Literature Review On Gas-Condensate Relative Permeability

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Abstract: Condensation takes place in gas-condensate reservoirs right after the moment, pressure falls below the dew point. This phenomenon is more severe in the vicinity of producing wells due to rapid pressure fall, as a result condensate saturation in this region is ahead of the critical saturation and condensate phase could move toward producing well, consequently reduces gas relative permeability. Gas relative permeability in the near well region is the most important parameter for determining condensate well productivity, therefore an understanding of the characteristics of high-velocity gas-condensate flow is necessary for accurate forecasts of well productivity. In this paper some experimental results and empirical correlations made on gas-condensate relative permeabilities in the literature have been reviewed.

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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 optimize the number of wells and to set gas sales contracts.

In gas-condensate reservoirs, condensate phase begins to form right after the pressure falls below the dew point, the more the pressure-drop the higher condensate saturation. As condensate saturation exceeds the critical saturation, this phase begins moving and accordingly making the flow of the gas phase more difficult. Afidick et al.[1], Barnum et al.[2], Engineer[3] and Ayyalasomayajula et al.[4] have reported field data that show significant productivity loss due to condensate accumulation.

Most of the pressure drop occurs within a few feet of the wellbore, where the gas phase will be flowing at a high velocity, therefore a condensate bank forms near the well, impairing the flow of gas and reducing productivity, consequently an understanding of the characteristics of high-velocity gas-condensate flow is necessary. The most important parameter for determining the impact of condensate blockage is the effective gas permeability in the near-well region.

Far from a well in a gas condensate reservoir gravitational and capillary forces are dominant, but as the vicinity of the wellbore is approached the main governing forces will become viscous and capillary forces within the vicinity of wells, where these forces govern, an increase in gas relative permeability has been reported by some authors. This runs contrary to conventional non-Darcy flow theory, where the permeability reduces with increasing velocity as the flow becomes turbulent.

As a result of this major difference, generating relative permeability data in the laboratory to be applied to the flow in gas condensate reservoirs requires experimental procedures which are representative of the condensing processes, therefore they should be implemented precisely to satisfy the conditions of near wellbore region like applying governing forces. It has been observed by Henderson et. al. and Haniff that conventional gas-oil displacement where the core is initially saturated with oil before gas injection, will show no relative permeability rate sensitivity. The flow of gas condensate fluids, however, is not same as flow of conventional fluids. Henderson et al. have reported that gas and condensate flow together in all pore spaces, with both phases flowing as if they were a single phase. The fluid distributions caused by the condensation process which make oil film form throughout the porous medium and result in flow of both phases in the same pore, is believed by them, to be responsible for the reported relative permeability rate effect. This effect is also named as positive coupling. The other well-known phenomenon which may cause the gas relative permeability to be rate-dependent is inertial flow. This effect, reducing gas relative permeability at high velocities is also termed as non-Darcy flow or Forchimer flow. These two high-velocity phenomena act in opposite directions. Rate-dependent k_r has the effect of improving well productivity, while inertial flow reduces the effective gas permeability and leads to lower productivity. Considering these two opposing phenomena, several gas-condensate relative permeability models, using appropriate parameters have been developed to fit all measured experimental data the best. The main difficulty in properly accounting for the non-Darcy effect in all the reported correlations is the requirement for an accurate estimate of two phase beta factor especially for the gas phase.

Literature review

IFT effect. The effect of IFT on relative permeability at low IFT values has been known for a considerable time. For example Asar & Handy[5] (February, 1988) conducted some experiments to understand better the effect of IFT on gas/oil relative permeabilities and measured steady-state relative permeabilities as functions of IFT. Their main conclusions were that as the IFT was reduced down to zero, the curvature of the relative permeability curves diminished, and residual saturations approached zero. Bardon & Longeron[6] (1980) showed that residual oil saturation and relative permeabilities determined from the displacement tests were affected strongly by IFT especially when it was lower than a specific value. Haniff & Ali[7] (October, 1990) made an experimental study on fluid flow and residual saturations in a methane-propane gas condensate fluid system. Significant reduction in residual saturation and much improved flow rates were observed below a critical IFT value. Above the critical IFT value high liquid residual saturations were reported.

Velocity effect. The improvement to the relative permeability of condensing systems due to an increase in velocity is also a relatively well established experimental finding. For instance Henderson et al.[8](June 1994) developed a steady state experimental procedure to figure out the rate-dependent effect at velocities where the effect of inertia was insignificant and reported for the first time that the relative permeability of the gas phase, and to a lesser extent the condensate phase, increased with increasing velocity using condensing fluids. The plot of sets of data related to higher IFT showed lower rate dependency. Jamiolahmady et al.[9](October 2000) proclaimed that they were the first to study the positive coupling effect mechanistically capturing the competition of viscous and capillary forces at the pore level. Over the period from 1994 to 2000, Henderson et al. have published a series of papers confirming the initial results obtained in 1994 by themselves. Furthermore, Chen et al.[10](1995) have performed similar experiments using a recombined gas-condensate system from a North Sea Field and captured similar results.

Incorporation of IFT & velocity. After perception of IFT and velocity effects on gas-condensate relative permeability, attempt has been made to incorporate these two phenomena. For example Henderson et al.[11](1996) tried to correlate relative permeability rigorously to capillary number. Boom et al.[12](October 1995) developed experiments aiming at demonstrating the existence of the mobility improvement, assessing its magnitude and identifying the dominant controlling parameter. In their experiments the key parameter proved to be the Bond number, and not the interfacial tension alone. In 1997 Blom et al.'s[13] experimental results show a strong dependence of relative permeability on interfacial tension and superficial velocity, likewise that the relative permeability to the non-wetting phase is affected at lower values of the capillary number. Also other attempts by other investigators have been made (e.g., Fevang et al.[14], Mott et al.[15], Pope et al.[16], Jamiolahmady et al.[17] and etc).

Empirical correlations. There are now several correlations in the literature and in commercial reservoir simulators (e.g., ECLIPSE, VIP, CMG) to express the capillary number dependence of the two-phase flow of gas and condensate at these low IFT systems. Here some are introduced briefly:

Henderson et al.[18](2000), set their objective to investigate the competition between the two effects of negative inertia and positive coupling at velocities causing significant inertia. Their results have shown that inertia was dominant at low condensate saturation in all cores, but as the condensate saturation increased an improvement in relative permeability due to positive coupling was observed over the entire range of velocities at all values of IFT tested specially for the gas phase. Combined effects of Inertia and positive coupling for a Clashach sandstone core at an IFT of 0.78 mNm^{-1} for the gas phase can be seen in Figure 1. Likewise their tests showed that as if the IFT value decreased the effect of inertia at lower condensate saturations was reduced considerably, and positive coupling was more pronounced. They proposed correlation for each phase, basically interpolates between the base relative permeability k_{rb} at a low capillary number, N_{cb}, and the miscible relative permeability, k_{rm}:

$$k_r = Y \cdot k_{rb} + (1-Y) \cdot k_{rm} \qquad (1)$$

They presented in a general form as:

$$k_{r(meas.)} = k_{r(N_c)} (1 + \frac{\rho k v_D \beta}{\mu})^{-1} \qquad (2)$$

$kr_{(meas.)}$, is the measured relative permeability containing the effect of inertia implicitly in its value and $kr_{(Nc)}$, is the calculated relative permeability by their model, including only the coupling effect. They found two phase β-factor dependent on velocity, and also increasing with an increase in IFT value and gas phase saturation, but for different core types contrary trends of two phase β-factor versus velocities were observed, so developed Heriot Watt correlation including single phase β-factor in it. In the absence of experimental data on β, they suggested the Geertsma correlation [19]. A preliminary version of the correlations has been incorporated in a major commercial compositional simulator.

In 1999, Fevang & Whitson[14] stated that once the k_{rg}=f (k_{rg}/k_{ro}) relationship is experimentally established and correlated with capillary number (N_c), accurate modeling of condensate blockage is possible, therefore they developed special steady-state experimental procedures without paying attention to saturation. But particular attention was paid to the effect of hysteresis on the relation k_{rg}=f (k_{rg}/k_{ro}), as many repeated cycles of partial/complete imbibition and drainage occur in the near-well region making the saturation history complex. In their generalized model they have linked immiscible curves with miscible curves by a transition function dependent on the capillary number which is a smooth and continuous relation without a threshold N_c value. Inertial high velocity flow was also treated. They have shown that the k_{rg}/k_{ro} ratio is given explicitly by PVT behavior:

$$k_{rg}/k_{ro} = \left(V_{ro}^{-1} - 1\right)\left(\mu_g/\mu_o\right) \quad (3)$$

They designed a closed-loop system to measure steady-state relative permeabilities using one of Corey[20], Chierici[21] and Arco[22] correlations to fit data in the form k_{rg}=f (k_{rg}/k_{ro}). The immiscible relative permeability models contain a number of (2-10) adjustable parameters, while the transition function f_I has only two adjustable parameters.

$$k_{rg} = f_I \cdot k_{rgI} + (1 - f_I) \cdot k_{rgM} \quad (4)$$

The limit to their approach is that it only can be used for the steady-state region where both gas and oil are flowing. The advantage is that only one set of parameters are required for correlating f_I data, not four potentially separate sets for k_{rg}, k_{ro}, S_{gc}, and S_{oc}. They proposed f_I be given by:

$$f_I = \frac{1}{(\alpha \cdot N_c)^n + 1} \quad (5)$$

To quantify the effect of inertial high velocity flow they defined k_{rgHVF} as an effective gas relative permeability.

$$\frac{k_{rgHVF}}{k_{rg}} = \left[1 + \frac{k \cdot k_{rg}}{\mu_g} \cdot \beta_{eff} \cdot \rho_g \cdot v_g\right]^{-1} \quad (6)$$

In 2000, Mott et al.[15] presented results of k_r measurements on a low permeability sandstone core, using a pseudo-steady-state technique at high pressure and high velocity. Their technique determined k_{rg} as a function of k_{rg}/k_{ro} and capillary number, together with an inertial flow correction to the gas permeability without the need to measure saturations directly. They concluded to two results: first at a fixed IFT, gas relative permeability increased with velocity and second At a fixed capillary number, gas relative permeability decreased with velocity. The second point is very important as most models have been based on the assumption that k_r can be correlated as a function of capillary number and saturation whereas these results do not fit into such a model. They stated that it may be subject to inertial flow effects and expected k_{rg} to be a function of both capillary number and velocity. Inertial flow effects were modeled through a multiplication factor F_{ND}, given by:

$$F_{ND} = \frac{1}{1 + \frac{\beta k \rho v}{\mu}} \quad (7)$$

The effective gas permeability was then calculated from:

$$k_{g,eff} = k \cdot F_{ND} \cdot \left\{k_{rg}\left(S_g, N_c\right) \text{ or } k_{rg}\left(k_{rg}/k_{ro}, N_c\right)\right\} \quad (8)$$

One of the problems of their model may be that they didn't use an exact correlation for two phase beta factor and just took it approximately a value greater than single phase beta factor. For correlating k_{rg} they used a correlation same as Fevang and Whitson's[14]. 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.

In 2000, Pope et al.[16] presented a simple two-parameter capillary trapping model. This model that has been used in a compositional simulator is a generalization of the approach first presented by Delshad et al.[23]. Pope et al.'s[16] model requires only the baseline relative permeability curve of each phase at low trapping number (high IFT) and the residual saturations as a function of the trapping number as input. First the residual saturation was modeled based on the trapping number and using two matching parameters that were obtained by fitting residual saturation data. The next step they correlated the endpoint relative permeability of each phase. Finally they calculated the relative permeability of each phase as a function of saturation. They compared their model curves with several published data sets and found reasonable agreement. Their modeling efforts showed that the measurement of endpoint relative permeabilities at different trapping numbers is more important than the measurement of relative permeabilities at various saturations at different trapping numbers. Furthermore in 2006, Bang et al.[24] correlated gas-condensate relative permeabilities as a function of the k_{rg}/k_{ro} ratio and the capillary number somewhat like the correlation of Pope et al.[16](2000). They presented gas-condensate relative permeability data over a wide range of capillary numbers measured on both sandstone and limestone rocks. They have reported the first set of limestone data for such high capillary numbers. A dynamic flashing method also called pseudo-steady state method was used to measure the steady-state gas-condensate relative permeabilities. They used Chopra et al.[25] steady-state theory in which k_{rg}/k_{ro} ratio can only be calculated by using PVT data in order to confirm and extend correlations constructed by Whitson et al.[14], Mott et al.[15], Ayyalasomayajula et al.[4], Cable et al.[26] and Kumar et al.[27] to a wider range of conditions and higher capillary numbers. Inertia flow was prevented by lowering the IFT. They obtained higher gas and condensate relative permeabilities for limestone cores than the sandstones at low capillary numbers but obtained the same at high capillary numbers.

In August 2003, Jamiolahmady et al.[17] developed a network model predicting some k_r values. They followed two objectives, first developing a correlation including both rate-dependent effects based on a sound physical ground and second providing reliable information on variation of k_r without the need of complex and expensive experiments. They expressed k_r values of both phases on cores of different characteristics in terms of fractional flow instead of saturation. A generalized k_r correlation for gas-condensate systems, which is based on relative permeability ratio, has been developed. The k_{rg} correlation interpolates between k_{rgb} and k_{rgm} curves, both modified for the effect of inertia, using a generalized interpolating parameter Y_g, which expresses the dependency of the relative permeability to velocity and interfacial tension including micro-pore effect. The parameters of their correlation are either constant for all cores or can be obtained from commonly available petrophysical rock properties which eliminates the need for difficult and expensive relative permeability measurements at near well conditions.

App & Burger[28](April 2009) experimentally measured gas-condensate relative permeabilities and assessed the magnitude of inertial effects. The non-Darcy coefficient was determined on the basis of a pressure analysis of the Forchheimer equation. They used the correlation proposed by Whitson et al.[14](1999) to fit both the gas and condensate relative permeability data. The match of data was excellent at low and moderate capillary number range but the model slightly over predicted the gas relative permeability at high capillary numbers.

Results and Discussions

In some gas-condensate relative permeability models, both rate-dependent effects have been correlated separately. Positive coupling has been correlated with N_c and saturation (e.g., Henderson et al.[18], Mott et al.[15], etc) or with N_c and k_{rg}/k_{rc} (eg, Fevang & Whitson[14], Mott et al.[15], Bang et al.[24], etc). However, Henderson et al.[18](2000) have eliminated some data corresponding to high velocities at very low CGR, because approaching such velocities requires higher differential pressure along the core, which caused a major difference between the inlet and outlet condensate saturation that is not justifiable. This is termed as phase behavior problem which is noticeable as long as the condensate saturation is measured. If, however, the data was plotted in the form of k_{rg} versus k_{rg}/k_{rc}, the effects of the variations in phase behavior would be masked as the condensate saturation would not be measured, making the data invalid. On the other hand, Fevang & Whitson[13] used the k_{rg}/k_{rc} ratio instead of saturation duo to complex saturation history near the wellbore made by several partial/complete drainage/imbibition processes. On contrary to such type of models, Jamiolahmady et al.[17](2003), developed a model combining both rate-dependent effects together as a function of fractional flow. Jamiolahmady et al.[17] used the comprehensive k_r data on cores with permeability ranging from 9 mD to 550 mD, and different lithology to develop the correlations presented in 2003. They proclaimed When the correlations were tested for a 3 mD sandstone, 7 mD carbonate and 146 D propped fracture core (Jamiolahmady et al.[28] 2008), none of which had been used in developing the correlation, with the corresponding basic test data the results were very satisfactory showing a relatively low and uniformly distributed deviations. These results confirm the generality of the correlation and reliability of the information obtained from it to great extent as these measurements covered a reasonably wide range of IFT and velocity variations for porous media with very different characteristics. Their correlation has been used in some version of Eclipse software.

The main difficulty in accounting for the inertial effect in all the reported correlations is the requirement for estimating βg. A number of correlations[29] for calculating the beta factor for two-phase systems have been proposed which relate β_g mainly to S_g and/or k_{rg}. However, the application of these correlations to gas-condensate systems is open to question as they have been developed mainly for gas-water systems, with the immobile water phase. Fevang & Whitson[14] used a correlation in the literature related to single phase β-factor and gas relative permeability. Henderson et al.[18](2000)

attributed the differential pressure between high and low velocities to inertial flow, then by using Forchheimer[30] method and their k_r model they estimated two phase β-factor. Measured data of two phase β-factor were in good agreement with the correlation developed by them. Confusion duo to inclusion of velocity made Henderson et al. to develop a correlation related to single phase β-factor, gas saturation and IFT. However in 2000 Henderson et al[18]. have proclaimed that none of correlations which have given no consideration to positive coupling effect are reliable.

Conclusion

1. This paper has summarized results of experiments made to investigate the effect of IFT and velocity changes on gas-condensate relative permeabilities.

2. Some applicable and empirical gas-condensate relative permeability correlations have been viewed briefly and in some cases compared with each other.

3. One of the most challenging parameter in determining the inertia effect has been accounted to be the two phase beta factor. Most introduced two phase beta factor correlations are considered to be open to question.

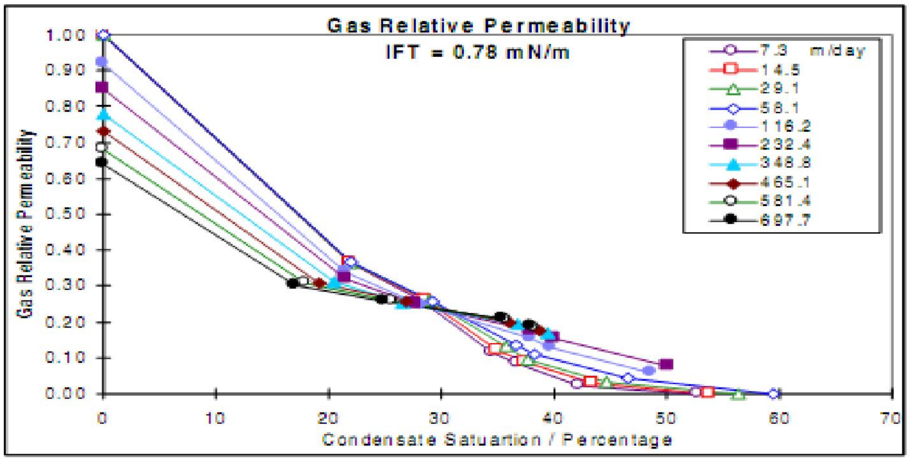

Figure 1-Clashach core gas relative permeability

Nomenclature

CGR = condensate to gas ratio (volume/volume at test conditions)

k = permeability

k_r = relative permeability

$kr_{(meas.)}$ = measured relative permeability

$kr_{(Nc)}$ = calculated relative permeability

Nc = capillary number

Y= scaling function for relative permeability

β = Beta factor

S = saturation

υ = fluid velocity

μ =viscosity

ρ = density

IFT = interfacial tension

f_I = immiscibility factor

V_{ro} = oil volume/total (gas + oil) volume at core pressure

α = scaling parameter for N_c

n = exponent in equation for immiscibility factor

F_{ND} = inertial (non-Darcy) flow factor

Subscripts

b = base

g = gas

o = oil

c = condensate

D= Darcy

mD= mil Darcy

m, M = miscible

I = immiscible

eff = effective

HVF = high velocity flow

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