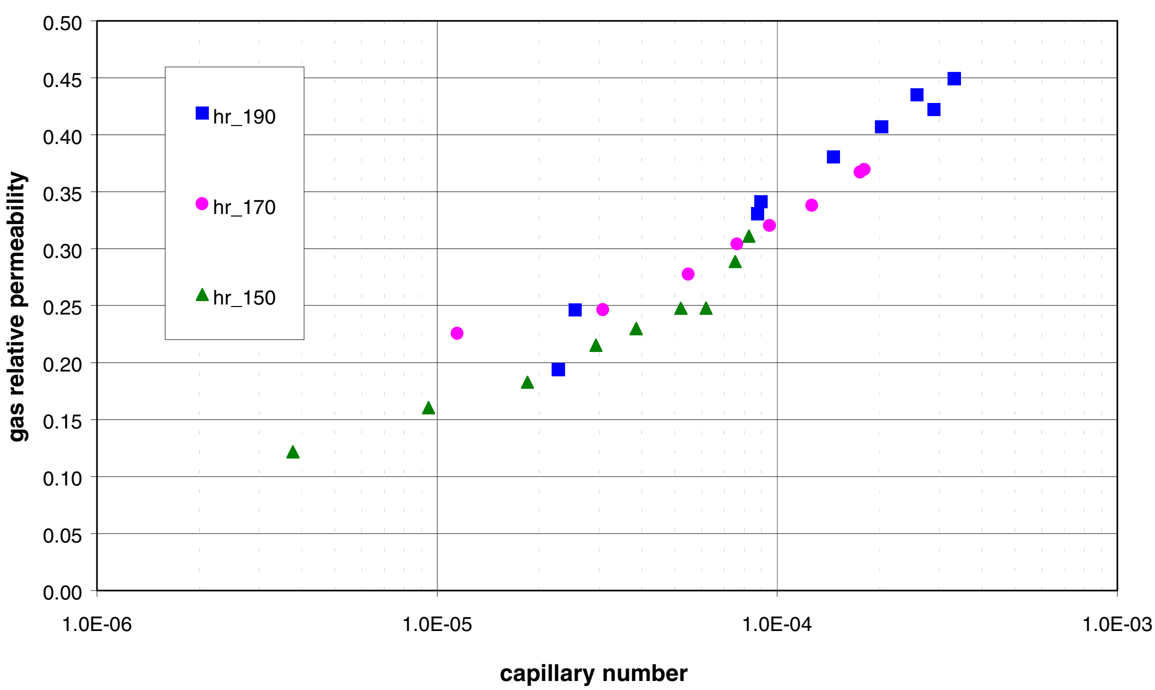


**Figure 8. Gas relative permeability versus capillary number where $k_{rg}/k_{ro}$ ~10. ($k_{rg}$ defined from Equation 5, $\beta = 3.1 \times 10^{9}\ m^{-1}$).**

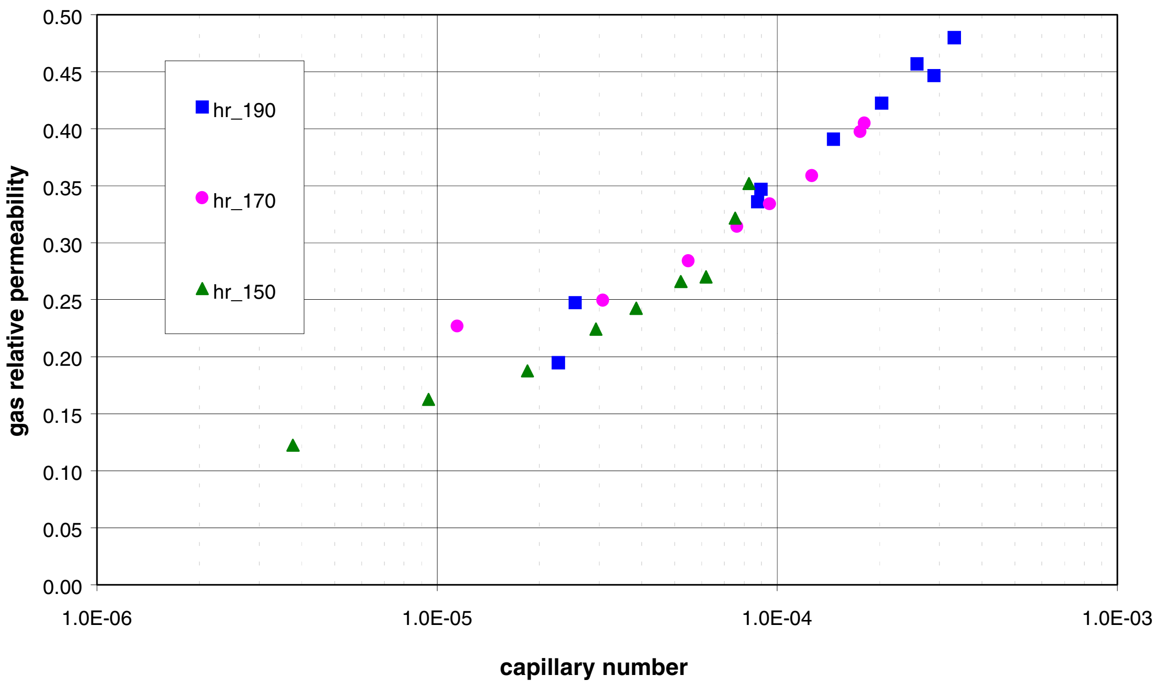


**Figure 9. Gas relative permeability versus capillary number where $k_{rg}/k_{ro}$ ~10. ($k_{rg}$ defined from Equation 5, $\beta = 4.6 \times 10^9\ m^{-1}$).**

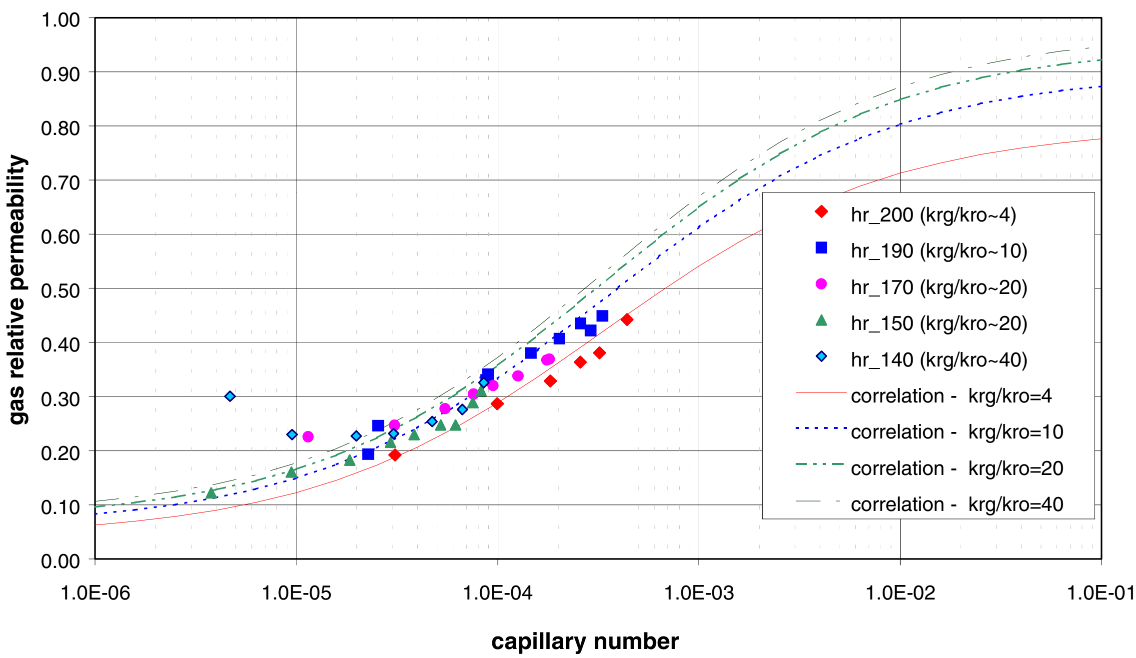


**Figure 10. Gas relative permeability versus capillary number – experimental data and results of correlation for $k_{rg}$ versus $k_{rg}/k_{ro}$.**

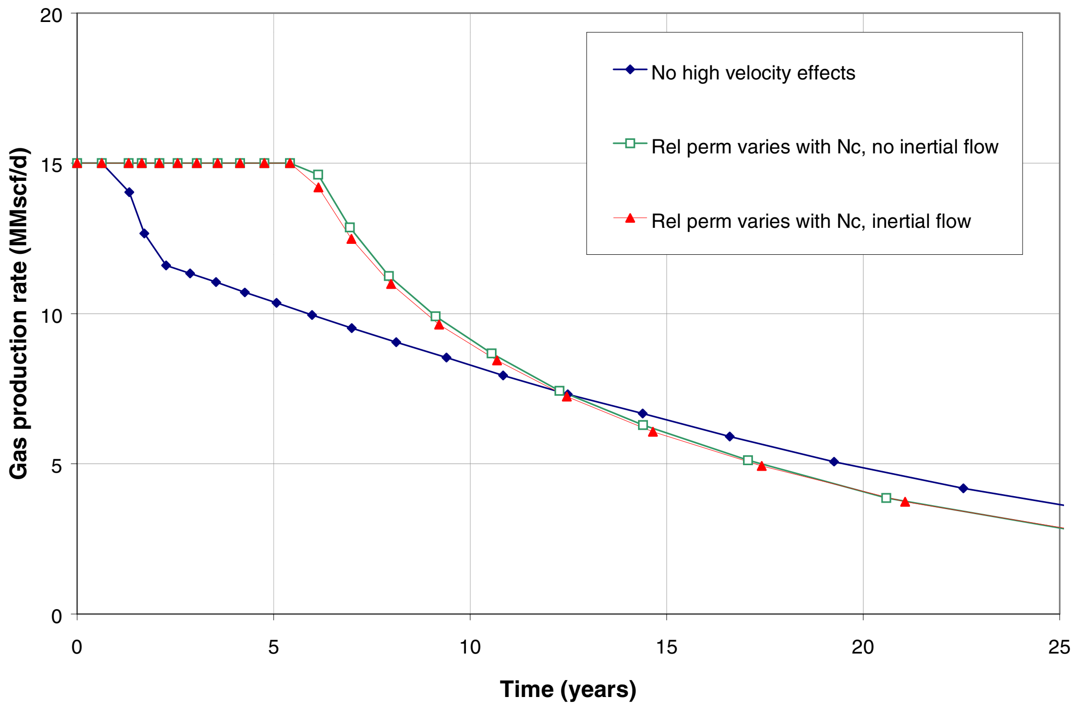


**Figure 11. Calculated gas production profiles using different models of high velocity flow.**